Volume 1: Application

Joint East-West Tie Designation Application

EB-2011-0140



ISOLUX infrastructure

TransCanada
In business to deliver

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Terms List

Term	Full Name
AEP	Aboriginal Engagement Plan
ANEEL	Electric Energy National Agency (Brazil)
Applicants, the	Iccon and TPT
CAD	Canadian Dollars
CEAA	Canadian Environmental Assessment Agency
CFE	Federal Electric Commission (Brazil)
CREZ	Competitive Renewable Energy Zone
CS&E	Community, Safety and Environment
DRBS	Dominion Bond Rating Service
EPC	Engineering, Procurement and Construction
E-W Tie	East-West Tie Line
GIS	Geographic Information Systems
Golder	Golder Associates Ltd.
GP	General Partner Corporation
HONI	Hydro One Networks Inc.
Iccon	Iccon Transmission, Inc.
IESO	Independent Electricity System Operator
Isolux Corsán	Grupo Isolux Corsán S.A.
Isolux Infrastructure	Isolux Infrastructure, S.A. together with its various subsidiaries including Iccon
Isolux Ingeniería	Isolux Ingeniería, S.A., an EPC company owned by Isolux Corsán, or one of its subsidiaries
I-USA	Isolux Ingeniería USA, LLC
KP	KP Environmental
MOE	Ministry of Environment
MOU	Memorandum of Understanding
MVA	Megavolt Amperes
MVAR	Mega Volt Ampere Reactive
NEB	National Energy Board
NERC	North American Electric Reliability Corporation
NGOs	Non-governmental Organizations
NPCC	Northeast Power Coordinating Council
OEB or the Board	Ontario Energy Board
OPA	Ontario Power Authority
OPGW	Optical Power Ground Wire
PLS-CADD	Power Line Systems - Computer Aided Design and Drafting
PSP	Public Service Pension Fund of Canada
PSP Investments	Public Sector Pension Investment Board
PUCT	Public Utility Commission Texas
ROW	Right of Way
SAP	Systems, Applications and Products
TPT	TransCanada Power Transmission (Ontario) L.P.
TransCanada	TransCanada Corporation
TSP	Transmission Service Provider
WETT	Wind Energy Transmission Texas

1 BACKGROUND INFORMATION

This is the joint application of Iccon Transmission, Inc. ("**Iccon**")[1] and TransCanada Power Transmission (Ontario) L.P. ("**TPT**", together with Iccon, the "**Applicants**") for designation by the Ontario Energy Board ("**OEB**" or the "**Board**") to undertake development work on the East-West Tie Line ("**E-W Tie**" or "**the project**").

Iccon is a wholly owned indirect subsidiary of Isolux Infrastructure Netherlands B.V. (which, together with its various subsidiaries including Iccon, will be referred to as "**Isolux Infrastructure**" throughout this application). Isolux Infrastructure is jointly owned by the Public Sector Pension Investment Board ("**PSP Investments**") and Grupo Isolux Corsán, S.A. (the term "**Isolux Corsán**" will be used in this application to refer to the entire Isolux corporate group). Isolux Infrastructure is engaged in the development, construction, ownership operation and management of concessions for transmission lines, toll highways and generation facilities. Isolux Corsán's key strengths are in the areas of project management, engineering, procurement, construction management and regulatory process management and approvals.

TPT is a wholly owned indirect subsidiary of TransCanada Corporation (the term "**TransCanada**" will be used in this application to refer to the entire TransCanada corporate group), a North American based energy infrastructure company with significant investments in natural gas pipelines, oil pipelines and power generation assets. For the purposes of the E-W Tie, TransCanada's key strengths are in the areas of project management, regulatory process management, regulatory approvals, First Nations and Métis engagement, stakeholder consultation, land acquisition, and health, safety and environmental stewardship.

The Applicants' joint proposal brings together a public energy infrastructure company with robust financial capabilities and extensive North American linear

[1] A list of all acronyms and defined terms appears immediately behind the Table of Contents.

project management experience with a global infrastructure company that has a virtually unrivalled record of successfully developing and operating electricity transmission projects. It is these complementary strengths which distinguish the Applicants and makes them the preferred choice to undertake development of the E-W Tie.

The Applicants will combine their respective strengths in developing and building the E-W Tie. They intend to utilize TransCanada's substantial North American development experience and expertise in engaging First Nations, Métis and other communities and stakeholders. The Applicants also plan to draw on TransCanada's knowledge and experience in navigating environmental, land acquisition and other regulatory processes. TransCanada's services will be billed at cost on a transparent basis without any markup for profit.

The Applicants likewise intend to draw on Isolux Corsán's EPC experience and expertise in constructing large complex transmission projects. Isolux Corsán's EPC affiliate Isolux Ingeniería has global procurement expertise and relationships which it will leverage to competitively purchase materials and equipment at the lowest cost. It will also efficiently manage and, as appropriate, competitively subcontract the major works required to build the E-W Tie. The Applicants intend to enter into a fixed fee EPC contract with Isolux Ingeniería at market-based rates prior to filing a leave to construct application. A fixed fee EPC contract will incentivize cost efficiency and limit ratepayer exposure to construction delays and cost overruns.

1.1 The Applicants

The applicant's name.

Iccon's legal name is Iccon Transmission, Inc.

TPT's legal name is TransCanada Power Transmission (Ontario) L.P.

1.2 Transmission Licence Numbers

The applicant's OEB transmission licence number.

Iccon's OEB transmission licence number is ET-2010-0403. In EB-2011-0384, the Board determined that the effective date of Iccon's licence is the earlier of the date on which Iccon is designated as a developer of transmission assets in Ontario pursuant to a Board designation process and the date upon which Iccon applies to amend Schedule 1 of its licence to specify the facilities to be owned and/or operated by Iccon. At the time of submission, Iccon's transmission licence has not come into effect.

TPT's OEB transmission licence number is ET-2010-0324. In accordance with EB-2011-0260, the Board determined that the effective date of TPT's licence is the earlier of the date on which TPT is designated as a developer of transmission assets in Ontario pursuant to a Board designation process and the date upon which TPT applies to amend Schedule 1 of its licence to specify the facilities to be owned and/or operated by TPT. At the time of submission, TPT's transmission licence has not come into effect.

1.3 Change in Information

Any change in information provided as part of the transmitter's licence application.

There has been a material change to Iccon's ownership structure since Iccon submitted its transmitter licence application. The new ownership structure is shown in Figure 1 below.

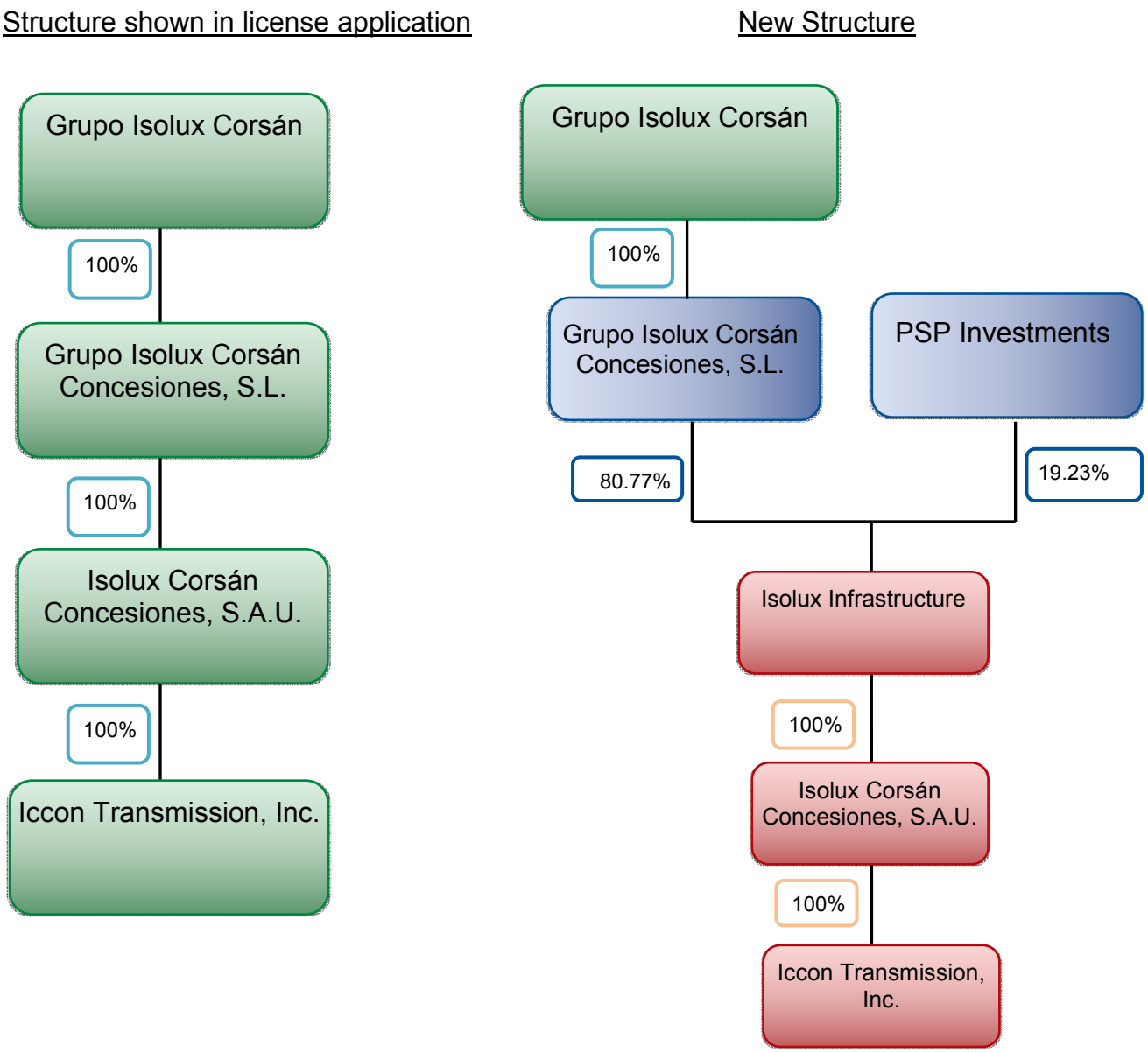
In October 2012, PSP Investments invested $500 million to become a 19.23% shareholder of Isolux Infrastructure, which owns Isolux Corsán Concesiones S.A.U. (the owner of Iccon Transmission). PSP Investments is a federal Crown Corporation established by the *Public Sector Pension Investment Board Act* to manage the

pension plans of the Canadian Federal Public Service, the Canadian Forces and the Royal Canadian Mounted Police.

Also, the new contact email address for Pablo de la Sierra Perez, Iccon's representative, is psierra@isoluxinfrastructure.com.

TPT confirms that there has been no material change to the information provided as part of its transmission licence application. TransCanada's former affiliate Zephyr Power Transmission LLC (which was referenced in TPT's transmission licence application) was sold in mid-2011.

Figure 1: Change to Iccon Ownership Structure



1.4 Licences and Permits in Good Standing

Confirmation that the applicant has not previously had a licence or permit revoked and is not currently under investigation by any regulatory body.

The Applicants confirm that they have not had any electricity licences or permits revoked and neither is under investigation by any regulatory body that could result in the revocation of a permit or licence.

1.5 Commitment to Develop

Confirmation that the applicant is committed to the completion of the development work for the East-West Tie line, and to the filing of a leave to construct application for the line, to the best of its ability.

The Applicants confirm that they are committed to completing development work for the E-W Tie, to the best of their ability, subject to an evaluation of any material expenditures or other obligations, conditions or restrictions that the Board decides to impose in the designation order.

The Applicants further confirm their commitment to the filing of a leave to construct application, to the best of their ability, subject to the customary approvals for such an undertaking, such as the authorization of their respective boards of directors and all other third party or governmental approvals and consents as may be reasonably necessary.

1.6 Statement of Completeness

A statement from a senior officer that the application for designation is complete and accurate to the best of his/her information and belief.

Attached as Appendix “A” to this section are statements from senior officers of each of the Applicants confirming the application for designation, as it relates to their

respective organizations, is complete and accurate to the best of their information and belief.

1.7 Willingness to be Named Runner-Up

An indication of whether the applicant is willing to be named as a runner up designated transmitter and a statement of any conditions necessary to this role.

The Applicants are willing to be named as runner-up designated transmitters subject to an evaluation of any material expenditures or other obligations, conditions or restrictions that the Board may decide to impose on the runner-up.

1.8 Co-operation/Co-ordination

A description of any co-ordination or co-operation with other parties that has contributed to this application.

Isolux Corsán and TransCanada have coordinated and cooperated on the preparation of this joint application for designation. The Applicants have not coordinated or cooperated with any other party to this proceeding in preparing this application.

Appendix A — Statements of Senior Officers

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

Senior Officer's Statement

I, Pablo de la Sierra Perez, am an officer and director of Iccon Transmission Inc. ("**Iccon**") which is preparing a joint application for designation in this proceeding with TransCanada Power Transmission (Ontario) L.P. ("**TPT**", collectively the "**Applicants**").

I state that, to the best of my information and belief, the application for designation in respect of the new electricity transmission line between Northeast and Northwest Ontario prepared by the Applicants is complete and accurate, as it relates to Iccon and Grupo Isolux Corsán, S.A.

DATED at Toronto this 4th day of January, 2013.



Name: Pablo de la Sierra Perez
Company: Iccon Transmission Inc.

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

Senior Officer's Statement

I, John Cashin, am the Assistant Secretary of TransCanada Power Transmission (Ontario) L.P. ("**TPT**") which is preparing a joint application for designation in this proceeding with Iccon Transmission, Inc. ("**Iccon**", collectively the "**Applicants**").

I state that, to the best of my information and belief, the application for designation in respect of the new electricity transmission line between Northeast and Northwest Ontario prepared by the Applicants is complete and accurate, as it relates to TPT and TransCanada Corporation.

DATED at Calgary this 3rd day of January, 2013.

Name: John Cashin
Company: TransCanada Power Transmission (Ontario) L.P.

2 ORGANIZATION

2.1 Organizational Plan

An overview of the organizational plan for undertaking the project, including:

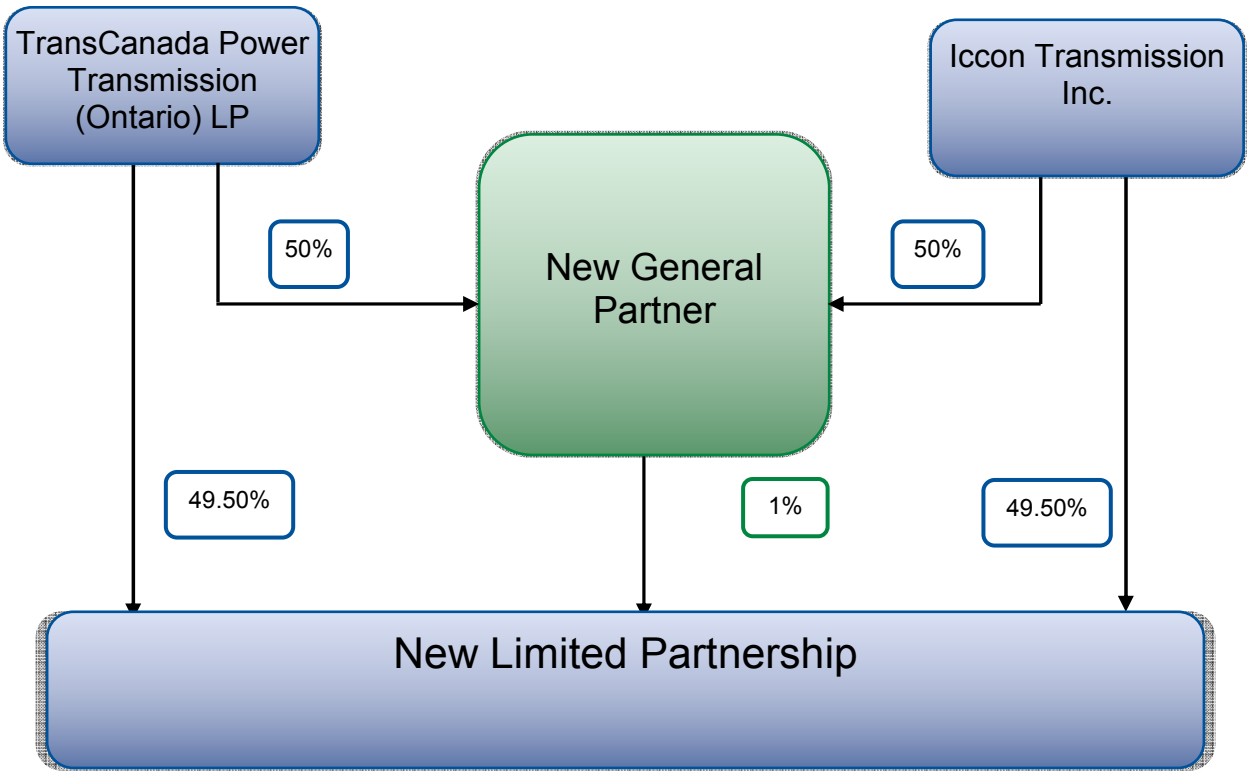
- *any partnerships or contracting for significant work;*
- *identification and description of the role of any third parties that are proposed to have a major role in the development, construction, operation or maintenance of the line; and*
- *a chart to illustrate the organizational structure described.*

If designated, the Applicants intend to form a new limited partnership that will be owned equally by TPT and Iccon. The new partnership will include a general partner corporation ("**GP**") to manage the day-to-day affairs of the venture. The GP will be equally owned by TPT and Iccon.[2] Figure 2 below shows the Applicants' proposed ownership structure.

Governance of the GP will be carried out through a management committee equally represented by the partners. A management team, which reports to the management committee, will be dedicated to the day-to-day management of the partnership's affairs and projects. Further details about the Applicants' proposed management team are provided in section 4.1.1.

[2] Hereinafter, references to the "Applicants" and the Applicants' plans for carrying out development of the East-West Tie are, as applicable, references to the GP on behalf of the Applicants.

Figure 2: The Applicants' Proposed Ownership Structure



The Applicants plan to contract preliminary engineering, detailed engineering, procurement and construction ("**EPC**") management to Isolux Ingeniería, S.A., an EPC company owned by Isolux Corsán, or one of its subsidiaries (jointly referred to as "**Isolux Ingeniería**" in this application). The EPC contract will be completed at arms-length and on financial terms that are at market-based rates.

The engagement of Isolux Ingeniería will minimize execution risks and drive efficiencies and cost savings for ratepayers by leveraging Isolux Ingeniería's engineering expertise, worldwide experience and expertise in transmission construction, and purchasing power from the project development phase through to commercial operation.

The retention of Isolux Ingeniería will provide the Applicants with access to skills, capabilities and expertise that are not readily available in the market and are critical to the construction of the project. This is important because project success will largely depend on the efficient and reliable construction of the E-W Tie.

The use of Isolux Ingeniería also better aligns the interests of the EPC contractor with the Applicants' objectives. There is better cooperation and greater incentive for cost reductions, expeditious project execution and risk mitigation all of which delivers value to the project and Ontario ratepayers.

The Applicants have retained Golder Associates Ltd. ("**Golder**") to assist with the routing and environmental approvals processes. Golder is a global company that provides a broad range of environmental and engineering services to transmission line companies including siting, permitting, environmental impact assessments, and First Nations and Métis engagement. Golder has a strong presence in Ontario and considerable experience assisting proponents in obtaining environmental approvals for energy projects, including the completion of environmental assessments.

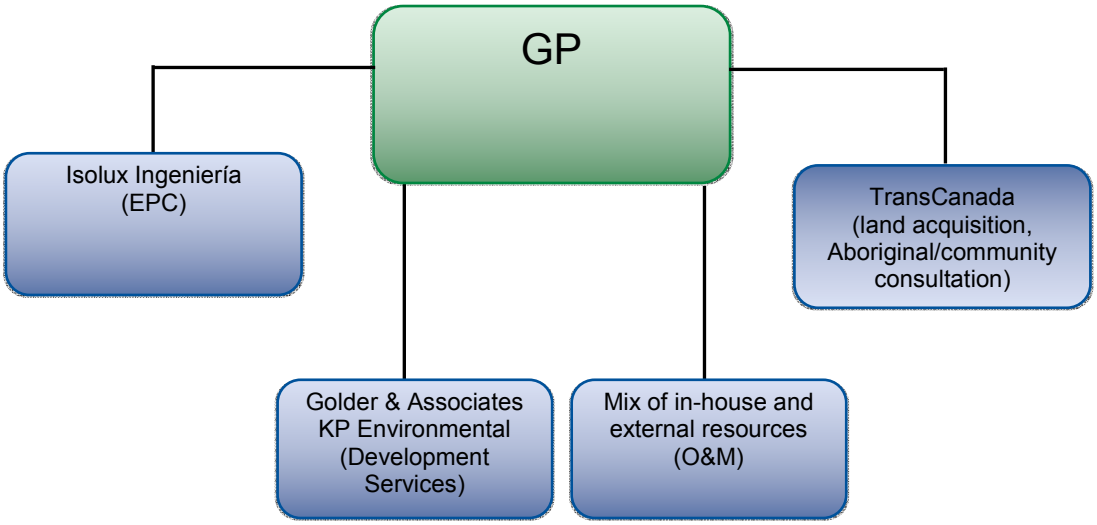
Golder will work with KP Environmental ("**KP**"), which provides specialized services related to the siting of large extra high-voltage transmission lines and energy projects, including environmental impact analysis and interactive geographic information systems ("**GIS**") mapping. The Applicants have retained KP because of KP's considerable experience in the siting of transmission lines across the United States and throughout the world.

Finally, the Applicants intend for the GP to enter into service agreements with TransCanada for the provision of land acquisition services, community relations services and First Nations and Métis engagement and consultation services. All service agreements with TransCanada and its affiliates (or Isolux Corsán and its affiliates, with the exception of the EPC contract) will be at cost on a transparent basis without any mark-up for profit.

The Applicants' organizational plan is shown in Figure 3.

All activities will be directly managed by the GP and its management team.

Figure 3: The Applicants' Organizational Plan



2.2 Specific Management Team Personnel

Identification of the specific management team for the project, with resumés for key management personnel.

Through Isolux Corsán and TransCanada, the Applicants have ready access to senior personnel with significant experience managing and overseeing the development and construction of large complex linear infrastructure projects. The Applicants plan to draw on these resources to form the management team for the venture. The Applicants' preliminary list of personnel to be considered for the management team is shown below in Table 1.

Table 1: Preliminary Management Team Candidates

Name	Organization	Title
Luis Rein	Isolux Infrastructure	Director of Power Concessions
Juan Soto	Isolux Infrastructure	Technical Director, Power Concessions
Pablo De La Sierra	Isolux Infrastructure	North America Director, Power Concessions
Juan Ramón Jiménez	Isolux Infrastructure	Operating Director, Power Concessions
John Soini	TransCanada	Vice President , Facilities and Pipeline Projects
Bill Small	TransCanada	Director, Facilities Projects
Terry Bennett	TransCanada	Vice President, Power Development
Tom Patterson	TransCanada	Director, Eastern Power Business Development

Resumes for the above management team candidates are included as Exhibit "A" in Volume 2.

2.3 Overview of the Applicants' Experience

An overview of the applicant's experience with:

- *the management of similar projects; and*
- *regulatory processes and approvals related to similar projects.*

The Applicants are world leaders in the development, construction and operation of major linear infrastructure projects in the energy sector. They have extensive experience managing major projects and navigating associated regulatory processes in Canada and globally.

The following provides a brief overview of Isolux Corsán and TransCanada and their experience and expertise in developing major infrastructure projects.

2.3.1 Isolux Corsán Overview

Isolux Corsán is a world leader in electricity transmission and distribution, energy generation, concessions and large-scale infrastructure development. It has specific expertise and experience in developing and constructing greenfield transmission projects.

Isolux Corsán was formed in 2004 through the merger of Corsán Corvian and Isolux Wat, both of which companies dated back more than 80 years. Isolux Corsán has its head office in Madrid and its operations span more than 30 countries and five continents. Isolux Corsán's international business has grown exponentially since its 2004 merger and today accounts for a significant majority of the company's revenues.

Isolux Corsán is the largest privately owned Spanish group in the engineering and infrastructure sector and has total assets of approximately $10.7 billion. In 2011, the company reported revenues of $4.5 billion. Isolux Corsán's revenues have increased every year since 2004 (with the exception of a small recession-induced decline between 2008 and 2009) and its revenues have approximately doubled since 2004. As of 2011, Isolux Corsán's business portfolio totaled a record $57.1 billion and the company's global workforce was approximately 9,000.

Isolux Corsán is also one of the largest companies in the global transmission and distribution market. It has extraordinary experience and expertise in developing, constructing and owning/operating greenfield transmission projects. As well, it has experience as an EPC contractor executing "turnkey" projects (i.e., providing integral management solutions, delivering high quality design and engineering services, equipment and materials sourcing, construction and erection, commissioning and maintenance) and turning them over to other transmission owners/operators, typically incumbent utilities. Isolux Corsán has developed and built transmission projects on its own and in partnership with local/regional companies.

In the last 12 years, Isolux Corsán has developed and brought into operation over 60 transmission projects totaling more than 12,000 km of high-voltage transmission lines and 145 substations; it is currently constructing another 16 transmission lines totaling 3,500 km and over 25 substations; and, it is managing and operating 1,246 km of transmission lines and related substations.

Isolux Corsán's transmission experience and expertise spans the globe. It has developed, constructed and operated transmission systems in more than 30 countries over five continents (Europe, South America, North America, Africa and Asia). In doing so, Isolux Corsán has confronted and overcome some of the most challenging physical terrain on earth such as tropical rainforests, extreme winter conditions, mountain ranges and deserts. In Brazil, where Isolux Corsán has developed and built over 5,500 km of transmission lines, Isolux Corsán has had to design and develop routes and string transmission lines through ecologically sensitive and physically challenging mountain ranges and rainforests. In addition to the enormous technical challenges these projects have posed, Isolux Corsán has developed significant experience and expertise in navigating stringent environmental standards and assessment processes, negotiating rights-of-way and consulting and negotiating with aboriginal groups.

Isolux Corsán has demonstrated the ability to navigate and adapt itself to a variety of regulatory and commercial structures. In Brazil and India, Isolux Corsán participated in and was awarded projects through competitive auction processes which selected proponents based on lowest-cost offers; in those jurisdictions, transmission rates are largely fixed through the competitive auction process. In Texas, a partnership between Isolux Corsán and a large asset management company was designated to construct over 600 km of new transmission lines pursuant to a regulatory proceeding managed by the Public Utility Commission of Texas ("**PUCT**"); in this case, Isolux Corsán's transmission rates will be fixed by the State regulator in transmission rate proceedings.

Finally, Isolux Corsán is committed to sustainable, safe and responsible development through enhanced Corporate Responsibility, Risk Management, Health and Safety and Environmental Sustainability Policies and Programs. Among other things, Isolux Corsán has:

- Established a Corporate Environmental Policy which ensures adherence to international standards; controls compliance with environmental objectives; requires the application of practices aimed at the prevention and reduction of pollution.

- Subjected Quality and Environmental Management Systems to annual assessments and audits by certified bodies and auditors.

- Implemented a Risk Management System which, among other things, ensures that the company complies with all standards and best practices and aligns the company's strategic objectives with identified risks/controls.

- Implemented a Health and Safety Policy Statement under which the company commits to safe conditions and the continued improvement of the Prevention Management System.

- Participated in projects that create local value. In developing countries, Isolux Corsán has combined project development with activities and programs that deliver social benefits — i.e., recruiting local manpower to fulfill employment requirements; guaranteeing local electricity supply; providing occupational training; providing health services and covering health costs; and, sponsoring and financing community/sports initiatives.

2.3.2 TransCanada Overview

TransCanada is a leader in the development of technically advanced and reliable energy infrastructure projects throughout North America. An extensive network of

wholly owned and affiliated pipelines and power generation facilities enables TransCanada to meet the ever growing demand for energy.

TransCanada, as shown by its significant growth in the past seven years, has the people, the experience and the systems to bring projects to successful completion. TransCanada's corporate values of integrity, collaboration, innovation and responsibility lay the foundation for working with its business partners, stakeholders and regulators. TransCanada is recognized as a world-class pipeline and power generation developer, owner and operator. TransCanada's success is a reflection of its exceptional team of approximately 4,600 committed and motivated employees who bring skill, experience, energy and knowledge to the work they do. TransCanada's employees are highly skilled in designing, building and operating complex infrastructure and take pride in the company's record of delivering major projects on time and on budget.

TransCanada is recognized as a valued participant in energy infrastructure business ventures. Through 60 years of experience, TransCanada has exemplified the following values and attributes:

- Knowledge and expertise, gained from a continuous cycle of improvement based on the experience of skilled employees.
- Pioneering strategic solutions for meeting North American energy requirements.
- Comprehensive understanding of industry and regulatory frameworks to implement more efficient materials and processes.
- A strong financial position demonstrated through a sound balance sheet and excellent corporate credit ratings.

- Projects carried out from initial concept to full operation. TransCanada develops projects and operates facilities across North America, highlighting its ability to work successfully within diverse jurisdictions.

- A solid record in corporate citizenship, with programs to help protect the environment, people and communities.

TransCanada is also an industry leader in health, safety and environmental practices, maintaining a culture of continuous improvement and doing business with companies that share these expectations.

As of the end of 2011, TransCanada wholly or partially owned and operated approximately 40,000 km of regulated natural gas pipelines in Canada. The vast majority of these facilities are regulated by the National Energy Board (the "**NEB**") under the terms of the *National Energy Board Act* (Canada). TransCanada's NEB experience is particularly relevant to the regulatory processes administered by the OEB in the regulation of the electrical transmission business. Like the OEB, the NEB sets rates on a cost of service model including return of capital (depreciation) and return on average investment base. In addition, the NEB like the OEB is required to approve the construction and operation of new linear infrastructure facilities.

Further, over the course of more than 60 years of developing and operating linear infrastructure in North America, including in Northern Ontario, TransCanada has developed relationships with and gained substantial experience engaging First Nations and Métis peoples, as well as other northern communities. TransCanada has also developed expertise in navigating the environmental, land acquisition and other regulatory processes that are important prerequisites to successfully developing major linear projects.

Since 2005, TransCanada has completed the development and construction of greater than 4,500 km of linear infrastructure in Canada, the U.S. and Mexico with 4,800 km under construction or development. Details of sample projects within Canada that highlight TransCanada's core competencies and experience in the execution of linear infrastructure projects are referenced in section 4.3.

2.4 Relevance of the Applicants' Experience

An explanation of the relevance of the applicant's experience to the East-West Tie line project.

This application brings together a public energy infrastructure company with robust financial capabilities and extensive North American project management experience and a global infrastructure company that has a virtually unrivalled record of successfully developing and operating greenfield electric transmission projects.

The blend of TransCanada's and Isolux Corsán's capabilities make the Applicants especially well-suited to develop the E-W Tie. In short:

- The E-W Tie is a large complex transmission project. Isolux Corsán has built over 60 transmission projects totalling over 12,000 km of high-voltage transmission lines and 145 substations in just over 12 years; it is currently constructing another 16 transmission lines totalling approximately 3,500 km and over 25 substations. Its experience and track record clearly demonstrates its capability to complete major projects like the E-W Tie to specification, on time and on budget.

- The E-W poses significant weather and terrain challenges. Isolux Corsán has successfully developed transmission projects over five continents under a range of challenging geography and weather conditions. It has built transmission projects under harsh winter conditions; it is currently completing construction of a 142 km 132kV transmission line in the Patagonia region of

Argentina, which experiences extreme high wind conditions and ice storms. It has also built transmission lines through and across deserts, jungles and tropical rainforests (e.g., Brazil, Kenya, Mexico, etc.); it is currently constructing 1,191 km of high-voltage transmission lines through the heart of the Amazon jungle and across the Amazon River.

- The E-W Tie project will entail a significant financial undertaking. The Applicants are extraordinarily well resourced and their track records demonstrate the ability to successfully develop all manner of major infrastructure projects. TransCanada has a current A- credit rating by Standard & Poor's, $49 billion in assets and an annual cash flow from operations in excess of $3.9 billon. Isolux Corsán has $10.7 billion in assets, annual revenues of $4.5 billion, and it recently received a $500 million investment by PSP, which has over $65 billion in funds under management (as of March 31, 2012).

- Isolux Ingeniería's in-house engineering expertise and its global procurement powers offer tremendous efficiency advantages for Ontario ratepayers. Being able to draw on in-house resources from conception through engineering to construction offers significant advantages on such a major and complex project, as does the ability to leverage global procurement strength and relationships.

- TransCanada has operated in northern Ontario since 1958. Its Canadian Mainline pipeline traverses much of the same area as the proposed E-W Tie between Thunder Bay and Nipigon. The existing transmission line crosses the ROW for TransCanada's mainline at two points. TransCanada is extremely familiar with the northern climate and terrain and has developed strong relationships and ties with northern communities.

- TransCanada has substantial experience engaging with First Nations and Métis peoples, communities, landowners and other stakeholders in relation to its projects and maintains those relationships through ongoing engagement. Isolux Corsán has extensive experience in engaging with aboriginal communities in other jurisdictions where it operates.

- TransCanada has substantial experience with federal and provincial regulatory processes in Canada and has a high degree of familiarity and expertise coordinating with the various regulatory agencies that will be required to give numerous approvals for the E-W Tie project and the associated construction.

3 FIRST NATIONS AND MÉTIS PARTICIPATION

3.1 Arrangements for First Nations and Métis Participation

If arrangements for First Nation and Métis participation have been made, a description of:

- *the First Nation and Métis communities that will be participating in the project;*
- *the nature of the participation (e.g. type of arrangement, timing of participation);*
- *benefits to First Nation and Métis communities arising from the participation; and*
- *whether participation opportunities are available for other First Nation and Métis communities in proximity to the line.*

In spring 2011, TransCanada initiated communications with a number of affected First Nations and Métis communities in discussions about the project.

For those groups that expressed an interest in meeting, TransCanada provided preliminary project information and communications were focused on the groups' respective interests, issues or concerns with the project, expectations for consultation, economic benefits (employment, ownership/partnership, and contracting opportunities and other benefits), and involvement in the environmental assessment process. TransCanada met with the following First Nations and Métis groups:

- Fort William First Nation
- Red Rock Indian Band
- Pays Plat First Nation
- Ojibways of Pic River

- Pic Mobert First Nation
- Métis Nation of Ontario
- Thunder Bay Métis Council
- Greenstone Métis Council
- Superior North Shore Council

In accordance with the advice given by the Ontario Power Authority ("**OPA**") in January 2012, the Applicants did not initiate any further discussions with potentially affected First Nations and Métis communities. Section 3.2 below sets out the Applicants' plan for constructive, meaningful communications and negotiations with the potentially affected communities.

3.2 Plan for First Nations and Métis Participation

If arrangements for First Nation and Métis participation have not been made but are planned, a description of:

- *the plan for First Nation and Métis participation in the project, including the method and schedule for seeking participation;*
- *the nature of the planned participation; and*
- *the planned benefits to First Nation and Métis communities arising from the participation;*

The Applicants' engagement efforts will largely be undertaken by TransCanada's Aboriginal and Stakeholder Engagement group (under a services contract) and will commence immediately after designation. TransCanada has substantial experience engaging with First Nations and Métis communities related to gas pipelines, oil pipelines, and power generation projects (including conventional and renewable power) across North America.

The Applicants have prepared an Aboriginal Engagement Plan ("**AEP**"), which is attached as Appendix "A" to this section. The AEP details TransCanada's experience and explains how the Applicants will engage affected First Nations and Métis communities in the project. The AEP outlines a number of mechanisms through which affected First Nations and Métis communities might wish to be involved in the project. The precise mechanisms through which communities may participate in the project can only be determined through direct discussions between the Applicants and the affected parties post-designation.

Key steps in the strategy that TransCanada, on behalf of the Applicants, will employ immediately upon designation to achieve the Aboriginal engagement goals and objectives include:

- Identification of a team to work on First Nation and Métis specific strategies and execution plans for this project, as well as any additional resources that may be needed for this project.

- Initiation of pre-engagement activities with First Nations and Métis communities to solidify relationships, understand their interests with respect to the project, determine capacity and engagement needs, and to have exploratory discussions to develop opportunities and benefits.

- Implementation of a comprehensive engagement process to share project information, to identify and understand Aboriginal issues, and to develop appropriate measures to avoid or mitigate potential effects.

- Offering capacity funding to support participation in the engagement process.

- Formation of an Aboriginal working group as a forum for discussions and coordination amongst affected Aboriginal communities and to share information on the project.

- Community participation in Traditional Ecological Knowledge and Traditional Land Use studies and field studies.
- Provision of access to and resources for education and training programs.
- Exploration of a range of options for community benefits based on existing TransCanada practices including employment, contracting and procurement practices.
- Exploration of additional options to provide long term financial benefits derived from the Project.

Section 3.3 of the Filing Requirements is not applicable given the Applicants' plan for First Nations and Métis participation.

Appendix A — Aboriginal Engagement Plan

East-West Tie Line Project

Aboriginal and Stakeholder Engagement Plan

January 3, 2013

Aboriginal and Stakeholder Engagement Program
TPT-Isolux Approach to Aboriginal Engagement

The Applicants know that the key to a successful project is achieving and maintaining solid relationships with First Nations and Métis communities and stakeholders. Acknowledging the Ontario Energy Board's usage of First Nations and Métis, the Applicants use the term Aboriginal throughout this application. While the trigger for developing these relationships often is a project, the Applicants believe that the relationship should transcend any specific proposal. Prior to forming a joint venture with Isolux, TransCanada had exploratory discussions with Aboriginal communities about the East-West Tie Line Project (Project) dating back to the Spring of 2011. In keeping with the advice given by the Ontario Power Authority (OPA) in January 2012, further discussions with potentially affected Aboriginal communities were not actively pursued. Following the Designation, the Applicants will contract with TPT's parent company, TransCanada, to implement its Aboriginal and Stakeholder Engagement program for this Project on behalf of the venture.

TransCanada's Aboriginal and Stakeholder engagement approach is founded on corporate values and the principle of deep and long standing relationships. The approach proposed for this Project will rely on existing TransCanada programs developed over numerous years to be consistent with TransCanada practices and policies for meaningful engagement. TransCanada is recognized as being a leader in this area of engagement and has a proven track record in successfully engaging with Aboriginal communities. As demonstrated in Section 7.4 – Schedule in the main body of the Application, this engagement approach has been successful at building relationships and enabling projects to be brought in service in line with originally anticipated expectations.

The determination of appropriate benefits for the Aboriginal communities affected by the Project will be dependant upon further discussions with each of the Aboriginal communities about their specific interests and desires and the final Aboriginal and Stakeholder engagement strategy will ultimately be refined through a collaborative process of engagement with Aboriginal communities and other Stakeholders.

This Aboriginal and Stakeholder Engagement Plan should be read in conjunction with Section 9 Landowner, Municipal and Community Consultation provided in the main body of the application.

TransCanada's Experience with Aboriginal and Stakeholder Engagement

TransCanada has worked with Aboriginal communities and stakeholders across North America for more than 50 years. TransCanada owns and operates pipeline and energy facilities in 3 countries, 7 provinces, 31 states, and almost 250 locations across the continent. With over 60,000 kilometers of current and proposed pipelines, along with power generation facilities generating 10,800 megawatts of power, TransCanada works with over 60,000 landowners, 7 tribal reservations and 13 First Nation reserves and Métis settlements where our assets directly cross their lands. TransCanada works with many Aboriginal communities where our assets are located on traditional lands, and has agreements with a number of communities throughout Canada.

TransCanada believes that meaningful consultation is critical to the success of any project. We are guided by our corporate values of Responsibility, Integrity, Innovation and Collaboration, as well as our Stakeholder Engagement Commitment Statement and our guiding policies and principles. TransCanada's Aboriginal engagement professionals understand the ever changing environment of Aboriginal relations and the critical importance of first gaining trust, and then maintaining trust with all of the interested Aboriginal communities.

TransCanada's Aboriginal engagement plans always provide for the identification of interests and concerns related to the project, and assists in establishing a long-term, positive relationship with Aboriginal communities located along the proposed Project footprint. Working directly with the Project team and alongside several key disciplines (e.g., environment, supply chain management, human resources, community relations, government relations, and regulatory), the engagement plan incorporates the projects goals and objectives and supports building relationships based on mutual respect and trust. In addition to working in collaboration with the various disciplines for the Project, the Aboriginal Relations team will effectively coordinate its activities with communities, regulatory bodies and government to ensure the successful execution of the Project.

Factors to Success:

- Successful Aboriginal and stakeholder engagement strategies and proven track record in its execution for numerous projects throughout North America;
- Experience-based approach of building and maintaining relationships with Aboriginal communities and other stakeholders;
- Included on the Dow Jones Sustainability World Index for the last 11 years, receiving a score of 100 percent for stakeholder engagement in 2011;
- Integrated management structure and internal communications coordination for Aboriginal and stakeholder engagement team;
- Regional project office through to operations;
- Early explorative discussions with Aboriginal communities, community members, governments and landowners.

Highlights of the First Nation and Métis Engagement Process

This section provides a summary of the key highlights and strategies TransCanada on behalf of the Applicants will employ to achieve the Aboriginal and Stakeholder engagement objectives. A detailed overview of the multi-phased engagement process follows this list.

- Immediate identification of a team to work on Aboriginal community specific strategies and execution plans for this Project, as well as any additional resources that may be needed for this Project.

- Initiation of pre-engagement activities with Aboriginal communities to solidify relationships, understand their interests with respect to the Project, determine capacity and engagement needs, and to have exploratory discussions to develop opportunities and benefits.

- Implementation of a comprehensive engagement process to share Project information, to identify and understand issues, and to develop appropriate measures to avoid or mitigate potential effects.

- Offer capacity funding to support participation in the engagement process. Capacity funding could be in the form of funding to support negotiations, funding to assist the Aboriginal communities to assess Project information or in another form that would be determined through our engagement with communities.

- Initiate an Aboriginal working group as a forum for discussions and coordination amongst affected Aboriginal communities and to share information on the Project. Engagement between the applicant and the Aboriginal communities will determine composition of the working group.

- Supporting participation in Traditional Ecological Knowledge and Traditional Land Use studies and field studies.

- Providing access and resources for education and training programs.

- Exploring a range of options for community benefits based on existing TransCanada practices including employment, contracting and procurement practices.

- Exploring additional options to provide long term financial benefits derived from the Project.

TransCanada Governance

TransCanada's approach to Aboriginal and stakeholder engagement is grounded in a number of policies and guiding principles reflecting its values.

TransCanada's Aboriginal and Stakeholder Guiding Principles, Policies and Programs:

TransCanada has a number of publicly-available policy and programs and commitment statements that provide the framework for strategies, plans and programs, as well as guidance to staff in planning their work. These include:

- Corporate Values of Integrity, Collaboration, Responsibility and Innovation:
- Stakeholder Engagement Commitment Statement:
- Aboriginal Relations Policy;
- Code of Business Ethics;
- Community Investment Program;
- Integrated Public Awareness Program;
- Corporate Social Responsibility Report.

All of these documents are available on TransCanada's web site or can be provided upon request.

Aboriginal and Stakeholder Engagement Goals and Objectives

The objectives of the engagement process are to:

- Identify potentially interested Aboriginal communities and stakeholders and the nature of their interest, and engage them in an informed, effective and meaningful way.
- Provide timely, honest, accurate information to share "what we know, when we know it" about the Project and the process to assess the effects of the Project.
- Proactively engage Aboriginal communities and stakeholders in:
    - scoping project related issues;
    - identifying the potential effects of the Project on Aboriginal communities use of the land for traditional activities and sites of historical or cultural importance;
    - participating in the development of mitigation measures;
    - providing input into the implementation of the engagement process;
    - identifying and providing opportunities to participate in the Project.

TransCanada's goal is also to ensure that:

- Aboriginal communities and stakeholders have information on how to be involved in the regulatory process.
- All communications materials are consistent, straightforward, and easy to understand.

- There are a variety of means for Aboriginal communities and stakeholders to get involved in the process.
- Aboriginal communities and stakeholders are aware of how their input has been considered in decisions related the Project.

Plan for Aboriginal Engagement

The Applicants acknowledge that for the project to be successful, it must incorporate meaningful engagement throughout the project life cycle including long-term benefits to Aboriginal communities affected by the Project.

Existing forms of Engagement

As noted above, the Applicants agree with the Board that there are a wide variety of mechanisms through which Aboriginal communities could engage in the Project. As designate, the Applicants would expect to consult immediately with the Aboriginal communities to determine the mechanisms that are most attractive to each community.

Since the costs and benefits of various mechanisms depend on such things as the community's size, capacity and desire or willingness to work in conjunction with other communities, there can be no "one size fits all" solution to optimizing the value of engagement. Further discussions with communities will be necessary to determine the appropriate benefits for this Project.

While it is too early in the process for the Applicants to determine with precision the final engagement model for this Project, the Applicants will rely on the extensive experience of TransCanada and the programs TransCanada has developed to provide financial benefits Aboriginal communities on previous projects. Below is a description of some of the programs that TransCanada has developed for Aboriginal communities which the Applicants may consider for this Project following further engagement with Aboriginal communities immediately upon being designated. As the engagement progresses additional programs may become relevant and may be further considered.

Financial Component

Funding to communities may be incorporated into a Project Agreement (which is discussed below). The funds are provided directly to the community and may vary but are often linked to specific milestones such as permitting, commissioning and in-service date. The Applicants would anticipate Project Agreements of approximately 5 years in length in the context of this Project. The purpose of these payments is to provide community capacity and community investment funding,

Financial benefit commencing from the commercial operation date for the Project would be developed as a result of our engagement with Aboriginal communities.

On-Going Community Engagement in Project: Working Group

The Project will be developed over several years, and operated and maintained over several decades and engage numerous Aboriginal communities. The issues to be addressed in the context of the Project are complex and evolving. The Applicants believe that a Project working group would benefit the Project by providing a forum for meaningful interactions between the participating communities and with the Applicants and would assist to collaboratively address the Project's many complexities before, during and after construction.

The working group could also serve as a common forum for undertaking joint and cooperative studies in support of the Project.

TransCanada on behalf of the Applicants will suggest the establishment of this working group and will provide resources for its operation including administrative and professional support and facilitation, if requested.

Education and Training

The opportunity for Aboriginal communities to participate directly in the Project will be, in part, a function of the community's capacity to supply a skilled and capable workforce. This capacity can vary widely between communities.

To enhance the communities' capacity to participate in the Project, some training opportunities will be available. The scope of this training, the skills development targeted, and its costs will be finalized through discussions with the communities taking into account their needs and existing skills.

The Applicants may also provide funding directly to a community, an Aboriginal organization, a private or public training institution on a case by case basis. Consideration will be given to:

- Industry-related skills training for Aboriginal people or businesses where other funding sources are not readily available;
- Skill enhancement for new and experienced Aboriginal businesses;
- Aboriginal organizations or Aboriginal communities pursuing skill development with the goal of providing goods or services to the Applicants;
- Skill development activities that demonstrate measurable benefits and achievements;
- The working group or a similar body may be tasked to oversee skills training and development on the Project.

As part of its ongoing business practices, TransCanada operates, or supports, a series of programs to assist Aboriginal people and communities achieve their economic, social and cultural goals. TransCanada would make the following programs available to the Applicants where available:

- Reading and Numeracy Literacy
- Career pathing workshops with self-assessments and exploration of career alternatives
- Native Ambassador Partnership Initiative
- Building Environmental Aboriginal Human Resources – which utilizes five environmental and culturally inclusive training programs. Applying this program to the Project will assist us in readying Aboriginal people to participate in project construction and land rehabilitation activities

Employment

The majority of employment opportunities available on transmission projects are related to construction. Maintenance of the right-of-way will be contracted. (see Contracting and Procurement section below). With respect to employment related to construction and operations including positions associated with contracting opportunities, the Applicants will identify the employment requirements for the Project and seek to recruit qualified Aboriginal companies or individuals to fill those positions. To do this, the Applicants will conduct outreach workshops in communities near the Project as well as in secondary and post-secondary educations institutions. The Applicants will work with Aboriginal community economic development and employment organizations to help organize the outreach and identify companies or individuals who may be interested in available employment opportunities.

The Applicants' activities in support of employment and training of local Aboriginal people will be cognizant of the need to focus on those skills and experiences that have long-term career employment potential associated with the Project, but also those which are transferable to other industry or government sectors, especially in the region.

Contracting and Procurement

The Applicants will adopt TransCanada's Aboriginal contracting strategy that has resulted in demonstrated successes for Aboriginal communities in the past. TransCanada's Aboriginal investment related to contracted services has grown from approximately $5 million to approximately $50 million a year over the last seven years. The program works diligently to match contract size with the capacity of the local communities. TransCanada's approach has been to pre-qualify Aboriginal contactors for upcoming work and evaluate and award based on overall competitiveness. As a condition of the EPC contract, a contracting strategy consistent with TransCanada's best practice will be implemented. These best practices include recognition of Aboriginal joint venture partnerships, set-aside opportunities for Aboriginal businesses where qualified and weightings incorporated for Aboriginal participation in awarding prime and sub contracting opportunities. The following demonstrates approaches the Applicants will implement related to contracting opportunities.

The Applicants will, in collaboration with the Aboriginal Communities, create an inventory of Aboriginal businesses that might be able to fill its needs. Creating this inventory will consist of:

- Preparing a list of the contracting requirements for the Project, including the required personnel, skills, certifications (as appropriate), experience and equipment
- Submitting the list to the Aboriginal communities for them to identify if the members or member-owned businesses have an interest and the capacity to provide the service.

The Applicants will also:

- Hold workshops in interested Aboriginal communities near the route and explain the Applicants needs and our requirements for responding to calls for tenders or proposals;
- Make business resources available to Aboriginal communities resources to help them respond to calls for tenders or proposals;
- Ensure that Aboriginal businesses are aware of the timing of required services and supplies, the time windows in which the services and supplies; and
- Communicate in advance long-term resources that the Applicants will need to operate and maintain the transmission line.

The Applicants have a sound understanding of the elements that make for successful Aboriginal procurement programs, and looks forward as designated transmitter to exploring these opportunities with affected communities.

Community Benefits

The Applicants dedicated team members will also work with the Aboriginal communities to identify the local needs that should be addressed through a Community Investment program. TransCanada's community investments are focused on funding three key pillars:

- **Wellness** – This is our opportunity to support healthy living, lifelong learning, community development and community services. With our support and assistance, we build thriving communities.
- **Safety** – We support and develop tools and resources to safeguard our communities so they can thrive. First responders, emergency preparedness and prevention are key themes that guide our thinking to help identify programs or organizations to partner with.
- **Environment** – By building awareness and supporting a healthy natural environment, our communities can thrive. To do that, our decision-making is guided by themes such as education, protection and restoration to select programs and organizations that enrich our natural environment.

Methods to Formulate and Secure Engagement

The Applicants will undertake Project engagement as described in the Aboriginal Communities Consultation Plan below, concurrently with agreement negotiations. The Applicants will rely on TransCanada's experience to conclude agreements with Aboriginal communities. The Applicants will be guided by TransCanada's proactive approach to agreements which include a suite of agreement options. These include Protocol Agreements, Memorandum of Understanding Agreements, Negotiation Agreements and Project Agreements.

Further discussions with Aboriginal communities will determine which agreements are most appropriate for this Project and to the circumstance of each community engaged by the Applicants. What follows is a description of the types of agreements the Applicants may use for this Project.

Protocol Agreements

Protocol Agreements establish how the company and an Aboriginal community , a group of communities or an Aboriginal organization will work with one another. TransCanada has entered into a number of these agreements. Typically such agreements will commit the parties to respectful interactions, and administrative and procedural guidelines.

Memorandum of Understanding

A MOU is a process oriented agreement to facilitate the assessment of the Project and usually addresses:

- Participation in engagement activities;
- Capacity funding to review the Project;
- A schedule for meetings and timelines for the Project assessment;
- Participation in field work, studies, analyses and recommendations;
- Commitments to further agreements where appropriate, such as a Project Agreement.

Negotiation Agreement

A Negotiation Agreement sets out the terms and funding for the negotiation of a Project Agreement.

Project Agreement

A Project Agreement contains the benefit agreed to between the company and the Aboriginal community. The Project Agreement usually includes but is not limited to:

- Commitments for employment, contracting and training
- Financial benefits (short or long term or both)
- Certainty provisions
- Dispute resolution mechanism
- Remedies

The Applicants expect that Project Agreements will be negotiated with some communities. Discussions with communities will determine when and with which community a Project Agreement will be negotiated as well as the content of the agreement.

Regulatory Approvals in the Absence of Agreements

The Applicants will undertake Project engagement concurrently with any Agreement negotiations so that opportunities for communities with whom agreements have not been finalized will be available, also ensuring that consultation requirements are met.

Should TransCanada be unable to conclude agreements with some Aboriginal communities, or attain a desired level of support from some Aboriginal communities, the Applicants will move forward through the regulatory process, and maintain the ability to demonstrate the level of its engagement, its understanding of issues as presented by Aboriginal communities, and proposed mitigation measures to address identified outstanding concerns. TransCanada will continue to work on concluding agreements with those Aboriginal communities in parallel to the regulatory process.

Costs for Aboriginal Communities Engagement the Project

The Applicants believe the costs of Aboriginal community engagement must be informed by discussions with communities.

As mentioned previously, some initial discussions occurred with a number of identified communities, however, substantive and meaningful engagement with all communities has not occurred.

Upon designation the Applicants will commence discussions with Aboriginal communities to determine what arrangements are best suited to this Project and to their interests. The Applicants anticipate being able to provide concise costs prior to, or no later than the submission of the Leave to Construct application.

While it is still early to determine the precise costs of engagement activities and benefits to Aboriginal communities, based on TransCanada experience with linear projects, the Applicants expect these costs to fall within the ranges as described below. The Applicants will work with communities to encourage collaboration and thereby reduce costs where possible. The Applicants will draw from the following tools to engage with

communities anticipating these will vary between communities depending on a wide variety of factors:

- Capacity funding, including initial engagement funding, capacity funding in an MOU, project liaison and monitoring: $5 to $7 million;
- Participation in studies including biophysical, archaeological, traditional knowledge and traditional land use studies: $3 to $4 million;
- Agreements including short-term financial benefits and community investment benefits: $6 to $12 million.

Additional work is required to estimate the costs of longer-term benefits and the form they would take. These costs do not include fees associated with crossing reserve lands should that route option be selected. The Applicants are committed to further discussions with the Aboriginal Communities to identify the potential beneficiaries of long-term financial benefits, the range of options available for this Project and the costs associated with these options.

Aboriginal and Stakeholder Engagement Team

The Applicants will rely on a team who are subject matter experts with respect to Aboriginal and Stakeholder engagement and major energy projects in Ontario. The total number of team members and configuration will be determined following finalization of the Project route and a complimentary assessment of the potential risks, resources, and schedule completion.

The Aboriginal and Stakeholder Engagement team will be comprised of experts in the following fields: Land, Aboriginal and Stakeholder Engagement, Communications, Supply Chain and Government Relations. Team members will collaboratively work together and with other interrelated field experts such as environment and project management to ensure that outreach to all Aboriginal communities and stakeholders is managed in a consistent and coordinated fashion through the lifecycle of the Project.

Some team members for this Project will be located in communities near the transmission corridor. These employees will liaise with the Aboriginal communities and

local municipalities on a daily basis and will be cornerstones to developing the relationships required to make this Project successful.

The Applicants will ensure that the Project team has experts who can manage and implement the following:

- Aboriginal Relations: Engagement with Aboriginal communities;
- Stakeholder Relations: Engagement with local communities, municipalities, government landowners and other stakeholders;
- Supply Chain Management: Development and implementation of Aboriginal employment, contracting and procurement strategies;;
- Traditional Land Use (TLU) and Traditional Ecological Knowledge (TEK) studies coordination: Management of TLU/TEK studies;
- Government Relations: Coordination of communication and sharing of information with all levels of government;
- Communications: Coordination of all communications to the public, media, stakeholders and Aboriginal communities;
- Operations: Management of the day-to-day and long-term interactions with Aboriginal communities including opportunities for employment, training, community benefits, procurement and contracting.

The final composition of the team may change in response to information gathered through Project engagement.

A qualified business systems analyst will manage the consultation management system for to record engagement activities, issues and concerns and commitments to Aboriginal communities

Following a Leave to Construct, ongoing agreement support, administration and coordination would transition into the operating entity managing the asset.

Aboriginal Communities Consultation Plan

Aboriginal Engagement Methodology

The Applicants' engagement methodology will rely on TransCanada's Aboriginal engagement process that is comprised of five components:

1. Initial identification and confirmation of Aboriginal communities;
2. Sharing project information and project-specific activities;
3. Procedures for responding to questions, issues and concerns;
4. Project-specific Activities including Traditional Land Use (TLU) and Traditional Ecological Knowledge (TEK) studies; and
5. Ongoing engagement throughout the life-cycle of the project.

1. Initial Identification and Confirmation

An initial list of Aboriginal communities potentially affected by the Project is developed through a combination of desktop research, operating experience, and established network of contacts with Aboriginal communities.

TransCanada also considers Project location relative to reserve location, First Nations asserted traditional territory, Métis communities and harvesting and traditional use areas.

Based on this initial identification process, Aboriginal communities identified are contacted to:

- confirm whether the project crosses lands identified by Aboriginal communities as being within their asserted traditional territory or harvesting area and traditional use area;
- help identify other Aboriginal communities with asserted traditional territory or harvesting area and traditional use area in the Project area;
- note any expressed interests or concerns;

- provide the project team with updated information about the Aboriginal communities and organizations that may be affected by, or have an interest in the Project;
- confirm the appropriate first point of contact for all identified Aboriginal communities and communicate with them;

The community consultation list is usually vetted with appropriate government departments. In this case, the Ontario Minister of Energy provided a list of Aboriginal communities.

Engagement with government and regulatory agencies also helps to identify and refine the number of communities that are engaged.

2. Project Information Sharing

Project-related information is provided to Aboriginal communities through ongoing communications and face-to-face meetings. Project-specific information packages are reviewed and feedback is sought, generally at face-to-face initial meetings. Ongoing engagement allows to the Applicants to continue to share Project information through updates and to gain an understanding of each Aboriginal community's concerns and issues.

3. Procedures for Responding to Questions, Issues and Concerns

Questions, issues and concerns raised during the engagement process are recorded and where possible, addressed immediately. Issues regarding overall communication and engagement are addressed during meetings with leadership or a delegated authority for the Aboriginal community such as lands departments. Issues that may arise from field surveys as well as the appropriate mitigation measures designed to address theses issues are discussed with the Aboriginal community representatives in collaboration with technical experts. Mitigation measures for the Project are discussed and developed with in the input of Aboriginal communities.

4. Project-specific Activities Including Traditional Ecological Knowledge (TEK) and Traditional Land Use (TLU) Studies

The Applicants will work with Aboriginal communities to determine project-specific engagement activities. Discussions may include a range of options including methods to assess the project such as capacity, participation in biophysical studies, the undertaking of TEK or TLU studies, economic opportunities associated with the Project and community investment.

The Applicants recognize that Aboriginal communities have often maintained close ties to the land, and recognize the importance of integrating relevant TEK into project planning to complement western science. Community participation may include direct involvement in field work.

Environmental Consultants, on behalf of the Applicants, assist in the TLU studies which focus on current use of land for traditional activities. Field reconnaissance activities may also be carried out on Crown land.

The information gathered is used to determine the potential effects a project may have on identified traditional land use sites and on the ability of the users to maintain the use of the land. Appropriate mitigation measures identified for specific projects are determined through ongoing dialogue with government agencies, technical experts, stakeholders, Aboriginal community representatives.

5. Ongoing Engagement

The Applicants are committed to ongoing communications and engagement throughout the life-cycle of the project. The Applicants will strive to build collaborative relationships in whose territory the company operates through listening and working with communities to address concerns, to identify economic benefit opportunities related to the Project and support community interests through community investment and other programs.

Preliminary List of Aboriginal Communities Affected by the Project

In a letter to the Ontario Power Authority (OPA), on May 31, 2011, the Ontario Ministry of Energy provided a First Nation and Métis community consultation list as noted below. The methodology identified above will be used to validate and complement this list.

First Nations:

Robinson-Superior Treaty

1. Animbiigoo Zaagi'igan Anishinaabek First Nation (Gull Bay)
2. Biinjitiwaabik Zaaging Anishinaabek First (Rocky Bay)
3. Bingwi Neyaashi Anishinaabek (Sand Point)
4. Fort William First Nation
5. Michipicoten First Nation
6. Ojibways of Pic River
7. Pays Plat First Nation
8. Pic Mobert First Nation
9. Red Rock Indian Band

Treaty #9

10. Ginoogaming First Nation
11. Missanabie Cree First Nation
12. Long Lake No. 58 First Nation

Robinson-Huron

13. Ojibways of Garden River
14. Ojibways of Batchewana

Métis Region and Council

1. Greenstone Métis Council
2. Thunder Bay Métis Council
3. Superior North Shore Métis Council
4. Red Sky Métis Independent Nation.

Exploratory Discussions

Following the Ontario Energy Board's decision that it was prepared to proceed with a designation process for the Project, and before its partnership with Isolux, TransCanada initiated exploratory discussions with a number of Aboriginal groups and municipalities in the spring of 2011.

For those groups that expressed an interest in meeting, TransCanada provided project information and discussions were focused on their respective interests, issues or concerns, expectations for consultation, economic benefits (employment, ownership/partnership, and equity), and involvement in the environmental assessment process. Although a number of groups were contacted, the following list provides an overview of the Aboriginal groups TransCanada met with.

- Fort William First Nation
- Red Rock Indian Band
- Pays Plat First Nation
- Ojibways of Pic River
- Pic Mobert First Nation
- Métis Nation of Ontario
- Thunder Bay Métis Council
- Greenstone Métis Council
- Superior North Shore Council

The Applicants will upon designation, pursue the engagement program described in this document.

Crown Consultation – Procedural Aspects

In the Phase 1 Decision and Order, the Board wrote that Applicants seeking designation would be:

> "…required to demonstrate their ability to conduct successful consultations with First Nations and Métis communities, as may be delegated by the Crown, by providing a plan for such consultations, and evidence of their experience in conducting such consultations."

On November 26, 2012, Mr. Sergio Imbrogno, Deputy Minister of Energy, wrote to the Board in furtherance of the March 29 Letter. Reiterating the importance to government that the Crown's duty to consult be fulfilled in respect of the Project, government set out its intention to consult the same communities as were consulted in the initial outreach undertaken by the Ontario Power Authority. For the next phase of consultations, however, the Crown stated that it intends to delegate the procedural aspects of its consultation obligation to the transmitter designated by the Board.

To effect this outcome, the Crown has said that it anticipates that the designated transmitter will enter into a memorandum of understanding ("MOU") with the Ministry of Energy that will set out the respective roles and responsibilities of the Crown and the designated transmitter. In particular, the government has pointed the Bruce to Milton transmission reinforcement project as a model for the MOU applicable in the application for the Leave to Construct.

Should the Applicants be designated as the transmitter for this Project, it will work diligently with the Ministry of Energy to negotiate the terms of an MOU for this Project s soon as possible following designation.

Significant Issues and Plans to Address Them

The Applicants have identified some potential issues listed below, followed by suggested approaches to mitigation:

Issue: Potential Impact on Traditional Activities

Aboriginal communities undertake many activities on the land that might be affected by the Project, particularly during its construction phase.

Mitigation:

The Applicants will conduct traditional land use studies with Aboriginal communities along the transmission corridor routing. The results of these studies will inform the Applicants of the potential effects of the Project on traditional activities and the Applicants will work with Aboriginal communities to design appropriate ways to avoid or reduce potential effects. Some examples of mitigation measures could include:

- Re-routing portions of the transmission line to avoid particularly sensitive sites;
- Relocating or planting important animal forage, medicinal plants and important food sources (berries, for example) to areas that will not be impacted by the Project.

Issue: Cumulative Effects

Aboriginal communities have been increasingly raising the issue of the combined effects of the many activities in their traditional territories. That is, while one more project may not in itself have a great impact, the cumulative effect of all the projects over time has eroded their useable land base and affected their traditions and way of life.

Mitigation:

While it is beyond the ability of any one project proponent to deal with the issue of cumulative effects as described above, the Applicants will design its Project to minimize the impacts of its Project. The Applicants will work collaboratively where possible with Aboriginal communities to support regional studies with other industry participants and will help Aboriginal communities communicate their concerns regarding cumulative effects to government.

4 TECHNICAL CAPABILITY

4.1 Project Resources

A discussion of the type of resources, including relevant capability (in-house personnel, contractors, other transmitters, etc.) that would be dedicated to each activity associated with developing, constructing, operating and maintaining the line, including:

- *design;*
- *engineering;*
- *material and equipment procurement;*
- *licensing and permitting;*
- *consultations, both with First Nation and Métis, and other communities;*
- *construction;*
- *operation and maintenance; and*
- *project management.*

The Applicants will devote the following resources to the E-W Tie project:

4.1.1 Project Management

If designated, the Applicants plan to appoint to the GP a General Manager experienced in the development and construction of linear infrastructure, where possible with electric transmission experience. The General Manager will be accountable to the management committee of the GP and will be responsible for the overall coordination of project execution, administration and regulatory matters with the overall purpose of ensuring projects are delivered safely, in accordance with specifications, on time and on budget.

The General Manager will have three primary support personnel — a Project Director, a Legal/Regulatory Manager and a Controller. The Project Director will be responsible for the development and execution of the project and will be supported by local project management teams. The Legal/Regulatory Manager will coordinate the regulatory applications and filings. The Controller will manage the finance and administrative activities.

The GP's specific resource needs may vary depending on the phase of the project and requisite activities. Some resources may be required for only short periods, and will typically be better served by external contractors and other service providers. The Applicants expect to employ a mix of in-house employees, parent company internal resources and third party resources that will be prudently managed and continuously optimized based on the project's evolving needs.

4.1.2 Design and Engineering

As detailed in section 2.1, the Applicants plan to enter into an EPC contract with Isolux Ingeniería after designation. This will provide the Applicants with access to in-house experts and resources within Isolux Ingeniería (including Isolux Ingeniería USA, LLC ("**I-USA**") which is based in Austin, Texas) to assist with design and engineering for all phases of the project.

I-USA's engineering team consists of full-time transmission line engineers who have approximately 100 years of combined specialized experience in transmission line design. The I-USA team has assisted with the preparation of this application and will provide support throughout the development process. A description of Isolux Ingeniería's capabilities is contained in Exhibit "B" in Volume 2.

As further explained herein, the Applicants have involved Isolux Ingeniería early on in preparing this application. This ensures that the Applicants' plan is informed by an early analysis and assessment of the OEB's technical specifications which are

instrumental in estimating the EPC cost. This is the approach Isolux Corsán has followed in actual competitive transmission auction processes — where selection is based on the lowest-cost bid (and the winner is bound by its bid costs) — and it is essential to formulating realistic preliminary estimates of overall project cost.

By engaging the EPC contractor at the outset, the Applicants are also able to leverage Isolux Ingeniería's experience and skills to drive cost efficiency throughout the development phase, including route selection. The EPC contractor is able to best evaluate, analyze and quantify the implications of route options on design, schedule, logistics and other material impacts. Utilizing Isolux Ingeniería to perform EPC management also eliminates costly bottlenecks and other logistical difficulties in accessing a limited pool of specialized general contractors and engineers to design and manage development and construction.

Isolux Ingeniería will develop the engineering for the Project and, if necessary, will subcontract engineering consulting firm(s) on a competitive basis to support the detailed engineering design, geotechnical investigation, and implementation of environmental impact mitigation for the proposed transmission line. Isolux Ingeniería will supervise and manage the subcontractors and provide oversight to ensure that the Project will be designed to meet or exceed applicable North American Electric Reliability Corporation ("**NERC**"), Northeast Power Coordinating Council ("**NPCC**") and IESO reliability standards and the OEB's applicable *Minimum Technical Requirements.*

Isolux Ingeniería's engineers utilize computer-aided design software to review and analyze terrain modeling, conductor design and modeling, structure design and span analysis, and development of the construction documents (plan and profile drawings, staking tables, stringing charts, etc.).

The Applicants will also benefit from TransCanada's engineering expertise related to interconnection of electrical facilities in Ontario as well as other North American jurisdictions during the development phase.

4.1.3 Material and Equipment Procurement

The Applicants intend to include the procurement of material and equipment as part of the EPC contract in order to harness the global procurement resources of Isolux Ingeniería.

Isolux Ingeniería's procurement activities are centered in Madrid where specialized procurement experts and engineers coordinate procurements in order to maximize efficiencies. Where appropriate, Isolux Ingeniería also draws on local procurement expertise.

Due to its global scale, Isolux Ingeniería has long-term established relationships with reputable suppliers of all materials and equipment the project will need and is able to leverage its global relationships and procurement expertise to secure material and equipment purchases at lowest cost in accordance with prescribed standards. Certain transmission materials and components can often be sourced at materially lower prices in countries like Turkey, India or China; Isolux Ingeniería has relationships with suppliers in these countries. Isolux Ingeniería will also work with the conductor manufacturer to hedge the cost of aluminum on the London Metal Exchange.

Isolux Ingeniería has well-established and transparent purchasing processes which it follows in procuring equipment and services of the nature and scope required by a project of this size and importance. Isolux Ingeniería utilizes SAP Purchasing System to follow procurement processes, including creating bid comparatives, documenting purchase orders and change orders and streamlining invoice

payments. Details of Isolux Ingeniería's procurement practices are provided in section 4.4.

Equipment and material costs may constitute as much as 20% of the overall cost of the E-W Tie; Isolux Ingeniería's global procurement strengths are accordingly a significant advantage.

TransCanada also has extensive supply chain management expertise to support its many generation and pipeline projects as well as an ongoing business relationship with suppliers in Ontario and throughout the world. Where necessary, these existing relationships can be utilized to improve the overall execution of the project.

4.1.4 Licensing and Permitting

The Applicants will contract with local consultants, such as Golder, a reputable global firm with expertise in environmental studies for transmission projects in Ontario. A summary of Golder's experience is included as Exhibit "C" in Volume 2.

The Applicants have also retained KP, a respected and experienced routing and environmental consultant that has been involved in the routing of more than 100 transmission and energy projects around the world, including in Canada. A summary of KP's experience is included as Exhibit "D" in Volume 2. Golder and KP will be managed by the Project Director and the project team.

Golder and KP will perform the necessary environmental studies and analysis that define the final route alternatives. They will also prepare supporting documentation for the environmental assessment application and the leave to construct application. In parallel with those tasks, they will file any necessary requests for other required permits and authorizations, a preliminary list of which appears in Exhibit "E" in Volume 2.

TransCanada has extensive experience in permitting and licensing processes in Ontario. The Applicants may utilize certain qualified and experienced TransCanada personnel, who have permitted major power and pipeline infrastructure projects in Ontario, to coordinate the licensing and permitting activities.

4.1.5 ROW/Land Acquisition

The Applicants plan to contract with TransCanada for land acquisition and ongoing land file administration services. TransCanada, on behalf of the Applicants, will manage third party firms or consultants for the identification of potentially affected properties, definition of easement agreements and for the physical acquisition of the required property rights; some of these third parties would likely be local to the project area. The Program Manager, or support staff, would manage the contract with TransCanada.

TransCanada's land team has a proven track record of securing property rights for linear infrastructure projects on Crown, First Nation reserve, Métis settlement and private lands across North America, including significant experience in Ontario. TransCanada has acquired over 10,000 easements and over 80 freehold parcels in the past six years in Canada, the United States and Mexico. TransCanada's Canadian Mainline traverses extensive Crown lands in Ontario. TransCanada has had extensive dealings with the Ontario government in relation to these lands since the 1950s.

TransCanada's land team has proven systems in place to manage the acquisition of property rights as required for this type of project, as well as experienced personnel with strengths in formulating strategies and managing risk related to land acquisition. The team has the ability to adapt to various regulatory regimes while bringing the high standards that the Applicants expect in dealing and building relationships with landowners. The land team is part of a larger Community, Safety and Environment ("**CS&E**") group within TransCanada. This ensures that TransCanada's Community

Consultation and Aboriginal Relations and Land groups are integrated and work collaboratively.

Where necessary, the Applicants can also draw on Isolux Corsán's experience with land acquisition.

4.1.6 First Nations, Métis and Community Consultation

The Applicants' consultation activities will largely be undertaken by TransCanada's Aboriginal and Stakeholder Engagement group, with support from contracted resources such as Golder and Isolux Corsán.

TransCanada has a proven track record of successful Aboriginal and stakeholder engagement strategies throughout North America as demonstrated by its score of 100% for stakeholder engagement on the Dow Jones Sustainability Index in 2011. TransCanada has worked with Aboriginal communities across North America for more than 50 years. TransCanada owns and operates pipeline and energy facilities in three countries, seven provinces, 31 states, and almost 250 locations across the continent. With over 60,000 km of current and projected pipelines and other energy infrastructure, TransCanada works with 60,000 landowners, numerous tribal reservations, First Nation reserves and Métis settlements. TransCanada has agreements with Aboriginal communities throughout Canada and has developed and continues to maintain working relationships with these Aboriginal communities.

4.1.7 Construction

As detailed in section 2.1, the Applicants plan to enter into an EPC contract with Isolux Ingeniería. As the project nears the construction stage, a fully dedicated construction management team from Isolux Ingeniería will be put in place.

It is the Applicants' view that, depending on the volume of activity, workload, environmental and other logistical issues, it may be cost-effective to divide the

project into two distinct and physically separate transmission line segments (one from Wawa to Marathon and the other from Marathon to Thunder Bay). This may also minimize project risk. The Applicants will explore this option in the course of carrying out development work.

The EPC contract will be managed by the Project Director with support of a Contracts Manager. The Project Director will be supported in the management of the EPC contract during the construction phase by one or possibly two Project Managers, who may split the work for the identified sub-projects, and provide each other support and back-up when necessary.

Isolux Ingeniería plans to set up a site office near the project in order to support the project, along with two material yards for the storage of materials and equipment. Thunder Bay and Marathon have been identified as potential locations for the site office. Isolux Ingeniería plans to staff the on-site field office with technical and administrative support. It anticipates having to staff positions for construction management, cost control, scheduling, purchasing, engineering, environmental, cultural mitigation, health and safety, purchasing, quality assurance/quality control, contract administration, human resources, IT and general services.

4.1.8 Operations Phase

Once the E-W Tie line enters into service, the Applicants will utilize a relatively small in-house management and technical team to manage one or two outsourced maintenance companies. The GP may also engage regulatory and legal support to fulfil regulatory obligations.

The General Manager will remain responsible for overall management, stakeholder relationships and reporting to the management committee. The Project Director will be responsible for transmission planning obligations, system expansions and maintenance. The Controller will be in charge of finance, administration and control.

4.2 Key Technical Team Personnel

Resumes for key technical team personnel

If designated, the Applicants will establish a strong technical team comprised of a combination of new hires, key technical personnel from their affiliates, and consultants. A preliminary list of technical team candidates appears in Table 2 below.

Table 2: Preliminary Technical Team Candidates

Name	Organization	Title
Luis García-Monge	Isolux Infrastructure	Operating Director, Brazil Power Concessions
Ailton Costa	Isolux Infrastructure	Transmission Concessions Director, Brazil Power Concessions
Evandro Cavalcanti	Isolux Infrastructure	Technical Director JTE Transmissora Energía, Brazil Power Concessions
Victor Fretes	Isolux Infrastructure	O&M Director, Brazil Power Concessions
Juan Provvidente	I-USA	Vice President of Operations
Raul Magaña	I-USA	Engineering Manager
Flavio Parpinelli	I-USA	Tendering and Contracting Manager
Kenda Pollio	KP Environmental	Senior Environmental Planner and Project Director
Anthony Ciccone	Golder Associates Ltd.	Principal.
Caitlin Burley	Golder Associates Ltd.	Stakeholder Engagement Specialist
Murray G. Robertson	TransCanada	Senior Land & Community Representative
Robert A. Mattei	TransCanada	Manager, Facility Projects
Ryan McFadden	TransCanada	Senior Aboriginal Relations Advisor, Aboriginal & Tribal Relations
Larry Scheuerman	TransCanada	Manager, Energy Projects Development
Christine Cinnamon	TransCanada	Environmental Manager, Power Generation Development and Operations
Rebecca McElhoes	TransCanada	Community Relations Advisor
Art Cunningham	TransCanada	Senior Aboriginal / Tribal Relations Policy Advisor
Carl Letwin	TransCanada	Senior Land Representative
Leslie Thomas	TransCanada	Manager, Land Administration

Resumes for the above persons are included in Exhibit "F" in Volume 2.

4.3 Sample Projects

A description of sample projects, and other evidence of experience in Ontario and/ or other jurisdictions in developing, constructing and operating transmission lines or other infrastructure and why these projects and experience are relevant to the East-West Tie line project. The evidence should include a description of experience with:

- *The acquisition of land use rights from private landowners and the Crown;*
- *The acquisition of necessary permits from government agencies;*
- *Obtaining environmental approvals similar to the environmental approvals that will be necessary for the East- West Tie line;*
- *Community consultation; and*
- *Completion of the procedural aspects of Crown consultation with First Nations and Métis communities.*

4.3.1 Isolux Corsán Transmission Projects

Isolux Corsán has substantial experience with the development, construction and operation of transmission facilities throughout the world. The following briefly summarizes its experience in Brazil, the United States, India and several other countries.

4.3.1.1 Brazil Transmission Projects

In 2000, Brazil restructured its power market and introduced competition. As part of this process, the Electric Energy National Agency ("**ANEEL"**) initiated a competitive transmission procurement process under which Isolux Corsán affiliates were awarded 17 projects totaling approximately 8,000 km of 500/230 kV transmission lines. Isolux Corsán's success in the Brazilian competitive auction process — which

was primarily focussed on the selection of the lowest cost bidders — is a testament to Isolux Corsán's capability and cost competitiveness.

Isolux Infrastructure has brought into service 13 projects in Brazil (approximately 6,000 km) at a total investment cost of approximately $2.5 billion. Another four projects (approximately 2,000 km) are currently under construction; these additional projects will require further investment of approximately $1.6 billion. All of the transmission projects awarded to the company had contractual schedules of between 16 and 30 months including licensing, engineering and construction phases. Isolux Corsán brought all projects in-service on or prior to the contractual in-service date, in some cases as much as five months early (see section 7.4 for more details on Isolux Corsán's experience in completing projects on schedule). Isolux Corsán also has an excellent operability record, having exceeded reliability and operability standards imposed by the Brazilian energy sector regulator and system operator.

As a result of this process, Isolux Corsán became one of the largest private owners and operators of high-voltage transmission in Brazil. Isolux Corsán's participation also contributed substantial benefits to the Brazilian power sector. Since competition was introduced to the transmission sector, transmission costs and rates in Brazil have dropped by approximately 60% (due in part to the introduction of cost-effective construction management and procurement). Isolux Corsán's participation also delivered significant economic benefits through hiring of local employees and contracting with local suppliers.

Amazon Transmission Project — As a sample project, the Applicants have included as Exhibit "G" in Volume 2, a description and DVD of Isolux Corsán's Amazon Project. The Amazon Project entails the construction of 1,191 km of high-voltage transmission through the heart of the Amazon jungle and is one of the most technically and environmentally complex projects ever undertaken in South America.

The project combines enormous technical and environmental challenges. The 1,191 km of double-circuit 500 kV and 230 kV transmission line will be built through the heart of the Amazon and will be required to traverse dense jungle, extreme mountainous areas, rivers and swamps. At one juncture, the transmission line will be required to span 2 km across the Amazon River, the first ever power line crossing of the Amazon. In order to accomplish this feat, Isolux engineers are constructing two 295 metre high, 2,500 tonne pylons to facilitate crossing of the river; each tower will be the approximate height of the Eiffel Tower.

At another juncture, the line will traverse 70 km of swamp. In this section, Isolux engineers have designed and are constructing raft-like structures to support the transmission towers. Close to the Amazon River crossing, Isolux is constructing the Jurupari substation on a 240,000m^2 site (equivalent to approximately 50 football fields). It will house seven high powered transformers and 20 reactors (66 and 45 MVAR), and will include 6,500 linear meters of drainage pipelines. To carry out this undertaking Isolux has built 12 fully equipped camps which are being used to house up to 4,200 workers and it has also built two cement plants which, over the course of six months, are required to produce over 30,000m^3 of cement. In addition to the terrain challenges, this project poses significant seasonal difficulties. In particular, Isolux has had to stage certain work to ensure it is completed within tight time frames to avoid the January to May rainy season.

To address the environmental challenges, Isolux has retained a large team of biologists and other scientists and has undertaken numerous studies and instituted robust environmental programs including flora and fauna protection and rescue initiatives. Numerous innovative and unique measures are being instituted to prevent and mitigate ecological impacts.

Despite the complexity and enormous challenges of this project, the project is well advanced and scheduled to be completed in May 2013.

4.3.1.2 United States Transmission Projects

In early 2009, Isolux Infrastructure, through its affiliate Wind Energy Transmission Texas ("**WETT**"), a 50/50 partnership with a major asset management company, was selected as a transmission service provider ("**TSP**") by the PUCT under the State's CREZ program.[3] The Competitive Renewable Energy Zone ("**CREZ**") program was designed to facilitate the development of new transmission to deliver energy from wind farms in northwest Texas to load centers in the southeast. WETT, which was granted a transmission license by PUCT, was the only foreign consortium to be awarded a contract under the CREZ competitive procurement process and was awarded contracts to develop, construct and operate seven high-voltage transmission lines totaling 605 km. This project is currently in construction (approximately 60% complete) and I-USA is acting as the EPC contractor on this project.

Notably, WETT's successful application was largely premised on Isolux Corsán's preeminent expertise and experience in greenfield transmission development and construction and on the basis that Isolux Corsán would primarily undertake project management and engineering, procurement and construction.

[3] WETT was selected by the PUCT based on criteria similar to the filing criteria in this proceeding: "… In selecting entities to construct, operate, and maintain the [CREZ Transmission Plan's] CTP facilities, the Commission evaluated each interested Transmission Service Provider's (TSP) proposal by considering several factors, including: the interested TSP's current and expected capabilities to finance, license, construct, operate, and maintain the CTP facilities in the most beneficial and cost-effective manner; the expertise of the TSP's staff; the TSP's projected capital costs and operating and maintenance costs for each CTP facility, proposed schedule for development and completion of each CTP facility, financial resources, expected use of historically under-utilized businesses (unless the TSP is an electorate cooperative or municipally-owned utility), and understanding of this specific requirement to implement the CTP facilities; and if applicable, the TSP's previous transmission experience and historical operating and maintenance costs for existing transmission facilities." See PUCT Order dated February 30, 2009, docket no. 35665 at pp. 1 – 2, 40.

4.3.1.3 India Transmission Projects

Isolux Corsán has in the last five years made extraordinary inroads into India and in that short time span has become the largest European developer of major infrastructure projects in the country.

In 2011, Isolux Corsán was awarded contracts to construct approximately 1,600 km of transmission lines (765 kV and 400 kV) and five substations (two GIS substations and three AIS substations) with 5,730 MVAs of different transformation combinations of 765/400/220/132 kV in Uttar Pradesh, the fifth most populous state in the country. This project is the largest high-voltage transmission lines concession in the country and one of the largest in the world. With an investment of approximately $1 billion the project will carry most of the 4,600 MW generated by new thermal plants being built in the eastern territory to a population of over 200 million people.

4.3.1.4 Transmission Experience in Other Jurisdictions

In addition to Brazil, the U.S. and India, Isolux Corsán has constructed and/or operated transmission facilities in Spain, Bosnia, Mozambique, Syria, Jordan, Tunisia, Morocco, Algeria, Gabon, Pakistan, Mexico, El Salvador, Guatemala and Argentina; notably:

- Since 2000, Isolux Corsán has built over 5,000 km of high-voltage lines and 30 substations in Mexico, becoming a preferred provider for the Federal Electric Commission (CFE).

- Isolux Corsán has developed four major transmission projects in Argentina totalling approximately 1,500 km; this is part of an initiative to expand Argentina's transmission network to provide broader national coverage.

- Isolux Corsán is building the largest high-voltage transmission line in Kenya, and one of the largest in Africa. The line will be 428 km long at a voltage of 400 kV.

- Isolux Corsán recently signed an agreement with the government of Gabon to develop 200 km of transmission lines to bring electricity to 33 rural villages in the northeast of the country that currently have no power supply.

The table attached as Appendix "A" to this section provides a sample list of recent transmission projects that Isolux Corsán has developed or is currently developing and provides details on the associated regulatory, land acquisition, environmental approval, community consultation and Aboriginal engagement and participation processes for each project.

A complete list of all transmission projects that Isolux Corsán has developed since 2000 or is currently developing is attached as Appendix "B" to this section.

4.3.2 TransCanada Experience

TransCanada operates over 60,000 km of pipeline and owns over 10,000 MW of electrical generation assets. TransCanada has significant technical expertise and strength in every aspect from project planning to execution to operation. In particular, TransCanada has superior safety performance from planning to operations, excellent relationships with experienced contractors, a proven ability to secure lasting and respectful relationships with First Nations, Métis and other communities, and a best practices capital project management and quality assurance system.

The table in Appendix "C" to this section lists recent sample linear infrastructure projects within Canada that TransCanada has developed and brought into service or intends to bring into service. These projects illustrate TransCanada's substantial experience with the implementation of major linear projects.

All of the projects listed are currently regulated by the NEB, which has similar processes to the OEB for approving the construction and operation of new linear infrastructure. As a result, TransCanada has a wealth of relevant experience in the management and execution of complex development activities that are required to ensure successful implementation of large linear infrastructure projects.

In addition, TransCanada is an active participant in energy infrastructure development, construction and facility operation throughout Ontario. Current linear energy infrastructure development includes the 13 km Parkway pipeline project near Brampton, Ontario. TransCanada also owns and operates large scale electrical generating facilities including the combined cycle Halton Hills Generating Station (683 MW) and, through a joint venture with Ontario Power Generation, the combined cycle Portlands Energy Center (550 MW) and the associated electrical connection facilities related to these projects.

TransCanada has constructed and currently operates 115 kV, 230 kV and 345 kV transmission systems in Canada and the US to interconnect load and generation assets to the local transmission grid. This includes a 48 km 115 kV tie-line for the Kibby Wind Power Project in Maine.

4.3.3 Relevance of the Applicants' Experience to the E-W Tie

As demonstrated by the responses to sections 4.3.1 and 4.3.2, both of the Applicants have substantial experience and expertise developing projects under challenging weather and physical conditions comparable to the E-W Tie project and which entail comparable regulatory and consultative processes, including those relating to:

- Acquiring land use rights held by private landowners and government;
- Acquiring necessary permits from government agencies;

- Acquiring environmental approvals similar to the environmental approvals that will be necessary for the E-W Tie;
- Community consultation; and
- Consultation with First Nations, Métis and other aboriginal communities.

4.4 Applicants' Business Practices

Evidence that the applicant's business practices are consistent with good utility practices for the following:

- *design;*
- *engineering;*
- *material and equipment procurement;*
- *right-of-way and other land use acquisitions;*
- *licensing and permitting;*
- *consultations, both with First Nation and Métis, and other communities*
- *construction;*
- *operation and maintenance;*
- *project management;*
- *safety;*
- *environmental compliance; and*
- *regulatory compliance*

Isolux Corsán and TransCanada have developed, built and operated transmission, pipeline and other infrastructure projects in North America and numerous other countries around the world.

In the jurisdictions where they operate, Isolux Corsán and TransCanada implement policies, procedures and practices that comply with all applicable reliability standards, operation and maintenance codes/rules, environmental requirements, procurement guidelines, safety codes/standards and other regulatory requirements. Isolux Corsán and TransCanada are strongly committed to lawful, sustainable, safe and responsible development through corporate responsibility, risk management, health and safety and environmental sustainability policies and programs.

Appendix "D" to this section contains a table that identifies how the Applicants' business practices are consistent with good utility practice in the specific areas identified by the Board.

4.5 Plan to Address the Challenges of the East-West Tie

A description of:

- *the challenges involved in achieving the required capacity and reliability of the East-West Tie line, including challenges related to terrain and weather; and*
- *the plan for addressing these challenges though the design and construction of the line (e.g. number and spacing of towers, planned resistance to failure).*

The Applicants have identified a number of challenges in achieving the required capacity and reliability of the E-W Tie. Isolux Ingeniería's skills in designing and constructing transmission lines in challenging environments combined with TransCanada's familiarity with Northern Ontario and winter construction techniques, equips the Applicants to address these challenges. The following briefly identifies the Applicants' plans for addressing some of these challenges (see also sections 6.5 and 7.5 for further details about the attributes of the Applicants' plan).

4.5.1 Accessibility

The E-W Tie will be difficult to access due to the rugged terrain and wetlands, which will prevent vehicular access to many parts of the transmission line route. Isolux Ingeniería will maximize use of existing access roads within or around the cleared ROW, to the extent the new ROW parallels the existing ROW, in order to minimize construction disturbance to the natural surroundings. Isolux Ingeniería also plans to set up temporary work areas within the existing ROW to the maximum extent allowed.

If the existing access roads are deemed unsuitable, Isolux Ingeniería's primary course of action will be to repair or rebuild the existing access roads. In areas that are too cost prohibitive to build an access road or where it is determined that new road construction is not desirable due to environmental or other concerns, helicopters will be used as an alternative method for transporting equipment, materials and workers. Helicopters also help in expediting the delivery of equipment and assisting with the stringing of the tower structures. Isolux Corsán has successfully implemented the use of helicopters on the WETT project and on other projects and believes the E-W Tie project may be a candidate for helicopter use.

4.5.2 Terrain

Isolux Ingeniería plans to address the complex terrain challenges in part through the design of a new family of steel lattice tower structures that will ensure that critical physical and environmentally sensitive conditions are avoided. The new family of towers will be designed specifically to the requirements of the Project rather than using the existing X10 tower family. The new family of towers will be fully designed, tested and customized for the site based on weather conditions, site conditions, topographic constraints and project limitations and requirements.

Isolux Ingeniería will have to navigate the numerous wetlands that exist in the project area. Wetlands, which are characterized by wetland vegetation and saturated or poorly drained soils, will be identified early on during the environmental assessment and clearly delineated on construction drawings. Mitigation includes designing around these environmentally sensitive areas and avoiding as many wetland crossings as possible. In instances where this is not possible, Isolux Ingeniería will restore, replace or recreate the same amount of wetland that is disturbed during construction.

Isolux Ingeniería's detailed (individual) tower foundation design will begin with an initial geotechnical investigation with borings at one km intervals, or closer in areas where special soil conditions are suspected, along the proposed route. This early detailed geotechnical investigation will help mitigate against the possibility of discovering unexpected soil conditions and a redesign of foundations in the middle of construction, mitigating potential time delays, added costs and environmental impact.

The selected route is expected to have highly variable soil conditions, ranging from a thin layer of soil on top of bedrock to deep pockets of sand and post-glacial sediment. The initial geotechnical investigation will enable Isolux Ingeniería engineers to provide site-specific foundation designs that may also provide opportunities to reduce the size of the foundations.

During construction, Isolux Ingeniería will safeguard against soil erosion as much as possible in order to protect the water quality of the numerous streams and rivers along the route. Extra precaution against steep slopes, erosive soil types, and excavation activities will be carried out under an engineer approved soil erosion and sedimentation control plan.

Isolux Ingeniería's plan includes two foundation designs, a rock anchor type and an auger type, for each tower at varying depths. With at least five tower types expected

to be included in the new structural family and two foundations per tower type, plus some special cases, more than ten foundation designs are expected for the E-W Tie project. Once the final tower locations have been determined, additional geotechnical investigations and studies will be conducted for the structure locations. Based on the geotechnical reports, the foundation schedule will be prepared by the engineering team and released to the contractors.

4.5.3 Climate

Due to the project's site location, the climate will likely expose workers to extreme weather conditions and reduced working hours. The Applicants and Isolux Ingeniera will ensure that appropriate safety procedures and requirements are put in place to manage extreme weather conditions. These will ensure that workers are safely transported to and from the work site and that on-site conditions are safe.

Isolux Ingeniería understands the potential for delays in the delivery of materials and equipment due to inclement weather and ground conditions that impede vehicular access (e.g., saturated or slippery conditions). To that end, Isolux Ingeniería will schedule the majority of the deliveries to accommodate seasonal conditions and environmental constraints. Timing of deliveries will be scheduled to manage risk associated with the inability to secure materials. Detailed transportation studies will commence upon the Applicants being named as the designated transmission developer. The materials and equipment will be stored at two material yards, one for each transmission segment. Appropriate storage areas will be arranged for each type of product with regard to the class, importance, quantity, characteristics and designated use in order to ensure adequate protection and preservation.

While winter conditions will slow down productivity to some degree, Isolux Ingeniería will implement measures to reduce this risk, including undertaking the majority of ROW clearing and building of access roads during appropriate climatic conditions to ensure that the construction phase of the project will proceed on schedule. Isolux

Ingeniería intends to continue major construction, including pouring foundations, tower erection, and line stringing, throughout the year.

Appendix A — Samples of Isolux Corsán Project Experience

Samples of the Isolux Corsán's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Environmental Approval and Community Consultation Processes	Aboriginal Engagement and Participation
Brazilian Transmission Projects Transmission Lines and Substations Capital cost = US $4.1 billion	17 projects totalling approximately 8,000 km of 500/230 kV transmission lines and substations 13 projects in-service; 4 currently under construction	Isolux Corsán awarded projects through a competitive auction process initiated by the Agência Nacional de Energia Elétrica (ANEEL) Environmental permits granted by Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais Renováveis (IBAMA)	Brazilian law requires the transmitter to acquire ROWs and/or easements. This process requires the transmitter to try to "amicably negotiate" a right-of-way agreement with landowners, failing which the transmitter may resort to judicial processes.	Brazil has a rugged and diverse natural environment and its environmental assessment and approval regime is aimed at minimizing and mitigating impacts on sensitive physical environments and ecosystems (rainforest, rivers/lakes, etc.), biodiversity, species and indigenous people. Environmental assessment process that requires: preparation of terms of reference; alternate route identification for proposed transmission lines; environmental impact assessments; public open house processes; and, consultation with state and federal environmental agencies to address potential environmental issues and potential impacts on aboriginal peoples.	A project's Environmental Impact Study must provide an analysis of the relationship with and potential impacts on aboriginal peoples; consultation on route and mitigation and/or compensation programs may be required. The Institution of the Historical and Artistic National Patrimony (IPHAN) must approve the route and programs to be developed in indigenous territories (i.e. training in reforestation, sustainability farm or fish factory) Isolux Corsán signed and implemented a Letter of Commitment with FUNAI (The National Indian Foundation) outlining agreed upon programs and compensation

Samples of the Isolux Corsán's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Environmental Approval and Community Consultation Processes	Aboriginal Engagement and Participation
Wind Energy Transmission Texas Transmission Lines and Substations Capital Cost = US $750 million	50/50 partnership with a major asset management company; joint managerial board oversees project management. 605 km of 345kV transmission line and 6 substations (345kV) to facilitate the development of new transmission to deliver energy from wind farms in north-west Texas to load centers in the southeast Construction is currently underway. As all CREZ Projects COD will be before December 31, 2013.	Selected as a transmission service provider by the Public Utility Commission Texas under the State's Competitive Renewable Energy Zones program (only foreign consortium selected) WETT's first rate hearing is currently underway and a settlement has been reached with all of the interveners Numerous federal, state, and local permits and approvals have been obtained	In compliance with self-imposed practices and applicable rules, the land acquisition process involves flexible negotiations with landowners with the objective of reaching amicable and reasonable agreements to acquire the easements. The process is similar to the established in Ontario for that purpose.	Completed the environmental assessment process and routing analysis as part of obtaining three Certificates of Convenience and Necessity (CCN). CCN process akin to s. 92 proceeding. CCN process was a 6-month Commission proceeding involving Commission staff and an average of approximately 10 interveners WETT settled its three CCN proceedings without a hearing	Consulted with potentially affected Native American Tribes (i.e., the Apache Tribe of Oklahoma, the Comanche Nation of Oklahoma and the Kiowa Tribe of Oklahoma) on how the project might adversely impact their traditional cultural properties and historic properties No potential adverse impacts were identified through the consultation process

Samples of the Isolux Corsán's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Environmental Approval and Community Consultation Processes	Aboriginal Engagement and Participation
Indian Transmission Project (State of Uttar Pradesh) Transmission Lines and Substations Capital Cost = US $1.054 billion	1,600 km of 765kV and 400kV transmission lines 5 substations (2 GIS substations and 3 AIS substations) Designed to transmit over 4,600 MW generated by new thermal plants	Licensing is coordinated with the Central/State Utility and with the Central/State Regulator through both in-house personnel and specialized consultants. Isolux Corsán is in the process of obtaining the Transmission License for the Project.	Land acquisition is typically required only for substations and is done through direct negotiations with private owners or through lease agreements with the government. Affected landowners also required to be compensated for specific tower construction activities.	During the bidding process several public hearings are held before the UPERC (the State Regulator) to address the terms of the Concession Contract. The public may raise concerns regarding development of the project and community impacts. Once the project is awarded, further public hearings held before the regulator to discuss the grant of the Transmission License to the selected bidder. The public may raise further concerns regarding the development of the Project from an environmental, business or social perspective. The UPERC take into account all the concerns raised by the public before approving the Concession Contract in the first stage or before granting any license in the second stage.	Not applicable.

Appendix B — List of Isolux Corsán Transmission Projects Since 2000

Isolux Infrastructure - POWER Project Concessions

Id	TL	Corporate Name	Country	kV	km	Investment million USD
1	ETEE	Expansion Transmissao de Energia Eletrica	Brazil	500	588	167
2	ETIM	Expansion Transmissao Itumbiara Marimbondo	Brazil	500	212	91
3	CPTE	Cahoeira Paulista Transmissora de Energia	Brazil	500	181	98
4	VCTE	Vila do Conde Transmissora de Energia	Brazil	500	324	147
5	PPTE	Porto Primavera Transmissora de Energia	Brazil	230	515	186
6	ITE	Itumbiara Transmissora de Energia	Brazil	500	814	404
7	SMTE	Serra da Mesa Transmissora de Energia	Brazil	500	681	310
8	LTT	LT Triangulo	Brazil	500	708	241
9	RPTE	Riberao Preto Transmissora de Energia	Brazil	500	413	110
10	SPTE	Serra Paracatu Transmissora de Energia	Brazil	500	246	114
11	PCTE	Poços de Caldas Transmissora de Energia	Brazil	500	308	140
12	JTE Sur*	Jauru Transmissora de Energia (South Phase)	Brazil	230	345	163
13	JTE Norte*	Jauru Transmissora de Energia (Norte Phase)	Brazil	230	595	135
14	IENNE	Interligaçao Eletrica Norte e Nordeste	Brazil	500	720	339
15	LXTE	Linhas de xingú Transmissora de Energia	Brazil	500	508	665
16	LMTE	Linhas de Macapá Transmissora de Energia	Brazil	500 / 230	683	621
17	LTTE	Linhas de Taubaté Transmissora de Energia	Brazil	500	247	181
		TOTAL BRAZIL			**8088**	**4110,72**
18	UPPTCL	Uttar Pradesh Transmission Company	India	765/400	1600	1054
		TOTAL INDIA			**1600**	**1054,14**
19	WETT	Wind Energy Transmission Texas	USA	345	605	750
		TOTAL USA			**605**	**750,00**
		TOTAL			**10.293**	**5914,86**

Isolux Infrastructure - TOLLROADS Project Concessions

Id	Project	Country	km	Construction value million USD
1	NH1 Panipat- Jalandhar	India	291	755
2	NH2 Varanasi - Aurang	India	192,4	583,7
3	NH6 Surat- Hazira	India	133	394,1
4	NH8 Kishang- Beawar	India	94	214,9
		TOTAL INDIA	**710,4**	**1947,7**
5	CAMS Monterrey- Saltillo	Mexico	95,13	219,5
6	COPEXA Perote Xalapa Highway	Mexico	59,63	224,2
		TOTAL MEXICO	**154,76**	**443,7**
7	BR116 Viabahía	Brazil	680,6	1930
8	A4 Madrid Ocaña Expressway	Spain	64	107,6
		TOTAL OTHERS	**744,6**	**2037,6**
	TOTAL		**1.609,76**	**4.429,00**

ISOLUX CORSÁN

'TURNKEY PROJECTS' TRANSMISSION LINES EXECUTED SINCE 2000

PROJECT NAME	YEAR OF EXECUTION	VOLTAGE (kV)	LENGTH KM	CLIENT	COUNTRY	VALUE USD
T.L. CHAMPAYÁN-ANAHUAC POTENCIA	2000	400	96	CFE	MEXICO	21.788.199
T.L. PUERTO ALTAMIRA-CHAMPAYÁN LINEA 1	2000	400	33	CFE	MEXICO	15.509.141
500 kV L.T SAMAMBAIA - ITUMBIARA - EMBORCAÇAO AND ASSOCIATED SUBSTATIONS	2002	500	285	ETEE	BRAZIL	132.367.265
500 kV T.L. ITUMBIARA - MARIMBONDO AND ASSOCIATED SUBSTATIONS	2002	500	213	ETIM	BRAZIL	42.646.629
500 kV T.L. TIJUCO PRETO - CACHOEIRA PAULISTA AND ASSOCIATED SUBSTATIONS	2002	500	181	CPTE	BRAZIL	42.137.700
T.L. AGUASCALIENTES POT-CALERA II	2002	230	154,8	CFE	MEXICO	8.625.344
T.L. MOCTEZUMA - EL ENCINO	2002	400	206,2	CFE	MEXICO	45.107.176
BOANE-SALAMANGA	2003	66	81	EDM	MOZAMBIQUE	3.250.000
INFULENE-CTM/SE6	2003	66	4,5	EDM	MOZAMBIQUE	3.250.000
KAEDI-BOGHE	2003	90	98	SOGEM	MAURITAINE	5.740.000
T.L. AGUASCALIENTES PABELLON	2003	115	53	CFE	MEXICO	4.100.000
T.L. LEÓN CENTRO-ENTQ.LEON NORTE-LEON ALFARO	2003	115	3,5	CFE	MEXICO	2.800.000
T.L. MATOLA-INFULENE-MAPUTO	2003	275	8,1	EDM	MOZAMBIQUE	1.670.000
T.L. MOCTEZUMA - NUEVO CASAS GRANDES	2003	400	165,25	CFE	MEXICO	23.434.221
T.L. NACOZARI - NUEVO CASAS GRANDES II	2003	400	213,4	CFE	MEXICO	40.662.339
T.L. OBREGÓN 4 - GUAYMAS II	2003	400	128,4	CFE	MEXICO	20.300.000
T.L. PRIMERO DE MAYO - CAÑADA	2003	400	220,5	TECHINT	MEXICO	2.132.775
T.L. STA.ANA-NOGALES AEROPUERTO, NOGALES AEROPUERTO ENTQ.MAGDALENA-NUEVO NOGALES Y NOGALES AEROPUERTO ENTQ.STA.ANA-NOGALES	2003	230	104	CFE	MEXICO	11.200.000
T.L. TEPATIPLÁN-CAPILLA DE GUADALUPE	2003	115	34,4	CFE	MEXICO	1.840.000
MATAM-KAEDI	2003	90	87	SOGEM	MAURITAINE	5.580.000
T.L. SIDI MANSOUR-MSAKEN II	2004	225	98,2	STEG	TUNISIA	7.030.000
230 kV PORTO PRIMAVERA-IMBIRISSU.DOURADOS AND ASSOCIATED SUBSTATIONS	2005	230	507	PPTE	BRAZIL	121.918.269
YAUTEPEC-TOPILEJO PROJECT	2005	400	47	CFE	MEXICO	11.790.000
LOT 702: PAGES VERACRUZ	2006	115	3,5	CFE	MEXICO	1.530.000
LOT 702: LAGUNA DE TÉRMINOS-ENTRONQUE CARMEN-CONCORDIA (METRO)	2006	115	1,1	CFE	MEXICO	890.000
LOT 702: CARDENAS-CHONTALPA	2006	115	21,4	CFE	MEXICO	1.460.000
500 kV TL CUIABA - ITUMBIARA AND ASSOCIATED SUBSTATIONS	2006	500	811	ITE	BRAZIL	271.341.698
PROJECT GTC/14/2002:	2006	132/66		KAHRAMAA	QATAR	22.500.000
PROJECT GTC/144/2008	2008	66/11		KAHRAMAA	QATAR	152.000.000
LOT 701	2006	115/69	121,39	SIEMENS/CFE	MEXICO	11.260.000
500 Kv TL SERRA DA MESA 2- LUZIANIA- SAMAMBAIA- PARACATU- EMBORCACAO AND ASSOCIATED SUBSTATIONS	2006	500	678	SPTME	BRAZIL	269.926.429
500 kV TL TUCURUI - VILA DO CONDE AND ASSOCIATED SUBSTATIONS	2006	500	325	VCTE	BRAZIL	87.303.687
T.L. CHILPACINGO POT-CHILPACINGO	2006	115	2,4	CFE	MEXICO	820.000
T.L. CHILPACINGO POT-ENTQ.CHILPACINGO-CHILAPA	2006	115	14,6	CFE	MEXICO	2.370.000
T.L. CHILPACINGO POT-ENTQ.MEZCALA-PIE DE LA CUESTA	2006	230	0,2	CFE	MEXICO	1.590.000
T.L. JILOTEPEC POT - DAÑU	2006	230	37,3	CFE	MEXICO	5.620.000
T.L. JILOTEPEC POT-ENTQ.JILOTEPEC -ACULCO	2006	115	1,7	CFE	MEXICO	580.000
T.L. JILOTEPEC-ACULCO	2006	115	0	CFE	MEXICO	240.000
T.L. STA.LUCIA - MACUSPANA II	2006	400	13,4	CFE	MEXICO	11.070.000
YACIRETA RINCON STA MARIA-RODRIGUEZ/ SUBTRAMO NORTE INTERCONNECTION	2006	500	672	CAF/UESTY	ARGENTINE	143.868.000
T.L. MATIGUAS-SIUNA	2007	69	141	ENATREL	NICARAGUA	4.656.598
T.L. CAPANDA-LUCALA-VIANA	2007	400	300	MINEA	ANGOLA	120.000.000
T.L. LUCALA-UIJE	2010	220	300	MINEA	ANGOLA	45.000.000
LOT 149 RFO OPTIC FIBRE CABLE CENTRAL NETWORK	2007	400/230/115	1954	CFE	MEXICO	45.970.000
GUATEMALA-MÉXICO OHL 400 kV INTERCONNECTION	2007	400	40	INDE	GUATEMALA	13.800.000
T.L. 1116 TRANSFORMACIÓN NOROESTE (PHASE 1)	2008	220	80	CFE	MEXICO	12.000.000
PROYECTO 218 LT 400 KV LA VENTOSA-JUILE	2010	400	135	CFE	MEXICO	81.420.000
PROYECTO 1116 2ª FASE LT 400 KV LAS GLORIAS ENTQ VILLA DE GRACIA-AEROPUERTO	2010	400	17	CFE	MEXICO	14.270.000
PROYECTO 1116 2ª FASE LT 115 KV LAS GLORIAS-PESQUERÍA	2010	115	11	CFE	MEXICO	4.380.000
L.T. AZUL DE CORTES	2010	115	11	AZUL DE CORTES	MÉXICO	3.000.000
L.T. OAXACA II, III Y IV	2010	230	33	SIEMENS/ACCIONA	MÉXICO	7.400.000
LOT D: 500 kV TL ITUMBIARA - SAO GOTARDO - NOVA PONTE - EMBORCAÇAO - BOM DESPACHO-ESTREITO AND ASSOCIATED SUBSTATIONS	2008	500	695	LTT	BRAZIL	259.572.493
500 kV TL SAO SIMAO - MARIMBONDO, RIBERAO PRETO MARIMBONDO AND ASSOCIATED SUBSTATIONS	2009	500	408	RPTE	BRAZIL	109.882.870
LOT A: 500 kV TL PARACATU 4 - PIRAPORA 2 AND ASSOCIATED SUBSTATIONS	2009	500	244	SPTE	BRAZIL	120.775.046
LOT B: 500 kV TL JAGUARA - RIBEIRAO PRETO AND ASSOCIATED SUBSTATIONS	2009	500	300	PCTE	BRAZIL	144.870.333
T.L. 500 KV RIBEIRO GONZALVEZ	2010	500	300	IENNE	BRAZIL	110.000.000
LOT 500 KV T.L. COLINAS-SAO JOAO DE PIAUÍ	2010	500	420	IENNE	BRAZIL	75.000.000
T.L. ESTREITO-IMPERATRIZ	2010	500	140	CESTE	BRAZIL	30.000.000
INTERCONEXIÓN NEA-NOA - TRAMO ESTE	2011	500	572	CAF/UESTY	ARGENTINE	100.000.000
INTERCONEXIÓN COMAHUE-CUYO - TRAMO NORTE	2011	500	197	CAF/UESTY	ARGENTINE	75.000.000
INTERCONEXIÓN CALINGASTA-RODEO-IGLESIA T.L. 500 KV	2011	500	100	EPRE	ARGENTINE	50.000.000
KWANZA SUL PROJECT O.H.L.	2011	30/60	140	ENE	ANGOLA	60.000.000
MALANGE PROJECT UNDERGROUND T..L.	2011	15	20	ENE	ANGOLA	33.000.000

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'TURNKEY PROJECTS' TRANSMISSION LINES IN EXECUTION

PROJECT NAME	CONTRACT DATE	PROJECT DATA (kV, km, Customer, Country)				VALUE M. USD
T.L. 500 KV INTERCONEXIÓN ESPERANZA-CALAFATE	2010	132	150	CAF/UESTY	ARGENTINA	35
LOT T.L. 500 KV TUCURUI-XINGU-JURUPARI	2008	500	600	ANNEEL	BRAZIL	600
LOT B T.L. 500/230 KV. ORIXIMINÁ-JURUPARI-LARANJAL-MACAPÁ	2008	230	600	ANNEEL	BRAZIL	600
LOT A: TL 230 KV JAURU-SAMUEL	2009	230	600	PLENA	BRAZIL	34
HV, MV AND LV NETWORKS CABINDA-LANDANA O.H.L.	2010	30/60	105	ENE	ANGOLA	30
GAS POWER PLANT FÚTILA O.H.L.	2010	30/60	12	ENE	ANGOLA	90
ELECTRIFICATION LIBREVILLE T.L. LIBREVILLE-FRANCEVILLE	2011	60	100	MINIST. ENERGÍA	GABÓN	15
T.L. 220/132 KV AND 1.300 KM MSETCL (MAHATRANSCO) REF. LL2B	2011	220/132	651	MAHATRANSCO	INDIA	50,8
400 kV DOUBLE CIRCUIT TRANSMISSION LINE	2010	400	132	UPPTCL	INDIA	12,8
TL 345 kV COTTONWOOD - DERMOTT / DOUBLE CIRCUIT	2011	345	119	WETT	USA	110,2
TL 345 kV SCURRY - LONG DRAW / DOUBLE CIRCUIT	2011	345	82	WETT	USA	73,7
TL 345 kV LONG DRAW - GRELTON / DOUBLE CIRCUIT CAPABLE	2011	345	89	WETT	USA	68,6
TL 345 kV GRELTON - ODESSA / DOUBLE CIRCUIT CAPABLE	2011	345	80	WETT	USA	69,5
TL 345 kV LONG DRAW - SAND BLUFF / DOUBLE CIRCUIT CAPABLE	2011	345	125	WETT	USA	96,8
TL 345 kV SAND BLUFF - DIVIDE / DOUBLE CIRCUIT CAPABLE	2011	345	60	WETT	USA	47,3
TL 345 kV SAND BLUFF - BEARKAT / DOUBLE CIRCUIT CAPABLE	2011	345	47	WETT	USA	38,0

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'TURNKEY PROJECTS' SUBSTATIONS EXECUTED SINCE 2000

PROJECT NAME	YEAR OF EXECUTION	VOLTAGE (kV)	CLIENT	COUNTRY	VALUE USD
SAN CRISTOBAL AND ENGOMBE SUBSTATIONS	2000	138/34,5/12,5	CDE	DOMINICAN REPUBLIC	7.800.345
LOT 306: 1 SUBSTATION OF 115 kV	2001	400/115	CFE	MEXICO	45.000.000
LOT 306: 1 SUBSTATION OF 400/230 kV	2001	400/230	CFE	MEXICO	45.000.000
LOT 306: 12 SUBSTATIONS OF 115/13,8	2001	115/13,8	CFE	MEXICO	45.000.000
LOT 306: 2 SUBSTATIONS OF 230 kV	2001	230	CFE	MEXICO	45.000.000
LOT 306: 2 SUBSTATIONS OF 230/115 kV	2001	230/15	CFE	MEXICO	45.000.000
LOT 407: CHAMPAYAN SUBSTATION	2001	400	CFE	MEXICO	26.681.577
LOT 407: PUERTO ALTAMIRA	2001	400	CFE	MEXICO	19.169.960
12 SUBSTATIONS INCLUDED IN THE REHABILITATION OF THE TRANSMISSION SYSTEM	2002	115/46	CEL	EL SALVADOR	17.500.000
BATAHOLA, PORTEZUELO SUBSTATION	2002	138/13,8	ENTRESA	NICARAGUA	5.500.000
ELECTRICITY II PROJECT: 6 SUBSTATIONS	2003	110/66/33	EDM	MOZAMBIQUE	5.900.000
EMBORCAÇAO SUBSTATION	2003	500	ETEE	BRAZIL	132.367.265
ITUMBIARA SUBSTATION	2003	500	ETEE	BRAZIL	132.367.265
LOT 414: AGUASCALIENTES POT. SUBSTATION	2003	230	CFE	MEXICO	2.355.692
LOT 414: CALERA II SUBSTATION	2003	230	CFE	MEXICO	1.461.070
LOT 414: EL ENCINO SUBSTATION	2003	230	CFE	MEXICO	1.691.030
LOT 414: MOCTEZUMA SUBSTATION	2003	230	CFE	MEXICO	5.552.599
MATOLA PROJECT: INFULENE SUBSTATION	2003	275/66	EDM	MOZAMBIQUE	12.000.000
MATOLA PROJECT: MATOLA SUBSTATION	2003	275/66	EDM	MOZAMBIQUE	12.000.000
MATOLA PROJECT: SE5 SUBSTATION	2003	66	EDM	MOZAMBIQUE	12.000.000
SAMAMBAIA SUBSTATION	2003	500	ETEE	BRAZIL	132.367.265
TICUANTEPE AND ASSOCIATED WORKS	2003	230	ENATREL	NICARAGUA	6.346.811
CONTRACT S/S 23/2001: AMMAN NORTH GIS SUBSTATION	2004	132	NEPCO	JORDAN	4.680.000
CONTRACT S/S 23/2001: AMMAN NORTH SUBSTATION	2004	400/132/33	NEPCO	JORDAN	9.580.000
CONTRACT S/S 23/2001: AMMAN SOUTH SUBSTATION	2004	33	NEPCO	JORDAN	530.000
CONTRACT S/S 23/2001: QATRANA EXTENSION	2004	132/33	NEPCO	JORDAN	840.000
CONTRACT S/S 23/2001: QATRANA SUBSTATION	2004	400/132/33	NEPCO	JORDAN	14.250.000
ITUMBIARA SUBSTATION	2004	500	ETIM	BRAZIL	42.646.629
LOT 610: MOCTEZUMA SUBSTATION	2004	230	CFE	MEXICO	1.510.000
LOT 610: NUEVO CASAS GRANDES SUBSTATION	2004	230	CFE	MEXICO	6.260.000
LOT 613: CAPILLA DE GUADALUPE SUBSTATION	2004	115	CFE	MEXICO	2.500.000
LOT 613: PABELLON SUBSTATION	2004	115	CFE	MEXICO	690.000
LOT 613: SAN ANTONIO SUBSTATION	2004	115	CFE	MEXICO	580.000
LOT 613: SAN FRANCISCO SUBSTATION	2004	115	CFE	MEXICO	620.000
LOT 613: TEPATITLAN SUBSTATION	2004	115	CFE	MEXICO	340.000
MARIMBONDO SUBSTATION	2004	500	ETIM	BRAZIL	42.646.629
CACHOEIRA PAULISTA SUBSTATION	2005	500	CPTE	BRAZIL	42.137.700
CONTRACT S/S 62/2002: AL HASSAN INDUSTRIAL STATE	2005	132/33	NEPCO	JORDAN	3.600.000
CONTRACT S/S 62/2002: REHAB SUBSTATION	2005	132/33	NEPCO	JORDAN	3.600.000
CONTRACT S/S 62/2002: ZERQA SUBSTATION	2005	132/33	NEPCO	JORDAN	3.600.000
PEMBA PROJECT SUBSTATION: CPS EXTENSION	2005	110/33	EDM	MOZAMBIQUE	4.500.000
PEMBA PROJECT SUBSTATION: NAMPULA	2005	110/33	EDM	MOZAMBIQUE	4.500.000
PEMBA PROJECT SUBSTATION: PEMBA	2005	110/33	EDM	MOZAMBIQUE	4.500.000
PROJECT GTC 14/2002: URGENT TRANSMISSION NETWORK. REINFORCEMENT OLYMPIC GAMES	2005	66	KAHRAMAA	QATAR	19.000.000
TIJUCO PRETO SUBSTATION	2005	500	CPTE	BRAZIL	42.137.700
BARRA DO PEIXE SUBSTATION	2006	230	ITE	BRAZIL	271.341.698
CUIABA SUBSTATION	2006	500	ITE	BRAZIL	271.341.698
DOURADOS SUBSTATION	2006	230	PPTE	BRAZIL	121.918.269
IMBIRUSSU SUBSTATION	2006	230	PPTE	BRAZIL	121.918.269
ITUMBIARA SUBSTATION	2006	500	ITE	BRAZIL	271.341.698
NOVA PORTO PRIMAVERA SUBSTATION	2006	230	PPTE	BRAZIL	121.918.269

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'TURNKEY PROJECTS' SUBSTATIONS EXECUTED SINCE 2000

PROJECT NAME	YEAR OF EXECUTION	VOLTAGE (kV)	CLIENT	COUNTRY	VALUE USD
RIBEIRAOZINHO SUBSTATION	2006	500/230	ITE	BRAZIL	271.341.698
RIO VERDE NORTE SUBSTATION	2006	500	ITE	BRAZIL	271.341.698
TUCURUI SUBSTATION	2006	500	VCTE	BRAZIL	87.303.687
VILA DO CONDE SUBSTATION	2006	500	VCTE	BRAZIL	87.303.687
AL-KHISSA O801 (GIS)	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
AL-KHISSA NORTH O806	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
AL-KHISSA WEST O805	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
EDC SIDRA SUBSTATION	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
GTC 144/2006 PHASE VIII SUBSTATIONS	2007		KHARAMAA	QATAR	152.000.000,00
LOT 702: LAGUNA DE TERMINUS, CARDENAS AND CHONTALPA SUBSTATIONS EXTENSION	2007	115	CFE	MEXICO	4.900.000
LOT 902: CHILPACINGO POT.	2007	230/115	CFE	MEXICO	12.380.000
LOT 902: DAÑU	2007	230	CFE	MEXICO	1.000.000
LOT 902: JILOTEPEC + MVAR	2007	115	CFE	MEXICO	1.290.000
LOT 902: JILOTEPEC POT. BANCO I	2007	230/115	CFE	MEXICO	12.060.000
LOT 902: MACUSPANA II	2007	230	CFE	MEXICO	1.880.000
LOT 902: SAN MARTIN POTENCIA	2007	115	CFE	MEXICO	1.170.000
LOT 902: SANTA LUCIA	2007	230	CFE	MEXICO	5.350.000
LOT 902: XUL-HA BANCO I	2007	230/115	CFE	MEXICO	5.020.000
LUSAIL DEVELOPMENT SUPER-1 O811	2007	230/66/11 KV	KHARAMAA	QATAR	152.000.000,00
MESSAEED INDUSTRIAL CITY O809	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
MESSAEED INDUSTRIAL CITY O810	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
MIC SUPER (MODIFICATION) O817	2007	230/66 KV	KHARAMAA	QATAR	152.000.000,00
MOBILE SUBSTATION	2007	138/24,9/13,8	ENTRESA	NICARAGUA	1.000.000
NEW DOHA J (EXTENSION) O812 (GIS)	2007	230/66/11 KV	KHARAMAA	QATAR	152.000.000,00
NEW DOHA-G O802	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
NUEVA PIMENTEL, VILLA VASQUEZ-ANILLO NOROESTE, EL EMBRUJO-SANTIAGO SUBSTATIONS	2007	138	CDE	DOMINICAN REPUBLIC	10.000.000
QATAR FOUNDATION SUPER (MODIFICATION) O814	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
SOUTH EAST WAKRAH O807	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
SOUTH WEST WAKRAH 1 (MODIFICATION) O816	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
SOUTH WEST WAKRAH O808	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
TIPITAPA EXTENSION SUBSTATION AND CIVIL WORKS	2007	138/13,8	ENTRESA	NICARAGUA	3.000.000
TISHREEN SUBSTATION	2007	230/66/20	PEEGT	SYRIA	28.750.000
UMM SALAL ALI (MODIFICATION) O813	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
UMM SALAL WEST O804	2007	66/11 KV	KHARAMAA	QATAR	152.000.000,00
WAKRAH 2 (MODIFICATION) O815	2007	132/66/11 KV	KHARAMAA	QATAR	152.000.000,00
YAUTEPEC - TOPILEJO SUBSTATION EXTENSION	2007	115	CFE	MEXICO	6.030.000
BOM DESPACHO SUBSTATION	2008	500	LTT	BRAZIL	259.572.493
CONTRACT 395: HASSAKEH	2008	400/230	PEEGT	SYRIA	25.600.000
CONTRACT 395: WEST ALEPPO SUBSTATION	2008	400/230	PEEGT	SYRIA	25.600.000
DIMAS EXTENSION BAHÍA 400 kV.	2008	400/230	PEEGT	SYRIA	12.000.000
EMBORCAÇAO SUBSTATION	2008	500	LTT	BRAZIL	259.572.493
EMBORCAÇAO SUBSTATION	2008	500	SMTE	BRAZIL	269.926.428
ESTREITO SUBSTATION	2008	345	LTT	BRAZIL	259.572.493
ESTREITO SUBSTATION	2008	500	LTT	BRAZIL	259.572.493
ITUMBIARA SUBSTATION	2008	500	LTT	BRAZIL	259.572.493
LUZIANIA SUBSTATION	2008	500	SMTE	BRAZIL	269.926.428
NOVA PONTE SUBSTATION	2008	500	LTT	BRAZIL	259.572.493
PARACATU 4 SUBSTATION	2008	138	SMTE	BRAZIL	269.926.428
PARACATU 4 SUBSTATION	2008	500	SMTE	BRAZIL	269.926.428
SAMAMBAIA SUBSTATION	2008	500	SMTE	BRAZIL	269.926.428
SAO GOTARDO 2 SUBSTATION	2008	500	LTT	BRAZIL	259.572.493

ISOLUX CORSÁN
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'TURNKEY PROJECTS' SUBSTATIONS EXECUTED SINCE 2000

PROJECT NAME	YEAR OF EXECUTION	VOLTAGE (kV)	CLIENT	COUNTRY	VALUE USD
SERRA DA MESA 2 SUBSTATION	2008	500	SMTE	BRAZIL	269.926.428
SUBSTATION CAPOPA	2008	30	ENE	ANGOLA	22.000.000,00
SUBSTATION CASUA (PORTO AMOIM)	2008	60	ENE	ANGOLA	30.000.000,00
SUBSTATION SUMBE	2008	30	ENE	ANGOLA	30.000.000,00
CAPANDA VIANA PROJECT: CAPANDA ELEVADORA SUBSTATION	2009	220/400	ENE	ANGOLA	68.040.000
CAPANDA VIANA PROJECT: CAPANDA SUBSTATION	2009	220	ENE	ANGOLA	68.040.000
CAPANDA VIANA PROJECT: LUCALA SUBSTATON	2009	400/220	ENE	ANGOLA	68.040.000
CAPANDA VIANA PROJECT: VIANA SUBSTATION	2009	400/220	ENE	ANGOLA	68.040.000
ESTREITO SUBSTATION	2009	500	PCTE	BRAZIL	144.870.333
JAGUARA SUBSTATION	2009	500	PCTE	BRAZIL	144.870.333
MARIMBONDO SUBSTATION	2009	500	RPTE	BRAZIL	109.882.870
PARACATU 4 SUBSTATION	2009	500	SPTE	BRAZIL	120.775.046
PIRAPORA 2 SUBSTATION	2009	138	SPTE	BRAZIL	120.775.046
PIRAPORA 2 SUBSTATION	2009	345	SPTE	BRAZIL	120.775.046
PIRAPORA 2 SUBSTATION	2009	500	SPTE	BRAZIL	120.775.046
POÇOS DE CALDAS SUBSTATION	2009	500	PCTE	BRAZIL	144.870.333
RIBEIRAO PRETO SUBSTATION	2009	440	PCTE	BRAZIL	144.870.333
RIBEIRAO PRETO SUBSTATION	2009	500	RPTE	BRAZIL	109.882.870
RIBEIRAO PRETO SUBSTATION	2009	500	PCTE	BRAZIL	144.870.333
SAO SIMAO SUBSTATION	2009	500	RPTE	BRAZIL	109.882.870
SUBSTATION KHENCHELA	2009	220/60	SONELGAZ	ALGERIA	10.000.000
TENDER 216/2006 230 KV SUBSTATION KODSAYA	2009	230/66/20	PEEGT	SYRIA	17.000.000
YACIRETA PROJECT: MERCEDES SUBSTATION	2009	500/132/33	CAF	ARGENTINA	143.868.000
YACIRETA PROJECT: RINCON STA. MARIA SUBSTATION EXTENSION	2009	500	CAF	ARGENTINA	143.868.000
YACIRETA PROJECT: SAN ISIDRO SUBSTATION EXTENSION	2009	500/132/33	CAF	ARGENTINA	143.868.000
ESTREITO SUBSTATION	2010	500	CESTE	BRAZIL	17.000.000,00
IMPERATRIZ SUBSTATION	2010	500	CESTE	BRAZIL	17.000.000,00
LOT A: SS COLINAS, RIBEIRO GONÇALVES & S. JOAO DE PIAUÍ	2010	500	IENNE	BRAZIL	40.000.000,00
SUBESTACIÓN JUILE. AMPLIACIÓN 3 SALIDAS 400 KV + REACTOR	2010	400	CFE	MÉXICO	15.000.000,00
SUBESTACIÓN LAS GLORIAS 400/230 KV (SF6)	2010	400/230	CFE	MÉXICO	46.560.000,00
SUBSTATION LUCALA	2010	220	MINEA	ANGOLA	45.520.000
SUBSTATION NEGAGE	2010	60	MINEA	ANGOLA	45.520.000
SUBSTATION PAMBOS DE SONHE	2010	220	MINEA	ANGOLA	45.520.000
SUBSTATION UIJE 1	2010	220	MINEA	ANGOLA	45.520.000
SUBSTATION UIJE 2	2010	60	MINEA	ANGOLA	45.520.000
GRAN FORMOSA SUBSTATION	2011	500/132/33	CAF-UESTY	ARGENTINA	70.000.000,00
GRAN MENDOZA SUBSTATION EXTENSION	2011	500	CAF-UESTY	ARGENTINA	60.000.000,00
MONTE QUEMADO SUBSTATION	2011	500/132/33	CAF-UESTY	ARGENTINA	70.000.000,00
RESISTENCIA SUBSTATION EXTENSION	2011	500	CAF-UESTY	ARGENTINA	70.000.000,00
REYUNOS SUBSTATION EXTENSION	2011	220	CAF-UESTY	ARGENTINA	60.000.000,00
RIO DIAMANTE SUBSTATION	2011	500/220/33	CAF-UESTY	ARGENTINA	60.000.000,00
ROQUE SANZ PEÑA SUBSTATION	2011	500/132/33	CAF-UESTY	ARGENTINA	70.000.000,00
SUBESTACIÓN "ET CALINGASTA"	2011	500/132/33	EPRE	ARGENTINA	70.600.000,00
SUBESTACIÓN "NUEVA E.T. CALINGASTA"	2011	500/132/33	EPRE	ARGENTINA	70.600.000,00
SUBESTACIÓN AZUL DE CORTES	2011	400	CFE	MÉXICO	3.500.000,00

ISOLUX CORSÁN ISOLUX WAT

'TURNKEY PROJECTS' SUBSTATIONS IN EXECUTION

PROJECT NAME	VOLTAGE (kV)	CLIENT	COUNTRY	VALUE USD MILLION
LOT A : T.L. 230 KV Jauru - Samuel		PLENA	BRAZIL	33,95
Pimenta Bueno S/S	230			
Ji Parana S/S	230			
Ariquemes S/S	230			
Samuel S/S	230			
Project Central Turbina a Gas en Fútila		ENE	ANGOLA	
Substation Fútila	60			12,75
Substation Cabinda	60			8,45
Project L.T. Cabinda-Lándana		ENE	ANGOLA	40
Substation Lándana	60			
Substation Sao Pedro	60			
Substation M´Buco	60			
LOT A. T.L. Tucuruí-Jurupari		LINHAS DE XINGU	BRAZIL	160
Tucurui S/S	500			
Xingu S/S	500			
Juruparí S/S	500/230			
LOT B. T.L. Macapá-Juraparí / Juruparí-Oriximiná		LINHAS DE MACAPA	BRAZIL	138,3
Juruparí S/S	500			
Oriximiná	500/138			
Laranjal	230/69			
Macapá	230/69			
TL Coletora Porto Velho-Araraquara em 600 kV CC		IEMADEIRA	BRAZIL	130
Construçao SS Porto Velho	600 KV DC			
Construçao SS Araraquara	600 KV DC			
Interconexión Esperanza-Calafate		CAF/UESTY	ARGENTIN	10
Ejecución Subestación "Calafate"	132/33/13,2			
Project MSTECL	220/132 kV	MAHATRANSC	INDIA	6,26
WETT C.R.EZ. PROJECT				
Cottonwood	345	WETT	USA	28,4
Long Draw	345	WETT	USA	12,3
Grelton	345	WETT	USA	10,3
Sand Bluff	345	WETT	USA	8,3
Bearkat	345	WETT	USA	4,2
Faraday	345	WETT	USA	8,0

Appendix C — Samples of TransCanada Project Experience

Samples of the TransCanada's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Community Consultation	Aboriginal Engagement and Participation
TransCanada Keystone Canada Crude Oil Pipeline Capital cost = CDN $ 1.845 billion	Located in eastern Alberta (AB) and southern Saskatchewan (SK) and Manitoba (MB) Conversion of 864 km of existing gas pipe to crude oil 373 km of new pipeline and 16 pump stations Construction primarily on agricultural land Construction Q1 2008 to Q3 2009	Regulated by the National Energy Board (NEB) Section 52 NEB Act application submitted in Q4 2006 Oral Hearing NEB approval received in Q3 2007 NEB Leave to Open (LTO) approval for Line 100-1 Conversion received in Q3 2009 NEB LTO approval for new sections of pipe in AB, SK and MB received in Q4 2009 NEB LTO approval for 16 pump stations received in Q1 2010	35% of AB right-of-way (ROW) is Crown land and 65% is freehold land; all of SK and MB ROW is freehold land 8 of the 16 pump stations are on freehold land; 8 are on TCPL-owned land Approx. 1600 directly affected landowners (including the Line 100-1 conversion) 2 landowner associations participated in proceedings 8 route deviations were filed, and 1 Right-of-Entry was filed under section 104 of the NEB Act	Several municipalities were contacted; resulted in some minor route refinements No objections	Engagement with 8 First Nations and Métis groups in AB, SK and MB 2 First Nations actively participated in oral hearings 1 First Nation filed a review and variance application. The NEB rejected the application.

Samples of the TransCanada's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Community Consultation	Aboriginal Engagement and Participation
Nova Gas Transmission Ltd. (NGTL) North Central Corridor Project Natural Gas Pipeline Capital cost = CDN $800 million	Located in north-central Alberta 300 km of 42-inch pipeline Meikle River Compressor Station Units 3 & 4 Construction Q4 2009 to Q1 2010 Construction primarily in forested area within caribou habitat zone	Initially regulated by the Alberta Utilities Commission (AUC) but now regulated by NEB Permit application submitted to AUC in Q4 2007 Oral Hearing AUC approval received in Q4 2008 Leave to Open was placed under NEB jurisdiction when NGTL's Alberta System came under federal jurisdiction in 2009	Primarily Crown land No objections from Crown disposition holders or trappers. No objections from landowners (non-objection letters from all affected landowners received)	No objections from communities and three municipalities	No objections from 8 of 10 First Nations and 3 Métis communities in project area 2 First Nations objected but the AUC found that that these groups had not demonstrated standing.

Samples of the TransCanada's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Community Consultation	Aboriginal Engagement and Participation
NGTL Groundbirch Mainline Natural Gas Pipeline Capital cost = CDN $251 million	Located in Dawson Creek, BC area 77 km of 36-inch pipe 3 meter stations Construction Q3 to Q4 2010 Construction primarily on agricultural lands	Regulated by the NEB Section 52 NEB Act application submitted in Q2 2009 Oral hearing NEB approval received in Q1 2010 (GH-1-2009) NEB LTO approval received in Q4 2010	58.6% of AB ROW is freehold land; 41.4% of AB ROW is Crown land; 98% of BC ROW is freehold land; 2% of BC ROW is Crown land Consultation with 133 directly and indirectly affected landowners 1 Landowner Association raised concerns; NGTL mitigated all concerns. 74 titled tracts of land held by private landowners (38 easement agreements had been obtained by oral hearing date) No detailed route hearing; no objections received	No objections	2 Tribal Organizations and 17 First Nations and Métis communities engaged (11 communities participated in the engagement process while 6 others expressed no concerns and chose not to participate) 2 First Nations involved in hearing process

Samples of the TransCanada's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Community Consultation	Aboriginal Engagement and Participation
NGTL Horn River Mainline and Komie East Extension Natural Gas Pipeline Capital cost = CDN $310 million	Located northeast of Fort Nelson, BC 72 km of 36-inch pipeline 2.5 km of 24-inch pipeline 4 meter stations Construction Q1 2011 to Q2 2012 Construction in discontinuous permafrost and caribou habitat	Regulated by the NEB Section 52 NEB Act application submitted in Q1 2010 NEB approval received in Q1 2011 No oral hearing NEB LTO approval received in Q2 2012	All ROW on BC Crown lands No objections to pipeline routing; no detailed route hearing	No objection from Northern Rockies Regional Municipality	7 First Nation and Métis communities engaged No objections from the communities and none registered as intervenors in the proceedings.
NGTL Fort McMurray and Fort McKay Area Expansion Projects Natural Gas Pipeline Capital cost = CDN $456 million	A series of gas pipeline projects located in northeast Alberta 99 km of 30-inch pipeline 61 km of 24-inch pipeline 114 km of 36-inch pipeline Constructed Q4 2006 to Q2 2008 Construction in forested / muskeg areas	Initially regulated by the Alberta Energy and Utilities Board (AEUB) but now regulated by NEB Fort McKay Area Projects received AEUB approval in 2006 Fort McMurray Area Projects received AEUB approval in 2007	Alberta Crown lands No objections from Crown disposition holders or trappers	No objections	TransCanada engaged with 8 First Nations and Métis communities for the Fort McMurray and Fort McKay Area Projects

Samples of the TransCanada's Project Experience

Project	Project Description	Regulatory Framework and Approvals	Land Acquisition	Community Consultation	Aboriginal Engagement and Participation
NGTL Northwest System Expansion Projects Natural Gas Pipeline Capital cost = CDN $882 million	A series of gas pipeline expansion projects located in northeast BC and northwest Alberta 38 km of 48-inch pipeline 78 km of 42-inch pipeline (under construction) 32 km of 48-inch pipeline (under construction) 100 km of 36-inch pipeline (in regulatory review - planned in service Q2 2015) 33 km of 48-inch pipeline (in regulatory review – planned in service Q1 2014) Some pipeline construction in discontinuous permafrost and caribou habitat as well as forested lands	Regulated by the NEB Various NEB applications submitted NEB approvals received in Q3 2011 and Q1 2012 NEB decision on Komie North Extension and Chinchaga Loop Section expected in Q1 2013	All ROW on BC and Alberta Crown lands	No objections from urban and rural municipalities	TransCanada engaged with 11 First Nation and Métis communities for the Northwest System Expansion projects.

Appendix D — Summary of the Applicants' Business Practices

Summary of the Applicants' Business Practices

Business Practice	Isolux Corsán	TransCanada
Design and Engineering	When undertaking design and engineering, Isolux Corsán considers and ensures compliance with applicable international Standards defined by the international technical regulators (IEC, ASTM, etc.) and any local standards that exist. Isolux Corsán adheres to an Engineering Management Procedure that controls the quality of the in-house engineering as well the work to be performed by subcontractors. The Engineering Management Procedure outlines: • design and development stages for designs and specifications; • work scheduling; • material scheduling; • equipment scheduling; • required reviews of design development; • verification and validation methods appropriate to each engineering stage; • responsibilities and authorities for engineering, planning and design; • identification of the technical interfaces required for the project; and • updating of the engineering and the plan as the project progresses	TransCanada traditionally contracts detailed design and engineering services for its major linear infrastructure projects. Through its robust and comprehensive supply chain and project management systems as outlined below, TransCanada ensures that the high standards required for good utility design practice are attained by its external contractors.

Business Practice	Isolux Corsán	TransCanada
Material and Equipment Procurement	Isolux Corsán has a Procurement Procedure under which suppliers are evaluated and selected based on their ability to perform. Isolux Corsán procurement teams utilize SAP Purchasing System to follow procurement processes, including creating bid comparatives, documenting purchase orders and change orders and streamlining invoice payments. Isolux Corsán has well-established purchasing processes designed to procure equipment and services of the nature and scope required by a project of this size and importance. The general process for purchasing is outlined below. • Receive an approved requisition from engineering, construction or project management • Establish a providers list by commodity with pre-qualified vendors for review • Prepare Request for Proposals detailing requirements, including specifications, drawings, BOM's, scope, quantities, lead time, total capacity, total open capacity, pricing, escalation controls, payment terms, QA/QC, safety, and order terms and conditions • Process RFPs, prepare bid tabulations and distribute for technical and commercial evaluation • Engage in negotiations with the potential short-listed vendors • Submit award recommendation summarizing technical and commercial evaluation findings • Receive award approval • Execute and finalize the purchase order or contract	TransCanada has extensive supply chain management expertise to support its many generation and pipeline projects as well as an ongoing business relationship with suppliers in Ontario, Canada and throughout the world. These existing relationships will be combined with the international sourcing ability of Isolux Corsán to ensure high quality and low cost equipment and material are provided to the project. TransCanada has well-established procurement processes for evaluating the marketplace and developing a stable of pre-qualified suppliers, and well defined processes for issuing request for proposals (RFPs), evaluating proposals, awarding contracts and managing winning bidders. TransCanada has industry-leading experience in managing procurement of labour, goods and services at the regional and local level both directly and through primary contractors.

Business Practice	Isolux Corsán	TransCanada
Right-Of-Way and Other Land Use Acquisitions	Isolux Corsán will assist TransCanada in land right acquisition where necessary. Isolux Corsán has experience acquiring land rights in a variety of jurisdictions. Isolux Corsán complies with local regulations relating to the acquisition of land rights. It is Isolux Corsán's preference to obtain land rights through an amicable negotiation but if unavoidable, Isolux Corsán utilizes judicial/legal process following the applicable rules of each jurisdiction.	TransCanada's land management team is responsible for obtaining access to land required to support the development of major linear infrastructure projects. Field-tested and proven processes and criteria which treat landowners respectfully provide a strong foundation for Project land acquisition to be carried out smoothly and on schedule. The TransCanada team relies on a combination of internal resources and external resources to carry out the activities required to achieve the objectives of the organization. A key component to TransCanada's success is maintaining strong relationships with landowners during the critical implementation phase of a major project. Managing issues that arise during construction and ensuring all parties are engaged and properly informed is a key factor to success. Once projects are completed, TransCanada uses sophisticated land management tracking systems to ensure proper administration, timely payment and renewal of required property rights occurs.
Licensing and Permitting	As detailed in the response to Section 4.3, Isolux Corsán has experience in obtaining the necessary licences and permits for transmission lines in a number of jurisdictions.	TransCanada has extensive experience in permitting and licensing processes in Ontario. TransCanada will, as appropriate, make available experienced personnel who have assisted with the permitting of major power and pipeline infrastructure projects in Ontario. TransCanada's standard and proven strategy of consulting early and often with a broad range of stakeholders ensures interests are not overlooked and the relevant agencies are included. This mitigates potential delays related to concerns being raised late in the regulatory process.

Business Practice	Isolux Corsán	TransCanada
Consultations (both with First Nation and Métis and Other Communities)	Isolux Corsán has experience consulting indigenous peoples and local communities in a number of jurisdictions. Isolux Corsán will assist TransCanada with engagement with First Nation and Métis and other communities.	TransCanada has a Corporate group as well as regional resources dedicated to Aboriginal Relations and Community Relations. Accordingly, TransCanada has a number of publicly-available policy and programs and commitment statements that provide the framework for strategies, plans and programs, as well as guidance to staff in planning their work. These include: • Corporate Values of Integrity, Collaboration, Responsibility and Innovation • Stakeholder Engagement Commitment Statement • Aboriginal Relations Policy • Code of Business Ethics • Community Investment Program • Integrated Public Awareness Program TransCanada's standard and proven strategy of consulting early and often with a broad range of stakeholders ensures interests are not overlooked and the relevant First Nation, Métis, and other communities are included. This mitigates potential project delays and stakeholder impacts related to concerns being raised late in the project development process.

Business Practice	Isolux Corsán	TransCanada
Construction	Isolux Corsán construction management team meets project objectives through implementation of the following key strategies: • Promotion of Safety • Communication, Reporting and Information Sharing • Use of Schedule Management Tools (Microsoft Project or Primavera P6) • Performance Baseline Control (schedule baseline) • Material Management • Performance Measurement, Reporting, and Forecasting • Quality Assurance and Quality Control	TransCanada has significant experience in construction management and inspection with a strong focus on safety matters. TransCanada works with EPC contractors to ensure industry Health, Safety & Environmental practices and quality management are utilized during the construction phase of the project. TransCanada's standards for excellence in Health, Safety and Environment are maintained through contractual obligations (i.e. inspection and audit requirements). TransCanada endeavours to do business with companies and contractors which share our expectations for Health, Safety and Environment performance and we will regularly assess their performance.

Business Practice	Isolux Corsán	TransCanada
Operation and Maintenance	An affiliate of Isolux Infrastructure currently operates eight transmission facilities in Brazil (three owned by Isolux Infrastructure and five owned by other parties) and complies with prescribed utility practices and codes/rules governing electric transmission, operability and reliability, which include: • minimum conditions for designing, constructing, managing, maintaining and operating its transmission system; • rules governing transmitter customer connection; • obligations between neighbouring transmitters; and, • rules governing the economic evaluation of transmission system connections and expansions.	TransCanada is committed to designing, building, operating and maintaining safe and efficient assets. To maximize the value created from each asset, an asset management strategy is developed to focus appropriate resources on each asset. The purpose of TransCanada's asset management strategy is to ensure world-class leadership in operations, engineering, and maintenance, and the sustainability of the knowledge, processes and tools that are necessary for the ongoing management of TransCanada's assets. As part of the asset management strategy, asset specific documents are prepared including: • asset management plans which are incorporated into operations, • integrity management plans • operating and maintenance plans • facility and ROW maintenance and inspection plans, including facility specific Environmental Operating Guides that include compliance requirements • audit plans Asset reliability and life cycle cost management are a strategic advantage for TransCanada. As part of overall asset reliability and life cycle cost management, Operations and Engineering have implemented specialized processes, systems and functions, allowing the prediction, design, and operation of assets at a desired reliability and cost level.

Business Practice	Isolux Corsán	TransCanada
Project Management	Isolux Corsán largely manages it projects internally under its Project Management Procedures and, where appropriate, draws on additional local project management support. The Project Management Procedures are planned and carried out under controlled conditions, during the execution of the Project, by ensuring the following: • Plan and document the engineering, procurement and construction activities • Establish parameters for monitoring the process performances • Assure compliance with reference standards/ codes • Identify the suitable resources needed for each of the processes • Plan and perform actions to ensure continuing process capability • Assure the approval of activity/ process be followed as appropriate • Assure productivity process is within planned time frames in all phases of the project	TransCanada utilizes a best in class self-designed Capital Project Management System (CPMS) that governs the execution of capital projects and utilises a framework based on ISO 9001 Quality Management and best industry practices. The CPMS goal is to provide organizational and process structure and clear guidance to staff without stifling the ability of personnel to adapt to the unique requirements inherent in each project's circumstances. The CPMS allows TransCanada to meet the needs of customers and to achieve the objective of excellence in project delivery, while optimizing the combination of cost, quality and schedule to maximize the full-life value of major linear infrastructure projects. The scope of CPMS spans the design procurement and construction of capital processes. Key elements of the CPMS are: • A clearly articulated policy and leadership commitment. • A rigorous stage gate system, including minimum requirements for progressing through the project lifecycle. • An organizational structure that supports the management system and the successful implementation of capital projects • Management of project resources, including establishing minimum requirements for competency, awareness and training. • Operational controls including the documentation of process and procedures for hazard identification and risk management, design and material selection, construction, and operations and maintenance of our energy infrastructure projects.

Business Practice	Isolux Corsán	TransCanada
Safety and Environmental Compliance	Every Isolux Corsán affiliate has a Health & Safety, Quality and Environmental Management Program that meets international standard and is established and certified to: • ISO 9001 Quality Management Standard • ISO 14001 Environmental Management Standard • OHSAS 18001 Health & Safety Management Standard Isolux Corsán also has an Accident Prevention Plan (APP).	TransCanada has a Health, Safety and Environmental Management System that aligns with International Standards (ISO 9001 and 14001). TransCanada is committed to meeting or exceeding all applicable laws and regulations and minimizing risk to its employees, the public and the environment, as is committed to continuously improving our HSE performance. TransCanada continually promotes safety on and off the job and believes that all occupational injuries and illnesses are preventable
Regulatory Compliance	Isolux Corsán is required to comply with a variety of regulatory regimes in different jurisdictions and has a demonstrated history of complying with its regulatory obligations.	TransCanada has a Code of Business Ethics (COBE) that is the foundation of its corporate ethics and compliance program and the overarching guide to employee conduct. It is supported by other compliance-related policies and activities that help ensure compliance with legal requirements in all aspects of TransCanada's business. This includes facility specific Environmental Operations Guides and Compliance Calendars that detail the requirements that each facility must meet in order to comply with applicable regulation, pemits, approvals and authorizations, as well as associated policies and procedures. TransCanada requires all of its employees and contractors to comply with COBE.

5 FINANCIAL CAPACITY

5.1 Available Capital Resources

Evidence that it has capital resources that are sufficient to develop, finance, construct, operate and maintain the line.

The total development and construction costs are currently estimated to be in the range of $545 million to $712 million as detailed in section 8. The Applicants intend to fund the Project utilizing non-recourse debt to a minimum level of 60%, leaving 40% (approximately $218 to $285 million) to be funded by equity. This equates to approximately $109 to $143 million to be funded by each of TransCanada and Isolux Infrastructure.

The internal and external sources of funding available to Isolux Infrastructure and TransCanada are sufficient to meet the requirements relative to their respective ownership interests in the E-W Tie.

TransCanada is a public company with assets in excess of $49 billion as at year end 2011, earnings of $1.4 billion and cash flow from operations of $3.9 billion in that year.

Isolux Infrastructure's largest shareholder is Isolux Corsán, the largest private Spanish group in the engineering and infrastructure sector with total assets of approximately $10.7 billion. In 2011, Isolux Corsán reported revenues of $4.5 billion. Isolux Corsán's revenues have approximately doubled since 2004. As of 2011, Isolux Corsán's business portfolio totaled a record $57.1 billion.

As detailed in response to section 1.3, Isolux Infrastructure's ownership includes a recent $500 million investment by PSP Investments. PSP Investments is a Canadian Crown Corporation established by the Parliament of Canada under the *Public Sector Pension Investment Board Act* to manage the pension plans of the Canadian

Federal Public Service, the Canadian Forces and the Royal Canadian Mounted Police. Cumulative funds under management exceed $65 billion as of March 31, 2012.

Recent annual reports for TransCanada, Isolux Corsán and PSP Investments are found in Exhibits "H", "I" and "J" of Volume 2.

5.2 Current Credit Ratings

Evidence of the current credit rating of the applicant, its parent or associated companies.

TransCanada's debt credit ratings can be found at page 20 of its Annual Information Form in Exhibit "K" in Volume 2. TransCanada PipeLines Limited's senior unsecured debt is rated as A3 by Moody's, A- by Standard & Poor's and A by DBRS.

Neither Isolux Infrastructure nor Isolux Corsán have required credit ratings to date; however, in circumstances where specifically required, credit ratings have been obtained for affiliates. For example, Isolux Corsán Concesiones S.A.U. obtained a BBB+ credit rating in 2011 issued by Feller Rate in Chile. Also Isolux Ingeniería has a debt credit rating of "A-" as issued by Feller Rate in Chile in 2012. Feller Rate is a strategic affiliate of Standard & Poor's that is specifically focused on Latin America.

5.3 Impact on Creditworthiness or Financial Condition

Evidence that the financing, construction, operation, and maintenance of the line will not have a significant adverse effect on the applicant's creditworthiness or financial condition

The anticipated equity contributions by the Applicants during development and through the construction period are relatively small as compared to the size of the two companies and the future funds from operation from the respective

organizations. The expected contribution will not impact the creditworthiness of either Isolux Infrastructure or TransCanada.

Further, the Applicants intend to make use of non-recourse debt financing to fund the debt component of the Project. The use of non-recourse debt financing means that the Applicants' balance sheets will be insulated from recourse.

Once the Project reaches commercial operation, the resulting stable cash flows will serve to strengthen the creditworthiness of both Isolux Infrastructure and TransCanada. Ongoing maintenance costs are not expected to be significant relative to the respective organizations available funds from operation. Furthermore, these costs are recovered through the Uniform Transmission Rate. These costs will not impact the creditworthiness of either Isolux Infrastructure or TransCanada.

5.4 Financing Plan

The applicant's financing plan, including:

- *the estimated proportions of debt and equity; and*
- *the estimated cost of debt and equity, including:*
  - *the use of variable and fixed cost financing;*
  - *short-term and long-term maturities; and*
  - *a discussion of how the project might impact the applicant's cost of debt.*

The Applicants expect to finance the Project with a mix of equity contributions and non-recourse debt. The Applicants intend to enter into concrete negotiations with potential lenders for long-term debt financing once the project nears the final stages of its main permitting and licensing processes, approximately in 2015-2016. The

specific mix and terms of debt financing will be determined based on market conditions at the time.

The Applicants intend to fund the E-W Tie project at a ratio of 60% debt and 40% equity with long-term debt being raised on a non-recourse basis that is investment grade. Isolux has project financed all of its completed transmission concession projects in Brazil and its current project in Texas; accordingly, it has extensive expertise project financing large undertakings like the E-W Tie.[4] The Applicants will manage the financing process and apply their experience and expertise with the objective of obtaining the best terms.

The Applicants anticipate that the rate of return on equity will be set by the OEB pursuant to its well established expertise and procedures, including those for determining the cost of equity for transmission companies operating in Ontario.

The Applicants' individual track records in completing major infrastructure projects — and the enhanced capabilities brought about by their partnership on this project — will further contribute to raising debt at attractive rates.

5.5 Ability to Raise Debt and Equity

If the financing plan contemplates the need to raise additional debt or equity, evidence of the applicant's ability to access the debt and equity markets

TransCanada's strong credit metrics and corporate reputation have allowed it to successfully access capital markets, even during the immediate aftermath of the 2008 market correction. As shown in its annual report (Exhibit "H"), its cumulative capital expenditures during the five year period of 2007 to 2011 have exceeded $26 billion.

[4] Isolux Corsan has also project financed a number of other large infrastructure projects (e.g., toll roads, power generation facilities, etc.)

Since 2007, TransCanada has demonstrated unabated access to the capital markets, as evidenced by the issuance of in excess of $11 billion of senior debt, $1 billion of hybrid securities, $1 billion of preferred shares and $7 billion of common equity. TransCanada's "A" credit ratings, solid cash flow generation and continuous access to the capital markets in Canada and the United States provide ample liquidity to finance this Project.

Isolux Infrastructure's ability to raise capital is demonstrated by Table 3, which lists financing transactions entered into by Isolux Infrastructure:

Table 3: Financing Ability of Isolux Infrastructure

Project	Country	Total Project Cost (€ millions)	Long Term Debt (€ millions)	Tenure
Saltillo-Monterrey	MX	271	137	Senior: 18yr
Perote Banderilla	MX	608	279	Senior: 17yr
Via Bahia BR 116-BR 324	BR	1,246	574	BNDES:15 yr; BNB:16 yr
NH 1 Panipat-Jalandhar	IN	695	521	15yr
NH 2 Varanasi-Aurangabad	IN	520	285	Senior: 15yr
NH 6 Gujarat-Maharastra Border- Surat-Hazira Port	IN	372	279	15 yr
NH 8 Kishangarh-Ajmer-Beawar	IN	201	150	15 yr
Madrid-Ocaña A4	ESP	117	64	17,5 yr
Cachoeira Paulista	BR	108	58	10 yr
LXTE- Xingu	BR	450	327	20 yr
LMTE- Macapá	BR	431	309	20 yr
IENNE	BR	356	90	20 yr
JTE - Jaurú (Sur)	BR	356	107	14 yr

Project	Country	Total Project Cost (€ millions)	Long Term Debt (€ millions)	Tenure
JTE - Jaurú (Norte)	BR	115	65	Bridge facility
LTTE- Taubaté	BR	131	61	Bridge facility
WETT	USA	576	371	Construction +3yr
UPTE- Uttar Pradesh	IN	761	563	15 yr

The Applicants have obtained expressions of interest in providing non-recourse financing for the project from Société Générale, Natixis and Deutsche Bank that are attached to this section as Appendix "A".

5.6 Ability to Finance

Evidence of the applicant's ability to finance the project in the case of cost overruns, delay in completion of the project and other factors that may impact the financing plan

The Applicants' ability to finance the E-W Tie is demonstrated by the responses to sections 5.1 to 5.5.

5.7 Overview of Experience

Evidence of the applicant's experience in financing similar projects

The Applicants' experience in financing similar projects is demonstrated by the responses to sections 5.1 to 5.5.

5.8 Alternative Rate-making Treatment

The identification of any alternative mechanisms (e.g., rate treatment of construction work in progress) that the applicant is requesting or likely to request

The Applicants are not proposing any alternative rate making at this time but remain flexible in this regard should future conditions warrant.

Appendix A — Lenders' Expressions of Interest

SOCIETE GENERALE
Corporate & Investment Banking

New York, January 2nd 2013

Isolux Infrastructure
Caballero Andante, 8
28201 Madrid
Spain

Attention: Mr. Miguel Garrido Espa, International Finance; Pablo de la Sierra Perez, Director North-America

Ref.: East-West Tie Line, Northern Ontario

Dear Miguel and Pablo,

We refer to our preliminary discussion with Isolux Infrastructure ("Isolux") on a proposed 400 km, 230 kV transmission line to be developed in Northern Ontario, Canada, known as the East-West Tie Transmission Project (the "Project").

You have informed us that you and TransCanada intend to file a joint application to be awarded the development of the Project. You have indicated that capital costs for the Project could be in the vicinity of C$700 million and that the line could come into service in 2018. The Project will be a regulated asset, with revenue recovery under a traditional cost of service model which allows the owner/operator of the line to recover prudently incurred costs from the Ontario ratepayer through annual rates. You have further advised us that the Project will use commercially-proven technology to be supplied by reputable, experienced and creditworthy manufacturers, and that an affiliate of Isolux will be the EPC Contractor under acceptable commercial arrangements.

We have a strong relationship and a longstanding track record with Grupo Isolux Corsan and its affiliates and have provided structured financing to various international energy projects developed by Grupo Isolux Corsan. We also know TransCanada is a financially strong and reputable energy infrastructure developer, owner and operator with extensive experience in energy linear infrastructure in North-America, including n Ontario.

Based on the information you have provided us to date, and subject to additional review of the Project's contractual framework, we believe that the Project could be well suited for a non-recourse financing. While we have not yet performed due diligence on the Project, we would be interested in reviewing the fundamentals of the Project with a view to potentially arrange or provide financing. Our interest in providing financing will depend on the nature of the commercial framework for the Project and will be subject to a thorough due diligence process (including without limitation commercial, technical, legal, market and insurance due diligence) and the receipt of various internal approvals.

SOCIETE GENERALE
Corporate & Investment Banking

Based on previous North American transmission line financings that we arranged, we believe that a 60/40 debt /equity capital structure should be achievable for a project of this nature, assuming that the project cash flows allow for an acceptable debt service coverage ratio to be achieved. Regulated transmission line financings are highly sought-after assets by debt investors and lend themselves well either to commercial bank or debt capital markets financings. Subject to a review of detailed information, we believe that this financing can be structured in such as way to achieve an investment grade senior secured debt rating.

Société Générale, one of the largest financial institutions in the Euro zone, is a leading provider of debt capital for the energy sector in the Americas. We focus on a the energy sector broadly defined and provide debt advisory and arranging services for power generation, renewable energy, transmission and distribution, utilities, oil & gas, pipelines, liquefied natural gas, petrochemicals and refineries. We consistently rank among the top lead arrangers and financial advisors for project finance across asset classes and geographical regions.

Please note that this letter is for discussion purposes only and does not constitute an offer or a commitment by Société Générale or any of its affiliates to negotiate or provide a financing or otherwise participate in any transaction.

We look forward to continuing our dialogue on the Project in the coming months and would be happy to provide any further information, input or perspective that may be helpful in the interim.

Best Regards,



Daniel Mallo

Managing Director

Project and Energy Finance

Société Générale – New York

Deutsche Bank
Asset Finance & Leasing

Mr. Pablo de la Sierra Perez
Iccon Transmission, Inc.

January 04, 2013

Deutsche Bank Securities Inc.
60 Wall Street
New York, NY 10005

Dear Sir/Madam,

Re: East-West Tie Line Project

We refer to our correspondence with Iccon Transmission, Inc. ("Iccon"), who together with the TransCanada Corporation (collectively, the "Consortium") will be bidding to develop, build, finance, maintain and operate the East-West Tie Line (the "Project"), located in northern Ontario, Canada.

Deutsche Bank Securities Inc. ("Deutsche Bank") hereby expresses its keen interest in being considered for the provision of senior debt funding to the Consortium. If they are selected for the Project, we look forward to continuing our communications with the Consortium to establish the role we might play in the funding. Deutsche Bank is therefore pleased to be identified to the Ontario Energy Board ("OEB") as a potential financier to the Consortium, and we are pleased to provide a summary of our credentials to fulfill this role, if necessary.

Deutsche Bank has relevant experience in financing infrastructure investments of this type and in supporting sponsors and concessionaires. Deutsche Bank is familiar with the Project, as well as the various members of the Consortium. We believe that they possess both the financial wherewithal and the experience to achieve a financial close for this Project.

However, for clarity, it should be noted that this letter is an expression of interest and does not represent any form of commitment to underwrite or provide funds to this Consortium now or in the future. As is normal for this type of project, support of the Consortium's interest and the commitment of funding will be dependent on all necessary due diligence and internal approvals to evaluate the transaction. Deutsche Bank will be able in its absolute discretion to determine whether or not it will ultimately participate in the financing of the transaction with the Consortium or any other consortium in connection with the Project.

We look forward to a successful project and wish the Consortium every success in its bid.

Yours sincerely

Bhaswar Chatterjee
Director

Daniel Fuchs
Vice President

NATIXIS

January 3, 2013

Miguel Garrido
Director Financiero
Isolux Infrastructure
C/Caballero Andante, nº 8
28021 – Madrid – SPAIN

RE: Letter of Support – East-West Tie Line, Northern Ontario, CANADA

Dear Mr. Garrido,

NATIXIS New York Branch ("NATIXIS" or "We") is pleased to provide this confirmation letter to Isolux Infrastructure ("Isolux") in connection with its response to the Request for Qualifications ("RFQ") issued by the Ontario Energy Board ("OEB") on July 12, 2012 to design, build, finance and operate the East-West Tie Line, an approximately 400-km proposed transmission line located in Northern Ontario, Canada (the "Project").

It is our understanding that Isolux, a joint venture of Grupo Isolux Corsan and the Public Sector Pension Investment Board ("PSP"), will be bidding through its North American affiliate Iccon Transmission Inc. ("Iccon") in response to the RFQ issued by OEB, with an application filing deadline of January 4, 2013. We understand Iccon plans to partner with TransCanada (a Canadian energy infrastructure developer, owner and operator with presence where the Project is located) for this application.

NATIXIS is a global leader in partnering with clients active in the infrastructure field to develop and execute innovative project financing solutions. NATIXIS typically acts as mandated lead arranger, financial advisor, structuring bank, coordinating or syndication bank on limited recourse infrastructure / P3 financings for clients throughout the world. With a proven track record and an exceptional commitment to the infrastructure sector, NATIXIS brings over 25 years of expertise in project finance and the full resources of a global financial institution to each transaction. In North America alone, Natixis officers have acted as financial advisor, arranger, and structurer or bond underwriter in 15 infrastructure projects for a total debt value of US$ 8.7 billion.

As you probably know, NATIXIS is the corporate and investment bank of the BPCE Group (BPCE is the 2nd largest banking group in France with € 1,138 billion in total assets and about 117,000 employees as of the end of 2011). The institution is listed on the Paris stock exchange and currently has long-term ratings of A2/A/A+ by Moody's, Standard & Poor's and Fitch Ratings, respectively. NATIXIS is a leading project finance advisor and lender in the Americas (with teams based in New York and Montreal) and was ranked #2 Project Finance Bookrunner

in the US in 2011 (according to ThomsonReuters). In 20ll, NATIXIS was ranked #5 Global Financial Advisor by Project Finance International and received 15 Deal of the Year awards from various industry publications such as Project Finance International and Infrastructure Journal.

We hereby confirm to you that Isolux is an important client of ours, and we have worked with affiliates of Grupo Isolux Corsan on a number of transactions in the past. They are highly regarded by us, have an outstanding market reputation, and we believe that they have the technical ability to lead an operation of this magnitude and singular nature. We are also aware of TransCanada's outstanding strengths and reputation, and we believe they have the capabilities and experience to undertake the development of projects like this one.

We are also pleased to confirm NATIXIS' interest, on a non-exclusive basis, in potentially acting as a financier in the financing for the Project should Isolux and TransCanada be selected as the winning Applicants.

Please note, as is customary for a letter of this nature, that this letter does not constitute a commitment to lend to this Project or any other project and should not be relied upon as such. Any binding financial commitment would be subject to satisfactory completion of due diligence, including acceptable reports from consultants and an independent engineer, receipt of all required senior management and credit approvals (that, at this stage, have neither been sought nor obtained), and negotiation of satisfactory definitive loan documentation. NATIXIS shall not be responsible or liable to you or any person for any damages or costs which may be alleged or result from this letter.

We look forward to drawing on our extensive project finance skills, infrastructure related experience and financial strength to work with you on this exciting Project.

Sincerely yours,

Olivier Delay
Head of GIP Americas
NATIXIS, New York Branch

Aitor Alava
Head of GIP Spain & Portugal
NATIXIS, Sucursal en España

6 PROPOSED DESIGN

6.1 Summary of the Applicants' Plan

A summary description of how the Plan meets the specified requirements for the East-West Tie Line to the extent known at the time of the designation application. This could include the items listed below as well as any other relevant information the applicant may wish to provide. For items that are unknown, the applicant should describe the method and criteria for determination.

- *length of the proposed transmission line;*
- *number of circuits;*
- *voltage class;*
- *load carrying capacity;*
  - *summer continuous rating (MVA); and*
  - *summer emergency rating (MVA)*
- *resulting total transfer capability for the East-West Tie line (MW);*
- *anticipated lifetime of the line;*
- *structures and conductors*
  - *number and average spacing of towers;*
  - *tower structure types (lattice, monopole, etc.) and composition (wood, steel, concrete, hybrid, etc.);*
  - *conductor size and type; and*
  - *protection against cascading failure and conductor galloping;*
- *design assumptions; and*
- *other relevant transmission facility characteristics.*

The Applicants are proposing a design based on the OPA's Reference Option and the Board's *Minimum Technical Requirements*.

As discussed in section 9, a final route for the E-W Tie line has not been determined at this time. The length of the existing line is approximately 400 km. As shown in the Routing Analysis prepared by Golder (included as Appendix "A" to section 9), the length of E-W Tie line could be greater than 400 km depending on the routing corridor that is chosen during the development phase.

The Applicants intend to construct a double circuit 230 kV overhead transmission line, with each circuit having a rating of 465 MVA continuous (at 93°C) and 600 MVA limited emergency (at 127°C). In accordance with the IESO's *Feasibility Study* (August 2011), the proposed double-circuit line shall be equipped with ACSR 54/19 Grackle 1192.5 kcmil conductors.

The resulting total transfer capability for the E-W Tie line will be 650 MW with an anticipated lifetime expectancy of 50 years. The typical asset life of high-voltage transmission lines ranges between 40 and 75 years, and in some instances lines can be designed to exceed the high end of that range.

One of the main design criteria that directly impacts on the life of transmission assets is the historical recurrence of certain weather conditions (i.e. wind, ice, etc.) The Applicants have assumed design criteria at the low end of the range based on the Board's *Minimum Technical Requirements;* however, design life will be determined during the leave to construct phase. At that stage, the Applicants intend to propose a range of design life options with associated costs.

The Applicants performed a preliminary tower spotting study along the proposed route and anticipate a total of approximately 1,000 steel lattice structures spaced an average of 410 metres apart. For protection against cascading failure and conductor galloping, the Applicants' proposed design includes dead end towers every 5 km.

Preliminary tower spotting for the new 230 kV transmission line was carried out by a transmission line engineer who traveled to the project site and performed a site assessment of the selected route. The preliminary tower spotting was performed in PLS-CADD[5] based on the following requirements:

- Maximum allowable tensions for the selected conductor;
- Specified ground clearances; and
- Applicable spotting constraints.

The tower spotting constraints, such as road, river and stream crossings and the existing transmission lines, came from multiple sources, including field notes gathered by the transmission line engineer, Google Earth and a digital terrain model. The digital terrain data was provided by CanVec, a cartographic reference produced by Natural Resources of Canada. Future field studies will further delineate any other environmentally sensitive areas to avoid.

After the PLS-CADD model was analyzed, the engineering team from Isolux Ingeniería compiled a critical list of materials based on the OEB's *Minimum Technical Requirements*:

- Conductor: ACSR 1192.5 kcmil 54/19
- OPGW: 48 fiber single mode
- Insulators: Toughened glass
    - 52-5 for suspension strings
    - 52-11 for dead end strings

[5] PLS-CADD is a standard and accepted tool used in transmission development to assess the required number of transmission towers, tower types, span distances, etc. See: http://www.powline.com/products/pls_cadd.html

- Lattice tower family
    - Suspension 0-1º: Max Span 410 m
    - Suspension 2-5º: Max Span 640 m
    - Running Angle 5-10º. Max Span 410 m
    - Running Angle 10-25º: Max Span 410 m
    - Dead End 0-90º: Max Span 385 m

The Applicants intend to design a new family of steel lattice tower structures that will optimize design and ensure critical physical and environmentally sensitive conditions are avoided. The new family of towers will be designed specifically to the requirements of the project rather than using the existing X10 tower family. The family of towers will be fully designed, tested and customized for the site by taking into account design criteria, weather conditions, site conditions, topographic constraints and project limitations and requirements.

The Applicants have assumed that the majority of the towers will be lattice type with some monopoles. During the preliminary engineering phase, Isolux Ingeniería will investigate increasing the use of monopoles. Monopoles offer the opportunity for less ROW clearing, less visual impact and only one foundation instead of four. Monopoles also have a shorter lead time as no testing is typically required. This advantage will need to be weighed against the higher cost associated with the use of monopoles. For the purposes of this plan, the Applicants are assuming that monopoles will make up 3% of the total towers for the project.

6.2 Interconnections

Confirmation that the line will interconnect with the existing transformer stations at Wawa and Lakehead, and an indication of whether the line will be switched at the Marathon transformer station.

The Applicants' confirm the proposed transmission line design will interconnect with the existing transmissions stations at Wawa and Lakehead, and the line will be switched at the Marathon transmission station.

6.3 Reliability Standards

A signed affidavit from an officer of the licensed transmitter to confirm:

- *that the line will be designed to meet or exceed the existing NERC, NPCC and IESO reliability standards' and*
- *that the line will be designed to meet or exceed the Board's Minimum Technical Requirements; or documentation of where the applicant seeks to differ from the Minimum Technical Requirements and evidence as to the equivalence or superiority of the proposed alternative option.*

Affidavits from Pablo de la Sierra of Iccon and John Cashin of TPT confirming that the line will be designed to meet or exceed these requirements are attached as Appendix "A" to this section.

6.4 Reference Option

An indication as to whether the Plan will be based on the Reference Option for the East-West Tie line. Where the Plan is not based on the Reference Option, the applicant must file:

- *a description of the main differences between the applicant's Plan and the Reference Option;*
- *a description of the interconnection of the line with the relevant transformer stations; and*
- *a Feasibility Study performed by the IESO, or performed to IESO requirements.*

This requirement is inapplicable as the Applicants' proposed plan is based on the Reference Option.

6.5 Strengths of the Plan

A brief description which highlights the strengths of the Plan, which may include:

- *any technological innovation proposed for the line;*
- *reduction of ratepayer risk for the costs of development, construction, operation and maintenance;*
- *how the plan satisfies the identified need for the line at a lower cost than other options;*
- *local benefits (e.g. employment, partnerships); and*
- *enhanced reliability for the transmission grid.*

The Applicants agree that the double circuit 230 kV overhead transmission line proposed by the OPA/IESO in the Reference Option is the most reliable and cost effective transmission option for addressing the identified need. That said, the Applicants believe there may technological and design innovations that can be integrated as part of the Reference Option to limit environmental impact, reduce cost, reduce ratepayer risk and/or enhance the reliability of the transmission grid. These innovations, which the Applicants will explore further as part of the design and engineering process, include:

- Opportunities for cost savings by selecting different materials, such as ACSR 26/7 Drake 795 kcmil conductor and more basic hardware and OPGW. While the Applicants have planned the line to meet the Board's *Minimum Technical Requirements*, these alternative materials are considered standard for a typical 230 kV transmission line in other jurisdictions and may be suitable for Ontario. The Applicants believe the use of different materials could result in a cost savings of approximately $10 million.

- The possibility of reducing the protection for cascading failure and conductor galloping conditions by reducing the number of dead ends from eighty to thirty-four. The alternative design is considered standard for a typical 230 kV

transmission line in other jurisdictions. The estimated cost savings in material and construction labor is approximately $12 million.

- As discussed in section 6.1, the Applicants intend to design and utilize a new tower family engineered specifically for the E-W Tie. The optimization of a new tower family may significantly reduce steel and concrete requirements, as well as construction labor for tower erection and as a consequence, may further reduce cost by accelerating the overall schedule.

- The design and full scale testing of a new family of towers will also enhance reliability by ensuring the tower can withstand all the loads expected during the tower's lifetime. Isolux Ingeniería has found that making necessary adaptations to a current tower design to conform with new standards, design criteria, maintenance factors and weathering conditions is often more complicated and expensive than designing a new family of towers. A new family of towers will enhance reliability for the transmission grid, as it will be compatible with the requirements set forth by the Board and the latest design codes.

- The feasibility of designing lattice towers that span above the tree tops to reduce the number of trees that need to be cleared in a ROW. The Applicants will also investigate increasing the use of monopoles, which offer the opportunity for less ROW clearing, less visual impact and only one foundation instead of four. Monopoles also have a shorter lead time as no testing is typically required. This advantage will need to be weighed against the higher cost associated with using monopoles.

Construction of the line will, of course, also provide numerous benefits for local communities. The construction phase will require an estimated 600 workers and will generate substantial occupational training and other economic spin-off benefits for local communities and businesses. The AEP (attached as Appendix "A" to section

3) includes measures to engage Aboriginal contractors in the execution of the project.

For other attributes of the Applicants' plan, including benefits not related to the Proposed Design of the line, see sections 4.5 and 7.5.

6.6 Ownership and Operation

An indication as to whether the applicant's present intention is to own and operate the line once the line is in service.

The Applicants' present intention is to own and operate the E-W Tie line once it is in service.

Appendix A — Affidavits of Senior Officers

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

Affidavit of Pablo de la Sierra

(sworn January 3, 2013)

I, Pablo de la Sierra, of the City of Austin, in the State of Texas, United States of America, MAKE OATH AND SAY:

1. I am a director and officer of Iccon Transmission, Inc. ("**Iccon**") which is preparing a joint application for designation in this proceeding with TransCanada Power Transmission (Ontario) L.P. ("**TPT**", collectively the "**Applicants**").

2. I confirm that the East-West Tie Line designed by the Applicants will be designed to meet or exceed the applicable reliability standards of the North American Electric Reliability Corporation, Northeast Power Coordinating Council and Independent Electricity System Operator as well as the applicable *Minimum Technical Requirements* of the Ontario Energy Board.

SWORN BEFORE ME at the City of Toronto, Province of Ontario on January 4, 2013.

Commissioner for taking affidavits

Andrew Michael Sullivan, a
Commissioner etc., Province of Ontario,
while a Student-at-Law.
Expires May 10, 2014.

Pablo de la Sierra

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

Affidavit of John Cashin

(sworn January 3, 2013)

I, John Cashin, of the City of Calgary, in the Province of Alberta, MAKE OATH AND SAY:

1. I am the Assistant Secretary of TransCanada Power Transmission (Ontario) L.P. ("**TPT**") which is preparing a joint application for designation in this proceeding with Iccon Transmission, Inc. ("**Iccon**", collectively the "**Applicants**").

2. I confirm that the East-West Tie Line designed by the Applicants will be designed to meet or exceed the applicable reliability standards of the North American Electric Reliability Corporation, Northeast Power Coordinating Council and Independent Electricity System Operator as well as the applicable *Minimum Technical Requirements* of the Ontario Energy Board.

SWORN BEFORE ME at the City of Calgary, Province of Alberta on January 3, 2013.

Commissioner of Oaths

M. LORRAINE ARSENAULT
A Commissioner for Oaths in and for
The Province of Alberta
My Commission Expires August 27, 2013

John Cashin

7 SCHEDULE

7.1 Project Execution Chart

A project execution chart showing major milestones for both line development and line construction phases of the project.

The Applicants have prepared a preliminary schedule under which the E-W Tie would be ready to be brought into service in October 2018. A preliminary project execution chart showing the indicative milestones for both the line development and line construction phases is attached as Appendix "A" to this section.

The Applicants' schedule is based on using the Alternative A-Prime route identified in the Routing Analysis (attached as Appendix "A" to section 9). The Applicants believe the projected in-service date is a reasonable and achievable target for this route. The preliminary schedule will be refined during the development phase. Key assumptions that must be met to achieve an in-service date of October 2018 are detailed in response to requirements 7.2 and 7.3.

7.2 Development Phase of the Project

For the development phase of the project:

- *a detailed line development schedule identifying significant milestones that are part of the development phase of the project, and estimated dates for completing these milestones;*
- *proposed reporting requirements for the development phase;*
- *proposed consequences for failure to meet the required performance milestones and reporting requirements for the development phase;*
- *a chart of the major risks to achievement of the line development schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and*

- *a description of the applicant's strategy to mitigate or address the identified risks.*

A preliminary line development schedule for an in-service date of October 2018 is attached as Appendix "B" to this section. The schedule identifies significant milestones in the development process and estimates dates for completing these milestones.

For the development phase, the Applicants propose to file progress reports concurrent with the filings for licenced electricity transmitters required by the Board's *Electricity Reporting and Record Keeping Requirements*. The reports will track the actual development process against the preliminary schedule and will explain any deviations.

A preliminary risk register identifying the major risks to achievement of the line development schedule is attached as Appendix "D" to this section. The register describes the Applicants' risk mitigation strategies. The risk register is a living document that will continually evolve as the project progresses. The Applicants will use probabilistic/stochastic modeling techniques to model project risk. The Applicants will continue to identify new risks as they arise and, where possible, eliminate risks that have passed. Where a risk cannot be eliminated on an economic basis, the Applicants will identify reasonable steps to mitigate that risk.

The proposed schedule is premised on the following key assumptions:

- A final order in the Board's transmitter designation process is issued by June 28, 2013 and is not subject to an appeal to the Divisional Court.

- The Minister of the Environment meets the deadline for reviewing the Terms of Reference for the environmental assessment as set out in Ontario Regulation 616/98 under the *Environmental Assessment Act*.

- The Minister of the Environment meets the deadline for reviewing the completed environmental assessment report as set out in Ontario Regulation 616/98 under the *Environmental Assessment Act* and does not refer the application to the Environmental Review Tribunal.

- No party seeks a judicial review of the Minister's approval of the Terms of Reference or the environmental assessment.

- The Board processes the Applicants' leave to construct application under section 92 of the *Ontario Energy Board Act, 1998* in a manner consistent with the Board's *Performance Standards for Processing Applications* and its past practice with similar applications.

- The Ministry of the Environment and other applicable agencies process all environmental permit applications in a timely manner.

- The Applicants will not require access to the right-of-entry and expropriation procedures provided for in sections 98 and 99 of the *Ontario Energy Board Act, 1998*.

In the event that any of these key assumptions are not met, the Applicants anticipate a delay to the in-service date for the project. Any delay in the schedule risks creating a greater than day-for-day impact on the completion of the development process. For example, because of the need to collect seasonal data as part of the environmental assessment and approvals process, any delay that causes the Applicants to miss a critical season could result in a delay of 9 to 12 months.

7.3 Construction Phase of the Project

For the construction phase of the project:

- *a preliminary line construction schedule identifying significant milestones that are part of the construction phase of the project, and estimated dates for completing these milestones;*
- *proposed reporting requirements for the construction phase;*
- *proposed consequences for failure to meet the required performance milestones and reporting requirements for the construction phase;*
- *proposed in-service date for the line (can be 2017 or another date);*
- *a chart of the major risks to achievement of the construction schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g., minor, moderate, major); and*
- *a description of the applicant's strategy to mitigate or address the identified risks.*

A preliminary line construction schedule for the in-service date of October 8, 2018 is attached as Appendix "C" to this section. The schedule identifies significant milestones and estimated dates for completing these milestones. The preliminary line construction schedule would be refined during the development process and an updated schedule presented as part of the leave to construct application.

For the construction phase, the Applicants propose to continue filing progress reports concurrently with the filings for licenced electricity transmitters required by the Board's *Electricity Reporting and Record Keeping Requirements*. The reports will track the actual construction phase against the updated schedule presented in the leave to construct application and will explain any deviations.

A risk register identifying the major risks to achievement of the construction schedule is attached as Appendix "D" to this section. The chart also describes the Applicants' risk mitigation strategies.

7.4 Evidence of Past Experience

Evidence of the applicant's past experience in completing similar transmission line or other infrastructure projects within planned time frames. Such evidence could include a comparison of the construction schedule filed with a regulator when seeking approval to proceed with a transmission line project and the actual completion dates of the milestones identified in the schedule.

Isolux Infrastructure and TransCanada both have proven track records for completing similar infrastructure projects on time.

In Brazil, where Isolux Infrastructure was selected to develop, build and operate the designated transmission facilities, it brought all 13 of its completed projects (approximately 6,000 km of transmission lines and associated substations) into service by or prior to the contractual in-service date. In some cases, Isolux Infrastructure brought facilities into service as much as five months in advance of the contractual in-service date.

TransCanada also has an impressive record for completing major pipeline and other large infrastructure projects on time.

Table 4 lists (i) all the projects that Isolux Infrastructure has brought into service in Brazil, and (ii) all projects that were included in TransCanada's capital budget for the past three years.

Table 4: The Applicants' Past Experience with Project Schedules

Project	In-Service Date	Contractually Scheduled In-Service Date
Isolux Infrastructure		
Expansion Transmissao de Energia Eletrica	Q4 2002	On time
Expansion Transmissao Itumbiara Marimbondo	Q3 2004	On time
Cahoeira Paulista Transmissora de Energia	Q4 2004	On time
Vila do Conde Transmissora de Energia	Q2 2006	On time
Porto Primavera Transmissora de Energia	Q4 2006	On time
Itumbiara Transmissora de Energia	Q4 2006	On time
Serra da Mesa Transmissora de Energia	Q1 2008	On time
LT Triangulo	Q4 2008	On time
Riberao Preto Transmissora de Energia	Q2 2009	On time
Serra Paracatu Transmissora de Energia	Q2 2009	On time
Poços de Caldas Transmissora de Energia	Q2 2009	On time
Jauru Transmissora de Energia (South Phase)	Q4 2009	On time
Interligaçao Eletrica Norte e Nordeste	Q4 2010	On time
TransCanada		
Keystone (Phases I & II)	Q3,10/Q1,11	On time
North Central Corridor	Q2 2010	On time
Halton Hills	Q3 2010	On time
Bison	Q1 2011	60 days late
Coolidge	Q2 2011	On time
Kibby Wind (Phases I & II)	Q4,09/Q4,10	On time
Guadalajara	Q2 2011	On time
Groundbirch	Q4 2010	30 days late

7.5 Innovative Practices

Any innovative practices that the applicant is proposing to use to ensure compliance with, or accelerate, the line development and line construction schedules.

Development — The most significant risks to ensuring compliance with the line development schedule are the actions of third parties (approval agencies, stakeholders, etc.). As detailed in section 9, the Applicants will engage relevant agencies and stakeholders early in the process in an effort to avoid delays. The Applicants possess the requisite expertise and experience to address and solve the obvious challenges posed by the E-W Tie (and those that will invariably emerge in the course of development).

Construction — The greatest opportunities for accelerating construction are derived from the application of experience and expertise to the technical, environmental and logistical challenges that are an inherent part of any large and complex infrastructure project. The Applicants have tremendous experience and expertise in this regard. Specifically, they will draw on construction and project management methods and practices learned by Isolux Ingeniería in building transmission in many different environments and climates, and as necessary they will also draw on TransCanada's North America/Ontario project management knowledge and experience.

As detailed in section 4.1.7, the Applicants will consider dividing the project into two distinct and physically separate transmission line segments (one from Wawa to Marathon and the other from Marathon to Thunder Bay) to expedite construction and minimize project risk. The Applicants will, as noted in section 4.1.2, also benefit from the continuity of having an EPC contractor in place from the outset. Amongst other benefits, the EPC contractor will be in a position to monitor the manufacturing process and ensure quality control and on-time delivery.

At this stage, in advance of doing the necessary development work, the Applicants anticipate employing the various measures identified above in sections 4.5 and 6.5 as well as some of the following practices and techniques to expedite the line construction schedule:

- *Foundations:* In limited access areas where vehicle transport is impeded, the Applicants will utilize specialized smaller equipment and materials that may be transported via helicopter, e.g., screw type anchors which may be affixed with specialized smaller drills.

- *Assembly and Erection:* There are many techniques for the assembly of lattice towers. In areas with limited access the Applicants can set up pre-assembly yards and assemble sections of the towers and then transport the towers to the designated location via sky crane helicopter.

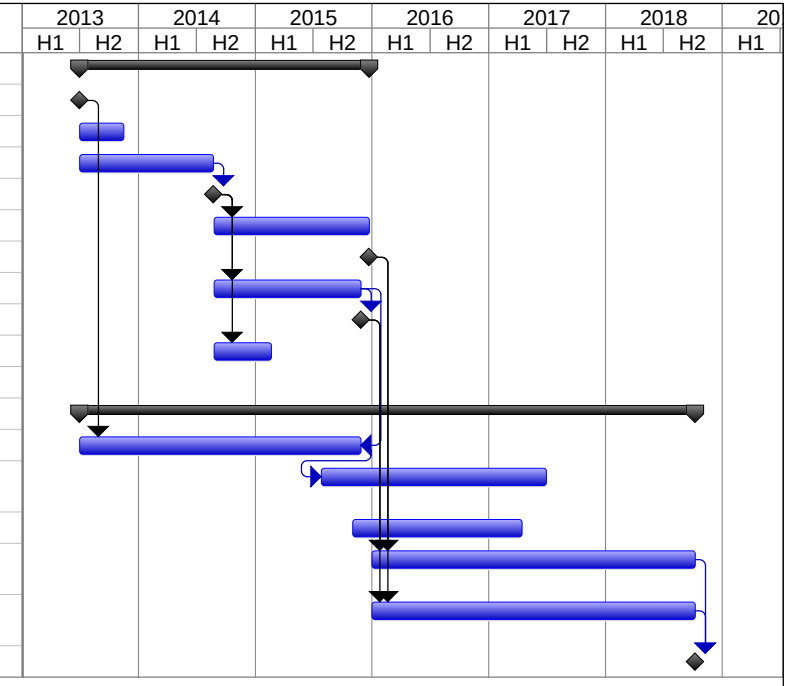
- *Line Stringing:* If there are difficulties with access, Isolux Ingeniería can use helicopters to transport material and equipment to the towers. Isolux Ingeniería can lower personnel and materials from helicopters onto the towers to complete the work. Another option is to deliver ladders by helicopter and the linemen can work from the ladder to clip the conductor.

- *Spacers and Clean up:* Spacers will be installed using spacer buggies or a helicopter eliminating the need for additional movement of bucket trucks or man lifts.

- *Materials:* In Isolux Ingeniería's experience, material fabrication errors can lead to significant delays in the construction schedule. Isolux Ingeniería will provide detailed material inspection from start to finish. Isolux Ingeniería has a worldwide network of inspectors and material coordinators that facilitate material inspection and coordination.

Appendix A — Schedule Summary

ID	Task Name	Duration	Start	Finish	Predecessors
1	**Development Phase**	**648 days**	**Mon 7/1/13**	**Wed 12/23/15**	
2	***Start***	0 days	Mon 7/1/13	Mon 7/1/13	
3	Project Initiation and EA Planning	100 days	Mon 7/1/13	Fri 11/15/13	
4	Develop TOR	300 days	Mon 7/1/13	Fri 8/22/14	
5	***Minister's Acceptance of TOR***	0 days	Fri 8/22/14	Fri 8/22/14	4
6	Conduct EA	348 days	Mon 8/25/14	Wed 12/23/15	5
7	***Minister's Decision on EA***	0 days	Wed 12/23/15	Wed 12/23/15	
8	Leave to Construct Process	330 days	Mon 8/25/14	Fri 11/27/15	5
9	***LTC granted***	0 days	Fri 11/27/15	Fri 11/27/15	8
10	ROW options acquisition	130 days	Mon 8/25/14	Fri 2/20/15	5
11					
12	**Engineering, Procurement, Construction Phase**	**1376 days**	**Mon 7/1/13**	**Mon 10/8/18**	
13	Engineering (Basic)	630 days	Mon 7/1/13	Fri 11/27/15	2,8FF
14	Engineering (Tower Design, Detailed, Line Design)	504 days	Mon 7/27/15	Thu 6/29/17	13FS-90 days
15	Procurement (RFP, PO, Fab, Ship, Deliver)	380 days	Mon 11/2/15	Fri 4/14/17	
16	Construction Segment 1, Thunder Bay-Marathon, 230 mls, 230 kV	722 days	Fri 1/1/16	Mon 10/8/18	7,9
17	Construction Segment 2, Marathon - Wawa, 113 mls, 230 kV	722 days	Fri 1/1/16	Mon 10/8/18	7,9
18	***Commercial Operation***	0 days	Mon 10/8/18	Mon 10/8/18	17,16

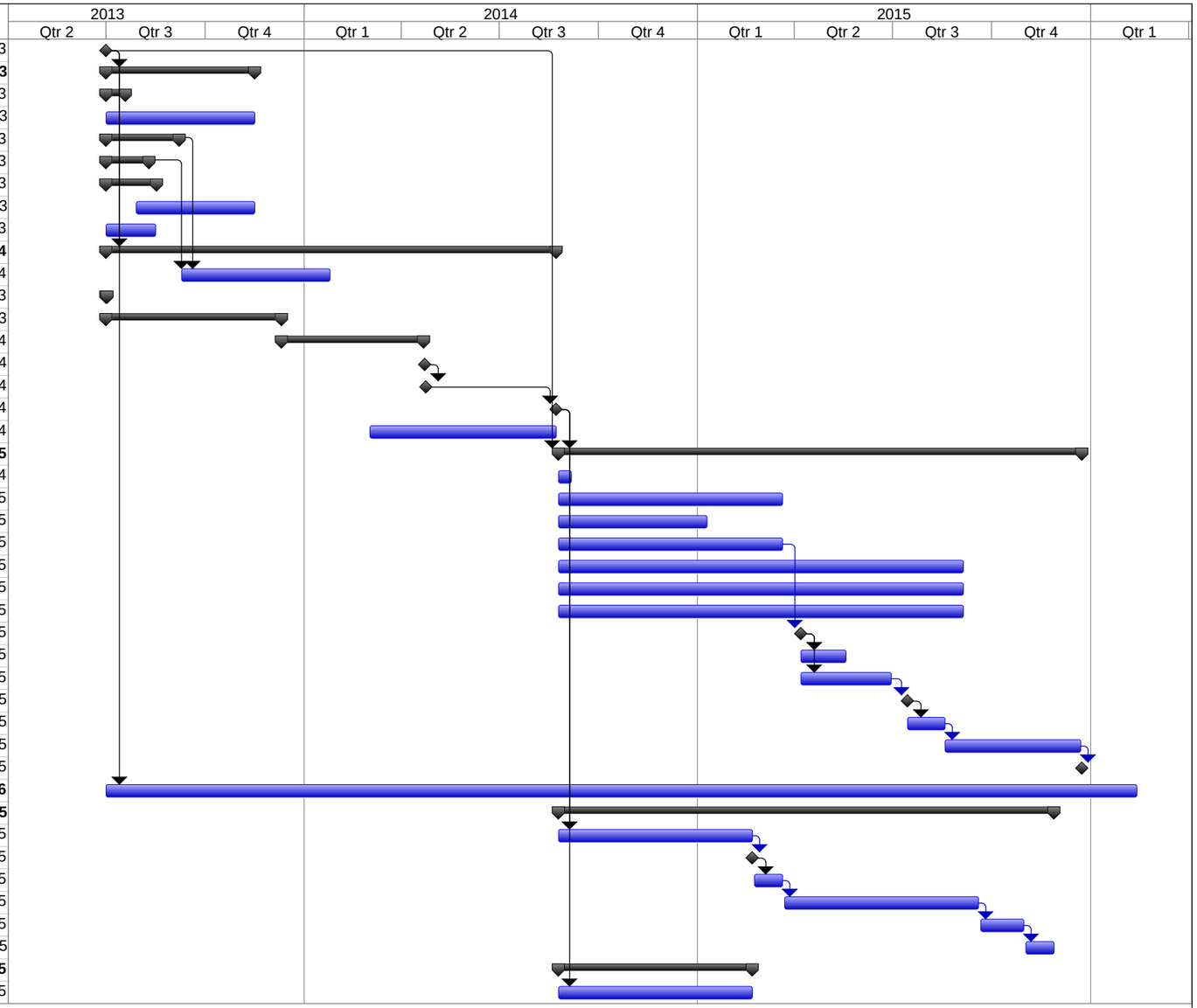


Project: EWT Development Detail 201
Date: Thu 1/3/13

Task		External Tasks		Duration-only	
Milestone		Project Summary		Manual Summary Rollup	
Summary		Group By Summary		Manual Summary	
Rolled Up Task		Inactive Task		Start-only	
Rolled Up Milestone		Inactive Milestone		Finish-only	
Rolled Up Progress		Inactive Summary		Progress	
Split		Manual Task		Deadline	

Appendix B — Development Schedule

ID	Task Name	Duration	Start	Finish
1	Start	0 days	Mon 7/1/13	Mon 7/1/13
2	**Phase 1: Project Initiation and EA Planning**	**100 days**	**Mon 7/1/13**	**Fri 11/15/13**
3	Project Initiation	14 days	Mon 7/1/13	Thu 7/18/13
7	Corridor Analysis	100 days	Mon 7/1/13	Fri 11/15/13
8	Finalize Aboriginal Engagement Plan	50 days	Mon 7/1/13	Fri 9/6/13
16	Finalize Stakeholder Engagement Plan	30 days	Mon 7/1/13	Fri 8/9/13
23	Finalize EA Plan for Required Permits and Approvals	35 days	Mon 7/1/13	Fri 8/16/13
30	Meet with Agencies (MOE, MNR, CEAA, etc.)	80 days	Mon 7/29/13	Fri 11/15/13
31	Finalize Field Work Plan	34 days	Mon 7/1/13	Thu 8/15/13
32	**Phase 2: Develop Terms of Reference**	**300 days**	**Mon 7/1/13**	**Fri 8/22/14**
33	Project Description	100 days	Mon 9/9/13	Fri 1/24/14
34	Project Announcement	1 day	Mon 7/1/13	Mon 7/1/13
36	Prepare draft TOR	117 days	Mon 7/1/13	Tue 12/10/13
65	Engagement Events on TOR	94 days	Wed 12/11/13	Mon 4/21/14
70	Finalize and Submit TOR	1 day	Tue 4/22/14	Tue 4/22/14
71	Issue Notice of Submission of the TOR	1 day	Wed 4/23/14	Wed 4/23/14
72	Minister's Acceptance of the TOR	1 day	Fri 8/22/14	Fri 8/22/14
73	Study and Describe Environment Potentially Affected	125 days	Mon 3/3/14	Fri 8/22/14
74	**Phase 3: Conduct EA**	**348 days**	**Mon 8/25/14**	**Wed 12/23/15**
75	Notice of Commencement	10 days	Mon 8/25/14	Fri 9/5/14
76	Study and Describe Environment Potentially Affected (ongoing field studies)	150 days	Mon 8/25/14	Fri 3/20/15
77	Prepare EA Study Documentation	100 days	Mon 8/25/14	Fri 1/9/15
78	Prepare and Submit EASR to MOE	150 days	Mon 8/25/14	Fri 3/20/15
79	Hold Rounds of Open House(s)	270 days	Mon 8/25/14	Fri 9/4/15
80	Meetings with Aboriginal Stakeholders	270 days	Mon 8/25/14	Fri 9/4/15
81	Agency Coordination and Meetings	270 days	Mon 8/25/14	Fri 9/4/15
82	Issue Initial Public Notice	1 day	Mon 4/6/15	Mon 4/6/15
83	Initial Comment Period	30 days	Tue 4/7/15	Mon 5/18/15
84	Ministry Review of EA	60 days	Tue 4/7/15	Mon 6/29/15
85	Issue Final Public Notice	1 day	Tue 7/14/15	Tue 7/14/15
86	Final Comment Period	25 days	Wed 7/15/15	Tue 8/18/15
87	Minister's Review	90 days	Wed 8/19/15	Tue 12/22/15
88	Minister's Decision on EA	1 day	Wed 12/23/15	Wed 12/23/15
89	**Other Permitting**	**685 days**	**Mon 7/1/13**	**Fri 2/12/16**
90	**Leave to Construct Process**	**330 days**	**Mon 8/25/14**	**Fri 11/27/15**
91	Prepare Leave to Construct Application	130 days	Mon 8/25/14	Fri 2/20/15
92	File Leave to Construct Application with the OEB	0 days	Fri 2/20/15	Fri 2/20/15
93	OEB staff review of application	20 days	Mon 2/23/15	Fri 3/20/15
94	Prehearing Procedures	130 days	Mon 3/23/15	Fri 9/18/15
95	Oral Hearing of Application and Final Submissions	30 days	Mon 9/21/15	Fri 10/30/15
96	OEB Decision	20 days	Mon 11/2/15	Fri 11/27/15
97	**Right of Way Acquisition**	**130 days**	**Mon 8/25/14**	**Fri 2/20/15**
98	Option Acquisition	130 days	Mon 8/25/14	Fri 2/20/15

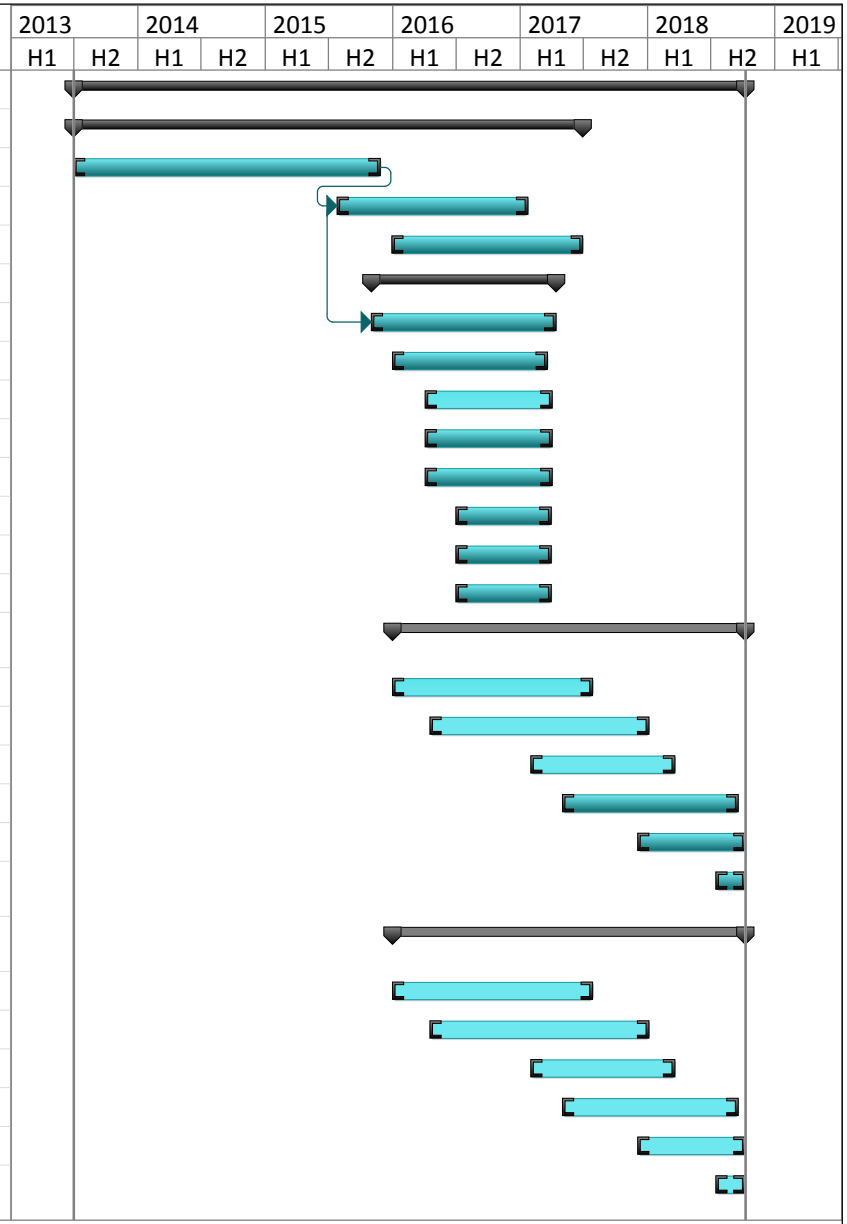


Project: EWT Development Detail 201
Date: Thu 1/3/13

Task	Rolled Up Progress	Inactive Task	Manual Summary Rollup	Deadline
Milestone	Split	Inactive Milestone	Manual Summary	
Summary	External Tasks	Inactive Summary	Start-only	
Rolled Up Task	Project Summary	Manual Task	Finish-only	
Rolled Up Milestone	Group By Summary	Duration-only	Progress	

Appendix C — Construction Schedule

ID	Task Name	Duration	Start	Finish
1	**Ontario Energy Board East-West Tie 230kV TL**	**1376 days**	**Mon 7/1/13**	**Mon 10/8/18**
2	**Engineering**	**1044 days**	**Mon 7/1/13**	**Thu 6/29/17**
3	Basic Engineering	630 days	Mon 7/1/13	Fri 11/27/15
4	Detailed Engineering	391 days	Mon 7/27/15	Mon 1/23/17
5	Line Design	391 days	Thu 12/31/15	Thu 6/29/17
6	**Procurement (RFP, PO, Fab, Ship, Deliver)**	**380 days**	**Mon 11/2/15**	**Fri 4/14/17**
7	Towers	380 days	Mon 11/2/15	Fri 4/14/17
8	Conductor	317 days	Fri 1/1/16	Mon 3/20/17
9	OPGW	261 days	Mon 4/4/16	Mon 4/3/17
10	Grounding Material	261 days	Mon 4/4/16	Mon 4/3/17
11	Insulators	261 days	Mon 4/4/16	Mon 4/3/17
12	Hardware	196 days	Fri 7/1/16	Fri 3/31/17
13	Spacer/Damper	196 days	Fri 7/1/16	Fri 3/31/17
14	Other Misc. Materials	196 days	Fri 7/1/16	Fri 3/31/17
15	**Seg. 1 Thunder Bay - Marathon 230 miles 230kV Construction**	**722 days**	**Fri 1/1/16**	**Mon 10/8/18**
16	ROW (Clearing, Access Roads, Environmental)	410 days	Fri 1/1/16	Thu 7/27/17
17	Foundations	450 days	Mon 4/18/16	Fri 1/5/18
18	Assembly & Tower Erection	295 days	Wed 2/1/17	Tue 3/20/18
19	Stringing	360 days	Wed 5/3/17	Tue 9/18/18
20	Cleanup and restoration	220 days	Tue 12/5/17	Mon 10/8/18
21	Construction Finish (Ready for Interconnection)	60 days	Tue 7/17/18	Mon 10/8/18
22	**Seg. 2 Marathon - Wawa 113 miles 230kV Construction**	**722 days**	**Fri 1/1/16**	**Mon 10/8/18**
23	ROW (Clearing, Access Roads, Environmental)	410 days	Fri 1/1/16	Thu 7/27/17
24	Foundations	450 days	Mon 4/18/16	Fri 1/5/18
25	Assembly & Tower Erection	295 days	Wed 2/1/17	Tue 3/20/18
26	Stringing	360 days	Wed 5/3/17	Tue 9/18/18
27	Cleanup and restoration	220 days	Tue 12/5/17	Mon 10/8/18
28	Construction Finish (Ready for Interconnection)	60 days	Tue 7/17/18	Mon 10/8/18



Project: EWT Construction Detail 2
Date: Thu 12/27/12

Task
Split
Milestone
Summary
Project Summary
External Tasks
External Milestone
Inactive Task
Inactive Milestone
Inactive Summary
Manual Task
Duration-only
Manual Summary Rollup
Manual Summary
Start-only
Finish-only
Deadline
Progress

Appendix D — Risk Register

East West Transmission Project

Risk Register

Prospecting Phase

Date: 1/2/2013

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
1		**Legal, Regulatory & Permits**								
1.01	Active	Section 92 approval delayed or appealed	- Incomplete filing - Stakeholder influence - Special interest groups - Change in law	Accept	- Completed comprehensive filings - Completed hearing process - Consulted with regulatory bodies - Devise efficient strategy -Early engagement of stakeholders and seek local support early		- Delay in receiving Section 92. could impact construction start date - Cost impact due to escalation or change orders		Medium	High
1.02	Active	Terms of Reference not accepted by Ministry or subjected to legal challenge	- Special interest groups - Poor preparation	Accept	- Consult widely prior to Terms of Reference submission		Cost to project		Medium	High
1.03	Active	EA process takes longer than anticipated or is not accepted by Minister	- Political Influence - Quality of Submittal	Accept	- Start EA early - Devise an EA approach plan		Cost and schedule impact		High	High
1.04	Active	Permit conditions contain conditions that drive additional costs	- Special interest groups - Environmental conditions	Accept			Cost and schedule impact		Medium	Medium
1.05	Active	Unforeseen events drive a re route late in the development process	Regulatory or permitting delays Archeological Issues Aboriginal issues Environmental	Accept	- Review multiple routes - Up front discussions with stakeholders - Archaeological studies and surveys Completed Early		Cost and Schedule impact		Low	Medium
2		**Land, Aboriginal, Community, Safety & Environment**								

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
2.01	Active	Aboriginal / Tribal Land Issues	- Engagement will be required, because the transmission line will be within traditional and treaty lands of aboriginal communities - Aboriginal community concerns could impact project schedule (engagement is ongoing)	Mitigate	- Address with standard TransCanada aboriginal group related processes - Early and ongoing consultation / engagement with aboriginal groups and tribes during the planning process - Partnering		- Contractor skips / re-mobilization costs - Additional community investment - Re-alignments around aboriginal/tribal lands		Medium	High
2.02	Active	Environmental Risks from Sensitive Areas	- May pass through wetland regions - Additional steps needed to minimize environmental impact - ROW may pass through Federal and Provincial parks	Mitigate	- Early consultation with regulators including Environment Canada - Follow Environment Canada's Wetland Policies Avoid parks or commence early discussions with regulator re parks issues	Early route planning and consultation will assist with mitigation	- Additional costs of environmental work to plan work in wetlands or around wetlands - Additional costs of post construction monitoring / rehabilitation of land - Cost to re route around parks		High	

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
2.03	Active	Threatened & Endangered Species Affects Construction	- Protected plant or animal species may be present in this area and could present schedule delays or additional costs -Migratory bird issues may cause construction impacts	Mitigate	Early preparation of ESA and EPP Contingency Plans early consultation with regulators plan around any wildlife driven construction windows		- Protected plants - additional costs to temporarily relocate - Protected animals - schedule delays if species are present / active during construction - Costs of second construction crew if construction schedule is compressed or pushed to windows		High	High
2.04	Active	Clean-up and Reclamation Problems	- Issues such as not having native plant seed available will add costs to the project - Reclamation / compensation issues at water crossing - Issues with weeds growing back	Mitigate	- Develop restoration plans required by the applicable permits - Early identification of reclamation requirements - Discuss reclamation plans with regulators - Have ongoing discussions re: conditional compliance		- Additional reclamation for a longer period of time - Extension of schedule - Re-seeding - Repairing sunken ditches - Removing rock fragments - Continual re-vegetation - Cost to develop and implement restoration plans required by the regulator		Medium	Low
2.05	Active	Critical Safety Issue or Fatality	- Contractors are responsible for their employees and the sub contractors hired - Safety stand-downs add schedule delays and lost productivity	Mitigate	- Proper safety pre-qualifications of all contractors before bidding - Consultation with Company Community, Safety, and Environment (CSE) group to develop and implement Project Specific Safety Plan (PSSP) - Additional Training, proper protective equipment - Implement new safety initiatives with contractors		- Additional safety stand downs - Additional safety meetings - Slower productivity - Schedule delays		Medium	Low
2.06	Active	Landowner Issues	-Landowners do not allow access -Landowners form associations and drive costs and create delay	Mitigate	Early notification Early negation and options in place with landowners		- Increased land cost - Increased entry fees - delays			

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
2.07	Active	Unexpected Paleontological/ Archaeological/ Cultural Findings	- Never completely certain of what could be found - Findings can trigger re-route and investigations	Mitigate	- Identify potential areas which could have findings - Complete geotech study to analyze this risk - Immediate consultation with agencies to determine mitigation or solution once a site is found		- Costs of investigations required - Cost to remove findings or implement mitigation - Cost of change orders		Remote	Low
3		**Engineering**								
3.01	Active	Detailed Engineering Issues Regarding Schedule, Deliverables and Quality	- Delay in completion of detailed engineering could impact construction award date, cost estimating work and construction contractor selection - Incomplete and/or inadequate engineering work will result in re-work - Changes in scope	Mitigate	- Confirmed scope and manpower availability with engineering contract early in project planning - Identify terms in contract so that IFC drawings are completed on time - Implement performance measures, including: on-site performance monitoring, periodic quality checks, progress reporting / measurements, etc. - Ensure enough time is available for review by Owner personnel		- Cost of re-work (contractor time and Developer internal review time) due to poor quality drawings and/or scope creep - Cost of additional change orders		Low	Low

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
4		**Materials, Equipment & Utilities**								
4.01	Active	Major Materials Delays	- Poor transportation service causes delays - Tower steel must be stockpiled and ready before construction can begin - Damage or loss during transportation causes delays	Transfer	- Consultation with Supply Chain Management to ensure correct contracting strategy is used - Ensure procurement strategy is in place to allow equipment orders at the correct time - Receive regular updates from manufacturers on progress	- Plan on stockpiling tower steel to allow some delay cushion - Company does not take possession of tower steel until it hits the stockpile	- Stand-by costs		Low	
4.02	Active	Material Price Increase	- Aluminum Costs - Steel Costs - Manufacturing Costs	Mitigate	- Lock in pricing with known escalation factors Maintain schedule		Increased project cost		High	Medium
4.03		Increase in Interest Rates	- Economy improves - Canadian dollar strengthens	Mitigate	- Hedge - Early contract placement		Increased project cost		Medium	Medium
4.04		Currency Exhchange Rates Change (Canadian or US Dollar)	- Canadian dollar devalues against currencies where we are buyng commodities	Mitigate	- Financial Hedging		Increased project cost		Medium	Medium
4.05	Active	Issues with material quality	- Quality problems for major materials after delivery could cause significant delays and costs	Mitigate	- Have third party inspection to identify and correct any quality issues - Have a quality assurance plan - Ensure vendors understand Company quality assurance and inspection conditions		- Cost to re-order / repair defects if found later in the inspection process - Cancelling an order due to quality issues could result in premiums - Construction schedule delays		Low	High

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
5		**Construction**								
5.01	Active	Construction Contractor Insolvency/Default	- Contractor default during construction would result in major problems and costs - Affects sub-contractors under the prime	Mitigate	- Due diligence by counter-party risk to assess company financials and credit-worthiness - Obtain proper securities from contractors (performance bonds, letter of credit, parental guarantee) - Use well established contractors	Impact changes depending on contractor availability	- Incremental contractor costs - Re-mob of new contractor - Additional PM/CM/Eng - Missing the rest of the construction season (esp. winter construction) - Learning curve for new contractor, - Schedule acceleration costs		Low	High
5.02	Active	Preferred Construction Contractors are Unavailable	- Preferred contractors may not be available for bid for the project - Heated market resulting in increased costs - Total number of contractors available on the market is limited - Qualified contractors may be unavailable - Experienced contractors may be unavailable - Financial capability of the contractors	Mitigate	- Start early to source contractors and determine availability (single sourcing, multi sourcing, etc.) - Contractor development - Engage contractors at early stages - Leverage existing agreements with existing contractors - Look internationally for qualified Contractors	- Significant transmission work commencing in Canada , there is a limited number of contractors able to complete this work	- Premiums associated with securing a qualified and experienced contractor - May not have most desired contractor, may result in quality issues and re-work - Lack of available contractor leads to missing timeline window		Medium	Low

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
5.03	Active	Productivity Issues with Contractor	Lower Productivity Due to: - Poor quality working leading to re-work - Inexperienced workforce driving errors	Mitigate	- Evaluate contractor schedule and manpower plan early - Ensure work is inspected in a timely manner - Provide support to construction contractor - Outline productivity rate in contract		- Additional costs associated with re-work and additional inspections		Remote	
5.04	Active	Labor Availability	-Labour shortage in geographic area or entire country - Availability of skilled labor - labor costs very high driven by other projects and Availability	Mitigate	- Offer incentives - use experience in international market to source skilled labor as needed - early discussions with unions Labor agreements - planning and communication	There are several potential competing projects in Canada and the US that may be seeking so source similiar labour pool	- Cost - Schedule - Safety impacts caused by inexperienced labor		Very High	High
5.05	Active	Weather Delays Affects Construction	- Above average temperatures during winter construction affects productivity and can cause delays and prevent construction kick-off (beyond what is already considered in the contract) - Warm weather shortens construction season and causes early melt - Rain or snow causes delays and or drives additional construction cost	Mitigate	- Add resources and equipment - Start as early as possible - Bring in special equipment to handle soft ground conditions (swamp mats, etc) - Helicopter construction	- Construction permits specify Owner can only construct during frozen and dry weather conditions	- Cost and Schedule		Medium	
5.05	Active	Force Majeure Event	- Force Majeure events can occur on any project for a variety of reasons - Any major/catastrophic weather which would cause the prime contractor to claim force majeure - Labour unrest in local areas	Accept			- Re-mobilization of contractors - Schedule delays - Damage to materials and equipment - Claims from contractors		Remote	

RISKS									PROBABILITY & IMPACT RANGES	
Only risk events with a probability less than 100% are included in the risk register. Risk events with a probability equal to 100% should migrate to the base estimate									Event Probability	Event Cost Impact
Item #	**Status**	**Risk Event**	**Risk Drivers**	**Risk Response**	**Risk Response Plans**	**Comments**	**Basis of Impact**	**Risk Owner**	**Desc.**	**Desc.**
6		**Commissioning and Start-Up**								
6.01	Active	Delays on Commissioning	Commissioning Delays Due to: - Catastrophic equipment failure or integrity issues - Inclement weather (blizzard, ice storms, etc.) resulting in lost workdays during commissioning will cause delays	Mitigate	- Proper maintenance and pre-commissioning testing of equipment - Organize longer shifts to make up for schedule losses - Engage Commissioning Manager in project early on - Allow for float in schedule		- Re-work due to inexperience workforce - Premium to obtain resources with the necessary commissioning skills - Schedule acceleration costs		Low	

8 COSTS

For purposes of this section, the Applicants have prepared a preliminary estimate of the anticipated development and construction costs using the Alternative A-Prime route identified in the Routing Analysis (attached as Appendix "A" to section 9) and that estimate is approximately $572 million (as detailed below). The annual average operation and maintenance costs will be approximately $5.5 million.

Depending on the length of the final route selected, the Applicants estimate that the total costs for the line will be in the range of $545 million to $712 million.

8.1 Amount Already Spent

The amount already spent for preparation of an application for designation, and an estimate of remaining costs to achieve designation.

The Applicants have spent a total of approximately $800,000 in preparing the application for designation and estimate that the total cost to achieve designation will be approximately $1.5 million.

8.2 Estimated Total Development Costs

The estimated total development costs of the line, broken down by the following categories of cost:

- *permitting, licensing, environmental assessment and other regulatory approvals*
- *engineering and design;*
- *procurement of material and equipment;*
- *costs of the acquisition of land use rights, First Nation and Métis participation, and consultations with landowners, municipalities, the public and First Nation and Métis communities;*

- *contingencies; and*
- *other significant expenditures.*

Table 5 provides a preliminary estimate of total development costs of the Applicants' proposal for the E-W Tie line, broken down by category.

Table 5: Estimated Development Costs

Item	Estimate
Permitting, Licensing, Environmental Assessment and other regulatory approvals	4,550,000
Engineering and Design	5,370,000
Procurement of material and equipment	
Cost of the acquisition of land use rights, First Nation and Metis participation, and consultation with landowners, municipalities, the public and First Nation and Metis communities[6]	22,706,000
Contingencies	4,140,000
Other significant expenditures	8,775,000
TOTAL	**45,541,000**

8.3 Basis and Assumptions

The basis for and assumptions underlying the development cost estimates, and a description of how the applicant plans to manage the cost of development.

The development cost estimate is based on the Applicants' expertise and experience in developing major linear infrastructure projects, including electricity

[6] Includes costs up to the time of granting leave to construct and approval of the environmental assessment (approximately end of 2015, see section 7). The estimate does not include the post-development costs of acquiring final easements for the approved ROW. Approximately $8 million has been included in the construction budget to cover these acquisition costs.

transmission, as well as specific input from local consultants and internal subject matter experts.

The estimate assumes that the development phase will require the level of resources detailed in this application and will proceed in accordance with the line development schedule and key assumptions presented in section 7, including:

- Staffing levels will be consistent with the resources outlined in section 4.
- The GP will have a main office in Toronto and a project office to support development closer to the project footprint.
- The costs of First Nation and Métis engagement will be consistent with the scope of the AEP (Appendix "A" to section 3).
- The scope of environmental work required is based on the permitting and approvals table in Exhibit "E" of Volume 2.
- Land acquisition costs will be consistent with the plan outlined in section 9.
- The cost of community consultation will align with the scope of the work detailed in section 9.
- The cost of design and engineering services is based on the Reference Option and route alternative A-Prime.
- An allowance for costs related to customer impact assessments and system impact assessments.
- Builder's all risk insurance including general liability insurance will be necessary.
- The Applicants will be responsible for third party regulatory costs related to supporting the environmental process and the leave to construct process.

- A 10% allowance for contingency on all costs.

The most significant risk to managing the cost of development is delay caused by the actions of third parties (approval agencies, stakeholders, etc.). As detailed in section 9, the Applicants will engage relevant agencies and stakeholders early in the process in an effort to avoid delays. The risk register attached as Appendix "D" to section 7 identifies a number of specific measures that the Applicants will implement to manage the risk of delay in the development process.

8.4 Schedule of Development Expenditures

A schedule of development expenditures.

Table 6 shows the Applicants schedule for development expenditures by year.

Table 6: Schedule of Development Expenditures

Year	Total Expenditures
2013	$7,955,600
2014	$21,989,700
2015	$15,595,700

8.5 Major Development Risks

A chart of the major risks that could lead the applicant to exceed the line development budget, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the budget (e.g. minor, moderate, major), and a description of the applicant's strategy to mitigate or address the identified risks.

A risk register identifying the major risks that could lead the Applicants to exceed the line development budget is attached as Appendix "D" to section 7. The risk register describes the Applicants' risk mitigation strategies.

8.6 Development Costs Risk Allocation

A statement as to the allocation between the applicant and transmission ratepayers of risks relating to costs of development. For example:

- *if the costs of development are less than budgeted, does the applicant propose to recover only spent costs, or all budgeted costs (spent and unspent) or spent costs plus a portion of unspent cost (savings sharing)? And*
- *if the costs of development exceed budgeted costs, does the applicant plan to seek recovery of the excess costs?*

The Applicants propose to recover their actual spent development costs. To the extent this is less than budgeted development costs, this saving will be passed along to ratepayers. If actual spent costs are above budget, recovery of these costs will be subject to the standard prudence review conducted by the Board for such expenses.

8.7 Estimated Construction Budget

An estimated budget for the construction of the line. This budget and its elements may be expressed as a range. If a range is used, the applicant must provide an explanation for the width of the range.

A preliminary estimate of the total construction costs is set out in Table 7. The Applicants have involved the specialized expertise of Isolux Ingeniería in preparing this plan. This ensures the plan is informed by an early analysis and assessment of the technical specifications and EPC requirements, which contributes to a more accurate preliminary construction cost estimate. The construction costs estimate will be refined during the development process and updated as part of the leave to construct application.

Table 7: Preliminary Estimate of Construction Costs

Item	Estimate ($)
Project Management	26,580,000
Engineering	11,770,000
Procurement	65,560,000
Construction	250,460,000
Risks/Escalation	70,228,000
Other	101,750,000
TOTAL	**526,348,000**

8.8 Reference Option

If the Plan is not based on the Reference Option, evidence as to the difference in cost (positive or negative) of work required at the transformer stations to which the line connects, and at any other location identified by the IESO.

This requirement is not applicable because the Applicants' plan is based on the Reference Option.

8.9 Major Construction Risks

A list of the major risks that could lead the applicant to exceed the line construction budget, and the applicant's strategies to mitigate or address those risks.

A risk register identifying the major risks that could lead the Applicants to exceed the line construction budget is attached as Appendix "D" to section 7. The risk register describes the Applicants' risk mitigation strategies.

8.10 The Applicants' Past Experience

Evidence of the applicant's past experience in completing similar transmission line projects within planned construction budgets. Such evidence could include a comparison of the budget filed with a regulator when seeking approval to proceed with a transmission line project and the actual costs of the project.

Both Isolux Corsán and TransCanada are commercial enterprises whose businesses are fundamentally based on completing projects on schedule and on budget.

All transmission projects that Isolux Infrastructure successfully completed in Brazil (see section 7.4) were based on fixed transmission rates established through a competitive auction process. Isolux Infrastructure was selected based on submitting the lowest bid and it accepted contractual risk if the projects were not completed on budget. Isolux Infrastructure has bid on and won 17 auctions since 2000 and has completed and brought 13 of those projects into operation; it is currently developing four additional projects in Brazil (including the $1.4 billion Amazon Project). Isolux Infrastructure's extensive track record and continuing work in Brazil is evidence of its real world expertise in developing projects on time and on budget.

As an experienced developer of linear infrastructure and other energy projects, TransCanada has a proven history of completing projects within its planned construction budgets. Details of the projects that TransCanada has brought into service within the planned construction budgets are shown in Table 8.

Table 8: TransCanada's Past Experience with Project Budgets

TransCanada		
Project	**Capital Cost ($ Billions)**	**Cost Performance**
Keystone (Phases I & II)	6.0	12% over
North Central Corridor	0.8	15% under
Halton Hills	0.7	On budget
Bison	0.6	11% over
Coolidge	0.5	12% under
Kibby Wind (Phases I & II)	0.4	On budget
Guadalajara	0.4	On budget
Groundbirch	0.2	44% under

8.11 Construction Costs Risk Allocation

A statement as to the allocation between the applicant and transmission ratepayers of the risks relating to construction costs.

The party best able to manage the majority of the risks associated with the engineering, procurement and construction of the project will be the EPC contractor, Isolux Ingeniería.

To reduce ratepayer risk associated with construction costs, the Applicants intend to enter into a fixed fee EPC contract with Isolux Ingeniería based on a well-defined scope and schedule which will be established prior to filing a leave to construct application. A fixed fee will incentivize cost efficiency and limit ratepayer exposure to construction delays and cost overruns.

Isolux Ingeniería will competitively procure materials on a worldwide basis. It will, as appropriate, also competitively subcontract the building of roads and tower foundations, the assembly and erection of the towers, the installation of the

conductors, insulators and other equipment, and the commissioning of the line. Such subcontracts will include performance bonus structures to balance risk/reward sharing and incentivize on time and early completion of the works.

The Applicants together with Isolux Ingeniería will formulate appropriate commodity and currency hedging strategies to manage movements in the prices of key commodities such as aluminum and in currency exchange rates.

8.12 Estimated Average Annual Cost of Operating

The estimated average annual cost of operating and maintaining the line. This cost may be expressed as a range. If a range is used, the applicant must provide an explanation for the width of the range.

The Applicants estimate that the annual average cost of operating and maintaining the line will be $5,500,000.

9 LANDOWNER, MUNICIPAL AND COMMUNITY CONSULTATION

9.1 Rights-of-Way

An overview of:

- *the rights-of-way and other land use rights, presented by category, that would need to be acquired for the purposes of the development, construction, operation and maintenance of the line;*
- *the applicant's plan for obtaining those rights; and*
- *a description of any significant issues anticipated in land acquisition or permitting and a plan to mitigate them.*

9.1.1 Types of Land Use Rights Required

The rights-of-way and other land use rights, presented by type of land use and phase, that need to be acquired for the purposes of the development, construction, operation and maintenance of the line are shown in Table 9.

Table 9: Land Use Rights Required

Phase	Land Use Rights Required
Crown Land	
Development	• ROW — request tenure for acquiring Licence of Occupation, Lease, Easement or Freehold rights • Temporary Work Space for Line Laydown Area and Third Party crossings • Temporary Storage area for Towers, Poles and Equipment • Access Rights on adjacent ROW Lands and for preliminary survey work • Agreements to use other parties ROW
Construction	• Temporary Work permit for Geotechnical work and/or for crossing other ROWs, utilities, roads or natural features. • Access agreements to allow access to various part of the ROW, storage areas and other miscellaneous areas.

Table 9: Land Use Rights Required

Phase	Land Use Rights Required
Operation	• Access Road Agreements • Ingress and egress rights for various purposes • Miscellaneous Surface Agreements
Maintenance	• Temporary Work Space for line repair • Access agreements to allow access to various parts of the ROW for line repair.
Private Land	
Development	• ROW Agreements • Surface Lease Agreements where necessary (towers) and/or Freehold Agreements (major facilities as required) • Temporary Access Agreements to access various parts of the ROW • Ingress and Egress rights for the ROW.
Construction	• Temporary Access Agreements to access various parts of the ROW • Workspace/Storage agreements for line laydown, geotechnical work, storage, third party crossings etc.
Operation	• Access roads • Miscellaneous Surface Agreements
Maintenance	• Temporary Work Space for line repair • Access agreements to allow access to various parts of the ROW for line repair.
Third Party Agreements	
Development	• Crossing Agreements • Joint use of ROW agreements • Workspace Agreements • Joint Use of Access Agreements • Temporary Access Agreements • Storage Agreements • Ontario One-Call

9.1.2 Plan for Land Acquisition

9.1.2.1 Private Land

The Applicants will enter into a services agreement to use TransCanada's land team for survey permission/notification, landowner contacts, and negotiating agreements for ingress and egress to construct on private lands. This commonly includes survey notifications, work permits, ROW agreements, access agreements and damage releases. The land team will lead engagement and resolution of concerns, issues and damages relating to the project.

Compensation for easement agreements will be based on land value; therefore the scope of work will include engaging an Ontario-based land appraisal firm to provide market-based land value information.

9.1.2.2 Crown Access & Acquisition

TransCanada's land team will be responsible for undertaking notifications, securing permissions and agreements from holders of interests in Crown lands. The land team will engage the Crown to provide project information and identify, address and resolve any potential issues.

9.1.2.3 Permitting for Crossing and Other Third Party Agreements

Once the routing is established, the land team will determine via survey/GIS analysis/land searches, the number and type of permits and third party agreements required. Typically, these agreements include crossings (roads, highways, railways, third party utilities including pipelines and power lines) and other third party agreements, both private land and Crown dispositions.

9.1.3 Anticipated Issues

A major risk to the project is delay caused by the inability to secure land rights on commercially reasonable terms. The team will mitigate this risk through appropriate agreements on reasonable terms. TransCanada's practices of fair and reasonable compensation and agreements, early and frequent consultation, sound and practical siting criteria and respect for the safety of the public and environment, have historically minimized this risk. If necessary, TransCanada's land team will utilize the full suite of tools, strategies and tactics available to it and will do so in accordance with TransCanada's business practices (detailed in Appendix "D" to section 4) and the GP's oversight.

Another risk is the failure to obtain Crown permits and other third party agreements in a timely manner. Mitigating this risk requires early identification of all required permits and the submission of complete and accurate applications that are supported by the requisite engineering and survey materials.

9.2 Consultation Plan

A landowner, municipal and community consultation plan for the line, including:

- *identification of the categories of parties to be consulted;*
- *the applicant's plan for consultation for each party or category of party, including method and tentative schedule in relation to the overall project schedule; and*
- *a description of any significant issues anticipated in consultation and a plan to mitigate them.*

The Applicants' consultation activities would be undertaken primarily as part of environmental assessment under the *Environmental Assessment Act* (Ontario).

Under the *Act*, consultation and engagement activities are proponent-driven. The objective of a successful proponent-driven consultation program is for a proponent to

share information with interested persons and receive relevant feedback that will help shape a project that is acceptable to the proponent and the affected communities, organizations and agencies.

The following consultation plan should be read in conjunction with the AEP attached as Appendix "A" to section 3.

9.2.1 Communities and Municipalities

The foundation for effective engagement with communities and municipalities is open and proactive communication with stakeholders. Engagement with these stakeholders will occur early and often in the project's planning phase. Working closely with affected stakeholders to foster an open and collaborative dialogue will assist in identifying a route with the lowest overall impact. Early engagement will allow feedback to be incorporated into the planning of the project and will address concerns or questions as the project evolves. The Applicants have prepared a preliminary list of communities and municipalities that they propose to consult as part of the development of the project:

- City of Thunder Bay
- Town of Nipigon
- Town of Schreiber
- Town of Marathon
- Town of Terrace Bay
- Town of White River
- Town of Wawa

Communities and municipalities are key stakeholders in the development of this transmission line. The Applicants aim to focus their consultation efforts on these municipalities using the methods described below:

- *Targeted Communications:* Specific municipal and community officials such as the Mayor and head of a local planning department will be contacted by phone or email to gauge interest in the project. Initial contact with these communities will occur prior to a mail-out to the public so that effective communication can be established with the appropriate audience and channels early on in the consultation process.

- *Project Mailings:* Municipal and community officials (political and staff) will be included in the key stakeholder mailing list developed in the early stages of the project. These officials will receive all project-related communications.

- *Newspaper and Radio:* Advertising will be used where appropriate, including invitations for feedback from the general public in the project area. This will allow for interested parties that have not been identified by the project team as potentially affected stakeholders to self-identify as stakeholders that would like to be involved.

- *Presentations to Town Council:* Project information will be presented to Council and members where possible. A question and answer session will follow the presentations and feedback acquired from these meetings will be fed to the project team for further consideration. Questions, comments and concerns will be addressed in a timely manner.

- *Community Open Houses:* If a community expresses interest, the Applicants will hold community open houses to further explain the project to the general public.

- *Workshops:* If a community expresses interest, the Applicants will facilitate community workshops with interested parties to increase the opportunity for open dialogue and foster a collaborative relationship.

- *Involvement in the Communities and Municipalities:* Through meaningful interactions with communities and municipalities, attempts to find avenues to improve relationships will be explored.

The level of consultation with communities will depend on each community's level of interest in the project. As a result, not all methods listed above will apply to all communities and consultation strategies may be tailored to address the needs of the communities. The Applicants' ultimate goal is to interact with communities and municipalities in a manner that will promote effective consultation and allow information and feedback to be integrated in the development of the lowest overall transmission route with the lowest overall impact.

Through the consultation process, it is expected that additional interested parties will be identified, either through self-identification or through interactions at the grassroots level.

There will be a minimum of two rounds of consultation that will reach out to stakeholders. Communities and municipalities will receive all project mailings and updates unless they ask to be omitted from future project updates. Although rounds of consultation will exist, the Applicants will remain active in consultation throughout the life of the project (consultation through construction and the life of the existence of the line).

Third party consultants will be used to ensure there is local outreach. TransCanada will provide project management, governance and leadership to the field representatives and will participate in the majority (if not all) of meetings, events and presentations.

9.2.2 Federal and Provincial Agencies

The Applicants have identified a number of federal and provincial agencies that will need to be consulted when conducting the environmental assessment. Two preliminary lists describing these agencies are found below.

9.2.2.1 Federal Agencies

- Aboriginal Affairs and Northern Development Canada
- Canadian Environmental Assessment Agency
- Department of Fisheries and Oceans Canada
- Environment Canada
- Natural Resources Canada
- Parks Canada
- Transport Canada

9.2.2.2 Provincial Agencies

- Ministry of the Environment
- Ministry of Aboriginal Affairs
- Ministry of Energy
- Ministry of Municipal Affairs and Housing
- Ministry of Natural Resources
- Ministry of Northern Development, Mines

- Ministry of Tourism and Culture
- Ministry of Transportation

The environmental assessment process, whether federal or provincial, typically operates using a one-window approach. That is to say that all of the above agencies will be included on the Applicants' key stakeholder mailing list; however consultation activities will be coordinated and overseen by one principal regulatory body such as the Ministry of Environment ("**MOE**") and/or Canadian Environmental Assessment Agency ("**CEAA**").

The Applicants will have regular meetings with the MOE and/or CEAA (depending on the type of environmental assessment that is required) to solicit feedback on the environmental assessment process and input on required documentation. Additionally, should MOE and/or CEAA express interest in having the Applicants communicate directly with other agencies, the Applicants will work with interested agencies to carry out meaningful dialogue.

9.2.3 Landowners

The Applicants will work with TransCanada's land team and other third party subcontractors to identify landowners whose properties will be directly impacted by the transmission line ROW. In addition to municipal consultation activities such as community Open Houses, directly impacted landowners will be more extensively consulted on the specific effects the project may have on their properties. These consultation efforts could lead to negotiations regarding reasonable changes in the design of the line and/or use of property.

9.2.4 Other Interested Stakeholders

In addition to the stakeholders already identified, the Applicants will consult with non-governmental organizations ("**NGOs**") and other interest groups as interest is

identified. Should a party express interest in receiving project materials they will be included on the stakeholder mailing list.

9.3 Proposed Route

If the applicant has identified a proposed route for the line, the applicant must file a general description of the planned route for the line and may include:

- *approximate right-of-way width;*
- *approximate portion of the route that is:*
  - *adjacent to the existing corridor (%); or*
  - *along a new corridor (%):*
- *a brief description of the environmental challenges posed by the proposed route; and*
- *an estimate of ownership by category of lands along the proposed route:*
  - *Crown (federal or provincial) (%);*
  - *Private (%);*
  - *First Nation or Métis (%); and*
  - *Other (%).*

Final route determination requires performing studies and consultations that only the designated transmitter will be in a position to undertake efficiently and with minimal disruption to the affected parties. Therefore, the Applicants have not identified a planned route for the line at this time. As detailed in section 9.4, the Applicants have conducted a Routing Analysis and identified potential routing corridors.

9.4 Route Analysis and Selection

If a proposed route for the line has not been identified, the applicant must file:

- *a list of alternative routes;*
- *an explanation of the method and decision criteria for route analysis and selection; and*
- *the planned schedule for route selection.*

A Routing Analysis prepared by Golder is attached as Appendix "A" to this section. The Routing Analysis includes a list of alternative corridors that will be evaluated during the development of the Terms of Reference for the environmental assessment. Section 4.0 of the Routing Analysis explains the method that will be used to compare the alternatives and presents a preliminary list of decision criteria in the form of a matrix evaluation.

As noted in sections 7 and 8, the Applicants used the Alternative A-Prime identified in the Routing Analysis as the basis for their development schedule and costs estimate.

Appendix A — Routing Analysis

21 December 2012

PRELIMINARY ROUTING ANALYSIS

East - West Tie Enhancement Project

Submitted to:
Iccon Transmission, Inc.
TransCanada Power Transmission (Ontario) L.P.

REPORT

Report **Number:** P1-1151-0156

Golder Associates

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APPENDICES

No table of contents entries found.

1.0 INTRODUCTION

In 2011, the Ontario Power Authority (OPA) retained Golder Associates Ltd (Golder) to carry out a high level analysis of potential environmental constraints on feasible corridors for the East-West Tie Enhancement Project (OPA, 2011). The purpose of this analysis is to determine if there are any significant natural or human environment effects or constraints which would prevent development of this project. In this analysis, the environmental effects of the project are considered at a corridor level, supporting a high-level understanding of the implications of the project within a defined study area. The following is a summary of the key findings of the analysis as it relates to the plan of Iccon Transmission, Inc. (Iccon) and TransCanada Power Transmission (Ontario) L.P. (TPT and together with Iccon, the Applicants).

The purpose of a corridor level analysis is to identify significant environmental constraints which limit the area to be considered during future transmission line routing studies. A standard transmission line Right of Way (ROW) is 40 m (approximately 20 m on either side of the line). For the purposes of this plan, the Applicants have identified a 2 km corridor to carry out baseline filed studies. This provides more flexibility if re-alignment is required as the study progresses.

2.0 POTENTIAL ROUTING CORRIDORS

A logical starting point in identifying corridor alternatives for the East-West Tie Enhancement Project would be to consider a corridor paralleling the existing East-West Tie transmission corridor (Figure 1).

The ROW for the existing East-West Tie transmission line is already situated between the defined start and termination points for this project and the route follows the eastern shoreline of Lake Superior, which represents the shortest route available across land. However, based on available information, the construction of the existing East-West Tie transmission line was not subject to the Ontario *Environmental Assessment Act* (proclaimed 1976) to assess, predict and minimize the effects of the proposed project on the environment before it was constructed. Accordingly, consideration in the assessment includes potential environmental effects of twinning this corridor as well as identifying other potential feasible areas for corridor placement within the study area.

Further, the eastern portion of the existing East-West Tie transmission line runs through Pukaskwa National Park. Under the *Canada National Parks Act*, the federal government is generally prohibited from entering into leases of, and easements and servitudes over, public lands in a park. The *Act* provides an exception for the ROW of an existing transmission line and other facilities associated with the existing line. It is unclear whether the federal government (absent a new regulation or new legislation) would have the authority under the *Act* and Right of Way Agreement with HONI dated February 6, 2001 to expand or use the existing ROW to accommodate

the development of a new transmission line. Consultation with Parks Canada on this issue would be required in the event that the Applicants are designated by the Board.

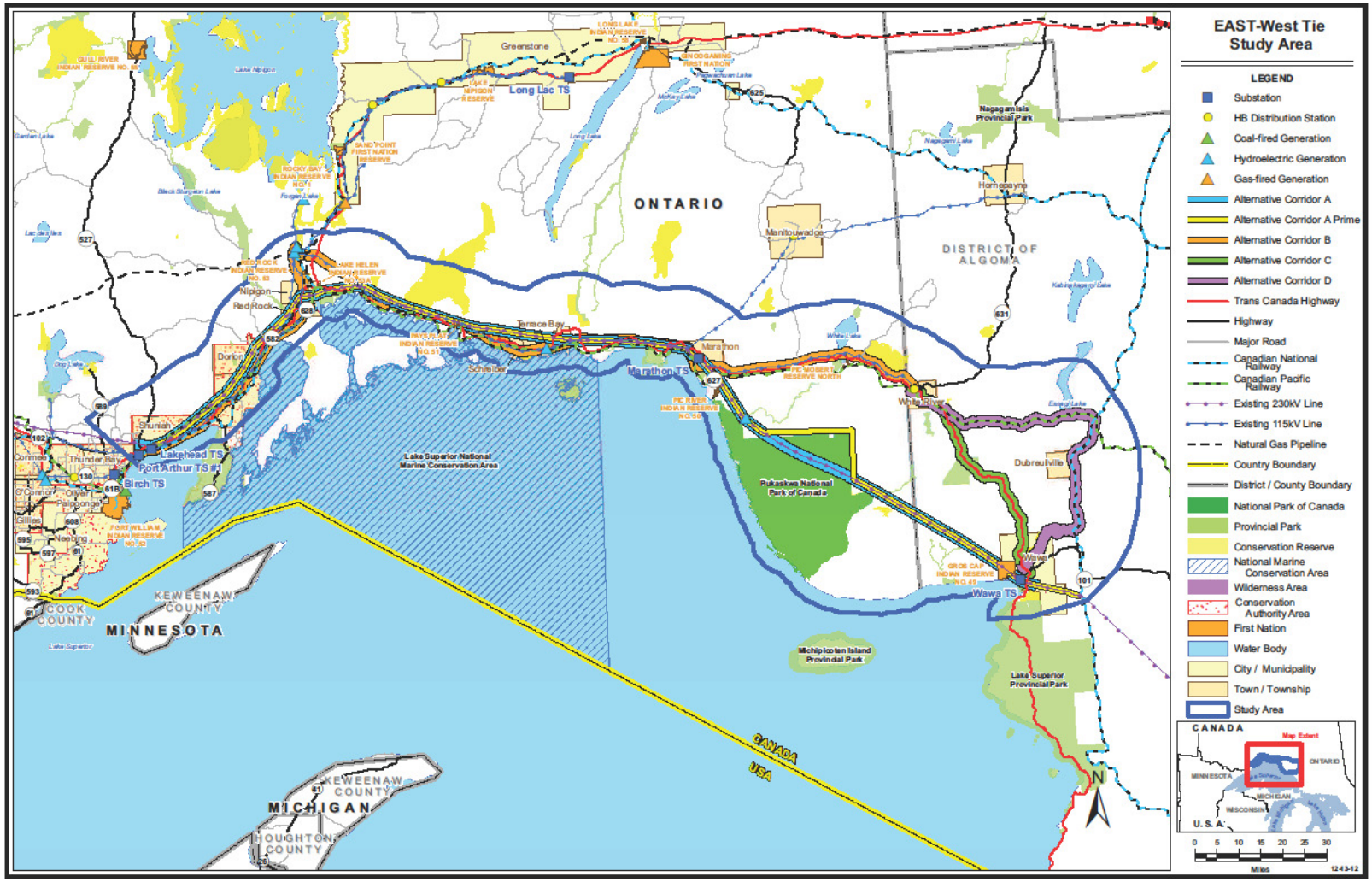


Figure 1: East-West Tie Study Area

For these reasons, corridors along other existing linear infrastructure where design and construction challenges have been proven achievable may be more desirable from a technical standpoint than paralleling the existing ROW. Within the western part of the study area from Thunder Bay to Nipigon to Marathon, linear infrastructure including Highways 11 and 17, CNR and CP rail lines, and Hydro One operated 115 kV and 230 kV transmission lines are closely aligned and follow the shoreline of Lake Superior (Figure 2 and Figure 3). The two exceptions to this close alignment of linear infrastructure are where the existing 115 kV transmission line diverges from the other linear infrastructure in the vicinity of Nipigon and Schreiber. In the eastern part of the study area from Marathon to Wawa, existing transmission lines (115 kV and 230 kV), Highway 17 and the Algoma Central and CP Railway corridors are widely separated compared to the western part of the study area (Figure 4)

Based on these existing linear alignments, the following corridor alternatives, shown on Figure 1, are identified for consideration of environmental effects:

- *Corridor Alternative A:* A 2 km corridor centered on existing 230 kV East-West Tie line ROW from Wawa TS to Lakehead TS (388 km). From the Wawa TS, the existing line passes through the Gros Cap 49 First Nation and runs west through the northwest corner of Pukaskwa National Park and crosses the Pukaskwa and White Rivers. The line runs within 1 km of the Pic River 50 First Nation and crosses the CP rail line before connecting to the Marathon TS. Heading west from the Marathon TS, the corridor runs in parallel with the 115 kV line, Highway 17 and the CP rail line diverging to go north of Schreiber. West of Schreiber, the line passes through the Pays Plat 51 First Nation. South of Nipigon, the line passes within 5 km of the Lake Helen 53A First Nation and southwest along the Lake Superior shoreline continuing in parallel with the 115 kV line, Highways 11 and 17 and the CP rail line, reaching the Lakehead TS west of Thunder Bay.

- *Corridor Alternative A-Prime:* A 2 km corridor centered on existing 230 kV East-West Tie line ROW from Wawa TS to the east side of Pukaskwa National Park but rather than pass through the Park the ROW could turn north and then west, avoiding the Park and rejoin Alternative A on the northwest side of the Park.

Corridor Alternative B could be combined with either Corridor Alternative C or D to provide another routing possibility.

- *Corridor Alternative B:* A 2 km corridor centered on existing 115 kV line ROW from the Town of White River to the Lakehead TS (363 km). From the northwestern side of White River, the 115 kV line follows Highway 17 and the CP rail line within 5 km of the Pic Mobert North First Nation and west to Marathon. West of Marathon, the 115 kV line runs parallel to the East-West Tie 230 kV line described for Corridor Alternative A. The 115 kV line diverges from the East-West Tie route in two places, going to the south of Schreiber and to the north of Nipigon. North of Nipigon this line is in parallel with Highway 585 and is within 5 km of the Red Rock 53 First Nation.

- *Corridor Alternative C:* A 2 km corridor centered on existing Highway 17 ROW from Wawa TS to the existing 115 kV line ROW at White River (92 km). This Corridor Alternative considers only the additional section of corridor required between White River and Wawa TS to tie into Corridor Alternative B at White River.

- *Corridor Alternative D:* A 2 km corridor centered on existing Highway 101 ROW from Wawa TS, heads north along the Algoma Central Railway ROW to the junction of the CP line at the village of Franz, then heads west to follow the CP line to O'Brien Station at Highway 17, just east of White River (158 km). The line then follows the 115 kV line and Highway 17 to the Marathon TS. This Corridor Alternative considers only the additional section of corridor required between White River and Wawa TS to tie into Corridor Alternative B at White River.

A preliminary comparison of landuse along each of the potential corridors is presented on Table 1. Note that the percentages may sum to greater than 100% because of the double counting of crownland and private property.

Table 1: Landuse by Alternative Route

	Alt A		Alt A-Prime		Alt B		Alt C		Alt D	
	Length (Km)	% of Line	Length (Km)	% of Line	Length (Km)	% of Line	Length (Km)	% of Line	Length (Km)	% of Line
Crownland	311.2	77.7%	350.7	82.7%	257.41	71%	90.4	87.2%	161.1	97.8%
Private	81.5	20.4%	81.5	19.2%	103.74	29%	13.2	12.7%	3.6	2.2%
FN	7.9	2.0%	7.9	1.9%	1.67	0%	0.0	0.0%	0.0	0.0%
Metis	0.0	0.0%	0.0	0.0%	0.00	0%	0.0	0.0%	0.0	0.0%
Park	39.5	9.9%	0.0	0.0%	2.44	1%	6.2	6.0%	0.0	0.0%
Total Length (Km)	400.7		424.1		362.8		103.7		164.7	

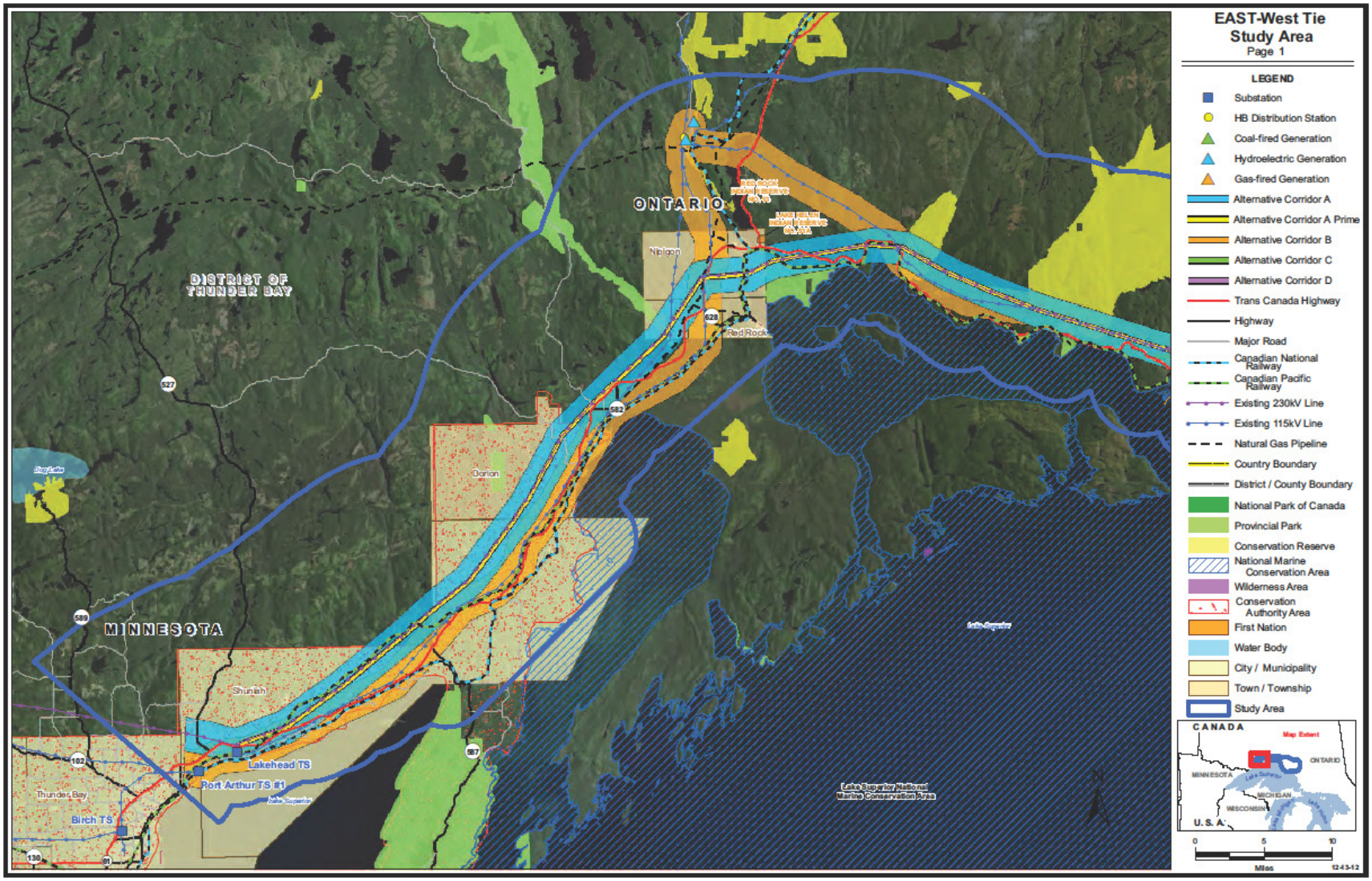


Figure 2: Thunder Bay to Nipigon Route

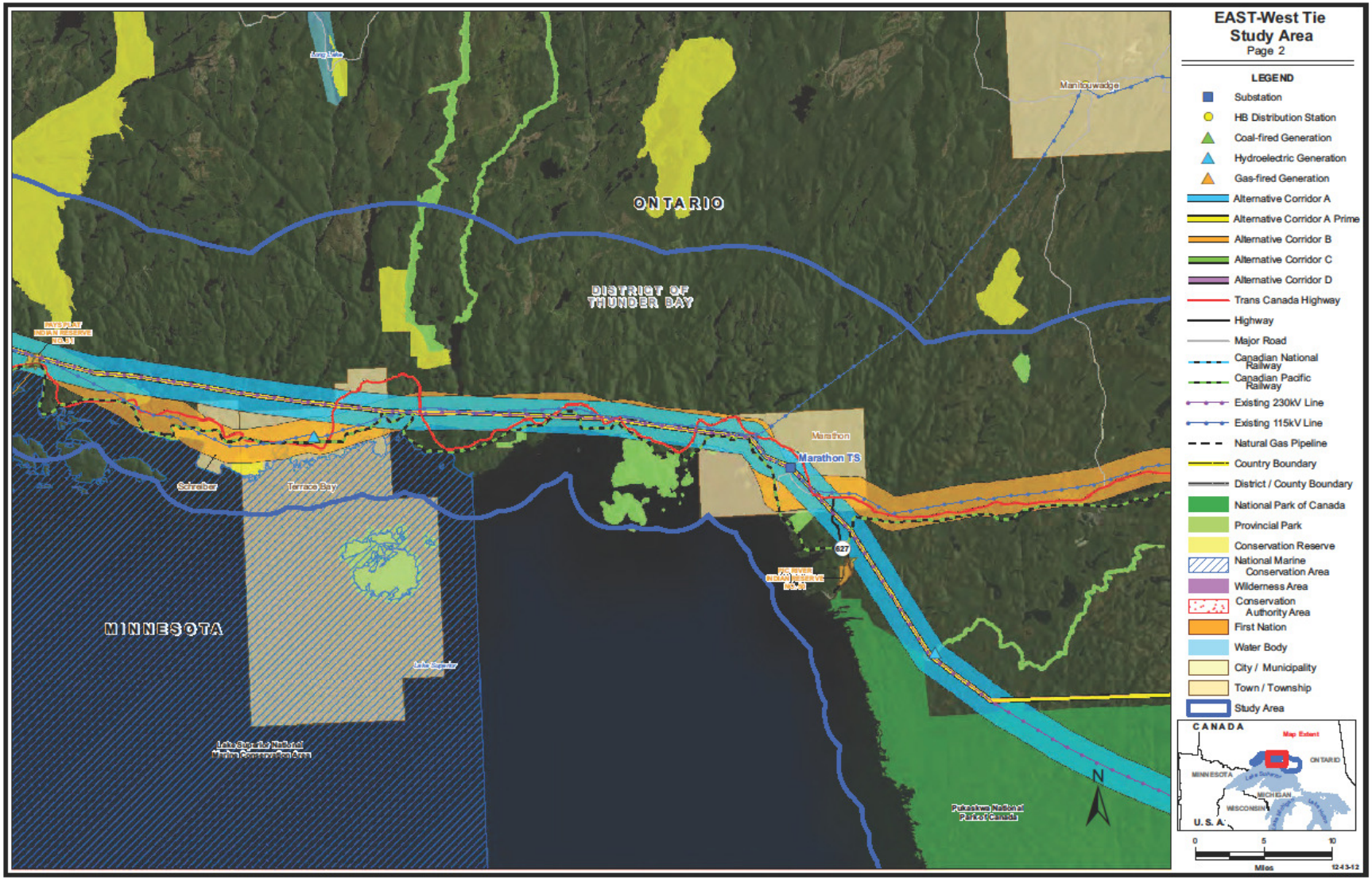


Figure 3: Nipigon to Marathon

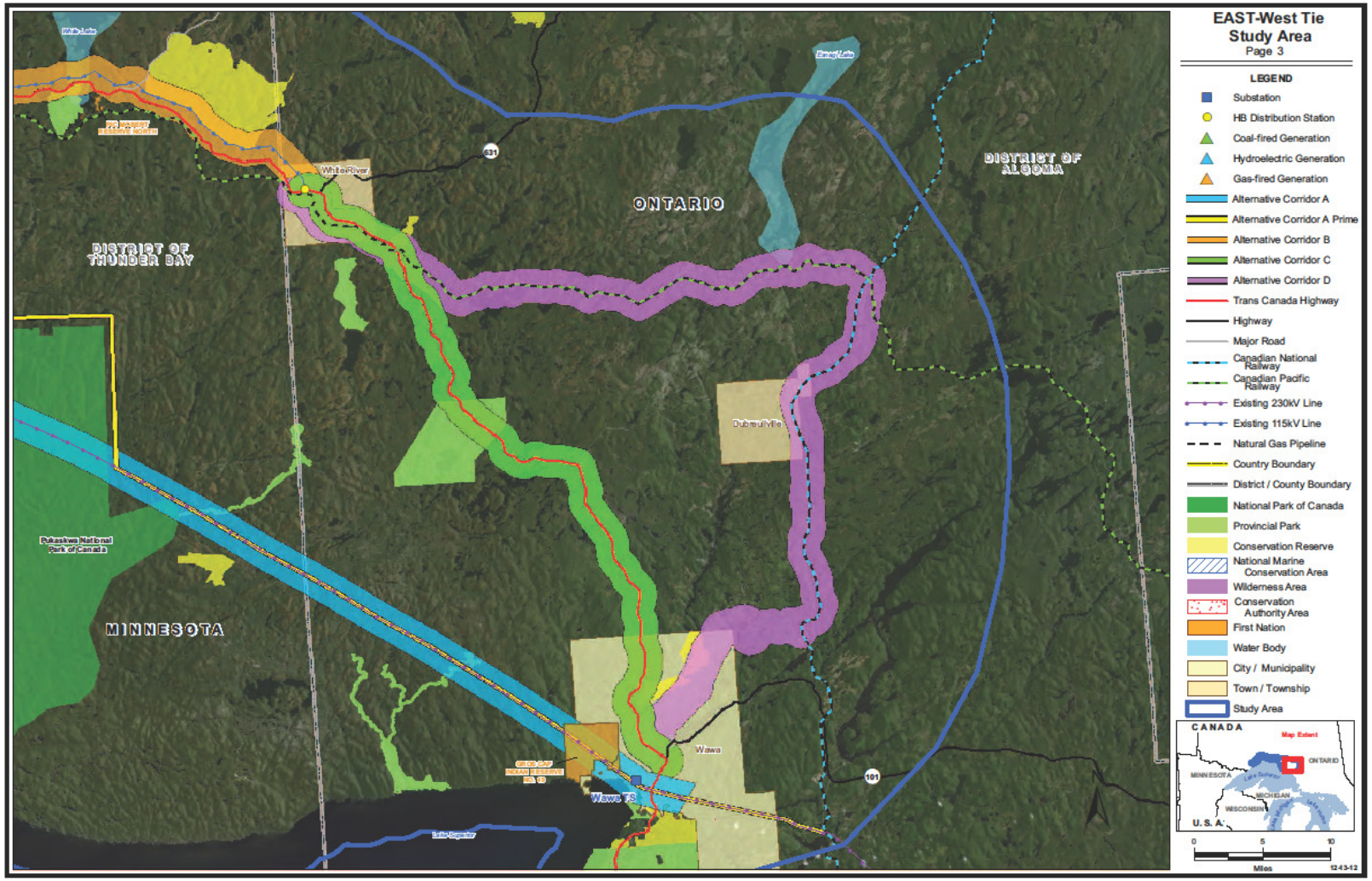


Figure 4: Marathon - Wawa Route

3.0 APPROACH TO SELECTION OF A PROPOSED ROUTE

The selection of a proposed route for the East-West Tie Line will be completed as part of the development of the Terms of Reference during the environmental assessment. This process will take about ten (10) months to complete and will include consultation with communities, Aboriginal groups, and public agencies.

The objective of the routing process is to fully conduct a defendable and successfully proven routing and alternatives analysis for the East-West Tie Line which would identify opportunities and sensitivities as well as provide a qualitative and quantitative analysis in order to determine potentially viable routing options. The routing analysis will include four stages:

- database development and mapping
- collection of existing data and field investigations
- opportunity and sensitivities analysis
- comparative analysis of routing alternatives

These analyses would evaluate the human environment (land use, land ownership, recreation resources, socioeconomics, transportation, electrical characteristics and public safety, visual resources, air quality and climate), the natural environment (earth resources including soils, geology, surface water, ground water, and floodplains; biological resources including vegetation, wildlife and fisheries, and threatened, endangered and other species of concern), and the cultural/First Nation environment.

Detailed investigation of any corridor area must be undertaken at the transmission routing stage to determine their technical, economic and environmental merit as part of the individual environmental assessment. In selecting a Preferred Corridor and ultimately a Preferred Alignment for the 230 kV transmission line, consideration must be given to good environmental planning principles to select the alignment or route that offers the best advantages and entails the fewest disadvantages from a multi-disciplinary perspective.

Criteria to be considered for the placement of a feasible corridor would include the following:

- Communities (Aboriginal and non-Aboriginal)
- Provincial and National Parks
- Conservation reserves
- Area of Natural & Scientific Interest (ANSI)
- Natural Heritage Value areas
- Provincially significant wetlands
- Large waterbodies
- Recreational areas
- Tourist sites

3.1 Database Development and Mapping

Project area GIS database development, analysis, and display mapping would be one of the first overall Project tasks initiated. GIS data analysis and display will play a critical role in the routing and siting analysis process. It is imperative that an accurate analytical graphical database and set of base maps for the Project area be generated. The base maps from the previous section are useful in conducting an initial analysis of the Project area and will be refined with additional data.

3.2 Collection of Existing Data and Field Investigations

Technical resource staff will collect data as needed for each resource area to fully develop a spatial database for the alternatives analysis. The initial data from the existing information would serve as baseline documentation for the existing conditions in the Project area and additional data collection and field investigations would expand these databases. Additionally, data collection efforts and field investigations would confirm that the initial resource information is accurate and up-to-date and would further refine the data.

Collection of existing data would be conducted as a primary Project task that would be a basis for the siting study as well as numerous other permitting tasks. The following data list below is a sample of the data that will be initially gathered and mapped:

- Land Use
- Land Use data will be obtained from many sources to capture existing land use and planned land use.
- Recreation
- Map identifying existing recreational facilities, including parks, wilderness, and other special management areas.

3.3 Visual Resources

Visual resources will have to be considered when routing the transmission line. Residences will need to be considered as well as siting along transportation corridors. Numerous visual simulations and renderings will need to be prepared.

- Map locations of the Key Observational Points (KOP) for the environmental assessment.
- Colour photographs and photo simulations of the proposed facilities on the landscape will be prepared for each KOP. These simulations will show the existing situation and the landscape with proposed facilities.
- A visual resource map will include VRM mapped inventory. Any sensitive viewing area will also be identified.

3.4 *Social* and Economic Resources

Socioeconomic resources will need to be reviewed and analyzed and the following will be included:

- Figures depicting the Project area, political boundaries, municipalities and unincorporated communities, as well as roads and highways
- Tables and graphs will summarized pertinent information

3.5 Biological Resources

Vegetation, wildlife and species at risk will need to be considered, analyzed and field verified for the permitting process. Maps of regional biological resources have been developed and reviewed by Golder as part of the OPA, 2011 study.

3.6 Vegetation, Wetlands and Riparian Areas

While much of the ecozone is dominated by closed stands of conifers, largely white and black spruce, balsam fir and tamarack, the study area is characterized by a more diverse mosaic of conifer and mixed woods forests (Ecological Stratification Working Group 1996). In a narrow zone along the east shore of Lake Superior, as far north as the east side of the Magpie River, stands of hardwoods are present on the south- and west-facing slopes of rock knobs, including sugar maple and yellow birch, as well as trembling aspen and white birch, with scattered eastern hemlock and white pine. A more diverse mix of trees and shrubs are present in the numerous stream and river valleys, with such species as eastern white cedar, balsam poplar and speckled alder becoming abundant along with trembling aspen, black spruce and tamarack (Ecological Stratification Working Group 1996).

Further work will be required to complete the following tasks:

- Description of regional vegetation types and historical influences
- Description of vegetation and wetland survey methods
- Characterization of existing vegetation
- Map of dominant vegetation types
- Documentation of noxious weeds
- Classification of wetlands
- Map of existing wetlands
- Identification of presence/absence of threatened, endangered, or sensitive plants

3.7 Wildlife

Portions of the study area provide terrestrial habitat for moose, woodland caribou (forest-dwelling, boreal population designated as threatened in Ontario and federally), black bear, lynx, wolf and coyote, waterfowl and various species of birds associated with the southern boreal forest (Dobbyn, 1994). The distribution of wildlife within the study area is generally widespread and of a low density (Dobbyn, 1994). Based on the data that has

been reviewed, no particular area within the study area has been identified as supporting a high concentration of wildlife or a unique wildlife habitat, although the OMNR has, through its Woodland Caribou Conservation Plan (OMNR 2009), identified the eastern half of the Lake Superior coastal zone as an area of 'continuous' caribou distribution, where conservation efforts are focused.

Six areas within the study area have been designated as regionally significant Life Science Areas of Natural and Scientific Interest (ANSIs). ANSI's are defined as areas with particular natural features that are considered outstanding examples of their kind and represent vegetation and wildlife assemblages that are characteristic of the landforms and eco-districts in which they occur.

Further work will be required to complete the following tasks:

- Description of regional wildlife setting and historical influences on the Project area
- Description of wildlife survey methods
- Documentation of existing wildlife
- Documentation of migratory waterfowl
- Wildlife maps that identify raptor nest locations, wildlife migration routes, and special interest habitats
- Identification of presence/absence of threatened, endangered, or sensitive wildlife

3.7.1 Species at Risk Act (SARA) / Ontario Endangered Species Act

Description of regional Species at Risk (SAR) occurrences and historical influences on the Project area

- Description of survey methods
- Documentation of existing SAR
- Wildlife maps that identify significant habitat for SAR

3.8 Cultural Resources

The Cultural Heritage screening will examine known archaeological and historic sites for the study area. Information on archaeological sites in Ontario will be obtained from Ontario Ministry of Tourism and Culture, through their Archaeological Sites Database. There are 209 known archaeological sites in and within a 5 km buffer of the study area. The registered archaeological sites ranged in cultural periods from the pre-contact Shield Archaic to the historic fur trade and Euro-Canadian settlement.

3.9 Geology, Soils, Hydrology

Geology, soils and hydrology are important aspects to review and analyze.

- Existing geologic environment
- Existing Soil Environment
- Description and map of surface water resources in the Project area

- Springs and seeps inventory

3.10 Opportunity and Sensitivity Analysis

After collecting the necessary data, the Applicants would conduct an opportunity and sensitivity analysis that would identify potential routes for comparative analysis. Using resource mapping and the base maps produced, the Applicants would use the opportunity and sensitivities analysis to map and illustrate environmental areas and routing opportunities Routing criteria would be developed in order to identify routing opportunities and to define sensitivities to routing the line.

This analysis would identify possible opportunities in the project area. For transmission projects, routing opportunities are existing linear facilities that can be paralleled so it is not necessary to introduce a new linear feature into the land use patterns of an area, including:

- Existing EHV Transmission Lines
- Existing Highways and Roadways
- Railroad Corridors
- Industrial Areas

The analysis would also identify avoidance and sensitive areas:

- *Avoidance Areas* – Areas where siting the line would be extremely difficult or nearly impossible because of several reasons (economics, politics, permitting timeframes, construction difficulty, etc). These areas would be excluded as potential areas through which the Project could be located. These areas would be mapped red to stand out in the Project area.

- *Sensitive Areas* – Areas where siting the line would be possible but specific issues or conditions exist that could make locating the Project more difficult, more time-consuming, or more costly. These areas would be mapped yellow to indicate the need for caution. For the purpose of this proposal, sensitive areas are generally consist of residences, high density neighborhoods, golf courses, passive open space, agricultural lands, schools, churches, and jurisdictional lands land.

Table 1 lists some general standard sensitivities and opportunities for 230kV transmission lines. The resource sensitivity identified in the Table 1 would be evaluated for their presence in the Project area and their relative sensitivity to the construction, operation, and maintenance of transmission line. Using the collected data, as well as information gathered during the initial agency contacts, the list of environmental opportunities and sensitivities would be refined.

Although this currently available information is cursory, it provides an indication of the approach in identifying opportunities and sensitivities within the Project area. As demonstrated on the maps the three project

components are all depicted on the maps with possible opportunities for siting. The sections below describe some of the opportunities and sensitivities identified for the Project area in this preliminary analysis.

4.0 COMPARATIVE ANALYSIS OF ROUTING ALTERNATIVES

Once the opportunity and sensitivity areas are identified, the Applicants would develop and compare potentially viable alternatives. Quantifiable resource information would be presented for each potential alternative to identify the comparative impacts associated with each. Assessment criteria to be used will focus on the consideration of environmental effects that could affect the feasibility of a potential corridor. Environmental criteria will be defined based on the screening criteria identified in the "*Guide to Environmental Assessment Requirements for Electricity Projects"* and *the "Class Environmental Assessment for Minor Transmission Facilities"*, which are likely to guide the development of scope for the Individual EA.

This process is described in the following sections.

4.1 Routing sensitivity

As previously discussed, the relative sensitivity of each of the resources classified as sensitivities would be determined to assist in identifying the potential corridors within the Project area and, ultimately, in route selection. By definition, avoidance areas would not be considered. But within the sensitive categories, different resources would have varying degrees of sensitivity to the construction and maintenance of a transmission line. Certain resource areas may be moderately sensitive (e.g., residential development) and should be avoided to the extent possible while others may be highly sensitive and should be excluded from consideration if there are other reasonable alternatives.

The identified sensitive areas and their relative sensitivities would be qualitatively and quantitatively considered in the corridor selection process. Project-specific corridor selection objectives would be developed based on the relative sensitivity of the resources within the Project area.

4.2 Comparative Analysis

To compare the alternatives, the Applicants would use GIS databases to quantify impacts for the various routing criteria. For instance, the Applicants would calculate the number of dwelling units along a specific route and quantitatively compare the number of impacted along each corridor for each alternative. A Project summary matrix would then be utilized to numerically present the impacts associated with each alternative and the identification of the most and least environmentally preferred alternatives.

A matrix would be developed for each segment of a corridor. The matrix would consist of the segments of routes on the y-axis and siting criteria on the x-axis. Each cell within the table would contain values identifying the resource by an applicable unit (i.e., wetlands crossed would be in acres and residences within determined

distance would be whole numbers, etc). Each alternative route would be comprised of segments. The alternatives would be summarized by segment and a ranking would be developed for each alternative. The values for these segments can then be consolidated into one summary table that contains the total quantifiable impact for each route alternative.

The Applicants have conducted this type analysis on many large linear infrastructure projects, including EHV transmission line projects, and have successfully permitted and testified to the routing process.

4.3 Matrix Results and Routing Study

The result of the routing analysis would be a quantified matrix and maps of the results. This would be documented at the end of the phase in an overall routing study. This document would be a thorough record of the process, why each route was considered, removed, retained, and when it was added, removed etc. An example of the matrix results is presented on **Table 2**.

Table 2: East – West Tie Alternatives Matrix Evaluation

	Cost					Technical					Land Use									Environmental										
	Route Length	Road Access	Large Water Crossings	Very Large Water Crossings	Infrastructure Crossings	Angle Points	Private and First Nations Reserve Land	Relative Cost	Length of Corridor	Connection to TS	Proportion of ROW that is Crown Land	Proportion of ROW that is First Nations Reserve	Proportion of ROW that is Provincial Park	Proportion of ROW that is Private Land	Cottage & Tourism Areas	Mining Claim Areas	Sustainable Forest Licences	Forest Management Unit	Trapline Areas & Cabins	Wetland Area	Waterbody	Ecological Management Areas	Significant Ecological Area	Habitat Alteration for Woodland Caribou	Water Supplies	Proximity to Buildings	Proximity to Provincial Parks	Proximity to Tourist Areas	Proximity to First Nations Reserves	**To9tal**
Alt A																														
Alt A-Prime																														
Alt B & C																														
Alt B + D																														

5.0 REFERENCES

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Report Signature Page

GOLDER ASSOCIATES LTD.

Anthony Ciccone
Principal

AC

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10 FIRST NATION AND MÉTIS CONSULTATION

10.1 Proposed First Nations and Métis Consultation Plan

A proposed First Nation and Métis consultation plan, including:

- *a list of First Nation and Métis communities that may have interests affected by the project;*
- *an approach for engaging with affected First Nations and Métis communities, along with rationale or other justification for such an approach;*
- *a description of any significant First Nation or Métis issues anticipated in consultation and a plan to address them;*
- *an overview of expected outcomes from the proposed consultation plan.*

The AEP attached as Appendix "A" to section 3 includes a detailed First Nations and Métis engagement plan.

The AEP identifies the affected First Nations and Métis communities and outlines an approach for engaging with these communities and the expected outcomes of the proposed consultation. The AEP also identifies the significant First Nations and Métis issues that the Applicants anticipate will arise and provides a preliminary plan to address those issues.

In respect of the Ministry of Energy's letter to the Board dated November 26, 2012, the Applicants confirm they are willing to enter into a memorandum of understanding ("**MOU**") on Aboriginal consultation with the Ministry of Energy containing terms and conditions that are satisfactory to both the Ministry of Energy and the Applicants, and are similar in principle to the MOU signed by HONI in respect of the Bruce to Milton transmission reinforcement project.

10.2 Experience of First Nations and Métis Consultation

Evidence of experience in undertaking procedural aspects of First Nations and Métis consultation in the development, construction or operation of transmission lines or other large construction projects. If applicable, previous engagement or existing relationships with the First Nation and Métis communities to be engaged.

As noted in response to section 3.2, it is anticipated that the Applicants will contract with TransCanada's Aboriginal and Stakeholder Engagement group to lead First Nations and Métis consultation processes for the project. TransCanada's experience with First Nations and Métis consultation is detailed in section 4.1.6, Appendix "C" to section 4, and the AEP. Details of Isolux Corsán's experience with aboriginal peoples in other jurisdictions is described in Appendix "A" to section 4.

Volume 2: Application Exhibits

Joint East-West Tie Designation Application

EB-2011-0140



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Iccon/TPT Joint East-West Tie Designation Application (EB-2011-0140)

Volume 2 – Application Exhibits

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I	Isolux Corsán 2011 Annual Report
J	PSP Investments 2011 Annual Report
K	TransCanada Annual Information Form

“Exhibit A”



LUIS REIN ROJO

[redacted]

PROFESSIONAL EXPERIENCE

Sept. 2012 - present	**ISOLUX CORSAN CONCESIONES S.A.** ***Director of Power Concessions***	Madrid, Spain
2009 - Aug. 2012	**ACS** ***Director of Concessions (Grupo Cobra)***	Madrid, Spain
2008-2009	**GRUPO ALDESA** ***Production Manager***	Sevilla, Spain
2006-2008	**AGUAS DE BARCELONA (AGBAR)** ***Director of Latin America***	Barcelona, Spain
2004-2006	**AGUAS DE BARCELONA (AGBAR)** ***Territorial Director of Andalucia***	Sevilla, Spain
2002-2004	**AGUAS DE BARCELONA (AGBAR)** ***General Manager of EMASAGRA & Regional Director of AGBAR***	Granada, Spain
2000-2002	**AGUAS DE BARCELONA (AGBAR)** ***General Manager of AGUASVIRA***	Granada, Spain
1998-2000	**AGUAS DE BARCELONA (AGBAR)** ***Technical Manager of EMASAGRA***	Granada, Spain
1997-1998	**ABENGOA** ***Delegate of ABENSUR Mexico (Hydraulic Projects)***	Mexico D.F.
1993-1997	**ABENGOA** ***Hydraulic Projects Division***	Sevilla, Spain

FORMAL EDUCATION

1988-1994	**Industrial Engineer** (Electrical Engineering) Escuela Técnica Superior de Ingenieros Industriales de Sevilla	Sevilla, Spain
2002	**Master in Business and Administration** Instituto San Telmo	Sevilla, Spain

LANGUAGES

Spanish	Mother tongue
English	High level, spoken and written

ADDITIONAL INFORMATION

IT	**Microsoft Office** Professional (Expert) (Word, Excel, PowerPoint), Internet Explorer



Juan J. Soto Martínez

[redacted]

PROFESSIONAL EXPERIENCE

Jul 2007 - Present	**Isolux Corsán Concesiones S.A.** ***Transmission Technical Director/ Power Concessions Department*** Responsible for the technical management of transmission projects. Member of the Board of Directors of the US joint venture with Brookfield, Wind Energy Transmission Texas, LLC (WETT)	Madrid, Spain
June 2006 – July 2007	**ISOLUX WAT, S.A.** ***Engineering Director of the International Energy Division***	Madrid, Spain
Feb 2002 – June 2006	**ISOLUX WAT, S.A.** ***Director of the International Energy Division*** Direct, coordinate, plan and oversee the issues concerning the market areas corresponding to the Division, as well as verify the compliance of all the programs and objectives established at a Group level.	Madrid, Spain
Oct 1988- Feb 2002	**SAINCO-TELVENT** *Different positions and finally* ***Commercial Director in the area of Control Systems for Electric Utilities.***	Madrid & Sevilla, Spain
June1974- Sep 1998	**Brown Boveri-ABB** *Different positions and finally* ***Director of the Hydraulic Power Station Division***	Madrid, Spain

FORMAL EDUCATION

1965-1970	BS in Electro-mechanical Engineering ICAI, Universidad Pontificia Comillas. After his graduation, he had been giving lectures for 10 years,	Madrid, Spain
1992-1993	Diploma in Business Management from the Instituto Internacional San Telmo / IESE.	Sevilla, Spain

LANGUAGES

Spanish	Mother tongue
English	High level, spoken and written
French	High level, spoken and written
Portuguese	High level, spoken and written

ADDITIONAL INFORMATION

IT **Microsoft Office** Professional (Expert) (Word, Excel, Access, PowerPoint), Internet Explorer

1970 -1981 **Teaching Activities - Technical School of Engineers of ICAI**
During 10 years of 1970-71 and 1980-81, he was intensely involved in teaching, combining it with his professional activity.

July 1988 **Consultancy Activities – United Nations Development Program (UNDP).**
Technical evaluation of the report presented by the Government of Mexico, along with its feasibility, concerning Technological support for the Manufacture of Electrical Rotary Machines

1995 – 2001 **Publications, Seminars and Working Groups**
He has presented more than 20 technical articles at a variety of National and International Technical Congresses, such as CIRED, DistribuTECH EUROPE, LATIN AMERICAN POWER, etc.

He was also a member of several Committees (ASINEL, Spanish Committee of IEC and CIGRE.

He was a member of the Working Group for the implementation of the Spanish Regulations concerning Electric Metering Points chair by the Market Operator.



Pablo de la Sierra Pérez

[redacted]

PROFESSIONAL EXPERIENCE

2009 – Present | Isolux Infrastructure | Austin (TX), US
Director North-America

- Leading investment and business development activities in North-America. Managing of resources assigned to the company's projects in the region, including $700 million in development and an additional pipeline of more than $3 billion in the US and Canada.
- Established first presence and opened the first office of the company in North America. Management, research, analysis and pursue of new investment opportunities.
- Full-cycle management of investment projects, including due diligence, regulatory analysis and requirements, project development, partner search and relationships and financing.
- Supervision of project execution, including project finance, environmental studies, permitting, Right-of-Way/land acquisitions, engineering, procurement and construction.
- Negotiated Equity and joint-venture agreements, coordinated and supervised negotiations of main development contracts and project financing arrangements.

2007 – 2009 | Head of Department | Madrid, Spain

- Managed and performed the research, analysis and development of energy infrastructure investments, mainly power transmission and conventional and renewable power generation projects in the Americas.
- Successfully lead and managed Isolux Corsán Concesiones' in the competitive bidding processes resulting in the market entry and award of a total of $1billion of infrastructure investment projects of the company in the US (2009) and Peru (2008).
- Managed and performed market and regulatory assessments, full preliminary Due Diligence, project appraisal and techno-economic, viability and risk analyses.

2005 – 2007 | Ingeniería Trading, SL | Oviedo, Spain & Nemours, France
Senior Consultant

- First line of support to company's CEO, advising on management, technical and commercial issues regarding power projects. Analysis of services and procurement contracts. Managing resources, including recruitment and supervision of staff. Business development: lead on energy commercial and market issues.
- Decisively participated in the re-implementation and redirection of a large construction project in France by providing strategic advice and client and subcontractor management support.

2005 | Freelance Consultant | Various locations

- Providing analysis, research and support, for private investment projects, including clean energy-related market research, assessment of project risks and needs and renewable energy regulatory analysis.
- Market analysis: assessment of recent and anticipated regulatory and legislation changes, including regarding renewable energy and their likely impact on the markets. Search for business opportunities derived from those changes.

2000 – 2004 | E.ON D-Gas b.v. | London, UK & The Hague, NL
Energy Trader - Head of Prompt Trading

- Portfolio optimization and trading in European energy markets, management of market risk and company's commodity position in various European trading hubs (UK, Netherlands, Belgium).
- Analysis, risk management and optimisation of gas-storage positions, power stations' long-term supply contracts and Oil, Coal, FX and Gas Transport Capacity exposure. Financial analysis of investment projects, such as peaker generation plants.
- Responsible for the set-up of a new Trading Desk, including proposal of new counterparties, system implementation and supervision of trading-analysis team.

- Research and analysis of European gas and power markets and companies. Evaluation and analysis of new business opportunities, potential risks and regulatory changes. Leading analyst for the Spanish market.
- Member of second-tier management group responsible for the operational and commercial development of the company's own storage facility project.

2002 2003 — Junior Energy Trader — London, UK

- Management and optimisation of European Gas portfolio.
- Analysis and trading of financial derivatives: Gas-oil, Fuel-oil, Weather and currency hedges.
- Analysis, evaluation and risk management of natural gas supply and transport contracts.
- Monitoring of European energy markets, research on existing and planned transport and storage infrastructures and estimated energy flows for price trends estimation purposes.
- Modelling, evaluating and pricing physical and financial products. Structuring and pricing products for the European market, including products designed for e-commerce.

2000 2002 — Energy Risk and Trading Analyst — London, UK

- Development of risk management and risk reporting quantitative tools used for the monitoring of the company's counterparty, market and operational exposure and daily P&L vs the market.
- Monitoring market movements and managing compliance with trading policies and limits, requesting corrective actions when required. Analysis of Master Trading and Netting Agreements to assure proper risk evaluation.
- Design and implementation of middle-office procedures to ensure data integrity and compliance with risk control requirements and policies.

2000 — Saint Gobain Cristalería S.A. — Avilés, Spain
Engineer

- Managing the development and implementation of new production components in a glass production line.
- Developing and implementing product quality-control systems and maintenance procedures.

1999 — Electricité de France — Grenoble, France
Trainee engineer
Final Project: developing in Matlab a simulation model of a power station alternator.

FORMAL EDUCATION

2005 — Open University — London, UK
Financial Strategy

2000 — Universidad de Oviedo — Oviedo, Spain
Ingeniero Superior Industrial – Electrotecnia (M.Eng Power Engineering)

1999 — Institut National Polytechnique de Grenoble — Grenoble, France
Ingenierur Electricien

LANGUAGES

Spanish	Mother tongue
English	High level, spoken and written
French	High level, spoken and written
Portuguese	Medium
German	Basic

ADDITIONAL INFORMATION

Affiliations	Member of SEDIGAS (Spanish Gas Association) and of Club Español de la Energía (Spanish Energy Association). Member of the "Colegio Oficial de Ingenieros Superiores Industriales de Asturias y León" (Spanish equivalent of Chartered Engineer).
Directorships	Wind Energy Transmission Texas, LLC Iccon Transmission, Inc



JUAN RAMÓN JIMÉNEZ MOGOLLÓN

[redacted]

PROFESSIONAL EXPERIENCE

Nov09 - Present	Isolux Infrastructure ▪ Power Concessions Operating Director	Madrid, Spain
Jan08 – Oct09	Unión Fenosa Distribución ▪ Madrid Area O&M Director	Madrid, Spain
Jan06 – Dec07	Unión Fenosa Colombia ▪ Chief Financial Officer and Resources Director	Madrid, Spain
Sep00 – Dec05	Unión Fenosa Internacional ▪ Controlling Director	Madrid, Spain
Jan97 – Aug00	Exide Technologies ▪ Manufacturing Manager	Madrid, Spain
Jan96 – Dec96	Opel España de Automóviles (General Motors Group) ▪ Vehicles Type Approvals Manager	Madrid, Spain

FORMAL EDUCATION

Master in Business and Administration	IE Business School	Madrid, Spain
Bachelor in Business and Administration	Universidad Nacional de Educación a Distancia (UNED)	Madrid, Spain
Mechanical Engineering	Universidad Politécnica de Madrid (ETSII – UPM)	Madrid, Spain
Industrial Enegineering	Universidad Pontificia Comillas (ICAI)	Madrid, Spain
Mechanical Engineering	Universidad Politécnica de Madrid (ETSII – UPM)	Madrid, Spain
Master in Power Transmission and Distribution	Universidad Corporativa Unión Fenosa	Ávila, Spain
Master in Automotive Engineering	Universidad Politécnica de Madrid (ETSII – UPM)	Madrid, Spain

LANGUAGES

Spanish	Mother language
English	High level, spoken and written
German	High level, spoken and written
Portuguese	Medium level, spoken and written

ADDITIONAL INFORMATION

IT	**Microsoft Office** (Expert) (Word, Excel, Access, PowerPoint), Internet Explorer Visual Basic and Fortram programming

John F. Soini, M.B.A., P.M.P., C.E.T.

Brief Profile

- Project Management Professional, MBA, Certified Engineering Technologist, and Stationary Engineer with 17 years of experience in oil, gas, conventional, and nuclear power businesses
- Exceptional interpersonal, coaching and leadership, planning & coordination skills
- Self motivated and enthusiastic with a high degree of creativity, initiative, and integrity
- Demonstrated ability and passion to infuse a high level of motivation and enthusiasm in others towards achieving organizational goals through peak performance
- Strategic thinker with the ability to engage others & build shared vision, ability to integrate conflicting perspectives of various stakeholders

Work Experience

Present **TransCanada**
Calgary, AB

Position: **Vice President – Facilities and Pipeline Projects.** Accountable for the development and safe implementation of natural gas pipelines, facilities, and conventional power facilities in North America. Annual portfolio of $500 million to $1 billion in projects.

Dec. 2010 – Present **Bruce Power / TransCanada**
Tiverton, Ontario

Position: **Vice President – Bruce A Restart Project.** Reporting to the President and Chief Executive Officer, Bruce Power for all areas related to a major refurbishment mega project. The Bruce A Restart is one of the most complex engineering challenges Ontario has ever seen and involves the complete refurbishment and safe start up of two 750 MW nuclear power stations for safe and reliable operation over a 25 year life cycle. Project budget of $4.8 Billion with a peak workforce of 3,800 people.

April 2009 – Dec. 2010 **Bruce Power / TransCanada**
Tiverton, Ontario

Position: **Deputy Vice President – Bruce A Restart Project.** Accountable to the Executive Vice President, Bruce A Restart for one of the largest infrastructure projects undertaken in Canada.

June 2007 – April 2009 **TransCanada**
Calgary, Alberta

Position: **Director – Facilities Projects, North America.** Accountable for project development, definition, and effective implementation of transmission facilities within North America. Effectively led a department of professionals, fostering a healthy and productive team atmosphere, and collectively managed a budget of $494M of capital capacity installations (including development of NEBC expansion).

July 2005 – June 2007 **TransCanada**
Calgary, Alberta

Position: **Manager – Compression Projects – Project Management.** Accountable for the overall project management of all compression projects within North America, measured in terms of cost, scope, schedule, and safety in accordance with all applicable regulations.

June 2003 – July 2005 **TransCanada**
Grande Prairie, Alberta

Position: **Facilities Manager**. Accountable for the complete facilities management and operations function for the Grande Prairie, Wapiti, Spirit River, Valleyview, and Beaverlodge Area.

January 2002 – June 2003 **TransCanada**
High Level, Alberta

Position: **Facilities Manager**. Overseeing the complete facilities management function for the Alberta sector area from Manning to the Northwest Territories border.

Dec. 1999 – Jan. 2002 **TransCanada**
Thunder Bay, Ontario

Position: **Maintenance Planner/Business Analyst**. Responsible for the coordination of maintenance personnel, equipment, parts, support services, and business performance analysis within eastern Saskatchewan, Manitoba, and Northwestern Ontario.

Sept. 1997 - Dec. 1999 **TransCanada**
Rapid City, Manitoba

Position: **Mechanical/Pipeline/Controls Technician.** Responsible for providing technical expertise to ensure all systems and equipment were properly constructed, effectively maintained, and safely operated.

March 1997 - Sept. 1997 **TransCanada**

Thunder Bay, Ontario

Position: **Mechanical Technician / Industrial Millwright**

Jan. 1997 - April 1997 **TransCanada**
Thunder Bay, Ontario

Position: **Construction Inspection and Technical Support**. Responsible for providing support in the areas of pipe bending, road crossings, valve installation, underground boring, etc. to ensure proper installation of new pipeline facilities in accordance with TransCanada's Construction Specifications.

June 1996 - Oct. 1996 **Placer Dome Inc.**
MusselWhite Mine
Pickle Lake, Ontario

Position: **Project Estimator**. Responsible for providing accurate estimation for quantity and cost, and to advise the most cost effective procedures during the construction stages of Placer Dome's MusselWhite Gold Mine. (Contract Position)

Education/Certification:

- May 2008 — Masters in Business Administration (MBA)
  Haskayne School of Business, Calgary, AB
  Masters Degree Achieved (with distinction)
- April 2006 — Haskayne Management Development Program
  Haskayne School of Business, Calgary, AB
  Full Certification Achieved
- September 2005 — Project Management Professional
  Project Management Institute
  Professional Designation Achieved
- September 2002 — Queens Executive Leadership Program
  Queens University, Kingston, ON
  Full Certification Achieved
- June 1999 — Industrial Accident Prevention Association
  Practical Loss Control Leadership
  Independent Study Program
  Full Certification Achieved
- May 1996 — Confederation College, Thunder Bay, ON

Stationary Engineering, 4th & 3rd Class
College Diploma Achieved

- May 1995 — Confederation College, Thunder Bay, ON
  Mechanical Engineering Technology
  College Diploma Achieved

Personal Accomplishments:

- 2008 — Masters Degree in Business Administration
  "A+" Average, with distinction
- 2005 — Project Management Professional Designation
- 2002 — Industrial Millwright Journeyman Status
- 2001 — Excellence in Project Management and Situational Leadership
  RLG International Certification Achieved
- 1998 — Certified Mechanical Engineering Technologist
  Full Member of the Ontario Association of Certified Technicians and Technologists
  C.E.T. Designation Achieved.
- 1996 — 1996 Honor Role
  1996 Deans Medal - Outstanding Academic Achievement - Stationary Engineering
  May 1996 Deans List - Stationary Engineering
  Jan. 1996 Deans List - Stationary Engineering
- 1995 — 1995 Deans Medal - Outstanding Academic Achievement - Mechanical Engineering Technology
  May 1995 - Deans List - Mechanical Technology
  Jan. 1995 - Deans List - Mechanical Technology

WILLIAM SMALL

PROFILE

Executive with over 30 years of project experience. Provided oversight of multiple construction projects including supervising the construction field teams and engineers, reviewing safety, quality and contractor performance and monitoring compliance with the project budget and schedule. Experience includes over 10 years working for contractors and over 20 years working for various owners. Citizen of the United States with Permanent Residency Status in Canada.

EDUCATION
B.S., Physics, Dickinson College, Carlisle, PA

EXPERIENCE

TransCanada Pipe Line

2012 - Present **Director Facilities Projects**
Responsible for the technical development and implementation of TransCanada's Energy Projects in the US, Canada and Mexico and the metering, measurement and compression projects in Canada. Provided oversight to the group and insured that the QMS system was implemented where practical on existing projects and fully implemented on new projects. Responsible for bringing projects in on time and budget in a safe manner and meeting the quality expectations of the organization.

2011 **Director Project Implementation and Risk Management Services**
Responsibilities included those listed under the Director of Energy Projects with the addition of responsibility for developing an ISO 9001 based Quality Management System to govern the Capital Projects process. In addition the responsibility included directing the group that was responsible for estimating, scheduling, cost forecasting, risk analysis and reporting functions for the regulated pipeline and energy projects groups.

2007 – 2010 **Director Energy Projects**
Responsible for the implementation of TransCanada's energy projects. Responsibilities include community relations, permitting, engineering and construction of a portfolio of hydro, wind and natural gas fired energy projects. Provided oversight for the construction teams to ensure that the projects are built safely, in accordance with the specifications, on time and within budget. Additional responsibilities include preparing board presentations, assisting in the technical development of projects and planning strategies to meet the department's goals.

TEC

2006 – 2007 **Site Construction Manager**
Contracted to Xcel Energy to oversee the construction of a new 750 MW super critical coal fired power plant and pollution control upgrades to the existing two units.

Calpine Corporation

2000 – 2006 **Director of Construction Management**
Responsible for 20 projects totaling 8,865 MW. The projects were spread over 13 states and 1 Canadian Province. The projects included 2 Westinghouse 501Gs, 2 GE LM6000s, 12 Siemens Westinghouse 501FDs, 16 GE 7FAs and 2 GE 7FBs. Provided oversight for the construction

teams to ensure that the projects were built safely, in accordance with the specifications, on time and within budget. The approximate value of the Program managed was five billion dollars.

1999 - 2000 **Project Manager**
Responsible for the construction of the Lost Pines Energy Center. Equipment included two (2) Siemens Westinghouse 501FD combustion turbines, a Toshiba Steam Turbine and Nooter Eriksen HRSGs. I was promoted to Director approximately halfway through this project. Responsible engineering, procurement and ensuring that the project was built safely on time and within budget. The project value was two hundred and twenty-nine million dollars.

1996 - 1999 **Project Manager**
Responsible for the construction of the Pasadena Cogeneration Project. Equipment included a Siemens Westinghouse 501FC combustion turbine, a Mitsubishi Steam Turbine and a Nooter Eriksen HRSG. Responsible engineering, procurement and ensuring that the project was built safely on time and within budget.

1994 - 1996 **Project Administration Manager**
Conducted evaluations of operating plants under consideration for acquisition. Leader of the transition team for newly acquired plants. Established and maintained a committed cost system for the operating plants. Determined optimal power cycle and equipment for new development projects. Performed preliminary rate of return analysis for proposed capital projects on the existing plants.

1992 - 1994 **Project Administration Manager**
Installed a Gas Cogeneration plant in Sumas, WA. Project included a GE Frame 7EA Gas Turbine, A Vogt HRSG and a 30 MW GE Steam Turbine. Responsibilities included subcontract administration, preparation of monthly reports for the Lender and General Partner, Quality control and preparation of monthly draw requests.

Kamtech Incorporated

1990 - 1991 **Site Manager**
Mechanical installation of a CLO2 generating plant for Potlatch in Lewiston, ID. Responsible for directing all field activities including self-performed equipment and piping installation and subcontracted insulation and painting. Contract Value $5 Million.

Weyher/Livsey Constructors, Inc.

1989 - 1990 **Site Manager**
Completion and start-up of a 400,000 pound/hour cogeneration plant for the P H Glatfelter Paper Company in York, PA. This project included the installation of a Pyropower Fluidized bed boiler and an ABB Turbine Generator. Responsibilities included completion of the construction and plant start-up with subcontracted civil, electrical and mechanical forces.

1988 - 1989 **Project Manager**
Completion of several Commercial projects including a gym for Georgia College, an elementary school for Cobb County, GA a hotel addition for The University of Georgia, and a new anatomic pathology building for The Medical College of Georgia.

1987 - 1988 **Site Manager**
Construction of the Saltstone Processing Facility for the Department of Energy at the Savannah River Plant in Aiken, SC. Responsible for all field activities including self-performed civil, mechanical, electrical and instrumentation installation. Contract Value $6 Million. Installed Value $35 Million.

1986 - 1987 **Site Manager**
Design and construction of a material handling conveyor for the South Eastern Public Service Authority, Portsmouth, VA. Responsible for all field activities including subcontracted equipment installation, siding and piping. Contract Value $2 Million.

1985 - 1986 **Project Electrical Engineer**
Design and construction of a cogeneration plant for the Norfolk Navy Shipyard, Portsmouth, VA. Responsibilities included expediting, purchasing electrical equipment, reviewing construction and interfacing with government inspectors. Contract value $110 Million.

1983 - 1985 **Project Engineer**
Design and construction of a Steam Generating Plant for the Corps of Engineer at the Red River Army Depot, Texarkana, TX. Responsibilities included establishing and administering subcontracts, preparing government submittals, purchasing, expediting, overseeing start-up, testing and training customer personnel. Contract Value $16 Million.

1982 - 1983 **Mechanical Estimator**
Responsible for equipment and piping estimates.

1980 - 1982 **Field Engineer**
Construction of a Lodge Cottrel Dresser Electrostatic precipitator at Virginia Power's Possum Point Power Station. Responsibilities included scheduling, design changes, purchasing and warehousing. Contract Value $3.5 Million.

Envirotech Corporation

1979-1980 **Field Service Representative**
Start-up and repair of Electrostatic precipitators and bag houses.

◙ TERRY J BENNETT ◙

Terry Bennett has over 20 years of experience in the energy sector in positions ranging from economic analysis through to power acquisitions and business development. Within TransCanada, Mr. Bennett has led numerous groups examining opportunities power generation including wind, biomass, solar, natural gas, oil, and coal projects; as well as analyzing overall energy market fundamentals. In his current role as Vice President, Power Development, Mr. Bennett has overall responsibility for power development in eastern Canada and the eastern US and has built a team of dedicated professions in this sector. TransCanada's power portfolio consists of 19 projects across North America totaling 11,000 MW of capacity.

Professional Experience

- **TransCanada Corporation** (February 1992 to Present)

Vice President, *Power Development (June 2010 to present)*

- Responsible for TransCanada's power development activities across the eastern half of North America
- Mandate is to seek out significant, economic power opportunities with a primary focus on TransCanada's existing geographical footprint
- Development includes green field, acquisitions and partnerships
- Responsible for building and managing TransCanada's power development team of approximately 20 professionals
- Efficient and effective assessment of opportunities for economic viability, tactical considerations and strategic fit
- Other Responsibilities include:
  - Establishing relationships with consultants and contractors
  - Directing landowner, community and stakeholder communication
  - Establishing contracts and processes for all development activities
  - Prioritizing activities of the Power Development team
  - Establishing project economics and bid pricing
  - Communicating and presenting individual projects and regional strategies to TransCanada senior management

Director, *TransCanada Wind Energy (July 2005 to June 2010)*

- Responsible for all of TransCanada's wind development activities

- Mandate is to seek out significant, economic wind opportunities in North America, with a primary focus on TransCanada's existing geographical footprint

- Development includes greenfield, acquisitions and partnerships

- Responsible for building TransCanada Wind Energy team

- Team quickly and effectively assesses opportunities for economic viability, tactical considerations and strategic fit

- Other Responsibilities include:
  - Establishing relationships with consultants and contractors
  - Directing landowner, community and stakeholder communication
  - Establishing contracts and processes for all development activities
  - Prioritizing activities of a small focused group to provide North American coverage
  - Establishing project economics and bid pricing
  - Communicating and presenting individual projects and regional strategies to TransCanada senior management

Director, Acquisitions*, TransCanada Power (May 1999 to June 2005)*

- Led project teams which successfully closed several major acquisitions totaling over 1,000 MW with a combined value of approx. $1 billion
- Closed on projects for both TransCanada Corporation and TransCanada Power, L.P.
- Led project teams which reviewed and bid on 14 major projects totaling 16,500 MW across North America
- Review and analysis of all types and sizes of power projects: gas-fired, coal, hydroelectric, wood-waste, oil
- Responsibilities:
  - initial review of projects
  - leading a due diligence team of professionals (legal, engineering, environmental, risk, accounting, tax, finance, human resources)
  - presentation of projects to TransCanada senior management and Board of Directors
  - preparation of bid including review of all project documents, evaluation model and Purchase and Sale Agreement review
  - negotiation of final Purchase and Sale Agreement with vendors
  - participate on team to decide strategic direction of Power Group

Manager, Planning and Market Analysis *(May 1997 to May 1999)*

- Supervision of five full-time staff
- Macroeconomic forecasts
- Energy demand and pricing/ Market Reports
- Team member of strategy formulation for TransCanada
- Facilities Application Hearing Witness

Economist/Senior Economist *(February 1992 to May 1997)*

Professional Experience (con't)

- **Nova Corporation of Alberta (***June 1989 to February 1992)*
  Economist

- **DRI/McGraw Hill (**M*ay 1988 to June 1989)*
  Senior Research Economist

- **The Centre for Resource Studies (***January 1987 to May 1988)*
  Research Analyst

- **Dun and Bradstreet Canada Limited** (J*une 1981 to September 1982)*
  Business Analyst

Education

- **M.A. Economics, 1987** *Queen's University, Kingston, Ontario*

- **B.A. (Honours) Economics, 1985** *University of Calgary, Calgary, Alberta*

- **Honours Graduate in Business Administration, 1980**
  Northern Alberta Institute of Technology, Edmonton, Alberta

Thomas (Tom) L. Patterson, P.Eng.

Work Experience

Director, Eastern Power Business Development, **TransCanada Corporation**
August 2012 – present

- Manage dedicated team of three professionals plus other support groups related to business development activities within TransCanada including engineering, operations, land, community relations, aboriginal relations
- Accountable for development of new energy infrastructure region in Eastern Canada and Eastern US
- Managed TransCanada response to OEB transmission development selection process

Manager, TransCanada Renewables, **TransCanada Corporation**
January 2008 – July 2012

- Manage a dedicated team of five professionals plus other support groups withinTransCanada
- Accountable for the bid response for two Ontario wind energy projects in 2008
- Accountable for the development of new wind energy developments across North America

Project Manager, Business Development,**TransCanada Corporation**
November 2004 - December 2007

- Managed the initial development of two wind energy projects in the province of Ontario
- Managed the development of a 1000 MW wind energy bid to Hydro Quebec (10 projects)
- Managed all aspects of the early development for the Kibby Wind Project including coordination of regulatory permitting activities, electrical interconnection applications, wind resource assessment programs
- Managed due diligence activities for various wind project initiatives
- Bid manager for a gas fired cogeneration bid to Hydro Quebec Distribution

Project Engineer, TransCanada Pipelines Ltd.
April 1999 – November 2004

- Member of the project team which secured PPA's for 739.5 MW of wind energy from Hydro Quebec Distribution (Cartier Wind Energy).
    - Responsible for the review of wind energy production estimates and project capital costs for wind energy projects
- Member of a project team successful in securing a 507 MW power purchase for a gas fired power plant with Hydro Quebec Distribution (Becancour Power Project)
    - Responsible for performance analysis of thermal power project development opportunities
    - Assisted in development of project cost estimates
- Project Manager for the engineering definition of a 40 MW biomass project
- Bid Manager for a 110 MW emergency power plant installed in Ontario
- Responsible for budgeting annual plant performance and operating margin for five power facilities in Ontario
- Responsible for the implementation of fuel gas arbitrage opportunities at operating power projects

Junior Designer, Charles G. Turner & Associates, Toronto, Ont.
May 1997 - April 1999, Sep. - Dec. 1996

- Performed the thermal design review for a 38 MW wood fired plant.

- Assisted in the design, and specification for controls upgrades to a 85,000 lb/hr boiler using single loop controllers.
- Assisted in the design and equipment selection for a new waste water system installed at a 40 MW generating facility.
- Assisted in the design, and specification for a new 20” steam and 6” condensate system.
- Prepared an energy audit and overall system analysis for a 57,000 scfm compressor plant and associated cooling tower equipment.
- Developed test procedures, and performance analysis spreadsheets for steam turbines, once-through boilers, air-cooled condensers, and gas turbines.
- Generated process and instrumentation diagrams for an air compressor plant and associated cooling water systems.

Relevant Courses of Study

- Turbomachinery Design
- Aerodynamics
- Machine Design
- Mechanical Vibrations
- Advanced Dynamics
- Combustion

Education

University of Waterloo, Waterloo, Ont.
Fall 1991 – May 1997

- Honours Bachelor of Applied Science in Mechanical Engineering
- Graduated on the Dean’s Honors List

References

- Available on request.

“Exhibit B”

ABOUT ISOLUX CORSAN

Grupo Isolux Corsan S.A. ("Isolux Corsan") is a privately held company founded in 1933 and headquartered in Madrid, Spain. With a substantial global presence in the high-voltage power transmission market worldwide, Isolux Corsan specializes in providing exceptional technology-driven Engineering, Procurement and Construction (EPC) services and project management for turn-key projects.

Isolux Corsan's global experience in the transmission and distribution market is vast. Isolux Corsan currently has T&D projects in the USA, Brazil, Mexico, Guatemala, Nicaragua, Argentina, Angola, Gabon, Jordan, Qatar, Syria and India. Isolux Corsan has a long history of successfully providing project management for high-voltage transmission line projects ranging from $6 million to $1 billion in investments. In the last ten years alone, Isolux Corsan has delivered high quality management solutions and services on turnkey high-voltage power transmission projects comprising of:

- 8,000 km of 500 kV–60 Hz OHL
- 2,100 km of 400 kV–345 kV – 60 Hz OHL
- 3,200 km of 230 kV–60/50 Hz OHL
- 40+ substations in 500 kV–400 kV–345 kV 60 Hz and 50 Hz
- 30+ substations in 230 kV–128 kV 60 Hz and 50 Hz

Isolux Corsan has a proven track record of completing projects with the highest level of professionalism, business ethics and commitment to excellence. Isolux Corsan's activities are driven by a determined commitment to sustainability and a goal of creating value in each environment in which it operates.

ABOUT ISOLUX INGENIERIA USA, LLC

Isolux Ingenieria USA, LLC ("IUSA") was established in 2009 and headquartered in Austin, Texas, USA when it was awarded with approximately 600 km of new 345 kV power lines to transmit clean energy produced by the wind farms in western Texas to the central part of the state where most of the industry and population are concentrated.



Helicopter assisting with stringing activity in Big Spring, TX.

Isolux Ingenieria USA, LLC is a wholly owned subsidiary of Isolux Ingenieria S.A. which is a wholly owned subsidiary of Grupo Isolux Corsan S.A.

IUSA provides full engineering design, procurement and construction management throughout a transmission line's project cycle.

ENGINEERING

IUSA has a dedicated team of engineers, with over ninety (90+) years of combined experience, specializing in transmission line design. In general, IUSA engineers perform the following engineering services:

- Basic and Detailed Engineering (route selection, preliminary siting, preliminary study, project analysis, surveying, preparation of route maps, plan and profile construction drawings, staking tables, structural design and testing, sag and tension tables, phasing diagrams, geotechnical investigations, foundation design and schedule, bill of material lists and all necessary drawings and supporting technical documents to support project permits and construction)

- Project Administration and Control (attend site visits, conference calls and meetings, project planning and schedules, monthly project status reports, document control)

- Procurement Support (support material requisition, issue bill of materials for quotation and purchase orders, review vendor specifications)

- Construction Support (review of field requested change orders, issue design changes when required)

Where required by applicable codes, laws or permits, all engineering drawings and documentation shall be signed and sealed by a professional engineer licensed in the state or province of the project. IUSA engineers provide project management and oversight to ensure that all work is in accordance to the client's specifications while respecting all applicable standards (NERC, ANSI, ASCE, ACI, AISC, ASTM, FAA, etc).

PROCUREMENT

All transmission-related materials and equipment are procured by both IUSA and Spain procurement teams. IUSA's capabilities to utilize headquarter resources to procure materials worldwide greatly increases the competitiveness of our purchase orders. Our goal is to meet or exceed the quality, delivery and cost goals established by the client.

IUSA has established a purchasing process using best purchasing practices of the procurement industry wherein all purchasing activities also comply with Isolux Corsan's corporate standards. The general process for IUSA purchasing is outlined below:

- Receive an approved requisition from engineering, construction or project management

- Establish a providers list by commodity with pre-qualified vendors for review

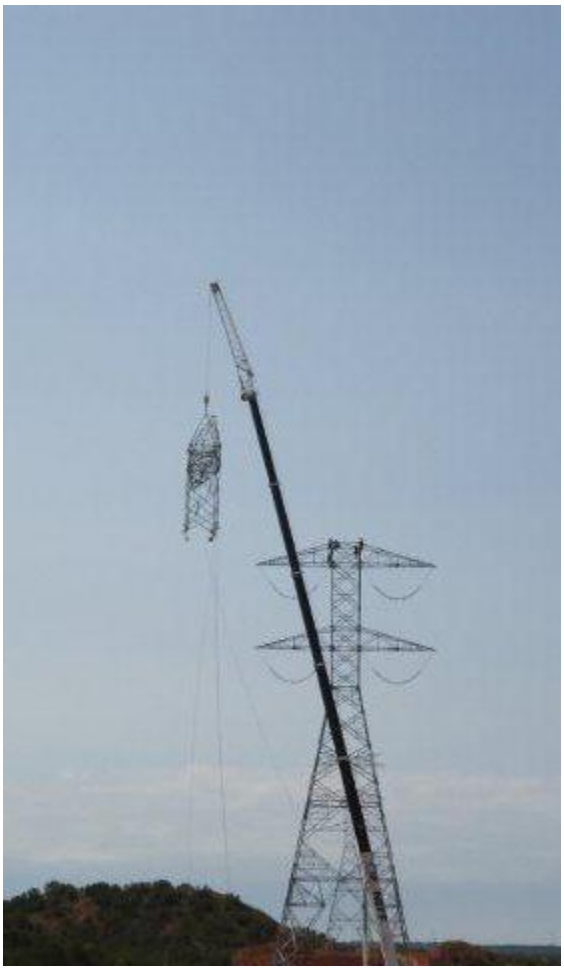
- Prepare Request for Proposals (RFP's) detailing requirements, including specifications, drawings, BOM's, scope, quantities, lead time, total capacity, total open capacity, pricing, escalation controls, payment terms, QA/QC, safety, and order terms and conditions

- Process RFP's, prepare bid tabulations and distribute for technical and commercial evaluation

- Engage in best and final negotiations with the potential short-listed vendors
- Submit award recommendation summarizing technical and commercial evaluation findings
- Receive client award approval
- Execute and finalize the purchase order or contract

IUSA and Spain procurement teams utilize SAP Purchasing System to step through the procurement processes, including creating bid comparatives, documenting purchase orders and change orders and streamlining invoice payments.

Purchasing services after the execution of the purchase order/contract include monitoring and tracking equipment and materials during manufacturing to final delivery, providing weekly updates to the schedule, issuing change orders using the same controls as the original purchase order, overseeing final close outs and providing full archival of the entire process with stringent document controls.



Crane lifting top crossarm's cage on a steel lattice tower for the WETT project.

CONSTRUCTION MANAGEMENT
IUSA's construction management team is well supported at the project site to ensure the complete execution of the project throughout the project cycle. IUSA staffs the on-site field office in all the areas below:

- Construction management
- Project controls (cost control, scheduling, reporting, contract administration)
- Purchasing and logistics
- Field Engineers
- Environmental
- Health and safety
- QA/QC
- Human resources
- IT
- Document control
- General administrative services

HEALTH, SAFETY AND ENVIRONMENTAL

IUSA's Health, Safety and Environmental HSE program meets the requirements of the international standard OSHAS 18001:2007 and addresses the safety and health issues associated with all of IUSA's activities, operations, services and products. IUSA provides a comprehensive HSE program which includes our site specific Accident Prevention Plan (APP) and all supporting health and safety procedures, policies, forms and other site specific documents.

IUSA operates in full compliance with all applicable environmental, health and safety laws, regulations, and standards. Along with this, IUSA establishes effective management systems to promote safety awareness and to protect employees, subcontractors, the general public, and the environment from physical hazards at all project locations. IUSA firmly believes in providing employees with the necessary training to ensure full compliance with all applicable environmental, health and safety issues and concerns.

IUSA's Safety Policy requires that only contractors with above average safety records are utilized. In support of this initiative, IUSA has an internal process to pre-qualify subcontractors, along with their multi-tier subcontractors, to evaluate their historical safety performance. The minimum requirements a subcontractor must meet in the pre-qualification process include:

- OSHA 300 log reporting records
- A recordable incident rate of less than 3.0 in the last three years.
- Experience Modification Rates (EMR) of less than 1.0 in the last three years.
- Written health, safety and environmental programs as applicable to the hazards present on the proposed construction activities

IUSA's safety principle is to be injury and accident free, every hour and every day. This means IUSA strives to have 0 recordable accidents and injuries on all IUSA projects, to conduct every operation in compliance with all applicable regulations, and to deliver each project on time and without injuries to personnel or occupational illnesses.

QUALITY MANAGEMENT

IUSA has developed and implemented a Quality Management System in order to document the company's best business practices, better satisfy the requirements and expectations of our clients, and improve the overall management in order to guarantee the performance of the company.

The Quality Management System of IUSA meets the requirements of the international standards ISO 9001:2008 with the intention to address and guarantee all the different phases of engineering and construction of its core of business.

In order to successfully address all the requirements set within the Quality Management System, IUSA develops the applicable quality requirements based on the actual work to be performed and prepares a specific quality manual for each project's scope of work.

PROJECT EXPERIENCE

TRANSMISSION AND DISTRIBUTION

PROJECT TYPE
BOT

CLIENT
Public Utility Commission of Texas (PUCT)

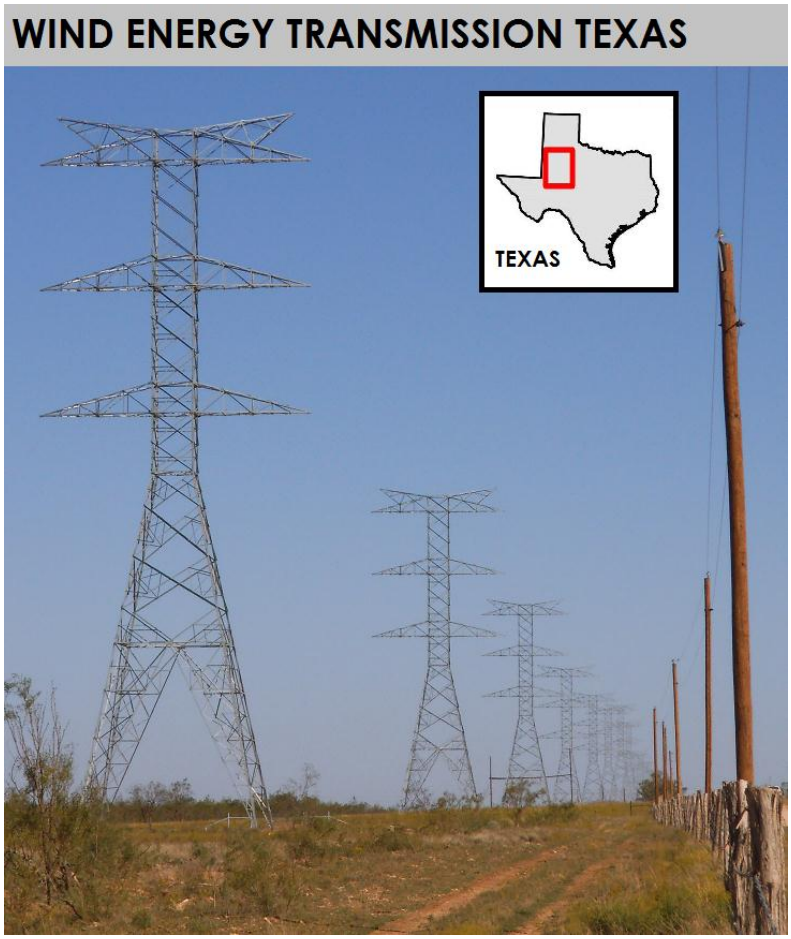
PROJECT NAME
Wind Energy Transmission Texas (WETT)

PROJECT LOCATION
Big Spring, Texas, USA

PROJECT VALUE
$600 million (USD)

DATE OF AWARD
2011

DATE OF COMPLETION
2013



Erected towers on Segment 1 from Cottonwood switching station (WETT) to Dermott switching station (Oncor).

PROJECT DETAILS

- 345 kV transmission line and six (6) 345 kV switching stations
- Total length: 600 km
- Combination of steel lattice towers and monopoles
- Double circuit
- Conductors per phase: 2
- Conductor size: ACSR 1590 kcmil

PROJECT DESCRIPTION

WETT is the construction and operation of new high-voltage transmission lines as part of a state-wide program, CREZ (Competitive Renewable Energy Zones), to deliver clean, renewable energy throughout the state of Texas. The Texas Legislature passed legislation in 2005 with the vision to develop the electric transmission infrastructure to increase the wind generation capacity to an estimated 18,000 MW by 2015.

IUSA carried out the preliminary engineering, environmental and construction permitting, detailed engineering design services, purchase of all materials and equipment, and construction management for the 600 km 345 kV transmission line and substations.

AMAZONAS PROJECT

PROJECT TYPE
BOT

CLIENT
Agencia Nacional De Energia Electrica (ANEEL)

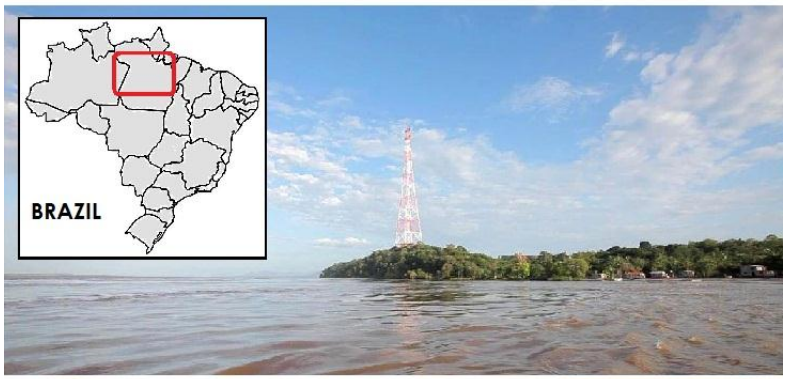
PROJECT NAME
Tucurui – Macapa – Manaus Transmission Line

PROJECT LOCATION
Angola, Africa

PROJECT VALUE
$1,200 million (USD)

DATE OF AWARD
2008

DATE OF COMPLETION
2012





Constructing a 295 m pylon, similar in height to the Eiffel Tower, for the Amazon River crossing.

PROJECT DETAILS

- 500 kV and 230 kV transmission line
- Total length: 1,200 km
- Steel lattice towers
- Double circuit
- Conductors per phase: 4
- Conductor size: AAAC 954 kcmil

PROJECT DESCRIPTION

Isolux Corsan was awarded the sole tender for building and running 1,191 kilometers of 500 kV and 230 kV high voltage lines interconnecting Manaus, the capital of the State of Amazonas, to the country's national grid through the Amazon jungle.

Special considerations

- Isolux built two (2) 2,500 tonne pylons, 295 meters in height, to cross the Amazon River.
- More than 4,000 professionals, mainly Brazilians, took part in the building works, living in fourteen (14) camps that were built to house the site workers.

TRIANGULO (TRIANGLE)

PROJECT TYPE
BOT

CLIENT
LTT / Plena Transmissoras

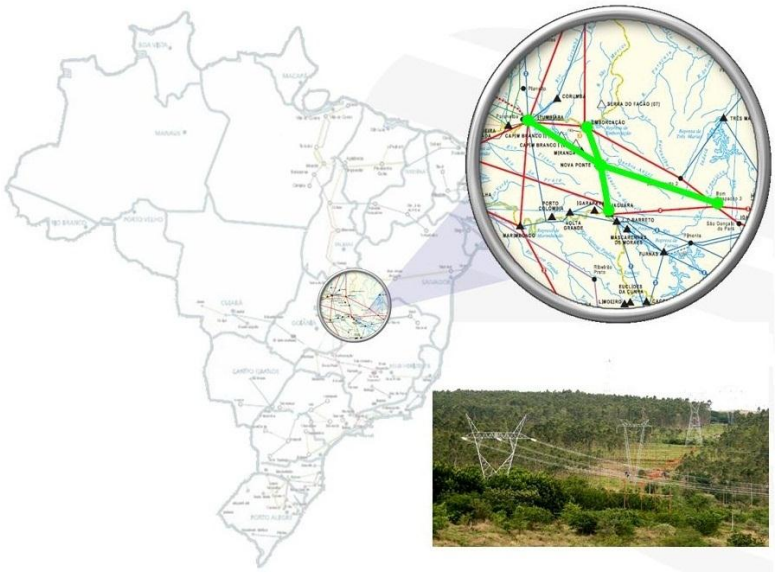
PROJECT NAME
Triangulo

PROJECT LOCATION
State of Minas Gerais, Brazil

PROJECT VALUE
$260 million (USD)

DATE OF AWARD
2007

DATE OF COMPLETION
2008



The Triangulo Project was part of a $735 million investment to build 2,800 km of lines throughout Brazil.

PROJECT DETAILS

- 500 kV transmission line and substations
- Total length: 695 km
- Steel lattice towers
- Single circuit
- Conductors per phase: 4
- Conductor size: ACSR 954 kcmil

PROJECT DESCRIPTION

Isolux Corsan provided turnkey EPC services for the 500 kV ITUMBIARA-SAO GOTARDO-NOVA PONTE-EMBORCAÇAO-BOM DESPACHO-ESTREITO transmission lines and associated substations. The new electrical transmission infrastructure was essential to increase the power transport capacity to the highly populated southern and south-eastern regions and to increase the connections to the northeastern and northern regions where power is scarcer.

PROJECT TYPE
EPC

CLIENT
Ministry of Energy of Angola (MINEA)

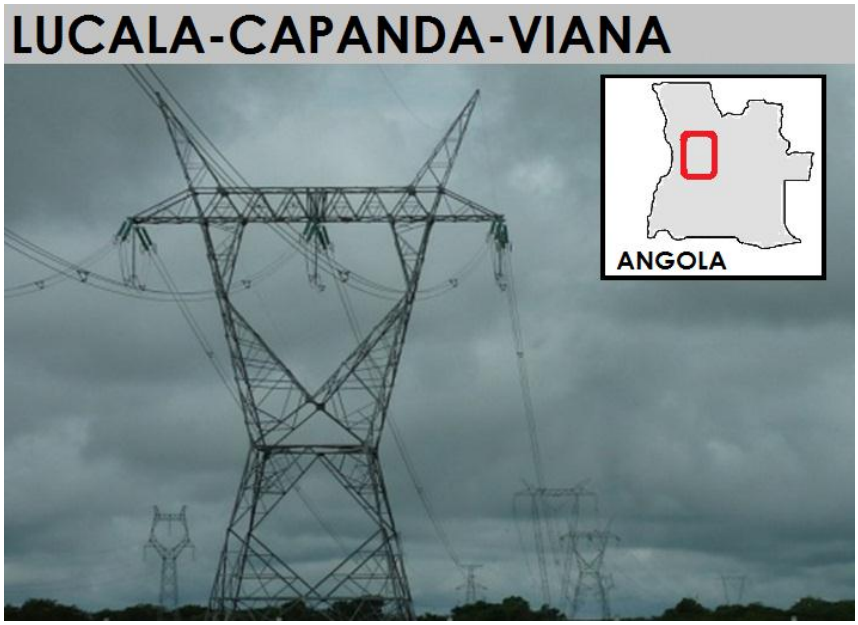
PROJECT NAME
Lucala-Capanda-Viana Transmission Line

PROJECT LOCATION
Angola, Africa

PROJECT VALUE
$120 million (USD)

DATE OF AWARD
2005

DATE OF COMPLETION
2007



Isolux Corsan built the first 400 kV transmission line in Angola.

PROJECT DETAILS
- 400 kV transmission line and substations
- Total length: 300 km
- Steel lattice towers
- Single circuit
- Conductors per phase: 3
- Conductor size: ACSR Crow 715.5 mcm

PROJECT DESCRIPTION
Isolux Corsan provided turnkey EPC services for the 400 kV LUCALA-CAPANDA-VIANA transmission lines and associated substations. The 400 kV transmission line in Angola transmits electricity output from the Capanda Dam to the capital, Luanda. Isolux also built the feed line for the Cabinda Stadium to ensure an adequate supply of electricity during Africa Nations' Cup.

In 2007, Isolux was awarded by MINEA with another 200 km 220 kV LUCALA-UIJE transmission line, which had a project value of $45 million (USD) and was completed in 2010.

PROJECT TYPE
BOT

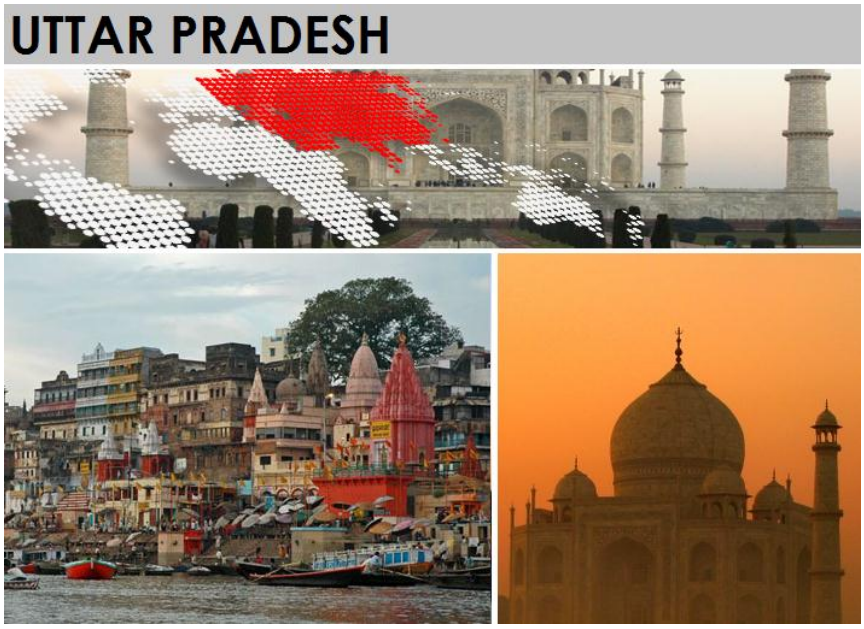
CLIENT
Uttar Pradesh Power Transmission Corp (UPPTC)

PROJECT NAME
Uttar Pradesh Transmission Line

PROJECT LOCATION
Uttar Pradesh, India

PROJECT VALUE
$1,100 million (USD)

DATE OF AWARD
2011



The new HV power line will collect the energy from new power stations and transport across Uttar Pradesh.

DATE OF COMPLETION
2013

PROJECT DETAILS

- 765 kV and 400 kV transmission line and five (5) substations
- Total length: 1,600 km
- Steel lattice towers
- Single circuit (765 kV) and double circuit (400 kV)
- Conductors per phase: 4
- Conductor size: ACSR Bersimis 724.97 mm2 (765 kV) and Moose 603.77 mm2 (400 kV)

PROJECT DESCRIPTION
Isolux Corsan was awarded by the Uttar Pradesh Power Transmission Corporation Limited to construct and operate 1,600 km of 765 kV and 400 kV transmission lines and five (5) transformer substations. The new high voltage transmission lines will reinforce the transmission network and transport over 4,600 MW, generated by new thermal power stations, throughout the territory.

PROJECT TYPE
EPC

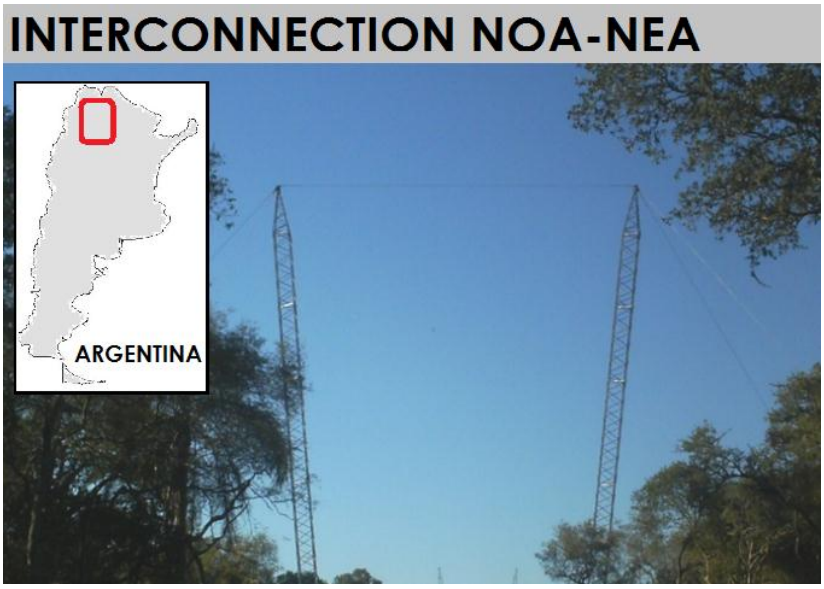
CLIENT
Government of Argentina

PROJECT NAME
Interconnection NOA-NEA

PROJECT LOCATION
Northwestern states of Argentina

PROJECT VALUE
$100 million (USD)

DATE OF AWARD
2008



The extra high voltage lines of the Interconnection NOA-NEA project have a maximum capacity of 1,150 MW.

DATE OF COMPLETION
2011

PROJECT DETAILS

- 500 kV transmission line
- Total length: 570 km
- Steel lattice towers
- Single circuit
- Conductors per phase: 4
- Conductor size: ACSR Peace River Modified 365/32 mm2

PROJECT DESCRIPTION
The Interconnection NOA-NEA project was part of a 230 km, $293 million dollar investment, by the Argentina government to bring energy to northern states of Argentina. The project was divided into two parts, the Northwest and the Northeast. Isolux Corsan provided turnkey EPC services for the Northwest 570 km 500 kV TUCUMAN-SALTA-JUJUY transmission line.

TURNKEY TRANSMISSION LINE (T.L.) PROJECTS EXECUTED IN THE LAST 10 YEARS	YEAR	KV	KM	COUNTRY
T.L. CHAMPAYÁN-ANAHUAC POTENCIA	2000	400	96	MEXICO
T.L. PUERTO ALTAMIRA-CHAMPAYÁN LINEA 1	2000	400	33	MEXICO
500 kV L.T SAMAMBAIA - ITUMBIARA - EMBORCAÇAO AND ASSOCIATED SUBSTATIONS	2002	500	285	BRAZIL
500 kV T.L. ITUMBIARA - MARIMBONDO AND ASSOCIATED SUBSTATIONS	2002	500	213	BRAZIL
500 kV T.L. TIJUCO PRETO - CACHOEIRA PAULISTA AND ASSOCIATED SUBSTATIONS	2002	500	181	BRAZIL
T.L. AGUASCALIENTES POT-CALERA II	2002	230	155	MEXICO
T.L. MOCTEZUMA - EL ENCINO	2002	400	206	MEXICO
BOANE-SALAMANGA	2003	66	81	MOZAMBIQUE
KAEDI-BOGHE	2003	90	98	MAURITAINE
T.L. AGUASCALIENTES PABELLON	2003	115	53	MEXICO
T.L. MOCTEZUMA - NUEVO CASAS GRANDES	2003	400	165	MEXICO
T.L. NACOZARI - NUEVO CASAS GRANDES II	2003	400	213	MEXICO
T.L. OBREGÓN 4 - GUAYMAS II	2003	400	128	MEXICO
T.L. PRIMERO DE MAYO - CAÑADA	2003	400	221	MEXICO
T.L. STA.ANA-NOGALES AEROPUERTO, NOGALES AEROPUERTO ENTQ.MAGDALENA-NUEVO NOGALES Y NOGALES AEROPUERTO ENTQ.STA.ANA-NOGALES	2003	230	104	MEXICO
T.L. TEPATIPLÁN-CAPILLA DE GUADALUPE	2003	115	34	MEXICO
MATAM-KAEDI	2003	90	87	MAURITAINE

TURNKEY TRANSMISSION LINE (T.L.) PROJECTS EXECUTED IN THE LAST 10 YEARS	YEAR	KV	KM	COUNTRY
T.L. SIDI MANSOUR-MSAKEN II	2004	225	98	TUNISIA
230 kV PORTO PRIMAVERA-IMBIRISSU.DOURADOS AND ASSOCIATED SUBSTATIONS	2005	500	507	BRAZIL
YAUTEPEC-TOPILEJO PROJECT	2005	400	47	MEXICO
LOT 702: CARDENAS-CHONTALPA	2006	115	21	MEXICO
500 kV TL CUIABA - ITUMBIARA AND ASSOCIATED SUBSTATIONS	2006	500	811	BRAZIL
LOT 701	2006	115/69	121	MEXICO
500 Kv TL SERRA DA MESA 2- LUZIANIA- SAMAMBAIA- PARACATU-EMBORCACAO AND ASSOCIATED SUBSTATIONS	2006	500	678	BRAZIL
500 kV TL TUCURUI - VILA DO CONDE AND ASSOCIATED SUBSTATIONS	2006	500	325	BRAZIL
T.L. CHILPACINGO POT-ENTQ.CHILPACINGO-CHILAPA	2006	115	15	MEXICO
T.L. JILOTEPEC POT - DAÑU	2006	230	37	MEXICO
T.L. STA.LUCIA - MACUSPANA II	2006	400	13	MEXICO
YACIRETA RINCON STA MARIA-RODRIGUEZ/ SUBTRAMO NORTE INTERCONNECTION	2006	500	672	ARGENTINA
T.L. MATIGUAS-SIUNA	2007	69	141	NICARAGUA
T.L. CAPANDA-LUCALA-VIANA	2007	400	300	ANGOLA
T.L. LUCALA-UIJE	2010	220	200	ANGOLA
LOT 149 RFO OPTIC FIBRE CABLE CENTRAL NETWORK	2007	400/230/115	1954	MEXICO
LOT 150 RFO FIBRE OPTIC NORTH NETWORK (CABLE)	2007	400/230/115	885	MEXICO

TURNKEY TRANSMISSION LINE (T.L.) PROJECTS EXECUTED IN THE LAST 10 YEARS	YEAR	KV	KM	COUNTRY
LOT 148 RFO OPTIC FIBRE SOUTH NETWORK	2007	400/230/15/ 69/13,8	485	MEXICO
GUATEMALA-MÉXICO OHL 400 kV INTERCONNECTION	2007	400	40	GUATEMALA
T.L. 1116 TRANSFORMACIÓN NOROESTE (PHASE 1)	2,008	220	80	MEXICO
PROYECTO 218 LT 400 KV LA VENTOSA-JUILE	2010	400	135	MEXICO
L.T. OAXACA II, III Y IV	2010	230	33	MEXICO
LOT D: 500 kV TL ITUMBIARA - SAO GOTARDO - NOVA PONTE - EMBORCAÇAO - BOM DESPACHO-ESTREITO AND ASSOCIATED SUBSTATIONS	2008	500	695	BRAZIL
500 kV TL SAO SIMAO - MARIMBONDO, RIBERAO PRETO MARIMBONDO AND ASSOCIATED SUBSTATIONS	2009	500	408	BRAZIL
LOT A: 500 kV TL PARACATU 4 - PIRAPORA 2 AND ASSOCIATED SUBSTATIONS	2009	500	244	BRAZIL
LOT B: 500 kV TL JAGUARA - RIBEIRAO PRETO AND ASSOCIATED SUBSTATIONS	2009	500	300	BRAZIL
T.L. 500 KV RIBEIRO GONZALVEZ	2010	500	300	BRAZIL
LOT 500 KV T.L. COLINAS-SAO JOAO DE PIAUÍ	2010	500	420	BRAZIL
T.L. ESTREITO-IMPERATRIZ	2010	500	140	BRAZIL
INTERCONEXIÓN NOA-NEA	2011	500	572	ARGENTINA
INTERCONEXIÓN COMAHUE-CUYO - TRAMO NORTE	2011	500	197	ARGENTINA
INTERCONEXIÓN CALINGASTA-RODEO-IGLESIA T.L. 500 KV	2011	500	100	ARGENTINA
KWANZA SUL PROJECT O.H.L.	2011	30/60	140	ANGOLA
MALANGE PROJECT UNDERGROUND T..L.	2011	15	20	ANGOLA

“Exhibit C”

1.0 INTRODUCTION

Golder Associates Ltd (Golder) is pleased to present our capabilities and experience to address environmental assessments for the East-West Tie in support of Iccon.

Golder strongly believes that early attention given to planning, strategic thinking and pre-EA consultation are key components to a successful project. Golder's completion of an Environmental Analysis of the East-West Tie Expansion for the Ontario Power Authority (OPA) in 2011 aids in our ability to employ a focussed and strategic approach customized for the EWT Project.

We will provide a team of professionals with the requisite experience gained from the successful completion of a wide range of EA studies throughout Ontario. Key features of our our team are as follows:

The Project Requires	Golder Provides
Local Office and Experience	Golder has opened a Thunder Bay Office in 2013 with experience stakeholder consultation and environmental expertise
Experience with the Coordinated Federal/Provincial EA Process	Current experience working with the Ministry of the Environment (MOE) and the Canadian Environmental Assessment Agency (CEA Agency) to formulate a coordinated EA approach related to the development of two mining projects – Cliffs Chromite Project and Osisko Hammond Reef Gold Project. Golder is also in the preliminary phase of a coordinated EA process for the Dinorwic to Pickle Lake Transmission Line EA. This has provided Golder with a unique opportunity to assist in guiding this process and learning from its challenges first hand. Moreover, this EA experience provides Golder a rare insight into how this coordinated process will continue to evolve.
Linear Corridor EA Expertise	■ Many members of Golder's EWT Project team have recent experience participating on the Hammond Reef Gold and Cliffs Chromite Projects, both of which require linear coordinate developments, the preliminary phase of the Dinorwic to Pickle Lake Transmission Line EA, as well as the federal screening process for Bell Aliant. ■ We are supported by the extensive experience of our colleagues in Alberta and British Columbia on transmission line development.
Demonstrated Aboriginal Engagement Experience	■ Through several years of supporting clients in their activities with Aboriginal communities, Golder has developed a practical approach based on balancing principles of understanding and respect to Aboriginal communities with the needs of our clients. ■ Golder follows a set of guiding principles to ensure effective engagement, including cultural sensitivity training for our Project team focussed on the Aboriginal communities to be engaged in the Project. ■ Members of Golder's team have experience in engagement with a number of the First Nations communities to be engaged, including Fort Williams, Pic Mobert and Pic River First Nations. ■ On the Dinorwic to Pickle Lake Transmission EA, Golder's client is a First Nations-led partnership providing us with insight into the standard for engagement in northern Ontario that will be set by this project.
Field Experience in Northern Ontario	■ Golder's biophysical team in our Sudbury office have designed

The Project Requires	Golder Provides
	and implemented field studies across northern Ontario with teams of up to 25 people. ■ Their skilled teams understand the logistic challenges of working in this remote environment in all seasons and integrate their experience into targeted, efficient and cost-effective field study designs. ■ Recently their work has included field studies in support of linear corridors for the Hammond Reef and Cliffs' Chromite Projects, as well as across northwestern Ontario in support of Bell Aliant's Remote Northern Ontario Broadband Expansion Initiative Projects and for the Dinorwic to Pickle Lake Transmission EA project. ■ Studies have included breeding birds, water birds, shore birds, vegetation, winter track counts, caribou calving surveys, basking turtles, whip-poor-will and aerial caribou and raptor nest surveys, as well as aquatic habitat mapping, fish and benthic community characterization surveys.
An Integrated Project Team	■ Golder's team will be based from two office locations (Mississauga and Sudbury) and coordinated through our Project office being established in Thunder Bay, which allows for consistent and reliable communication across an established network for collaboration. Golder staff from these offices have successfully collaborated on previous projects, including: ■ Corridor Level Environmental Analysis of the East-West Tie Transmission Line Enhancement for OPA; and ■ Baseline characterization field studies for the Dinorwic to Pickle Lake Transmission, Hammond Reef, Cliffs Chromite and Bell Aliant Remote Northern Ontario Broadband Expansion Initiative Projects in Northern Ontario. Our network of staff across the globe allows us to draw on a depth of resources and specialized skills to serve Iccon's Project needs.

2.0 QUALIFICATIONS AND EXPERIENCE

3.0 CONSULTANT QUALIFICATIONS

3.1 Golder Associates Ltd

3.1.1 Corporate Profile

At Golder we strive to be one of the most respected global companies providing consulting, design, and construction services in earth, environment, and energy. With Golder, clients gain the advantage of working with highly skilled engineers, scientists, project managers, and other technical specialists who are committed to helping them succeed. By building strong relationships and meeting the needs of clients, our people have created one of the most trusted professional services firms in the world. Employee owned since our formation in 1960, we have created a unique culture with pride in ownership, resulting in enduring relationships and long-term organizational stability. Golder's professionals take the time to build an understanding of client needs and of the specific environments in which they operate. This enables us to help our clients achieve their short- and long-term financial, social, and environmental goals. Golder's service areas have grown to accommodate our clients' needs, from specialist services to total project management and complete solutions. From our original foundations in geotechnical and soil science, our experience has expanded into all aspects of environmental science.

Golder employs engineers, hydrogeologists, hydrologists, geologists, and other scientists to provide professional services and quality to our clients. Golder offers in a wide range of services, including the following:

- Air Quality Engineering & Management
- Greenhouse Emissions and Carbon Management
- Energy Management
- Acoustics, Noise & Vibration Engineering
- Meteorology
- Environmental Engineering
- Biological Sciences
- Construction Quality Assurance
- Cultural Sciences
- Environmental Health & Safety
- Geosciences
- Geotechnical Engineering
- Information Management
- Mining Engineering
- Risk and Decision Analysis
- Training and Education

To enhance the value we provide to clients and to better address the diverse and changing needs of the various market sectors, we formed specialised industry groups across the Golder companies, which share information and best practices from around the world. Through such cross-industry knowledge, we help our clients find the best solution. Sectors served include, but are not limited, to the following:

- Transportation
- Manufacturing
- Oil & Gas
- Power
- Waste Management
- Mining
- Land Development
- Water Resource Development
- Agriculture
- Forestry, Wood Products, Pulp & Paper
- Finance, Insurance, Real Estate & Legal Professions
- Public Sector

The success of Golder's approach can be seen through our steady growth. We now employ nearly 8,000 people who operate from more than 160 offices located throughout Africa, Asia, Australasia, Europe, North America, and South America. Our knowledge of local cultures, languages, and regulatory requirements, combined with our global resources, makes it possible for us to help our clients achieve their business objectives around the world and at home.

3.1.2 Partnerships with Aboriginal Communities

Golder has worked with Aboriginal Communities for over 40 years and has built strong relationships with the Aboriginal people. We are committed to strengthening these relationships by training local staff to develop the skills necessary to build a stronger economy in the region. We work with communities to provide local employment, training, education, and ongoing protection of the land by teaching local communities to foster the skills necessary to work in partnership with our clients. We understand that a high value is placed on traditional ties to the land. Golder offers traditional knowledge services in-house and liaises with other local parties when necessary.

Golder has established several partnerships and strategic alliances with Aboriginal communities which are outlined in detail in Table 1below.

Table 1: Our Aboriginal and Community Partnerships

Company Name	Relationship	Head Office	Services
IMG-Golder Corporation	Majority Inuvialuit owned incorporated company with Golder Associates Ltd. as a minority shareholder	Inuvik, Northwest Territories	Environmental and engineering consulting
West Delta Golder Corporation	Majority Gwich'in owned incorporated company with Golder Associates Ltd. as a minority shareholder	Fort McPherson, Northwest Territories	Environmental and engineering consulting
CLAW (Clean Land, Air, and Water) Environmental Services Inc.	Majority Aboriginal owned incorporated company with Golder Associates Ltd. as a minority shareholder.	Kanata, Ontario	Environmental and engineering consulting to Aboriginal, Inuit, northern communities, and federal government departments
Maskwa-Golder Environmental Ltd.	Majority Aboriginal owned incorporated company with Golder Associates Ltd. as a minority shareholder	Hay River, Northwest Territories	Environmental consulting, geotechnical engineering and biological sciences in oil & gas, mining, infrastructure, and contaminated land markets in Northern Canada
Kēyeh Nejéh Golder Corporation	Majority Aboriginal owned incorporated company with Golder Associated Ltd. as a minority shareholder, partnership with Liard First Nation Development Corporation	Whitehorse, Yukon (near Watson Lake)	Engineering and environmental consulting focusing initially in the Kaska Territory (Yukon, northern BC, and northern Alberta)
Angoniatit Niovikvia Ltd. (ANL)	100% Inuit owned company, strategic alliance with Golder Associates Ltd.	Kugluktuk, Nunavut	Engineering and environmental consulting (environmental assessments, hydrology, fisheries and wildlife, and

Company Name	Relationship	Head Office	Services
			traditional knowledge)
Fond du Lac First Nation Development Corporation	100% Denesuline owned company, strategic alliance between Fond du Lac First Nation Development Corporation and Golder Associates Ltd.	Fond du Lac, Saskatchewan	Environmental and engineering consulting in the Athabasca Basin area
La Compagnie de Construction et Développement Crie (CCDC)	100% Cree owned company	Chisasibi, Quebec	Civil engineering, environmental, special projects, building works and equipment, and road maintenance
Haida Environmental Company	100% Aboriginal owned company, managed by the community	Queen Charlotte Islands, British Columbia	Environmental consulting

3.1.3 Relevant Project Experience

Golder is a premier full-service environmental consulting company with established and well tuned skills in the planning, design, environmental assessment, construction, operations and closure phases of development projects. Golder's technical skills have been honed on undertaking complex and challenging EAs, including environmental constraints analysis for clients representing numerous industries (e.g., natural resource development, power sector, transportation, financial institutions, mortgage companies, insurance companies, industrial and commercial property owners), as well as all three levels of government. Our experience ranges from single-building sites to large, long-term, multi-disciplinary engagements involving major pipeline and transmission line initiatives, power generation facilities, and industrial complexes. In addition, our network of staff across Ontario and across Canada, have relevant experience in the proposed study areas and this knowledge base will also feed into the study.

The Golder EA approach is simple — a completely transparent process, where potential impacts are identified early and wherever possible are avoided or mitigated. The approach is tried, tested, and proven successful, regardless of the project location, type or size, and its legal and regulatory environment. Golder's approach to EA is based on the following guiding principles:

- solutions oriented;
- balanced and interactive;
- focused on key issues;
- iterative;
- transparent framework; and
- comprehensive.

Following these six principles enables Golder to produce high quality, relevant assessments. These principles have enabled us to bring the following skills, experience and resources to this Project:

- Our project personnel have carried out numerous EAs in Ontario, across Canada and abroad, which provides us with a solid understanding of the potential risks to the implementation of this Project.
- Our project experience in conducting similar assessments and in the same geographic area permits us to provide a work program focused on the issues of concern, thus providing added value for the cost.
- Our extensive experience allows us to put forward recommendations that are technically defensible and economically feasible.

3.1.4 East-West Tie Transmission Line Enhancement – Corridor Level Environmental Analysis

Having been retained by OPA in June 2011 to carry out a high level analysis of potential environmental constraints on the feasible corridors for the East-West Tie Enhancement Project, Golder has first-hand knowledge of the study area corridor and is therefore uniquely qualified to carry out the EA for the EWT Project. The purpose of this analysis was to determine any significant natural or human environment effects or constraints which would prevent development of this Project by a future proponent. The environmental effects of the EWT Project were considered at a corridor level, providing Golder's project team and the OPA as our client, a high-level understanding of the implications of the EWT Project within a defined study area. The scope of the assessment consisted of a review of existing conditions and potential effects related to physiography, land use, access to non-renewable resources, archaeological and cultural resources, aquatic resources, vegetation, wildlife, and socio-economic resources. Through completion of this project, Golder has also obtained much of the available desk top information and GIS data required to initiate the EA.

3.1.5 Selected Environmental Assessment Project Experience

Golder's Ontario offices are currently working on a number of projects in northern Ontario that require either a provincial Individual EA process or a coordinated provincial/federal EA process. The following project examples characterize our relevant skills and experience:

- **Dryden to Pickle Lake Transmission Line Project** – Golder has recently initiated work with Goldcorp and the Central Corridor Energy Group (CCEG), who have created a partnership called Wataynikaneyap Power, for the EA of another of the five priority projects identified within the Ontario Long-Term Energy Plan. The proposed project is a 298 km long 230 kV transmission line from Dryden (Dinorwic) to Pickle Lake, in northern Ontario.

  Golder is working closely with Wataynikaneyap in the initial phases of a coordinated EA to meet both provincial and federal requirements. As part of this work, Golder will undertake the required baseline studies (e.g., biology, socio-economic and cultural resources), complete the required EA document and lead the non-Aboriginal stakeholder engagement program. Golder is supporting Wataynikaneyap Power on their Aboriginal engagement program for the EA.

- **Hammond Reef Gold Project** – Golder is currently working with Osisko Mining Corporation (Osisko) to carry out an EA on the Hammond Reef Gold Project, located near Atikokan in northwestern Ontario. The Project consists of extracting and processing gold using crushing/grinding, flotation, cyanide leaching and carbon stripping/refining techniques. The Project is subject to both the Ontario *Environmental Assessment*

*Act (*EAA) and the *Canadian Environmental Assessment Act* (CEA Act*)* respectively and is therefore proceeding as a coordinated EA designed to meet both provincial and federal EA requirements.

Golder is responsible for managing the EA, including completion of the required baseline investigations (e.g., water quality and quantity, biology and socio-economic resources), preparation of a ToR for the Individual EA and participation in meetings with regulatory agencies. Golder is also advising Osisko on their consultation strategy for affected stakeholders, and affected Aboriginal communities and organizations.

- **Cliffs Chromite Project** – Golder is presently working with Cliffs Natural Resources Inc. (Cliffs) to carry out an EA to facilitate development of the Black Thor deposit in the McFaulds Lake area in Northern Ontario. Known as the Cliffs Chromite Project (the Project), it consists of extracting and processing chromite ore from the Black Thor deposit and transporting the concentrate to a Ferrochrome Production Facility (FPF). Golder has been instrumental in formulating the strategy for the coordinated EA to meet both provincial and federal requirements.

  In addition to managing the EA, Golder is managing the execution of environmental and social baseline studies to characterize the existing conditions. Currently, Golder is preparing a ToR for the Individual EA component of this Project. Golder's role also includes advising Cliffs on a consultation strategy that meets regulatory requirements and the expectations of Aboriginal communities and organizations, and other interested and/or affected stakeholders.

- **Environmental Assessment of the Expansion of the Brighton Landfill** – Golder is currently providing professional consulting services to the County of Northumberland to undertake an EA to allow for the expansion of the Brighton Landfill in Brighton, Ontario. The first phase of the assignment was the preparation of the ToR for a focused Individual EA. The ToR was submitted to the Minister of the Environment in January 2011 and obtained approval after the minimum government review period of 90 days in April 2011. The approved ToR can be found at www.northumberlandcounty.ca/BrightonlandfillEA.

  The proposed undertaking will include expansion of the existing Brighton Landfill. Golder is providing a technically appropriate, efficient approach to support the County throughout the project, including public consultation, EA, technical assessments, regulatory applications, and any necessary follow-up actions.

- **Environmental Assessments for the Remote Northern Ontario Broadband Expansion Initiative** – In 2010, Bell Aliant retained Golder to assist them in obtaining environmental approvals for three projects in northwestern Ontario. Each project involved the installation, operation/maintenance and eventual decommissioning of fibre optic cable along existing and new corridors. The overall program, which was named the Remote Northern Ontario Broadband Expansion Initiative, involved placing about 1000 km of fibre optic cable to transmit light signals and provide broadband internet services to communities located in northwestern Ontario. The EA for the three projects completed by Golder were:

  - Project #1 – Pickle Lake and Pikangikum;
  - Project #2 – Angling Lake, Musselwhite Mine and Cat Lake; and
  - Project #3 – Poplar Hill, Kingfisher Lake and Koocheching.

Golder prepared Project Description reports which were submitted to the CEA Agency, Industry Canada and Public Works and Government Services Canada. Using these documents, the federal agencies determined that each project required that a screening EA be completed pursuant to the CEA Act. Golder conducted environmental desktop studies for a wide range of environmental components including the physical environment (climate, meteorology, air quality, noise, seismicity, geology, hydrogeology, groundwater quality, hydrology and surface water quality), the biological environment (including terrestrial and aquatic biology) and the socio-economic environment (including heritage sites, archaeology, cultural resources, land use and Aboriginal interests).

The Golder EA team then conducted an assessment of potential effects of the project on the environment, recommended mitigation measures to reduce or avoid impacts and assessed the significance of residual effects. Other requirements under the CEA Act were also addressed including an assessment of cumulative effects, an assessment of the effects of the environment on the project, follow-up monitoring requirements and consultation. Golder assisted Bell Aliant with its consultation process with federal and provincial agencies and the identification of other environmental approvals and permits required for the project. Golder helped Bell Aliant to achieve an expedited schedule and receive its approvals. Approvals of the three EAs have been received and the project is under construction.

3.1.6 Transmission Line Project Experience

Golder is currently working on the Dinorwic to Pickle Lake Transmission EA in northern Ontario, as described in Section 2.1.3 and has completed a number of other transmission-related EA projects across Canada. The following provides a sample of our experience:

- **Foothills Area Transmission Development Land Impact Assessment** – Calgary, Alberta (2010 to present); ENMAX. Golder completed a Land Impact Assessment for ENMAX to assess seven route options for development of a new 240 kV transmission line from the ENMAX service territory boundary to an existing substation in the City of Calgary. The scope of the assessment was developed to meet the regulatory requirements of the Alberta Utilities Commission. A GIS approach was used to assess the impact of the project on agricultural, residential, environmental and visual indicators. The results of the analyses will be used to identify the least impact route or routes.

- **Labrador Island Transmission Link Environmental Impact Statement** – Newfoundland and Labrador; (2010 to present); Nalcor Energy. Nalcor Energy retained Golder as the lead author for the development of an EIS to meet the requirements of the *Newfoundland and Labrador Environmental Protection Act* and the CEA Act for the Labrador Island Transmission Link Project. The Project includes the development of a 1,100 km long high voltage direct current power transmission line from Muskrat Falls, Labrador to Soldiers Pond, Newfoundland. This includes above-ground transmission towers on land, converter stations, electrode sites, and a 17 km submarine crossing of the Strait of Belle Isle.

- **Hanna Region Transmission Development** – Drumheller to Consort, Alberta; (2009 – present); ATCO Electric. Golder was retained by ATCO Electric to provide consulting services for numerous transmission facility projects included in the Hanna Region Transmission Development. The Hanna Region Transmission Development includes approximately 250 km of new 240 kV transmission lines, 100 km of new 144 kV transmission lines, 4 new substations and modifications to existing transmission facilities. Golder's scope for the various projects includes:

- **Route and Site Development and Selection:** study area definition, field data collection, preliminary route and site option development, route and site analysis and selection;
- **Consultation Support:** stakeholder information package development, open house support, key agency consultation;
- **Environmental Review:** regulatory review and environmental permit scoping; environmental field data collection program; data management and mapping; and
- **Application Preparation:** preparation of applications to the Alberta Utilities Commission, along with various other environmental permit applications.

- **Northwest Transmission Line (NTL) Project** – Terrace to Bob Quinn Lake, BC; (2006 – ongoing); BC Hydro. The project involves construction of a new 344 km, 287 kV transmission line between the Skeena Substation (near Terrace) and a new substation to be built near Bob Quinn Lake. Golder's role included preparation of a preliminary environmental overview of the NTL Project to identify environmental issues and constraints and to identify potential EA and permitting requirements and timelines. Provided senior technical review and comment on the draft Environmental Assessment Certificate (EAC) Application. Prepared a Construction Environmental Management Plan (CEMP), including detailed orthophoto alignment sheets showing environmentally-sensitive areas. Provided First Nations Consultation services through BC Hydro. On-going work includes development of a Habitat Compensation Plan.
- **Interior to Lower Mainland Transmission Project** – Coquitlam to Merritt, British Columbia, Canada; (2006 – ongoing); British Columbia Transmission Corporation. Project entails construction of a new 500 kV transmission line from the Nicola Substation (NIC) near Merritt, BC to the Meridian Substation (MDN) in Coquitlam, BC spanning a total length of approximately 255 km. Golder's role on the project includes EA and regulatory approvals for the proposed transmission line. In this regard, Golder has:
  - conducted and managed biophysical, cultural, and socioeconomic technical studies to satisfy environmental regulatory review and approval requirements;
  - completed a Heritage Resources Overview Assessment and Archaeological Impact Assessment for the Project corridor; and
  - prepared a preliminary CEMP, including detailed strip-maps showing environmentally- and culturally-sensitive areas.

  As well, Golder is currently serving as BC Hydro's Environmental Program Manager during the construction phase of the Project.
- **Brada to Lloydminster 230 kV Power Transmission Line** – Brada to Lloydminister; (1990); SaskPower. Evaluated several route options with GIS assistance, directed the field assessment of the preferred option, prepared and submitted the EIS for the approximately 200 km long power transmission line. Participated in the public open house meetings and subsequent public hearing process as the environmental representative for SaskPower.

In addition to the above, Golder has worked on a number of transmission-related projects for Hydro One, with over 30 projects completed from 1999 to the present. These projects have ranged from Stage 1-4 archeological

assessments, to site drainage studies (with issue mitigation), to soil and materials testing services, to Phase II ESAs.

3.2 Study Team

For this project, staff from the Golder Sudbury office will provide their skills and experience in biological studies as part of the EA team, coordinated through our Thunder Bay Project office. Golder's complement of over 700 personnel within the Greater Toronto Area provide a wealth of resources to draw from, as required, during the EA including project management, bioscience, air and noise, geology and hydrogeology, stakeholder engagement, geotechnical and land management experts. Moreover, the project team can draw upon our colleagues in British Columbia, Alberta and Saskatchewan, who have a wealth of experience in transmission-related EA work.

The qualifications and experience for key project personnel, along with their allocated time commitment on the project, are indicated in Table 2. Full Resumes describing our key team members' experience are included in **Appendix A**.

Table 2: Golder Project Team

Individual	Project Role	Experience Highlights
Name: Dr. Anthony Ciccone **Qualifications:** Ph.D., P.Eng. **Address:** 141 Adelaide Street West Toronto, Ontario M5H 3L5	Dr. Anthony Ciccone will have corporate responsibility for ensuring the Project is completed according to our proposal.	■ Principal with Golder in Toronto ■ Canadian Power Sector Leader ■ Mechanical engineer with more than 30 years of experience in environmental consulting and expert testimony currently project director for multiple renewable and non-renewable power project EAs across Canada (gas-fired, wind, solar, biomass and waste-to-energy) ■ Currently Project Director of the EA for the New Transmission Line to Pickle Lake project. ■ Primarily responsible for stakeholder consultation, maintenance of client relationships
Name: Allen Eade **Qualifications:** B.Sc. **Address:** 2390 Argentia Road Mississauga, ON, L5N 5Z7	Mr. Eade will be overall Project Manager for this project and will lead the EA. Allen will also be responsible for overall budget and schedule implementation and tracking.	■ Senior Environmental Consultant with the Environment Management Division. ■ Has 15 years of experience in the environmental field including environmental impact assessment, regulatory permitting, environmental effects monitoring and environmental management planning in Canada, United States, Peru and Africa. ■ Has led or been involved in managing numerous major projects through applicable regulatory environmental assessment processes and World Bank requirements. ■ In this capacity, Mr. Eade identified regulatory permitting requirements, provided regulatory strategic advice, conducted public and regulatory consultation, prepared environmental impact assessment reports and managed multi-disciplinary environmental assessment teams. ■ Currently EA Manager of the EA for the New Transmission Line to Pickle Lake project. ■ Prepared the corridor routing option study as part of the alternatives analysis for the New Transmission Line to Pickle Lake project.
Name: Andrew Evers **Qualifications:** M.Sc. **Address:** 2390 Argentia Road Mississauga, ON, L5N 5Z7	Mr. Evers will assist Allen in the management of the project and will work with Ms. Beri on the corridor routing analysis.	■ Experience coordinating EA of power projects and renewable energy approvals ■ EA specialist on power, renewable and waste projects including development of Provincial ToRs, EA study reports, document review ■ Contributed to the preparation of the corridor routing option study as part of the alternatives analysis for the New Transmission Line to Pickle Lake project. ■ Project coordinator for the EA of the New Transmission Line to Pickle Lake project.

Individual	Project Role	Experience Highlights
Name: Caitlin Burley **Qualifications:** M.A.Sc., IAP2 Certification **Address:** Thunder Bay, ON	Caitlin, along with Ms. Papageorgiou, will be responsible for the preparation of the engagement materials for the routing analysis report workshop (Stage 2 workshop). She will also provide senior guidance on engagement strategy for this project and eventual EA.	■ Public Participation Specialist with an M.A.Sc. specializing in Risk Communication and Public Consultation and six years of experience in her field ■ Successfully managed engagement programs for numerous individual and class EA studies involving the construction/operation of a range of projects in accordance with applicable legislative requirements throughout Canada and abroad ■ Currently EA engagement lead for the New Transmission Line to Pickle Lake project. ■ Currently EA engagement lead for the Cliffs Chromite Project, responsible for providing advice and reporting on the EA engagement process with First Nation communities and stakeholders (public, agencies and NGOs) through a coordinated federal/provincial EA process
Name: Agni Papageorgiou **Qualifications:** M.Env.Sc. **Project Role:** Public Participation Specialist **Address:** 2390 Argentia Road Mississauga, ON, L5N 5Z7	Ms. Papageorgiou will be primarily responsible for the preparation of engagement materials for the routing analysis report for the Stage 2 workshop.	■ Cultural Sciences Consultant whose role at Golder is to coordinate Public Consultation and Aboriginal Engagement, and Socio-Economic Assessments in support of Environmental Assessments, Renewable Energy Approvals and other environmental applications and processes. ■ Has experience coordinating various levels of community and Aboriginal engagement, including planning and facilitation of public meetings and workshops, as well as reporting. ■ Responsible for research, data collection and report preparation for Socio-Economic Impact Assessments in support of international, federal and provincial Environmental Assessments. ■ Currently engagement specialist for the New Transmission Line to Pickle Lake.
Name: John Campo **Qualifications:** B.Sc. **Address:** 6700 Century Avenue Mississauga, ON, L5N 6A4	John will be leading the preparation of GIS and mapping deliverables for the Stage 1 and Stage 2 report and support the technical routing study analysis.	■ GIS analyst highly skilled in compiling, processing and managing spatial and remote sensing data ■ Experience in mapping for environmental and social issues, scoping, baseline studies, impact assessments and management plans for local and international projects ■ GIS support for the EA and the corridor routing analysis for the New Transmission Line to Pickle Lake project.
Name: Robert Mellow **Qualifications:** H.B.Sc.	Mr. Mellow will act as Senior Aquatic Specialist and will attend the meeting with DFO and provide input into the routing study analysis from an aquatic ecology perspective.	■ Has over 13 years of experience working for Golder, with a focus on aquatic biology and projects that are typically related to providing clients with documentation to support the environmental assessment and regulatory permitting processes associated with mining, hydro-electric and corridor (i.e.

Individual	Project Role	Experience Highlights
Address: 1010 Lorne Street Sudbury, ON, P3C 4R9		transmission line) development projects. ■ Has experience in emergency response and with contaminated site investigations and has used this knowledge to assist in coordinating emergency environmental response services to Golder's rail transportation clients in Northeastern Ontario. ■ Has specific work experience related to Environment Canada's Metal Mining Effluent Regulations and associated environmental effects monitoring (EEM) programs. ■ For the past nine years, Rob's aquatic science experience has been broadened by his involvement in a Lake Sturgeon (Acipenser fluvescens) spawning and habitat study on the Groundhog River for Xstrata Nickel's Montcalm Mine.
Name: Brad Walker **Qualifications:** M.Sc. **Address:** 1010 Lorne Street Sudbury, ON, P3C 4R9	Brad will be the Senior Terrestrial Ecologist and will attend the meeting with MNR and provide input into the routing study analysis from a terrestrial ecology perspective	■ Experience in environmental permitting of road, pipeline and transmission corridors ■ Led biological investigations of aquatic and terrestrial communities including terrestrial studies for the Cliffs Chromite and Bell Aliant projects in Northern Ontario. ■ Senior terrestrial ecologist for EA of the New Transmission Line to Pickle Lake project. Developed environmental criteria and analysis of species at risk in support of the corridor routing analysis for this project.
Name: Carla Parslow **Qualifications:** Ph.D. **Address:** 2390 Argentia Road Mississauga, ON, L5N 5Z7	Ms. Parslow will be the Senior Archaeologist and will provide review and input into the routing study analysis from an archaeology and heritage resources perspective.	■ Senior Archaeologist with Golder with over 15 years of experience in the field of archaeology and Aboriginal consultation as well as managing Environmental Assessments within Ontario and liaising with government bodies. ■ Responsible for the coordination, technical review and quality assurance of archaeological, Aboriginal consultation and cultural heritage projects.

“Exhibit D”

Services and Project Capabilities

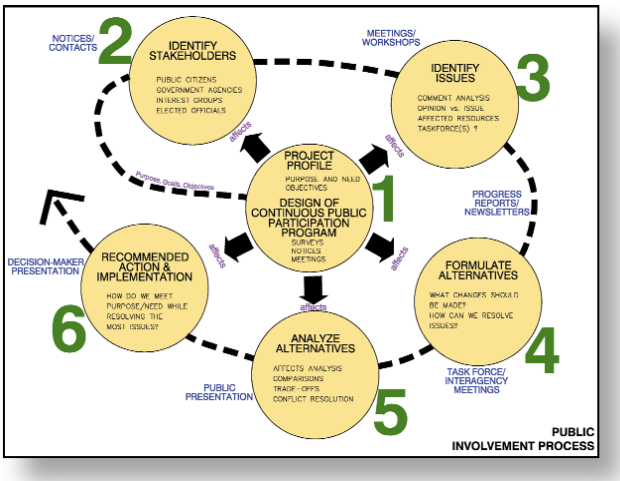
kp environmental, LLC (kpe) is a women-owned business certified by the California Public Utilities Commission (CPUC) VON#8EN00030, specializing in Environmental Project Management, Environmental Permitting, Utility Development Project Strategic Planning, Environmental Compliance and Construction Monitoring and Public Process Planning and Public Outreach/Relation Efforts. Capabilities include providing technical expertise in all natural resource areas as well as providing GIS and data management services.

kpe specializes in power generation, linear corridor and right-of-way assessment, siting, acquisition, permitting, easements, government and construction compliance. kpe has conducted environmental assessments, public participation programming, land use planning and zoning, and socioeconomic planning. kpe has obtained federal, state, and local approvals for a variety of projects and is familiar with local government zoning processes, state regulatory requirements throughout the United States, and federal compliance requirements for EISs, EAs, and ERPs that have been for FERC, BLM, USDA Forest Service, BOR, BIA and COE.



Through developed teaming arrangements with colleagues, kpe has brought together the brightest and best team of individuals in the industry. kpe's teamwork and close working relations with clients, has resulted in environmentally feasible, cost-effective solutions that balance project requirements with compliance needs. kpe has full service capabilities to conduct analysis and complete the following types of documents:

- Environmental Impact Statements
- Environmental Impact Reports
- Environmental Assessments
- Environmental Analysis
- Fatal Flaw Analysis
- Siting and Routing Studies and Reports
- Environmental Monitoring and Construction Documentation (POD/COMP Plans)
- Environmental Mitigation Planning and Implementation



Public and Stakeholder Outreach

kpe has developed Public Participation Programs (PPP) and facilitated public consultation processes, public workshops and meetings both internationally and domestically. PPP's have included development of public outreach programs, stakeholder identification and coordination, NGO and elected official coordination, environmental education, development and publication of newsletters, interface with media and neighbors. kpe

specializes in developing public involvement programs for generation and transmission projects and has coordinated/attended over 75 public process venues which totals over 600 public process meetings.

kpe has significant experience conducting environmental compliance monitoring for construction projects. This includes biological and cultural monitoring as well as environmental compliance coordination for power projects and transmission utilities in California and Arizona. We conduct health and safety and field crew management and environmental training. kpe also develops environmental mitigation plans and construction documentation to ensue compliance with regulatory environmental mitigation on projects. We understand the importance of not only getting a project through environmental permitting but ensuring all mitigations are implemented properly to avoid regulatory non-compliance issues and fines.

Expert Witness Testimony

Kenda Pollio, Principal of kpe, has provided expert witness testimony before the Arizona Transmission Line and Power Plant Siting Committee, California Public Utilities Commission and the Public Utilities Commission of Texas in the following cases:

- Arlington Valley Solar Energy Project – LS Power
- Arlington Valley Solar Energy Project II – LS Power
- Solana 230 kV Transmission Line Project – Abengoa Solar
- Sundance to Pinal South 230 kV Transmission Line Project – APS
- Desert Basin Power Plant to Pinal South Substation 230KV Transmission Line Project – SRP
- Palo Verde to Pinal West 500 kV Transmission Line – SRP
- Pinal West to Southeast Valley/Browning 230/500 kV Transmission Line – SRP
- Agua Caliente Solar Project – Nextlight
- Q43 Substation -- APS
- Coolidge Generating Station – TransCanada
- Sunrise Powerlink 500kV Transmission Project – SDG&E
- Cottonwood to Dermott 345 kV – WETT
- Scurry County to Long Draw 345 kV – WETT
- Long Draw to Grelton 345 kV -- WETT
- Grelton to Odessa 345 kV – WETT
- Long Draw to Sand Bluff 345 kV -- WETT
- Sand Bluff to Divide 345 kV -- WETT
- Sand Bluff to Bearkat 345 kV WETT
- Arizona Solar 1-Solana Generating Station – Abengoa Solar
- Wellton-Mohawk Generating Facility – York Research

Environmental Impact Analysis Experience

We have conducted research and impact analyses for all environmental resources. The depth and level of detail of these analyses varied with the nature of the project and its location. The following summarizes our relevant technical expertise and demonstrates our ability to conduct interdisciplinary analysis.

Aesthetic Resources

We have conducted visual resource assessments using a variety of methods. Utilized the Visual Resource Management (VRM) system and the Visual Management System (VMS) used on some federal lands. Prepared visual assessments using computer, photo and video simulations. Developed landscape plans to minimize impacts.

Air Quality

We have completed air quality and meteorological data collection using a variety of field equipment. Conducted air quality modeling using a variety of available models including FDM, ISC, VALLEY, CALINE, MOBILE4, and others. Also developed and specified mitigation measures using BACT and determined compliance with state and federal air quality regulations.

Fish, Wildlife, and Botanical Resources

We have conducted baseline data collection and long-term monitoring for fish, wildlife, wetlands, and botanical resources. Conducted habitat surveys (HEP, IFIM, etc.), population surveys, and developed mitigation plans. Conducted surveys for threatened, endangered, and sensitive species and prepared Biological Assessments (BAs) to satisfy the requirements of the Endangered Species Act. Coordinated extensively with the USFWS, the National Marine Fisheries Service, state wildlife agencies, state natural heritage programs, and others. Much of this has been done in compliance with the Fish and Wildlife Coordination Act. Conducted many wetland surveys and developed mitigation plans in consultation with the Corps, EPA, USFWS, and state wildlife agencies.

Geology and Soils

We have conducted detailed geological and soils inventory and mapping programs, utilizing subsurface and surface inspection. Developed estimates of erosion and sedimentation using models such as USLE and SEDCAD. Prepared erosion and sediment control plans. Coordinated efforts with the USGS, state geological surveys, Natural Resource Conservation Service, and local and federal land management agencies. Also prepared detailed reclamation plans.

Hazardous Materials/Risk Assessment

We have completed hazardous materials site assessments to ASTM standards. Conducted risk evaluations using industry data and statistics to determine accident probabilities. Conducted transport analyses/modeling to determine fate of released materials.

Historic and Archaeological Resources / Tribal Issues

We have conducted surveys for historical, cultural, archaeological, paleontological and ethnographic resources. Conducted literature reviews, field surveys, and mitigation. Assisted in the development of Programmatic Agreements among agencies to ensure compliance with Section 106 of the National Historic Preservation Act. We coordinated activities with Native American groups through consultation and formally through ethnographic studies. We coordinated activities with federal land management agencies, and State Historic Preservation Offices (SHPOs), and the Advisory Council on Historic Preservation.

Land Use

We have conducted land use surveys using existing data and aerial surveys. Evaluated consistency with federal land management plans under the Federal Land Policy and Management Act (FLPMA) and evaluated state, county, and city/town land use plans and zoning policies. Developed site and local land use plans and assisted in the preparation of federal and regional plans. Evaluated the direction of special land management areas such as wild and scenic rivers, wilderness areas, state and local parks, natural areas, monuments, and others.

Noise

We have conducted noise surveys and modeling. Models were run to satisfy the requirements of FERC, HUD, and local planning ordinances.

Recreational Resources

We have conducted recreation data collection by doing facilities surveys and designing/implementing user surveys. Also used the Recreation Opportunity Spectrum (ROS) that was used to classify some federal lands. Developed site recreation plans and conducted feasibility studies for recreation projects. Conducted preliminary eligibility and compatibility studies for rivers being considered under the Wild and Scenic Rivers Act. Determined compatibility with State Comprehensive Outdoor Recreation Plans (SCORP) and federal and local plans.

Socioeconomics

We have prepared socioeconomic studies to determine impacts to population, services, infrastructure, employment, income, tax base and transportation and worked closely with state and local governments to generate accurate data and used a variety of economic models to predict impacts. We have also assisted in the development of land use plans for local governments and federal agencies.

Water Use and Quality

We have conducted baseline data collection and monitoring for both surface water and groundwater using a variety of sampling methodologies. Prepared impact analyses using several different surface and ground water quality and hydrology modeling programs including

BETTER, WQRRS, SEDCAD, HEC, MODFLOW, NT3D, VS2DT, and others. We have also prepared 404 Permits, 401 Certificates, NPDES permits, and stormwater permits and worked closely with state water quality agencies, the EPA, USGS, and water user groups.

GIS Capabilities

We have significant experience using ArcInfo-based Geographic Information Systems (GIS) to conduct project analyses and to prepare graphics to convey information to the public. We have conducted comprehensive GIS analyses for nearly all large projects we have completed.

We utilize a wide variety of software and data formats to meet the needs of our clients. Most GIS efforts are completed through ArcInfo or ArcView in the ArcGIS suite of software from ESRI (Environmental Systems Research, Inc.) operating in a Windows environment. Incorporating ESRI extensions such as Spatial Analyst and 3D Analyst provides greater flexibility for both analysis and illustrative purposes.

In addition to several ESRI software products, and AutoDesk's Land Development Desktop, we employ other tools such as Microimages' TNT mips (v.6.9) image processing software and 3D Nature's World Construction Set (v.6) to create high resolution terrain models, computer simulations, and animations.

ESRI 8.3 is the current software standard we use for GIS data. With many different tools at our disposal, we have the ability to convert georeferenced digital data to a format compatible with ESRI products and ESRI 8.3 format specifically. Once converted, this data may be incorporated into an easily transferable geodatabase for use within ArcGIS. Working with data obtained from a variety of sources and in various projections, parameters, and file formats (.dem, .bil, dwg, shapefiles, etc) is common and is converted to ESRI 8.3 routinely.

Web-Based Project Management System

We have developed a web-based project management system to use on comprehensive projects that allows real-time sharing of up-to-date project data among members of the project team. We could make this tool available for a project if warranted by its duration and scope, the number of entities (agencies and proponent) that are involved, and the variety of their locations. This site would be customized as defined by the project management team regarding the amount and type of data to include .The site can be designed with varying levels of access if you want some information available to all and other information available to only part of the project team. We can provide access to demo project management site if interested. In addition to managing information during the project, this system also provides an effective way to develop and maintain the administrative record that is required.

Additional Information

kpe understands the importance of location, schedule, and quality assurance and their correlation to the success of a project.

Location – kpe recognizes the value of maintaining a strong local presence as well as including knowledge and capacity for current projects and practices in surrounding regions. For that reason, kpe's main offices are centrally located in Cardiff by the Sea, California, Phoenix, Arizona, and Austin, Texas, allowing our staff to be flexible and readily available to suit the needs of our clients and their projects.

Schedule – kpe realizes the significance of schedule and timing. We are knowledgeable of federal, state, and local permitting timelines and strive to ensure that all project timelines are upheld to allow for timely completion of permitting that will meet project timing goals. For this project specifically, our staff has extensive experience working with the California Public Utility Commission and their schedules.

Quality Assurance – kpe prides itself on the production of quality documents in a timely manner. kpe will follow appropriate technical and procedural standards for all environmental data collection efforts, reports, and other work conducted. All deliverables are reviewed to check the technical information the author presents, evaluate the accuracy of the information, and verify that the information presented addresses all requirements in the statement of work. In addition, all deliverables are edited to improve the readability and clarity of the document, and verify that authors have followed any required formats.

Email: kpollio@kpenvironmental.com I Phone Number: 602-909-2636

“Exhibit E”

Environmental Approvals/Permits

The table below contains a preliminary list of environment approvals and permits and is provided below for illustrative purposes. This preliminary list is not an all-inclusive or exhaustive list, but represents those provincial/federal permits and approvals likely to be required prior to project construction to enable field studies to support the environmental assessment process, detailed engineering design and activities associated with pre-construction site preparation. In this regard, the list would be refined as the environmental assessment and/or design process progresses.

Agency	Applicability to the Project
Ministry of the Environment (MOE)	■ Approval of the Category C EA required pursuant to O. Reg. 116/01 *Electricity Projects* to satisfy the Ontario *Environmental Assessment Act* (1990). ■ Permit to Take Water under the *Ontario Water Resources Act* (1990) if Project construction requires taking more than 50,000 litres (L) in a day from a lake, stream, river or groundwater source. Likely required for winter ice bridge construction over water courses. ■ Approval under the *Health Protection and Promotion Act* (1990) to facilitate provision of potable water, and on-site sewage treatment and disposal systems at temporary construction camp(s). ■ Environmental Compliance Approval under the *Environmental Protection Act* (1990) to enable waste to be transported by haulers from the Project work site, and to enable emissions from on-site equipment. ■ Environmental Compliance Approval under the *Environmental Protection Act* (1990) for noise generation if a transformer to step down 230 kV to 115 kV is needed ■ A Generator Registration Number is required under O. Reg. 347 of the *Environmental Protection Act* (1990) in the event Hazardous and Liquid Industrial Wastes are generated during Project construction.
Ministry of Natural Resources (MNR)	■ Permit under Section 17 of the *Endangered Species Act* (2007) if the project affects a listed species or its habitat. ■ Permit to Collect Fish for Scientific Purpose under the *Fish and Wildlife Conservation Act* (1997) to facilitate the capture and transfer of fish during in-water works such as cofferdam construction or dewatering. ■ Permit to Collect Wildlife for Scientific Purpose under the *Fish and Wildlife Conservation Act* (1997) to facilitate the capture and transfer of wildlife. ■ Authorization to Conduct Research in Ontario Protected Areas from the Park Superintendant (if works required within Provincial Parks). ■ Authorization under the *Fish and Wildlife Conservation Act* (1997) in the event Project construction/operation is anticipated to destroy the nests or eggs of

Agency	Applicability to the Project
	birds, a beaver dam, or the den of a black bear or some furbearing mammals, or interfere with a black bear in its den. ■ Forest Resource Licence (Cutting Permit) is required to harvest and/or cut timber on Crown land under the *Crown Forest Sustainability Act* (1994). ■ Burn Permit under the *Forest Fires Prevention Act* (1990) to enable burning of materials from forest clearing, if required. ■ Work Permits under the *Public Lands Act* (1990) to authorize works on public lands and/or shore lands including geotechnical investigations, construction/upgrade of access roads and trails, culverts/bridges, and transmission lines. ■ Land Use Permits required for transmission line, access roads (to and within the Project site) and for temporary laydown and/or spoil areas. ■ Aggregate Permit under the *Aggregate Resources Act* (1990) to extract aggregate on all Crown land and also on private land in areas of the province designated (identified) in the regulations. ■ Approval to develop Project crossing Provincial Park area if required pursuant to *Provincial Parks and Conservation Reserves Act* (2006). ■ Licence of Occupation under the *Public Lands Act* (1990) as construction works are to occur on Crown lands.
Ministry of Transportation (MTO)	■ Encroachment Permit in the event overhead transmission line is to be constructed over or within the right-of-way of a Provincial Highway. ■ Temporary Road Entrance Permit in the event that an entrance from a highway is required for access to a construction site.
Ministry of Labour	■ Notice of Project under Section 23(2) of the *Occupational Health and Safety Act* (1990).
Ministry of Municipal Affairs and Housing (MMAH)	■ Potential for the Project to be located on unorganized territory. Letters of Conformity or Zoning Conformity Permits required for areas located in unorganized townships.
Ministry of Tourism, Culture and Sport	■ Archaeological assessment to be conducted as part of the EA under the *Ontario Heritage Act* (1990).
Ontario Energy Board (OEB)	■ Approval of Leave to Construct application.
Federal	
Environment Canada	■ Site specific permit from the Canadian Wildlife Service under the *Migratory Birds Convention Act* (1994), Migratory Birds Regulation. ■ Permit under Section 73 of the *Species at Risk Act* (2002) if project activities

Agency	Applicability to the Project
	affect a species listed under the Act, or its habitat.
Parks Canada	■ Authorization to use the existing transmission line right-of-way in a National Park under the *Canada National Parks Act* (2000)
Fisheries and Oceans Canada (DFO)	■ Authorization under the *Fisheries Act* (1985) for harmful alteration, disruption and/or destruction (HADD) of fish and fish habitat, related to in-water works such as blasting, cofferdam construction and/or diversion of water flows. ■ DFO Operational Statements apply for temporary stream crossings. ■ Letter of Advice if proposed in-water works relating to temporary or permanent water crossings do not result in destruction of fish habitat.
Transport Canada	■ Formal approval under the *Navigable Waters Protection Act* (1985) if Project construction involves works within a navigable waterway and is likely to substantially interfere with the public right to navigation. ■ Aeronautical Obstruction Clearance for Height Hazards issued by Transport Canada in the event the transmission line is located in the vicinity of a federal airport.
Aboriginal Affairs and Northern Development Canada (AANDC)	■ Aboriginal Affairs and Northern Development Canada (AANDC) must authorize activities on First Nations reserve lands by means of Section 28(2) of the *Indian Act* whereby: *"The Minister may by permit in writing authorize any person for a period not exceeding one year, or with the consent of the council of the band for any longer period, to occupy or use a reserve or to reside or otherwise exercise rights on a reserve."* ■ This would be the case if the Project is located on First Nations reserve lands.
Other	
Canadian National Railway (CN)	■ Clearance Letter for crossing of CN rail line, if required.
Canadian Pacific Railway Limited (CP)	■ Clearance Letter for crossing of CP rail line, if required.
Local Municipality	■ Building Permits in accordance with *Building Code Act* (1992) and by-laws of relevant municipality. ■ Changes to zoning by-laws under the *Planning Act* (1990) for areas located in organized territory.

“Exhibit F”

LUIS GARCIA-MONGE PIEDRA

[redacted]



PROFESSIONAL EXPERIENCE

Jan - 2008 Present	▪ **ISOLUX CORSAN CONCESIONES** Operational Director of the Isolux's power transmission lines concessions in Brazil: Linhas de Xingu, Linhas de Macapa Transmissora de Energia and Linhas de Taubate Transmissora de Energia. Member of the Executive Board of the Isolux's power transmission lines concessions. • Management of the construction process of the transmission line and substation. • Management of the environmental and land and right of way. Environmental license covering "EIA/RIMA", Preliminary Permit, Installation License and Operation License • Coordination of the engineering. Basic project and executive project • Planning, Schedule and Control cost • Coordination meeting with ANEEL, ONS and MME • Analysis of the power system of Brazil (Generation and Transmission). • Develop of specific methodology of CERs for Interconection of Isolated Systems. • Preparation of Transmission Lines Auctions.	Rio de Janeiro, Brazil
Apr – 2007 Jan - 2008	▪ **IBERINCO** Senior Engineer in the Nuclear Generation Department. • Heat Generator extraction of Nuclear Power Plant Angra 1, Brazil • Project Manager of the substitution of the Heat Exchanger of the Nuclear Plant Cofrentes, Spain.	Madrid, Spain
Dec – 2006 Apr – 2007	▪ **IBERINCO** Senior Engineer in the Construction Generation Department. • Bid preparation of Combined Cycles and Hydraulics power units. • Tender documents of civil works bidding, Hydraulic power units La Muela II.	Madrid, Spain
Aug – 2000 Dec – 2006	▪ **SOCOIN** Engineer in the Generation Department. • Project Manager EPC of the Hydraulic Power Plant of Santa Rosa (18 MW) La Paz, Bolivia. • Project Manager EPC of the Hydraulic Power Plant of Santa Isabel (21 MW) Cochabamba, Bolivia. • Technical projects of Hydraulics plants en South and Center America • Viability studies of Hydraulics plants en South and Center America	Madrid, Spain and Bolivia
Jun – 1998 Aug – 2000	▪ **SOCOIN** Intern in the Generation Department.	Madrid, Spain

FORMAL EDUCATION

	Civil Engineer – Ingeniero Superior de Caminos, Canales y Puertos en la Escuela Técnica Superior de Ingenieros de Caminos, Canales y Puertos de la Universidad Politécnica de Madrid. Especialidad en Cimientos July 2000.	Madrid, Spain

LANGUAGES

Spanish	Mother tongue
English	High level, spoken and written
Portuguese	High level, spoken and written

ADDITIONAL INFORMATION

IT	Word, Excel, PowerPoint, Autocad, Microsoft Project and Primavera Project Planner, Sispre, Hydraulics Aplications (Hec-Ras, Flowmaster, Hcanales y Dyagats), Calculation programs (GT Strudl)
2011	Qualified Finance for No Financier, Tecnológico de Monterrey
Sep-2007	Course Begining to Negociate
Mar-2007	Technical course GT Studl
Mar-2007	Prevention in Laboral Risks, 50 hours
May-2002	Regulation in Hydraulics Turbines
Mar-2002	Management of Projects, Shedule-Budget-Measurement
Feb-2002	Calculation if Channels in Variable Regimen, program Mike 11
Mar-2001	Similation of Operation of Hydraulic Units
Mar-2001	Project Planning, Primavera Project Planner program
Apr-2000	Introduction to the magement of companies
Oct-1998	Health and Safety course

Fully qualified Civil Engineer, Spain, Association of Civil Engineers , registration 17.010

CURRICULUM VITAE

Name - **Ailton Costa Ferreira**
Nationality – Brazilian (Belo Horizonte – MG)

Education – Bachelor's Degree, Electrical Engineering
(Graduated by Minas Gerais Catholic University – January /1968, CREA SP 29.221/D.)

Professional Development:

- Economical Engineering – Dom Cabral Foundation – Minas Gerais Catholic University
- ABB Executive Development Program – Dom Cabral Foundation – Minas Gerais Catholic University
- Total Quality Control (TQC)
- Analysis to reduce losses in power's systems – ABB Ludvika (Switzerland)
- Operation and maintenance in power's systems – Furnas Cerntrais Elétricas

Professional Experience:

1) August 2008 – Currently, Isolux Corsán S.A.

General Manager of the following Power Transmission Concessions:

- Cachoeira Paulista Transmissora de Energia S.A. – In operation since November 2004
- Linhas de Xingu Transmissora de Energia S.A.- In the construction final stage
- Linhas de Macapá Transmissora de Energia S.A. – In the construction final stage
- Linhas de Taubaté Transmissora de Energia S.A. – In the stage of environmental permits

CEO of Concessionaires with Isolux shareholding:

- IENNE – Interligação Elétrica Norte Nordeste – In operation since December 2010.
- Jauru Transmissora de Energia S.A. –
  (i) Tramo Sul – In operation since August 2009
  (ii) Tramo Norte – In the stage of implantation

2) February 2003 - August 2008 - PLENA TRANSMISSORAS

Technical Director of 12 Concessionaires of Plena Transmissoras (Isolux Corsan, Elecnor and Cobra), being responsible for the development, among others, the following main activities:

Basic design and Construction Project
Rate of way complexion
Environmental licensing, covering EIA/RIMA, ALS, Installation and Operation License
Share Coordination Contracts, in the National Basic Network Interconnected System
Monitoring, implementation and commissioning of all erection works
Operation and maintenance of transmission systems from inputs into commercial operation
Transmission Lines and Subestations

Expansion –
ETIM – Transmision Itumbiara Emborcacao
CPTE – Cachoeira Paulista Transmissora de Energia
VCTE – Vila do Conde Transmissora de Energia
ITE – Itumbiara Transmissora de Energia
PPTE – Porto Primavera Transmissora de Energia

SMTE – Serra da Mesa Transmissora de Energia
LTTE – Transmissora de Energia
SPTE – Serra Paracatu Transmissora de Energia
RPTE – Ribeirao Preto Transmissora de Energia
PCTE – Pocos de Caldas Transmissora de Energia

3) November 1994 – January 2003 - ABB - Asea Brown Boveri.

Director of Technical Business Development, Power Systems Division, directly responsible for technical and commercial negotiations with various customers of the electricity sector, covering metal structures, transmission lines and substations in 500 kV equipment and Systems Protection, Control and Monitoring transmission systems.

From June 1997 to December 1999, moved to ABB Chile as Director of Construction of T&D.

4) January 1980 to October 1994 - SBE – Sociedade Brasileira de Eletrificação S.A. (Brown Boveri Group)

Commercial Manager and Commercial Assistant Director, responsible of all contract negotiations, especially metal structures, supply of materials, equipment and services for transmission lines and substations.

5) January 1968 to December 1979 - SADE - Sul Americana de Engenharia – General

During his early years as engineer he worked as Works Chief Engineer, executing the most diverse works of industrial installations, substations and transmission lines.
He participated in the construction of various engineering projects in Peru and Colombia, and also in projects between Sade Brazil and its parent.

Rio de Janeiro, December 2012

Evandro Cavalcanti

[redacted]

Objective

Position of Director or General Manager.

Summary

Electrical Engineer since 1993 with 20 years of experience working on international companies as executive, business manager, project manager, services provider, technical sales supervisor, and works coordinator.

Academic Background

Graduation

Electrical Engineer at UFRJ – Federal University of Rio de Janeiro, march of 1993.

Post graduation - specialization

Elaboration of Technical sales proposals for protection and control systems, ALSTOM, Montpellier, France, august of 2003.

SPACE2000 Scada System of remote control and supervision for substations, ALSTOM, Montpellier, France, october of 2002.

Digital Protection, Control and Monitoring, GE Company, Philadelphia, November of 1997.

Post graduation - MBA

MBA for Project Management, 400 hours, in Chile, Peru, Uruguay, from february of 2006 until february of 2008, Global Group (www.globalgroup.es/)

Complementary studies

Oratory, Rogéria Guida, Rio de Janeiro, april of 2008.

Quality - Six Sigma Commercial – Green Belt, General Electric, São Paulo, july of 1999.

Languages

Portuguese: Native Language

English: Advanced

Spanish: Advanced

French: basic notions

Professional Background

JTE - JAURU TRANSMISSORA DE ENERGIA SA - since april of 2011

Spanish consortium focused on energy and construction (Isolux, Cobra, Elecnor)

TECHNICAL DIRECTOR

Director of public utility electric power transmission, responsible for all processes of implementation, operation, maintenance, reporting to the company's Board of Directors and Council at Spain;

Responsible for Concessionaire JTE:
- Resumption of the process of obtaining permits for construction of the northern section of the stage;

- Collection and maintenance of Environmental Permits (LI, LO);

- Technical management and support to financial for the turn-key EPC system of over 200 million dollars along with monitoring the management and periodic visits to places of work;

- Deployment and management throughout the company head office with 11 employees;

- Management of the regional office of the operation and maintenance in Rondônia with 23 employees;

- Management of the budget other contracts to provide services to the utility value of more than 20 million dollars;

- Support the Board in the financial long-term financing from BNDES and short-term private banks;

- Management of the Concession Agreement with Aneel, ONS with Service Delivery, Share with Eletronorte and all other company;

- Preparation and submission of monthly reports to the executive officers in Brazil and the members of the board of the company in Spain;

www.jaurutransmissora.com.br (public financial statements and photos)

ABENGOA BRAZIL – from june of 2004 to march of 2011

Spanish company focused on energy and construction

Public Concessionaires with national presence in Electrical Energy Transmission on the 500 kV of the brazilian national grid. Technical management of Concessionaires that pertain to ABENGOA, working on the basic project, the implantation, preoperational, beginning of the commercial operation, operation and maintenance, research and development, technical responsibility at brazilian inspectors (CREA) at the States from north to south (RJ, PR, SP, BA, PI, MA, TO), representing at federal agencies as ANEEL, ONS, information on development of works at the Federal Ministry of Energy MME, contractor of companies for services, contractor of consultants and preparation of the teams of engineering, operation and maintenance.

www.abengoabrasil.com

IMPLANTATION MANAGER

From 2010 until march 2011: responsible conjunctly with partners for implantation of the concessions of Manaus, Pré-Madeira and Madeira totaling 4.000 km of transmission lines and substations on 500, 230 kV AC and 600 kV DC, meaning investments of billions of brazilian reals; emphasizing the biggest transmission line in the world in project with 2.400 km (TL 600 kV CC from Porto Velho at Rondonia to Araraquara at São Paulo); responsible for all of the expansions of own substations and of the new ones coming from public auctions (when 100% of Abengoa);

TECHNICAL IMPLANTATION DIRECTOR

From 2008 to 2009: as Technical Implantation Director, responsible of the implantation of the System Operation Center (remote in Rio de Janeiro) and the implantation of the public concessions of ATE IV, ATE V, ATE VI, ATE VII, two expansions at ATE II, one expansion at ATE VI, one expansion of ATE VII, totalizing 450 km of transmission lines and substations on 500 and 230 kV; with the own team of engineers: 2 seniors engineers for project coordination, 3 young engineers and trainees and 4 technicians as inspectors of works at field;

TECHNICAL DIRECTOR

From 2004 to 2007: as Technical Director, total responsible for all activities described above for the public concessions of ATE, ATE II, ATE III, totalizing 1.740 km of transmission lines and 10 substations on 500 kV; emphasizing the investment of ATE II of 1 Billion on brazilian reals occured along of 24 months having this EPC – Engineering Procurement Company - subcontracted 4.000 people at the peak of works on the turn-key; and other contracts directly managed by the concessionaires; emphasizing the contracts with partners for operating and maintenance services approximately 120 people and 3 managers;

ALSTOM and AREVA T&D Brazil – from march of 2002 to may of 2004

French, Britain and Germany Company focused on digital systems for managing transmission and distribution of energy

World leader on solutions of protection, supervision, command and remote control for transmission and distribution of electrical energy.

www.alstom.com/brazil/pt/

SYSTEMS SALES SUPERVISOR

Technical sales supervisor doing technical and commercial proposals, presentations, and trainings at France on tools for mounting standard proposals; emphasizing the 'beat' of the annual objectives of all T&D team on the first 3 months of the year of 2004;

Technical and Commercial proposals for Energy Concessions of Transmission and Distribution (from ~200k to 30Million of brazilian reals – Mi BRL).

PROJECT COORDINATOR

Project Coordinator of protection, supervising, command and control systems working for customers at the stages of basic and executive projects, training the customer, projecting and be trained at the factory in France improving on the products and systems;

Technical Coordinator for projects of 6 substations on 500 and 230kV of Eletronorte (Retrofit Maranhão ~60Mi BRL), 16 substations on 138, 25kV and 13.8 kV of Light-RJ (COR2 ~20Mi BRL), and Bom Despacho substation of 500kV of CEMIG (~5Mi BRL).

EFACEC BRAZIL – from september of 2000 to march of 2002

Portuguese company focused on digital supervisory, command and protection, and remote control systems

World leader on solutions of protection, supervision, command and remote control for transmission and distribution of electrical energy.

www.efacec.com.br/mundo.php

SYSTEMS ENGINEER

Execution of configuration, standardizing, simulation tests, hardware preparation and implantation of the digital systems for substations of distribution and the centralized center of operations; emphasizing all of the 105 substations on 138, 69 and 13.8 kV of AMPLA and its center of operations (COS); and emphasizing the 'line of production' with customer approval of each local supervisory and protection systems for those substations;

GENERAL ELECTRIC BRAZIL – from august of 1997 to september of 2000

United States, Canadian and Spanish company focused on digital protection and control systems for managing transmission and distribution of electrical energy

World leader on solutions of protection, supervision, command and remote control for transmission and distribution of electrical energy.

APPLICATION ENGINEER

• Technical coordination of projects of protection systems for substations – sector of customer from concessionaires of energy;

• Coordination of contracts of projects and panels mounting;

• Customer care: chronogram, developing and following projects;

• Specialization training at the factory;

• Meetings and phone conferences with the factories (USA, Canada and Spain) - application;

• Customer training on the digital protection systems with elaboration of didactical material

See example at GE website:

http://www.gedigitalenergy.com/products/presentations/dffpo.pdf

• Main projects: Eletrosul´s Santo Ângelo substation 500/230kV (1999 ~2Mi BRL); Eletronorte´s Boa Vista substation 230kV interconnected to the city of Santa Elena de Uairén Venezuela (1998 ~1Mi BRL) and the Tramo Oeste project (Tucuruí) 500/230kV (1997/98 ~4Mi BRL);

• Emphasizing the Santo Ângelo ELETROSUL´s substation that was constructed in a record time of 6 months;

ANSETT TECNOLOGIA – from may of 1997 to july of 1997

Brazilian company focused on 'inteligent' buildings and digital security systems

Well-known company focused on digital security systems for patrimonial and industries

COORDINATOR ENGINEER

• Works coordinator for the Glaxowelcome factory, responsible for the automation systems at the site;

• Monthly report meetings with the managers from England;

• Acceptance of all infra-structure materials to be used at the site;

• Coordination of the Projects;

• Coordinator of the AutoCAD technician operator;

• Coordinator of the technician of "Primavera" software;

• Coordination with the project team at the main office at São Paulo-SP and meetings with the manufactures of the systems;

• Coordinator of the local team composed by one engineer, one technician and 32 assemblers;

• Involved Systems: central air conditioning and fan coils; fire detection and alarm; CCTV; card access control; vehicles counting; control of electrical consumption; substation supervision, clean rooms.

JOHNSON CONTROLS – from august of 1993 to april of 1997

USA company focused on 'intelligent' buildings and air conditioning

World leader on solutions for commercial buildings, shopping centers and industries;

RESIDENT ENGINEER

• Executor of the projects for installation of Comfort, Security and other systems;

• Coordinator of the installation teams;

• Executor of the Commissioning;

• Executor of the Customer training;

• Executor of the As Built project;

• Acquire the Final Acceptance Customer Certificates;

• Responsible of the installation team composed by 2 technicians and teams with 5 to 10 assemblers;

• Involved Systems: central air conditioning and fan coils; fire detection and alarm; CCTV; card access control; vehicles counting; control of electrical consumption; substation supervision;

• Main projects: Iguatemi Shopping RJ (1996); O Globo newspaper RJ (1995/96); Expansion of Barra Shopping RJ (1994/95); Big Shopping MG (1994/95); Via Parque Shopping RJ (1993);

• Emphasizing the expansion of Barra Shopping with 300 stores, made in a record time f 6 months, exceeding the margin prevision, and without any over hour;

FURNAS CENTRAIS ELÉTRICAS – from january to july 1993

State company concessionaire of generation and transmission of energy

TRAINEE

Maintenance Department of High Voltage Transmission Lines.

GENERAL ELECTRIC BRAZIL – Factory of Eletromechanical Relays – from january of 1992 to december of 1992

USA company – factory of relays

TRAINEE

Application

Customer care

Accompanying tests

Organization of Technical files

AutoCAD drawer

FURNAS CENTRAIS ELÉTRICAS – from january of 1991 to december of 1991

State company concessionaire of generation and transmission of energy

TRAINEE

Maintenance Department of Power Generators.

Site visits accompanying hidrogenerators maintenances, breakers, transformers.

Other objectives

Place of work: preference to be based in Rio de Janeiro

Accept to work in different States or Countries.

Accept to travel for the company.

Complementary information

Experienced on international companies: American (GE, Johnson Controls), Canadian (GE-Multilin), French (ALSTOM), Portuguese (EFACEC) and Spanish (ABENGOA and GE).

International and National traveling.

Complementary graduated MBA.

Many other complementary training, techincals, sales, management.

Victor Jose Fretes Gallo

[redacted]

PROFESSIONAL EXPERIENCE

PLENA TRANSMISSORAS (Brazil) - Since 2007
- Role
  – O&M Director

TRANSENER SA (Brazil) – 2002/2007
- Role
  – CEO

SADE I.C.S.A (Argentina) – 1997/2000
- Role
  – Transmission line maintenance Responsible
  – Construction Responsible
  – Construction Responsible in Chaco, Corrientes, Formosa and Misiones

FLOUR DANIEL ARGENTINA – SADE (Argentina) - 1996
- Role
  – Supervisor assembly in the mining Bajo La Alumbrera – Catamarca – 220 kV – Electromecanical assembly and conections of the electrical bays.

IATE (Argentina) – 1992/1995
- Role
  – Technical representative and responsible for the construction of the following facilities:
    132/33/13,2 kV Substation – Apostoles – Província de Misiones.
    132/33/13,2 kV Substation and Urugua-i-Iguazú transmission line – Província de Misiones.
    Crossing of the 220 kV transmission – Posadas (Argentina) – Encarnación (Paraguay) above the Paraná River.

ELETRICIDAD DE MISIONES S.A (Argentina) – 1988/1990
- Role
  – Supervisor assembly of the 132 kV substation and commissioning of the power supply for the Uruga-i Dam

FORMAL EDUCATION

NACIONAL DEL NORDESTE Corrientes – 1980/1988 — Corrientes, Argentina
Electrical Engineer (Industry)

EDUCACIÓN TÉCNICA Nº 1 – 1975/1979 — Posadas Misiones, Argentina
Mechanical Technician

December 2012

LANGUAGES

Spanish	Mother tongue
English	High level, spoken and written
Portuguese	High level, spoken and written

ADDITIONAL INFORMATION

English Course (2001)
Rice Houston Texas University

Project costs and control/managing people (1999)
Madrid University in Buenos Aires

Design of transmission line bases (1997)
Córdoba University

ISOLUX CORSAN USA	**Juan Provvidente** **Title:** Vice President of Operations **Dept:** EPC **Reports To:** CEO	**Work Experience** 39 Years **Industry Experience** 39 Years

PROFESSIONAL EXPERIENCE

Vice President of Operations (acting as Project Manager for WETT)
Isolux Ingenieria USA, LLC | Austin, Texas | July 2009 to July 2011

Directed the opening of Isolux Ingeniería USA, LLC headquarters in Austin, Texas, USA. Searched, selected and recruited engineering, procurement, construction, planning and cost control, QA / QC, HSE personnel. Prepared the operating budget and developed WETT's first pre-budget run. Preparation of preliminary strategic plans for implementation of the WETT project. Provided local market analysis of engineering, equipment and construction contractors in detail for transmission lines and substations. Evaluated and selected primary contractors. Reviewed and completed basic engineering for the development of the WETT proposal. Prepared the technical proposal submitted for execution under an EPC contract of 300 miles of 345 KV transmission lines and five (5) switchyards on 345 kv switch for CREZ project.

Director of Operations
Techint SA de CV | Santa Fe, Delegación Álvaro Obregón, México D.F. | 1997 to 2009

- Since 2005. Nitrogen Separation Plant. MMSPCD two trains of 315 each. For PEMEX / PEP. Ciudad Pemex. Tabasco.
- 2005 to 2007. Replacement of existing ground wire guard cable with optical fiber over 1900 km of transmission lines in the central, north and south. For Federal Electricity Commission.
- 2005 to 2008. Pipeline El Limon - La Garita. 123 kilometers of pipeline 12 inches in diameter. Costa Rica. For Costa Rican Petroleum Refinery (RECOPE).
- 2005 to 2007. Tamazunchale Pipeline Pipeline Project. 127 km pipeline of 36 "in diameter. As a subcontractor to transport Natural Gas from the Huasteca to the Federal Electricity Commission. In the states of Vera Cruz Hidalgo and San Luis Potosi.
- 2005 to 2007. Bypass Pipeline Querétaro. 65 km pipeline of 24 inches in diameter over a six-unit compressor station of 2200 HP each, in the State of Querétaro. Green Energy to Bypass S. de RL de CV.
- 2002 to 2003. 506 LT-Cañada Saltillo. Design, procurement, testing and startup of 2 and 3 lines of transmission substations (472 km in 400 kV). For Federal Electricity Commission.
- 2002 to 2003. LT Manuel Moreno Torres. Design, procurement, construction, testing and startup of 3 transmission lines and substations 3 (348.5 km in 400 kV). For Federal Electricity Commission.
- 2001 to 2002. LT 411 National System. Design, procurement, construction, testing and startup of 4 lines (129.2 km in 400 kV). For Federal Electricity Commission.
- 2000 to 2002. 407 LT Red Associated Altamira II, III and IV. Design, procurement, construction, testing and startup of a transmission line and substation 1 (168 km in 400 kV). For Federal Electricity Commission.
- 2000 to 2001. El Bajio Pipeline Project. Salamanca / Leon / Aguascalientes. 80 km pipeline of 16 "diameter pipeline over 120 miles of 12" in diameter. To Trascanada.
- 2000 to 2000. LT 304 Northwest. Construction, testing and start-up of 5 interconnected transmission lines (235.2 km of 230 kV). Abengoa as Subcontractor for the Federal Electricity Commission.
- 2000 to 2001. Pack 307. Engineering, procurement and construction of eight substations of 400, 230 and 115 KV in the northwest to the Federal Electricity Commission.
- 2000 to 2000. LT 20-Escárcega Km. Partial construction of the line (273.8 km in 400 and 230 kV). As a subcontractor to Alstom for the Federal Electricity Commission.
- 1999 to 2000. April 6 LT-Puerto Peñasco. Construction of civil works and electromechanical transmission line (109 km of 230 kV). Abengoa as Subcontractor for the Federal Electricity Commission.
- 1999 to 2000. Bledales LT-Santiago-Cabo San Lucas II. Assembly and installation of transmission line (194 km of 230 kV). As Subcontractor Isolux for CFE.
- 1998 to 1999. Package Center. Engineering, procurement and construction of four substations 400, 230 and 115 KV in the downtown area. For Federal Electricity Commission.
- 1998 to 1999. St. Barnabas-Cuajimalpa LT. Try partial construction of the electromechanical work of 2 transmission line (20 926 km of 230 kV). For Federal Electricity Commission.

- 1998 to 1999. Tula LT-Queretaro-Salamanca. Completion of engineering, equipment part, construction of civil works and electromechanical transmission line (232 km in 400 kV). For Federal Electricity Commission.
- 1998 to 1998. Escárcega LT-Power-Ticul II. Completion of civil construction and electromechanical transmission line (268 km in 400 kV). As Tribasa subcontractor for the Federal Electricity Commission.
- 1997 to 1999. Proyecto El Habal. Engineering, procurement, civil works, electromechanical assembly, testing and startup of 6 lines (576,287 km in 400, 230 and 115 kV). For Federal Electricity Commission.
- 1997 to 1998. Hercules project. Design, equipment, construction and opening of 9 lines (523.99 km of 230 kV). For Federal Electricity Commission.

Project Coordinator
Techint SA de CV | Santa Fe, Delegación Álvaro Obregón, México D.F. | 1995 to 2007

- 1995 - 1998. LT-Xul Ha Ticul Construction, procurement and start of the transmission line (269 km in 230 kV). For Federal Electricity Commission.
- 1995 - 1998. Sonora package. Design, detailed engineering, procurement, construction and startup of 7 lines (449.2 km in 230 and 115 kV). For Federal Electricity Commission.
- 1995 to 1997. Transmission Line Lázaro Cárdenas - Donato Guerra - San Bernabe. Design, equipment, construction and opening of 3 transmission lines (370 km in 400, 230 and 115 kV). For Federal Electricity Commission.

General Coordinator of Entrepreneurship | Swift / Campbell Soup SA | 1989 to 1995
Project Coordinator | Consultant Consortium Esin / Electrosistemas / COA / T. Murgia & Associates | 1978 to 1985
Head of Planning and Service Department | CIAE | 1973 to 1978

EDUCATION

University of Buenos Aires | Buenos Aires, Buenos Aires Province, Argentina
Bachelor of Science, Electromechanical Engineer, 1972

PROFESSIONAL DEVELOPMENT

Areas of Skill or Expertise

- Courses taken: power distribution, power systems, programming and systems analysis, Projection fluctuating load low voltage networks, Auditor of Quality Assurance Systems
- Fluent Languages: Spanish, English

ISOLUX CORSAN USA	**Raul Magana** **Title:** Engineering Manager **Dept:** Engineering **Reports To:** Project Manager	**Seniority** 14 Years **Industry Experience** 14 Years

PROFESSIONAL EXPERIENCE

Engineering Manager
Isolux Ingenieria USA, LLC | Austin, Texas | August 2010 to Present

Responsible for the overhead transmission line engineering department, coordinate design activities with the engineering contractor, respond technical questions raised by the client, contractors or other areas. Assist is the preparation of bids.

- Wind Energy Transmission Texas Project: 386 miles of 345kV transmission line near Big Spring, TX

Project Manager
SAE Towers | Monterrey, Mexico | February 2008 to August 2010

Management of latticed towers and steel poles design and fabrication projects, including development of entirely new tower families for clients in North America. Coordination with the testing station in Brazil in order to load test designed towers. Managed the tower and/or pole fabrication for each project.

- Georgia Transmission. Design of 7 new towers. Furnishing 6,000,000 lbs of steel lattice tower.
- PacifiCorp. Design of 12 new towers.
- Oaxaca. Furnishing 16,500,000 lbs of steel lattice towers.
- SNC Lavalin. Design of 5 new towers. Furnishing 2,000,000 lbs of steel lattice tower.

Engineering Manager
Iberdrola | Madrid, Spain | March 2006 to February 2008

Responsible for the overhead transmission line engineering department for international projects. Management and technical adviser for different engineering groups in projects and offices worldwide. Participation in the bid preparation for international offers in the Americas, Africa, Eastern Europe and Middle East.

- CADAFE. Venezuela. 18 steel pole design. 8 OHTL 138kV.
- NEK. Bulgaria. 3 OHTL 400kV.

Engineering Manager
ABB | Monterrey, Mexico | November 2004 to February 2008

Responsible for the engineering department in the pole and lattice tower fabrication facility. Responsible for the design and detail of poles and lattice structures for energy and telecommunications applications. Management and supervision of the design and detailing group. Assisting in the technical portion of the bid preparation for North American projects.

- Nevada Power: design of 8 new lattice towers
- Puget Sound Energy: design of 3 new lattice towers
- Tennessee Valley Authority (TVA): design of more than 20 new steel poles and H-frames
- East Kentucky Power Cooperative (EKPC): design of more than 20 new steel poles and H-frames

Engineering Manager
Techint | Mexico City, Mexico | November 1998 to November 2004

Responsible for overhead transmission line engineering group. Participating in the civil, electromechanical and structural design of more than 4,000 miles of HVTL. Management and supervision of the design group in the central office, as well as the technical supervisors at site.

- Comision Federal de Electricidad Project 411: design of 4 OHTL 400/230kV (270 miles)
- Comision Federal de Electricidad Project 407: design of 1 OHTL 400kV (160 miles)
- Comision Federal de Electricidad Project 409: design of 3 OHTL 400kV (470 miles)
- Comision Federal de Electricidad Project 506: design of 3 OHTL 400kV (480 miles)
- Comision Federal de Electricidad Project 609: design of 3 OHTL 400kV (450 miles)

ISOLUX CORSAN USA	**Raul Magana** **Title:** Engineering Manager **Dept:** Engineering **Reports To:** Project Manager	**Seniority** 14 Years **Industry Experience** 14 Years

EDUCATION

Instituto Politecnico Nacional | Mexico City, Mexico
Bachelor of Science, Civil Engineering, 1997

PROFESSIONAL DEVELOPMENT

Areas of Skill or Expertise

- Computer Skills: PLSCADD, PLS Pole, PLS Tower, AutoCad, Office + Visual Basic
- Special Training: Executive Training Program, Project Management
- Fluent Languages: English, Spanish, Italian

ISOLUX CORSAN USA	**Flavio Parpinelli** **Title:** Tendering & Contracting Manager **Dept:** Tendering and Contracting **Reports To:** Vice President of Operations	**Work Experience** 12 Years **Industry Experience** 12 Years

PROFESSIONAL EXPERIENCE

Tendering and Contracting T&D Manager
Isolux Ingenieria USA, LLC | Austin, Texas | April 2010 to Present
Responsible for contracting and tendering activities for the T&D division of Isolux in North America, including the contract management of current projects.

- Wind Energy Transmission Texas (WETT) project: 375 miles of 345KV transmission line and six (6) substations near Big Spring, TX

Tendering and Contracting T&D Manager
Isolux Ingenieria USA, LLC | Madrid, Spain | July 2007 to April 2010
Responsible for the Americas, including local and remote team/staff, management of commercial, proposal and contracting activities of Isolux in these markets includes all the T&D projects.

Tendering and Contracting T&D Manager
Isolux Projetos E Instalacoes LTDA | Rio de Janeiro, Brazil | May 2007 to July 2007
Managed several Isolux procedures and standards for the future work in headquarter in Madrid.

T&D Proposal Supervisor
Areva T&D Brasil Ltda (currently Alstom Grid) | São Paulo, Brazil | September 2005 to May 2007
Tender Leader of power systems division, including substations AIS / GIS and transmission lines. Responsible for review of customer's technical specifications, business development, elaboration of the proposal, negotiation with partners/suppliers and partnership development.

T&D Project Manager
VA Tech T&D Ltda (currently a Siemens Company) | São Paulo, Brazil | March 2002 to Month 2005
Project Manager of EPC power systems, overhead transmission line and up to 440kV substations contracts.

- EPC Turn-key contract for extension of an existing two 460kV S/S. The scope included two (2) transmission lines and two (2) reactor bays, including all the telecom, automation, and control and protection systems.
- EPC Turn-key contract for installation of four GIS (SF6) 460kV switching bays in a different existing substations.
- EPC Turn-key contract for 137km of transmission lines utilizing steel lattice towers in 230kV and the extension of the existing 230kV substations. The scope of works included all the EPC activities and obtaining environmental licenses.
- EPC Turn-key contract for transmission lines and a new 138kV Substations for a three hydro power plant.

T&D Proposal Coordinator | VA Tech T&D Ltda | São Paulo, Brazil | March 2000 to March 2002

EDUCATION

University São Judas Tadeu | São Paulo, Brazil
Bachelor's Degree, Electrical Engineering, 2002

PROFESSIONAL DEVELOPMENT

Certifications

- Professional Engineer (Brazil CREA No. 506.215.878)

ISOLUX CORSAN USA	**Flavio Parpinelli** **Title:** Tendering & Contracting Manager **Dept:** Tendering and Contracting **Reports To:** Vice President of Operations	**Work Experience** 12 Years **Industry Experience** 12 Years

Areas of Skill or Expertise

- Courses Taken: Results Motivation Institution (Areva T&D); "Construction self-leadership" Workshop (Schneider Electric HV); NR-10 Brazilian law about safety in electric (SENAI); Microsoft Project (Segawas Projetos, Treinamento e Informática)
- Fluent Languages: Portuguese, English, Spanish

KENDA POLLIO, AICP

kp environmental

EDUCATION

- **Masters of Arts**

(Political Science– International Environmental Policy)
University of South Florida

- **Bachelor of Science**

(Environmental/Urban & Regional Planning)
Florida State University

CERTIFICATIONS

- **AICP**, American Institute of Certified Planners

EXPERIENCE 22 Years

SPECIALTIES

- Environmental Planning
- Environmental Impact Assessment
- Permitting Strategy
- Public Involvement
- Local Government Compliance
- Socioeconomics
- Visual Resources
- Recreational Planning
- International Projects

Ms. Pollio is a Senior Environmental Planner and Project Manager specializing in transmission line and right-of-way assessment, siting, acquisition, permitting, easements, and government compliance. She has provided Project Management and technical expertise for utilities, independent transmission companies, independent power producers, governmental entities. She has analyzed over 50 transmission and substation projects including several 500kV and 345kV projects.

She has conducted environmental assessments, public participation programming, land use planning and zoning, and socioeconomic planning. She has obtained federal, state, and local approvals for a variety of projects. She is familiar with local government zoning processes, state regulatory requirements throughout the United States, and federal compliance requirements for EISs, EAs, and ERPs prepared for Western, FERC, BLM, USDA Forest Service, BOR, BIA and COE. She also has specialized in noise and air analysis for a variety of linear corridor projects. For these projects, Ms. Pollio has served in the capacities of technical lead, technical writer, editor, project coordinator, and project manager.

Ms. Pollio has recently completed serving as Project manager for the Sunrise Powerlink Project. a 130 mile- 500kV project that traversed, BLM, Forest Service, tribal lands and state lands. She has also served as Project Manager for several other large 500 kV and 345 kV transmission line projects in excess of 100 miles in length.

The following provides a comprehensive list of projects for which Ms. Pollio has provided Project Management, project planning, land use analysis, public involvement and environmental analysis. The environmental analysis has included providing and developing the following type of documents:

- Environmental Impact Statements
- Environmental Impact Reports
- Environmental Assessments
- Environmental Analysis
- Fatal Flaw Analysis
- Siting and Routing Studies and Reports
- Environmental Monitoring and Construction Documentation (POD/COMP Plans)

KENDA POLLIO, AICP

Ms. Pollio has developed Public Participation Programs and facilitated public consultation processes, public workshops and meetings both internationally and domestically. Public Participation Programs have included development of public outreach programs, stakeholder identification and coordination, NGO and elected official coordination, environmental education, development and publication of newsletters, and interface with media and neighbors. She specializes in developing public involvement programs for generation and transmission projects. She has coordinated or attended over 75 public process venues including stakeholder workshops and Open Houses which total over 600 public process meetings.

Expert Witness Testimony

She has provided expert witness testimony before the California Public Utilities Commission and Arizona Power Plant and Transmission Line Siting Committee and the in the following cases:

- Sunrise Powerlink 500kV Transmission Project – SDG&E
- Cottonwood to Dermott 345 kV – WETT
- Scurry County to Long Draw 345 kV – WETT
- Long Draw to Grelton 345 kV -- WETT
- Grelton to Odessa 345 kV – WETT
- Long Draw to Sand Bluff 345 kV -- WETT
- Sand Bluff to Divide 345 kV -- WETT
- Sand Bluff to Bearkat 345 kV WETT
- Arlington Valley Solar Project – LS Power
- Arlington Valley Solar II Project – LS Power
- Hualapai Valley Solar Project and Transmission Line – Mohave Sun LLC
- Agua Caliente Solar Project—Nextlight LLC
- Q43 Substation -- APS
- Coolidge Generating Station – TransCanada
- Solana Generating Station – Abengoa Solar
- Solona 230 kV Transmission Line Project – Abengoa Solar
- Sundance to Pinal South 230 kV Transmission Line Project – APS
- Desert Basin Power Plant to Pinal South Substation 230KV Transmission Line Project – SRP
- Palo Verde to Pinal West 500 kV Transmission Line – SRP
- Pinal West to Southeast Valley/Browning 230/500 kV Transmission Line – SRP
- Wellton-Mohawk Generating Facility – York Research

Transmission and Power Plant Projects:

- Bay Lake Project 345kV Transmission Project (Wisconsin-Michigan)– ATC
- Cardinal Bluffs 345kV Transmission Project (Wisconsin-Iowa) – ATC
- Price Road Corridor 230kV Transmission Project -- SRP
- Sunrise Powerlink 500kV Transmission Project – SDG&E
- Cleveland National Forest Wood to Steel Project – SDG&E
- Centinella Solar Project – LS Power
- Borrego Springs Solar Project – NRG
- Di Giorgio Solar Project – Aminox
- San Bernardino Solar Project -- Aminox
- Cottonwood to Dermott 345 kV – WETT
- Scurry County to Long Draw 345 kV – WETT
- Long Draw to Grelton 345 kV -- WETT
- Grelton to Odessa 345 kV – WETT
- Long Draw to Sand Bluff 345 kV -- WETT
- Sand Bluff to Divide 345 kV -- WETT
- Sand Bluff to Bearkat 345 kV WETT
- Mountain Home Energy 230 kV Transmission Line, Idaho Power

- Desert Southwest 500kV Transmission Project, DSWP
- Palo Verde to Pinal West 500 kV Transmission Line – SRP
- Pinal West to Southeast Valley/Browning 230/500 kV Transmission Line – SRP
- Gardner Park to Central Wisconsin 345kV Project – ATC
- Morgan to Central Wisconsin 345kV Project – ATC
- Central Wisconsin to Werner West 345 kV Project – ATC
- Clintonville to Werner West 138 kV Project – ATC
- Coolidge Generating Facility and Transmission Line Project– TransCanada
- Solana Generating Station and 230 kV Transmission Line Project – Abengoa Solar
- Sundance to Pinal South 230 kV Transmission Line Project – APS
- North Gila to TS-8 230 kV Transmission Line Project – APS
- Desert Basin Power Plant to Pinal South Substation 230KV Transmission Line Project – SRP
- Blythe Energy Project and Transmission Line - Wisvest
- Blythe Energy Project Expansion, Caithness
- Repauno Power Plant Project, Repauno Products LLC
- Adelanto Peaking Plant and Transmission Line Project, Adelanto LLC
- Westlake Energy Power Plant and Transmission Line Project, Westlake Energy
- Wellton-Mohawk Generating Facility – York Research
- Solar Energy Siting Study – Confidential Client
- Montezuma Power Generation Project and 230 kV Transmission Line to Santa Rosa Substation – AES
- Sundance Energy Generation Project and Sundance to Coolidge Substation 230 kV Transmission Line – PPL Global
- Desert Southwest High Voltage Interconnection 500 kV Transmission Line Project – Confidential Client
- Valmont to Broomfield 115kV Electric Transmission Line Permitting, Tri-State
- Interloken 230kV Electric Transmission Lines Permitting, Public Service of Colorado
- Florida Georgia 500kV Transmission Line Site Certification and Permitting, FPC
- Crane-Bridge-Plumosus 250kV Transmission Line Permitting, FPL
- DeBary-Winter Springs 230kV Transmission Line Permitting, FPL
- San Pedro de Macoris-Hainmosa 230kV Transmission Line EIS, Dominican Republic, World Bank
- Environmental Impact Statement for 500kV Transmission Line in Henan Province China, Asian Development Bank
- Limon Generation Facility, Transmission Line and Natural Gas Pipeline, Tri-State
- Colorado-New Mexico 230kV Interconnection Project, Tri-State
- Mountain Home Energy Project, Idaho Power
- Buffalo Power Plant 520 MW and Transmission Line Project, BPI
- Navitas White Wind Farm and Transmission Line, Western Area Power Administration
- San Luis Rio Colorado Power Plant and Transmission Line, Northbranch and Western Area Power Administration
- Metro Conversion 115kV to 230 kV Transmission Project, Public Service of CO
- Platte River Power Authority Substation and Transmission Line Interconnection Colorado, Platte River Power Authority
- Tucson Power Project, AES
- North Fiber Project and 230kV Transmission, Tri-State
- OrangeCo Cogeneration and Transmission Line, Polk County, Florida, PPP
- Mulberry Ethanol Facility and Cogeneration and Transmission Line, Polk County Florida, MELP
- Regional Environmental Assessment of Coal Power Plants and the associated Transmission Line and Transportation Routes and Ports (Chennai and Ennore Ports) in Madras (Chennai) India, Asian Development Bank
- Environmental Monitoring Puerta Plata Power Plant, Puerto Playa Dominican Republic, Confidential Client

- Environmental Social Soundness Assessment for Combined Cycle Power Plant – Port Qasim, Karachi, Pakistan.
- Environmental Social Soundness Assessment for Power Plant - Quetta, Pakistan.

Other Linear Facility Projects

- Wellton Mohawk Natural Gas Pipeline – WMIDD
- Yuma Lateral Natural Gas Pipeline
- Phoenix Pipeline Project Permitting, Southwest Gas
- Sunshine Pipeline Natural Gas Transmission Line, Sunshine Pipeline
- Rockport to Rawhide Natural Gas Pipeline Permitting, PRPA
- Gas Pipeline Alternatives Analysis, FPC
- Denver Metro Loop, Metro Media Fiber Network
- Environmental Assessment for a Fuel Transport Route, Bombay India, Asian Development Bank
- Cross Florida Greenway State Recreation and Conservation Area, FDEP, central Florida
- US 98 PDE for Florida Department of Transportation
- US 98 Re-Evaluation Study for Florida Department of Transportation
- Hike and Bike Trail, Port Richey, Florida, City of Port Richey

Other Environmental Projects

- Natural Gas Storage Facility Siting Study, Unocal
- Arizona Refinery, AZ Clean Fuels
- Pinellas County Bike Standards, Pinellas County, Florida
- Seminole County Natural Resource Management Plan, Seminole County, Florida
- Charlotte County Horse Arena, Charlotte County, Florida
- Hike and Bike Trail, Port Richey, Florida
- Waterfront Master Plan, Port Richey, Florida
- Proposed Florida Horse Park and Agriculture Center, FDACS, Marion County, Florida
- Recreational Facilities Assessment, Department of Natural and Environmental Resources, Puerto Rico
- Greenway and Trails Plan for City of Cajamarca, Cajamarca, Peru

Education

Ph.D. Mechanical Engineering, University of Toronto, 1988

M.Eng. Mechanical Engineering, University of Toronto, 1983

B.A.Sc. Mechanical Engineering, University of Toronto, 1980

Golder Associates Ltd. – Toronto

Anthony Ciccone, P.Eng., Ph.D.

Dr. Anthony Ciccone is a Principal with Golder Associates in Mississauga, Ontario, and is the Canadian Leader for Power & Energy as well as the Global Leader for the Air Quality Technical Service Team. He is a mechanical engineer with over 30 years of experience directing and participating in environmental assessments, air quality, meteorological, and energy development projects in Canada and globally. He received his doctorate from the University of Toronto in 1988 and has additional advanced training in computational fluid dynamics. Dr. Ciccone is an Adjunct Professor at University of Western Ontario with The Boundary-Layer Wind Tunnel Laboratory, in the Faculty of Engineering Science. Dr. Ciccone has acted as the Project Director and senior technical advisor for numerous energy and air quality projects. This includes over 2000 MW of wind power development work in Ontario, Quebec and Manitoba as well as for solar farms in Ontario. In addition, he has lead environmental assessments for various gas-fired cogeneration and Combined Heat & Power facilities. Dr. Ciccone is also involved in regional air quality modelling for urban areas as well as industrial applications including oil & gas, mining, power and others.

Employment History

Golder Associates – Mississauga, Ontario

Principal (2003 to Present)

Leader of the Canadian Power Sector which includes business development, delivery of power generation, transmission and engineering projects to clients across Canada. Develops and oversees various engineering and environmental tasks on behalf of clients and provides technical support to staff.

Responsible for the delivery and project management of environmental assessments and air quality, permitting, emission reduction measures and environmental services to power & energy, aggregate, mining, petroleum products, pulp & paper, iron & steel, automotive and other industrial clients in Canada and abroad. Principal investigator for long range transport, acid deposition and urban air quality modelling projects as well as the preparation on detailed emission inventories on a plant level as well as on a regional level. Expert testimony on air quality and meteorological issues for various clients. Responsibilities include staff supervision and management, client management and liaison and technical review of air quality related projects.

Global leader for air quality technical team ensuring consistency of work products and skill sets of 100 air quality modelling and monitoring professionals in ten countries across the company

Ontario Mining Association – Ontario

Environmental Committee (1998 to 2003)

Leader of the Air Quality Emissions Task Force. Provides advice and direction on air quality related issues which may impact mining operations in Ontario.

Earth Tech Canada Inc. – Markham, Ontario

Division Manager, Air Quality and Energy (2001 to 2003)

Management of air quality science, air pollution control and noise technical staff as well as the technical delivery of air quality modelling, noise and water quality related projects for various industries in Ontario. Projects include air quality and noise assessment, permitting of plants, emission inventory development, urban air quality modelling and analysis as well as the delivery of emission estimation training on O.Reg127 reporting to various industries. Provided environmental due diligence reviews on the acquisition of power plants and steel mills in Ontario, Alberta and British Columbia.

PM/O3 Options Assessment Working Group – Ontario
Smog Plan Steering Committee (1999 to 2001)

Participated as the representative of the Ontario Mining Association in the discussions on the relevance of new science on smog with the other industry representatives and Ontario Ministry of the Environment.

University of Western Ontario – London, Ontario
(1997 to 2000, 2012 - Current)

Adjunct Professor with the Boundary-Layer Wind Tunnel Laboratory, in the Faculty of Engineering Science.

Jacques Whitford Environment Limited – Markham
Director, National Air Quality Management/Division Manager, Environmental Sciences (1997 to 2001)

Manager of air quality and environmental staff in Markham. Responsibilities included business development, P/L statements, technical delivery of air quality modelling and analysis, GhG emission assessment, ambient air monitoring and government liaison for various industries including iron & steel, mining, pulp & paper, electricity sector and oil and gas.

Bovar-Concord Environmental – Toronto
Senior Engineer/Manager, Air Quality and Risk Assessment (1995 to 1989)

Project management and technical delivery of air quality modelling and assessment projects such as model development, meteorological assimilation, permitting and emission inventory development. Modelling included long-range transport, heavy gas modelling, jet plumes and concentration fluctuations in plumes.

University of Toronto, Dept. of Mechanical Engineering – Toronto
Research Associate & Post-Doctorate Fellow (1988 to 1989)

Extension of doctoral research on wind erosion/fugitive dust emissions using the Principals of two-phase flows and computational fluid dynamics.

University of Toronto – Toronto
Ph.D. Candidate in Mechanical Engineering (1984 to 1988)

MacLaren Plansearch Inc – Toronto
Project Engineer, Air Quality (1980 to 1984)

Carried out air quality and noise related projects included modelling, source testing, waste management assessment and emission inventories for various clients

PROJECT EXPERIENCE – POWER AND ENERGY SECTOR

Environmental Assessment for Transmission Line
Ontario

Project Director for the preparation and submission of the environmental assessment of a 300 km 250kv transmission line to Pickle Lake, Ontario on behalf of Wataynikaneyap Power.

Environmental Screening for Transmission Line
Ontario

Project Director for the environmental screen of the East-West Tie transmission line corridor between Thunder Bay and Wawa on behalf of the Ontario Power Authority..

Renewable Energy Application for Samsung
Ontario

Project Director for the preparation and submission of 100 MW wind farm REA for Samsung/Pattern wind farm in Ontario

Renewable Energy Application for NextEra
Ontario

Project Director for the preparation and submission of 200 MW wind farm the first large scale REA for NextEra Summerhaven wind farm in Ontario.

Environmental Permitting for Covanta EFW
Ontario

Project Director for the acquisition of multi-media environmental permits for 140,000 tonne/yr Energy-from-Waste plant in Durham, Ontario on behalf of Covanta.

Environmental Assessment and Permitting Waste to Energy
Ontario

Project Director and stakeholder consultation lead for the environmental assessment and permitting for a waste gasification facility in Ontario.

Environmental Permitting for Ontario Power Generation Biomass Fired Plant
Atikokan, Ontario

Responsible for the multi-media (air and wastewater) permitting for the a 227 MW biomass fuelled power plant in Northern Ontario on behalf of Ontario Power Generation.

Environmental Assessment of Biosolids Power Plant
Liberty Energy, Hamilton

Responsible for the environmental assessment of a 10 MW biosolid/biomass fired power plant in Hamilton. Environmental assessment was carried out under the Electricity Project Regulation in Ontario.

Environmental Assessment of CHP in Downtown Toronto Toronto	Project Director for the Environmental Assessment under Reg116 for a 45 MW Combined Heat and Power Plant at the Redpath Sugar Refinery in downtown Toronto.
Environmental Assessment of 400 MW Single Cycle Power Plant Ontario	Responsible for the completion of an environmental assessment and permitting of a 400 MW gas-fired single cycle peaker power plant in Ontario under O.Reg116.
Environmental Assessment of 800 MW Combined Cycle Power Plant Ontario	Responsible for the completion of an environmental assessment and permitting of a 800 MW gas-fired combined cycle power plant in Sarnia under O.Reg116. The combined cycle plant includes two gas turbines and cooling towers and impacts to all media were assessed.
Fatal Flaw analysis for 200 MW Combined Cycle Toronto	Project Director for the fatal flaw analysis of a 200 MW combined cycle cogeneration facility to be located in downtown urban centre. The analysis evaluated the potential “show stoppers” that could halt the project. Technical evaluation of air, noise and water impacts and mitigation was provided.
Environmental Assessment of 570 MW Gas-Fired Plant Sarnia	Responsible for the completion of an environmental assessment and permitting of a 570 MW gas-fired combined cycle power plant in Sarnia under O.Reg116 for Invenergy. The combined cycle plant includes two gas turbines and cooling towers and impacts to all media were assessed.
Environmental Assessment and Permitting For Wind Farms Ontario	Project Director for completion of a 75 MW wind farm for TCI Renewables under the Canadian Environmental Assessment Act (CEAA) and the Ontario Environmental Assessment Act. The projects include baseline studies for noise and avian/bat as well as impact analysis and mitigation for all environmental components.
Environmental Assessment and Permitting For Wind Farms Ontario	Project Director and leader for completion of a 100 MW wind farm for TransCanada Energy under the Canadian Environmental Assessment Act (CEAA) and the Ontario Environmental Assessment Act. The projects include baseline studies for noise and avian/bat as well as impact analysis and mitigation for all environmental components.
Environmental Assessment For Wind Farms Ontario	Project Director and leader for completion of six (6) wind farms totalling 100 MW for SkyPower under the Canadian Environmental Assessment Act (CEAA) and the Ontario Environmental Assessment Act. The projects include baseline studies for noise and avian/bat as well as impact analysis and mitigation for all environmental components.
Environmental Assessment For Wind Farms Manitoba	Project Director and leader for completion of four (4) wind farms totalling 400 MW for SkyPower under the Canadian Environmental Assessment Act (CEAA) and the provincial Environmental Assessment and License Application of the Manitoba Environment Act. The projects include baseline studies for noise and avian/bat as well as impact analysis and mitigation for all environmental components.

Environmental Assessment For Wind Farms Ontario	Project Director and leader for completion of five (5) wind farms totalling 50 MW for Engineering Systems under the Canadian Environmental Assessment Act (CEAA) and the Ontario Environmental Assessment Act.
Environmental Assessment For Wind Farms Quebec	Project Director and leader for completion of six (6) wind farms totalling 980 MW for SkyPower under the Canadian Environmental Assessment Act (CEAA) and the Quebec environmental process.
Environmental Assessment of Biosolids Power Plant Liberty Energy, Hamilton	Responsible for the environmental assessment of a 10 MW biosolid/biomass fired power plant in Hamilton. Environmental assessment was carried out under the Electricity Project Regulation in Ontario.
Modelling Emissions Nova Scotia Power	As part of Nova Scotia Power's committed to reducing acid deposition, modelling of the five coal-fired generating stations in the Province was carried out with the aid of the CALPUFF modelling system. The modelling included the development of 3-dimensional meteorology over the province and a fine-resolution over each station. CALPUFF was executed to include chemical transformation (SOx to sulphate and NOx to nitrate) as well as wet and dry deposition.
Site-Selection for A Gas-Turbine Constellation Power	Carried out a review of various potential sites for the potential location of a 1000 MW gas-fired turbine in West Toronto. Evaluation included water, air, soils and transmission corridor aspects as well municipal permitting issues.
Development of PEMs Sithe Energy	Development of a Predictive Emission Monitoring System (PEMS) using Neural Net technology to predicted NOx emissions from a natural gas turbine. Model will be used for reporting emissions in Ontario under various regulatory requirements.
Development and Implementation of PEMs TransCanada Energy	Development of a Predictive Emission Monitoring System (PEMS) for four (4) gas-fired power plants in Ontario. System was established to use data in remote locations without impacting the plant operations.
Wind Turbine Risk Assessment Ontario Power Generation-Green Power	Evaluation of wind turbine blade failure and potential risk to the Pickering Nuclear Generating Station. Analysis included development of a blade trajectory model, assessment of blade impact due to a catastrophic failure and probability of risk in specific directions. Methods used followed the Netherlands approach in assisting turbine blade consequences.
Long-Range Transport & Acid Deposition Nova Scotia	Principal Investigator for the long-range transport and acid deposition of SO2 and NOx emissions from the Northeastern States and Eastern Canada on Nova Scotia in support of Nova Scotia's Energy Policy, on behalf of the Nova Scotia Department of Environment and Labour. Modelling and assessment was carried out with the aid of the CALPUFF modelling system over a 2000 km grid on a 20 km grid resolution.

Long-Range Transport & Acid Deposition Nova Scotia	Project Modeller for the long range transport and wet deposition modelling of emissions from Nova Scotia Power coal-fired generating stations with the aid of MESOPUFF and ADEPT.
Human Health Risk Assessment Ontario Power Generation, Nanticoke	Principal Investigator on Human Health Risk Assessment of air emissions from the Ontario Power Generation Nanticoke coal-fired generating station on the local population. Using 2002 NPRI emissions along with the AERMOD-PRIME model, the dose and subsequent risk to the local populations were calculated.
NPRI/O.Reg127 Emission Reporting Ontario Power Generation	Responsible for the technical and management of the preparation of the 2002 NPRI/O.Reg 127 emission reporting for the six Ontario Power Generation fossil fuel generating stations. The project entailed obtaining site-specific plant information and adapting the OPG database system to report 2002 emissions. The project included coordination with all 6 generating stations and head office.
Emission Estimation & Modelling Ontario Power Generation	Project Manager for the preparation of emission inventories for PM, SOx, NOx, CO, VOCs, CO2 and metals from Ontario Power six coal-fired generating stations including fugitive, tank and stack sources. The dataset was used for permitting applications as well as for emissions reporting to the federal and provincial environment departments.
Long-Range Transport of NOx and SO2 Ontario Power Generation	Principal Investigator and Project manager for the investigation of long-range transport of SOx and NOx emissions from Ontario Power coal-fired generating stations as well as other major North American power plants. The study delineated the contribution of OPG facilities on major cities including Chicago, Rochester, Toronto, Montreal and Albany.
Permitting Cogeneration Facilities TransAlta, Sarnia	Project Manager for the preparation of technical documents for air, noise and water permits for the TransAlta Regional Cogeneration Plant in Sarnia including negotiations with the Ministry of Environment. The project was complex as the project included the transfer of power assets from Dow Chemical and Bayer to TransAlta plus the erection of three new gas-fired turbines.
Permitting of Gas-Fired Turbines TransAlta, Mississauga, Ottawa & Windsor	Project Manager for the preparation of air and noise support documents for the TransAlta Cogeneration facilities including gas-turbines with Heat-Recovery and ancillary boilers for facilities in Ontario. These were the first facilities built in Ontario.
Environmental Due Diligence of Gas-Turbines Ontario, Emera Inc.	Carried out a due diligence environmental review of Ontario based natural gas-fired power plants on behalf of Emera. Due diligence included site-visit and assessment of potential current and future environmental liabilities associated with the acquisition of the facilities.
Environmental Due Diligence of Hydro-Electric Assets Ontario, TransAlta	Carried out a due diligence environmental review of Ontario Power Generation hydro-electric plants on behalf of TransAlta. Due diligence included site-visit and assessment of potential current and future environmental liabilities associated with the acquisition of the facilities.

Environmental Due Diligence of Gas-Turbines
Alberta & Ontario, El Paso Energy

Carried out a due diligence environmental review of Duke Energy natural gas-fired power plants in Alberta, BC and Ontario on behalf of El Paso Energy. Due diligence included site-visit and assessment of potential current and future environmental liabilities associated with the acquisition of the facilities. Estimated costs for compliance and future emissions trading credits were developed and provided as part of the economic model.

Optimization of Monitoring Networks
Ontario Power Generation

Responsible for the optimization of Ontario Power Generation ambient air monitoring stations for Nanticoke, Lambton, Lennox and Lakeview Generating Stations. Study included the review of the existing SO2/NOx/Ozone and PM monitoring locations and with the aid of advance modelling techniques recommended the removal of re-deployment of monitoring equipment on behalf of each station.

Airborne Tritium Modelling
Pickering, Ontario Power Generation

Principal Investigator and Project Manager for the development and application of airborne tritium dispersion model for assessment of emissions from Ontario Power Pickering Nuclear Generating Station. The modelling system was used to determine if soil contamination was due to tritium airborne emissions on site.

Environmental Management System
Ontario Power Generation

Project manager and lead investigator for the gap analysis and review of the Fossil Fuel Business Unit Environmental Management System as per ISO14000 requirements.

Human Health and Environmental Risk Assessment
Ontario Power Generation

Principal Investigator on health and ecological risk assessment of emissions from six fossil fuelled generating stations for Ontario Power Generation. The resultant dose and risk were compared to various provincial standards to determine the risk to the local population to estimate the number of potential deaths around the generating stations.

Dispersion Modelling
Belledune, New Brunswick

Principal modeller for the dispersion modelling study of the New Brunswick Power Dalhousie, Belledune Generating Stations under various scenarios using an advance air quality model including complex terrain

Fugitive Dust Emissions
Canadian Electrical Association

Project Engineer on the review of fugitive emissions and control measures used by Canadian coal-fired thermal generating stations. Site visits and interviews were arranged with facilities in Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia. The data were complied to demonstrate the various control techniques used across Canada. Based on the data, a workbook was developed on estimating fugitive dust emissions form coal and ash piles, specific to the Canadian climate.

PROJECT EXPERIENCE – OIL & GAS

Evaluation of VOC Emissions
Rio De Janeiro, Brazil

Develop an emission inventory of speciated VOCs from tanks farms and unloading and loading of tankers off the coast of Brazil. Projected included developing a metrological data set and modelling emissions with the aid of ISC-PRIME.

Environmental Assessment of LNG Facility
Cacouna, Quebec

Meteorological and air quality assessment of the proposed LNG facility on the south shore of Quebec on behalf of TransCanada/Petro-Canada. The work entailed the application of CALMET/CALPUFF to a 75 km domain including the development of background ambient levels using a provincial emission inventory and the cumulative effects of the new LNG facility. Modelling and assessment included the land operations as well as marine operations.

Emission Estimation Workshop
Calgary, Toronto and Montreal

Prepared and delivery a workshop on emission estimation techniques to the Canadian Chemical Producers Associations and the Canadian Petroleum Producers Association. The workshop included means of calculating VOC fugitive emissions from leaks and processes as well as GhG emissions from heaters etc. The workshops were given in Calgary, Toronto and Montreal.

Air Quality Management
Come-By-Chance, Nfld.

Principal Investigator and Project Manager for a multi-year air quality management program at the North Atlantic Refinery Limited, Come-By-Chance refinery in Newfoundland. The program included modeling of emissions into the local airshed, ambient air monitoring and stack testing of emissions, public presentations and emission reduction plans in response to the facilities permit under the Department of Environment and Labour's.

Modelling of SO2, NOx, PM10/PM2.5, VOCs emissions was carried out with the aid of the CALPUFF/CALMET modeling system. The SO2 modeling results were used for regulatory compliance and determine potential emission reduction strategies. Modelling results (SO2) were also compared with local monitoring data to calibrate the modeling system.

A source testing plan was negotiated with the provincial authority and carried out by a 3rd party. The source testing data were used in the modeling system to further improve the system. A VOC flux monitoring system was used to characterize emissions from a wastewater holding pond. The data was speciated to further refine the impact on the local communities. Ambient air monitoring of VOC in the vicinity of the Come-By-Chance refinery including plant property lines and communities using SUMMA canisters was designed and implemented on behalf of the refinery.

Air Quality Modelling and Forecasting
Montreal, Quebec

Principal Investigator and Project Manager of a multi-year study for Shell and Petro-Canada on the air quality impact on the viability of combusting higher sulphur fuels at the East Montreal refineries. The project involved using an advanced air quality model system (GASMOD) to predict future impacts. The initial results were positive and it was determined that potential exceedences of the MUC air quality objectives could be avoided with the aid of a forecasting system which would allow the refineries to switch for higher sulphur fuels to low-sulphur or natural gas.

To meet the needs of the refineries, a Supplementary Emission Control system for the East Montreal airshed was developed and tested using ambient air quality monitoring, dispersion modelling and forecast meteorology. The forecast meteorology was initially provided by Environment Canada. This was subsequently replaced with a neutral network forecasting system. The design, installation and operation of an SO2 monitoring network for the East Montreal airshed include data acquisition, computer system design (Windows NT), interfacing with plants, reporting and forecasting.

Ambient Air Monitoring
Montreal, Quebec North Bay, Ontario

Project Manager and engineer on the installation and operation of continuous air quality (NOx, NO2, NO and O3) and meteorological (wind speed and direction, temperature profile and solar radiation) monitoring stations at TransCanada Pipeline (TCPL) compressor stations including data acquisition and remote access capabilities. Monthly reports were generated and provided to the client. These studies were carried out in response to National Energy Board requirements.

Air Quality Impact from Oil Terminals
Come-By-Chance, Newfoundland

Principal Investigator for the air quality modelling and emission inventory of the Newfoundland Transshipment Terminal as part of an environmental assessment for IMTT. The study including assessing emissions from on-shore and off-shore emissions including tanks (ship and dockside), compressors, back-up generators and marine engines.

PROFESSIONAL AFFILIATIONS

Association of Professional Engineers of Ontario

Air and Waste Management Association

Network of Environmental Risk Assessment and Management

American Meteorological Society

PUBLICATIONS

Other

Singh, R.B, Ciccone, A.D., Morgan, C. “Traffic Model for Assessing Air Quality Health Exposures”, Proc. 100th A&WMA Annual Meeting, Pittsburgh, PA, 2007.

Singh, R.B, Ciccone, A.D., Morgan, C. “Greenhouse Gas Emissions from Mobile Sources in the City of Toronto: A Comparison between Top-down and Bottom-up Approach for Emission Inventory Analysis”, Proc. 100th A&WMA Annual Meeting, Pittsburgh, PA, 2007.

Singh, R.B., Rawlings, M., Ciccone, A. “MicroFac – A High Resolution Microscale Motor Vehicle Emissions Model”, Poster at the Upwind Downwind Conference, Hamilton, ON, Canada, Feb 26-27, 2006.

Ciccone, A.D., Niejadlik, P. and Cinnamon, C. “An Artificial Neural Network Based Predictive Emission Monitoring System For Nitric Oxide Emissions From Natural Gas Fired Power Generating Facilities” Presented at the 16th Symposium on Industrial Application of Gas Turbines, Banff, Alberta, Paper 05-IAGT-2.4, 12-14 October 2005.

Ciccone, A.D., Morgan, Christopher and Barrett, A “Air Quality Modelling of the City of Toronto” Presented at the AWMA Conference Air Quality Modelling: New Methods for a New Reality” May 2004.

Ciccone, A.D. and Stobeck, J. “Fugitive SO2 and Particulate Emissions From a Smelter Complex”, Presented at the Annual Air & Waste Management Association's 90th Annual Meeting, 1997.

Ciccone, A.D., Frattolillo, P. and Crooks, G. “Computerised System to Integrate Air Quality and Fuel Switching For Optimal Emission Control”, Presented at the Annual Air & Waste Management Association's 90th Annual Meeting, 1997.

Complin, P.G., Burrows, P.A. and Ciccone, A.D. "An Assessment of Odour Control Technologies and Odour Impacts at Toronto's Main Treatment Plant". Presented at the Annual Air & Waste Management Association's 88th Annual Meeting, 1995.

Burrows, P.A., Ciccone, A.D. and Complin, P.G., "Emission Assessment at a large Canadian Waste Water Treatment Facility- What are the Impacts". Presented at the Annual Air & Waste Management Association's 88th Annual Meeting, 1995.

Ciccone, A.D. and Alp, E. (1991). "Modelling Concentration Fluctuations in the Atmosphere, Part II". Presented at the Environmental Research 1991 Technology Conference, Toronto, Ontario, November 25-26, 1991.

Alp, E., Ciccone, A.D. and Fung, C., 1990 "Modelling Concentration Fluctuations", Environmental Research Technology Transfer Conference, Proceedings of Air Quality Session, Vol. A. Toronto.

Chandler, A.J. and Ciccone, A.D., 1990 "Development of a Guide for the Design of Fugitive Emissions at Coal-Fired Power Plants" Canadian Electrical Association, Fall Meeting, Calgary.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1989 "An Investigation of Wind Generated Particle Transport Rates within a Turbulent Boundary-layer-Phase II", Environmental Research Technology Transfer Conference, Proceedings of Air Quality Session, Vol. A, Toronto.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1989, "On the Determination of Particle Erosion Rates within a Turbulent Boundary Layer", Seventh Symposium on Turbulent Shear Flows, Stanford University, 21-23 August.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1989, "Flow Visualisation/Digital Image Analysis of Saltating Particle Motions", Experiments in Fluids, Accepted by editor: 16 February 1989.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1989, "Computation of Wind Generated Particle Saltation and Suspension Rates", 12 Canadian Congress of Applied Mechanics, Ottawa, 29 May - 2 June.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1988, "An Investigation of Wind Generated Particle Transport Rates within a Turbulent Boundary-layer", Environmental Research Technology Transfer Conference, Proceedings of Air Quality Session, Vol. A, pp. 149-168, Toronto.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1987, "Flow Visualisation/Digital Image Analysis of Particles In a Turbulent Boundary-Layer", Submitted to Cray Canada Inc., Toronto.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1987 "Tracking of Macroscopic Particle Motions in Flow Visualisation Images", Sixth International Congress on Applications of Laser and Electo-Optics, ICALEO'87, Vol. 63, pp. 111-118.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1987, "An Experimental Investigation of a Wind-Generated Suspension of Particulate Matter from a Tailings Disposal Area", Boundary-Layer Meteorology, 38, pp. 339-368.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1987, "Tracking of Macroscopic Particle Motions Generated by a Turbulent Wind via Digital Image Analysis" Second International Symposium on Transport Phenomena in Turbulent Flows, pp. 613-612, Tokyo.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1987 "Digital Image Analysis of Macroscopic Particle Motions Generated by a Turbulent Wind", Sixth Symposium on Turbulent Shear Flows, pp. 6.5.1-6.5.6, Toulouse.

Ciccone, A.D. and Keffer, J.F., 1987, "An Investigation of the Turbulent Wind Erosion of Particles via Digital Image Processing", 11th Canadian Congress of Applied Mechanics, pp. B.116-B.117, Edmonton.

Ciccone, A.D., Kawall, J.G. and Keffer, J.F., 1986, "An Experimental Investigation of Wind-Generated Suspensions of Particulate Matter From Tailing Disposal Areas", Submitted to the National Uranium Tailings Program, CANMET, DSS Contract No. 14SQ.23241-3-1667, Ottawa.

Ciccone, A.D., Buchnea, A. and Cabaza, L., 1983, "A Model for the Calculation of Intrusion Exposures from Low Level Radioactive Waste Repositories", Canadian Radiation Protection Association 4th Annual Meeting, Toronto.

Ciccone, A.D., Buchnea, A., 1982, "Characterisation of Low Level Radioactive Waste in Canada", CNS International Conference on Radioactive Waste Management, Ottawa.

Education

M.A.Sc. Environmental Applied Science and Management Program, Ryerson University, 2007

B.Sc. Biology, Hon., University of Ottawa, 2005

Certifications

Public Participation Practitioner - International Association for Public Participation (IAP2), July 2009

Health and Safety Modules 1 and 2, 2007

WHMIS, August 2007

Languages

English – Fluent

French – Basic

Golder Associates Ltd. – Mississauga

Stakeholder Engagement Specialist

Caitlin Burley, M.A.Sc, IAP2, is an environmental scientist with a B.Sc. in biology and an M.A.Sc. specializing in Risk Communication and Public Consultation. Caitlin's role in the Cultural Sciences Group in Golder's Mississauga office is as a Public Participation Specialist. She has over 6 years of experience in her field and is responsible for leading and/or advising on a number of stakeholder engagement programs for environmental planning and construction-phase projects in the waste, power, manufacturing, mining, and oil and gas sectors.

Specifically, Caitlin's experience includes meeting, workshop and open house facilitation; advising clients on risk mitigation strategies from a stakeholder engagement perspective; the development and execution of effective stakeholder engagement plans of varying levels of complexity; and development and management of stakeholder databases (Excel, Access, StakeTracker® and Borealis).

Caitlin has both domestic and international facilitation experience that spans all levels of the public participation spectrum (inform, consult, involve, collaborate and empower) and tailors her facilitation approach to meet the expectations of the audience. Her current focus is managing and facilitating stakeholder engagement programs in support of long-term municipal planning processes and mining project environmental assessments in Northern Ontario.

Employment History

Golder Associates Ltd. – Thunder Bay, Ontario

Public Participation Specialist (December 2012 – present)

Responsible for developing and advising on public participation and stakeholder engagement programs for projects in the power, mining, waste and oil and gas sectors. Provides strategic advice to clients about how to manage social risks to their projects. Currently managing day-to-day Thunder Bay Office operations.

Golder Associates Ltd. – Mississauga, Ontario

Public Participation Specialist - Cultural Sciences Group, Environmental Sciences Division (May 2009 to December 2012)

Responsible for developing and leading public participation and stakeholder engagement programs for various projects in the power, mining, manufacturing, waste and oil and gas sectors. Oversees and reviews the development of materials and management of stakeholder databases. Provides strategic advice to clients about how to manage social risks to their projects.

Golder Associates Ltd. – Mississauga, Ontario

Environmental Assessment Coordinator, Environmental Assessment Group, Environmental Sciences Division (2007 to May 2009)

Responsible for assisting in the writing and organization of federal and provincial environmental assessments for various energy-related projects including nuclear,

wind power and natural gas. Assisted in the development of public participation and stakeholder engagement programs. Carried out and reported on socio-economic impact assessments for the aforementioned projects.

Masters of Environmental Applied Science and Management, Ryerson University
Research Assistant & Guest Lecturer (2005 to 2007)

Centre for Global Health, Institute of Population Health, University of Ottawa

Project Assistant (2003 to 2005)

Assisted in research projects about food security, global health information networks and nursing practices in developing countries. Organized two international health conferences. Organized the submission of, and assisted in the writing of, over 20 grant applications.

PROJECT EXPERIENCE – POWER

Pickle Lake New Transmission Line Environmental Assessment, ongoing
Northwestern Ontario

Aboriginal and Stakeholder Engagement Lead for an EA on a 300 km transmission line through Northwestern Ontario. Golder is currently working with Wataynikaneyap, a joint venture between Goldcorp and CCEG. CCEG is a wholly owned First Nations company managed by 13 First Nations in Northwestern Ontario. The Aboriginal and Stakeholder Engagement Program involves, but is not limited to:

- Regulatory notifications;
- Open Houses with community members;
- Face-to-face meeting with Aboriginal community/group leadership;
- Workshops with agencies; and
- Issues tracking, documentation and resolution.

Samsung/Pattern Armow Wind Power Project, Ongoing
Kindardine, Ontario

Designed and implemented an Aboriginal and Stakeholder Engagement program for a 180 MW wind power project that involves a number of face-to-face meetings with the leadership and administrative offices of interested and/or potentially affected First Nations, Métis Councils, municipalities and community members. Tasks include facilitation of Open Houses and meetings; development of plain language materials; issues tracking and documentation; and strategic advice with respect to issues resolution and engagement strategies.

Atikokan Biomass Conversion Project, 2011
Atikokan, Ontario

Advise client on community consultation program for the Certificate of Approval application to convert and existing coal-fired power plant into a biomass energy production facility. Tasks include reviewing Community Engagement Plan, materials and report.

Twenty-Two Degree and Arran Wind Power Projects, 2010 - 2011

Developed an Aboriginal and stakeholder engagement program for the TTD (up to 150 MW) and Arran (115 MW) Wind Power Projects. Activities included advising clients about the public participation requirements of the new REA process; managing the stakeholder comment and issue tracking database; and advising on open house strategies. Reviewed and advised on Open House materials, including fact sheets, display panels and comment sheets.

Armow and Zurich Wind Power Projects, 2010 - 2011
Bruce County, Municipality of Bluewater

Developed an Aboriginal and stakeholder engagement program for the Armow (80 MW) and Zurich (37.5 MW) Wind Power Projects. Public participation activities included advising clients about the public participation requirements of the new REA process; managing the stakeholder comment and issue tracking database; and organizing and carrying out open houses. Oversaw production of consultation materials, including fact sheets, display panels and comment sheets.

Churchill Renewable Energy Approval, 2010 - 2011
Lambton County, Ontario

Interim Manager and public participation lead for the proposed Churchill Wind Power Project (100 MW). Advised the client on the REA process as it relates to the Project. Managerial duties included client management, financial management and ensuring that component leads carry out their respective studies (e.g. natural heritage, cultural heritage, noise). As public participation lead, developed and currently executing a public participation program that meets the REA requirements.

Summerhaven Wind Power Project, 2008 - 2011
Nanticoke, Ontario

Developed and provided advice on the Aboriginal and stakeholder engagement program for the proposed Summerhaven Wind Power Project (up to 199 MW). Assisted in the formal transition of the Project from the O. Reg. 116/01 (environmental assessment) process to the O. Reg. 359/09 (REA) process. Public participation activities included advising clients about the public participation requirements of the new REA process; managing the stakeholder comment and issue tracking database; and organizing and carrying out open houses. Designed and produced consultation materials, including fact sheets, display panels and comment sheets. Transition duties included assisting the client in the development of a transitional document known as a gap analysis and meeting MOE expectations for this transition project.

Nanticoke Nuclear Power Plant Project Environmental Assessment, 2008 - 2009
Norfolk County, Ontario

Assist in the development of an Aboriginal and stakeholder engagement program and associated materials for the environmental assessment of the proposed new nuclear power plant on Lake Erie (3,000 MW). Assist in the organization of public participation activities such as Community Information Sessions, workshops, stakeholder briefings, learning centres and presentations. Responsible for reporting all public participation activities throughout the course of the environmental assessment, including public comments/questions and the client's responses to the public. Conduct interviews for the socio-economic impact assessment portion of the Environmental Assessment.

Bruce New Nuclear Power Plant Project Environmental Assessment, 2007 – 2009
Bruce County, Ontario

Assisted in the organization and reporting of Aboriginal, stakeholder and agency consultation activities such as Open Houses, workshops, stakeholder briefings, and presentations for the proposed new nuclear power plant on Lake Huron (3,400 MW). Developed the public participation portion of the Environmental Impact Statement (EIS). Performed interviews for the socio-economic impact assessment portion of the environmental assessment. Assisted in the compilation of the EIS, submitted to the Canadian Nuclear Safety Commission and the Canadian Environmental Assessment Agency in September 2008.

Adelaide Wind Power Project Environmental Assessment/REA, 2008 – 2010
Adelaide, Ontario

Developed and managed an Aboriginal and stakeholder engagement program for the proposed Adelaide Wind Power Project (60 MW). Assisted in the formal transition of the Project from the O. Reg. 116/01 (environmental assessment) process to the O. Reg. 359/09 (REA) process. Public participation activities included advising clients about the public participation requirements of the new REA process; managing the stakeholder comment and issue tracking database; and organizing and carrying out open houses. Designed and produced consultation materials, including fact sheets, display panels and comment sheets. Transition duties included assisting the client in the development of a transitional document known as a gap analysis and meeting MOE expectations for this transition project.

Romney Wind Power Project Environmental Assessment, 2008 - 2009
Essex County and Chatham-Kent, Ontario

Based on the legislative requirements of the Ontario Environmental Assessment Act, developed an Aboriginal and stakeholder engagement program, managed stakeholder database and comments, and completed three Open Houses for this 170 MW proposed wind power environmental assessment. Designed and produced consultation materials, including fact sheets, display panels and comment sheets, which allow the general public to learn about the project and environmental assessment process. Completed the public participation and the socio-economic conditions sections of the Environmental Review Report.

Amherst Island Wind Power Project Environmental Assessment, 2008 - 2009
Amherst Island

Developed preliminary Aboriginal and stakeholder engagement program for this 200 MW wind power project environmental assessment based on the Ontario Environmental Assessment Act requirements. Completed one Open House and designed/developed all associated materials. Managed stakeholder database and comments, and advised client responses to all stakeholder concerns/comments/questions.

SkyPower Wind Farms, 2007 - 2008
Wilno, Foymount, Killaloe and Madawaska, Ontario

Developed an Aboriginal and stakeholder engagement program for four wind power environmental assessments. Advise client about participation activities, stakeholder database management and stakeholder comment management.

PROJECT EXPERIENCE – MINING

Cliffs Black Thor Mining Project Environmental Assessment, Ongoing
Ontario

Developed Aboriginal and Stakeholder Engagement Plan for Project initiation and planning stage. Currently advising client on stakeholder and Aboriginal engagement strategies for the Environmental Assessment phase of the Project. Specific tasks include providing guidance to the client on the consultation and engagement requirements in the federal and provincial EA processes and meeting with agency representatives to obtain buy-in to the clients' proposed consultation and engagement approach. Additional tasks include managing comments received through the consultation and engagement processes.

Nunatsiavut Government Workshop on Uranium Mining, 2011

Facilitated and presented at a three day Workshop with Nunatsiavut (Inuit) Government Assembly and staff on the risks and benefits of uranium mining. The purpose of this workshop was to facilitate a decision around the moratorium on uranium mining in Labrador.

Golden Star Resources, Bogoso-Prestea Operations, 2011
Ghana

Advising on draft Resettlement Action Plan for the Prestea South-Nsuta Mbease Project and assisting on the rewrite of key document prior to submission to regulatory authority. Ensuring compliance with relevant International Finance Corporation (IFC) Performance Standards.

Hammond Reef Environmental Assessment, 2010
Atikokan, Ontario

Developed Stakeholder and Aboriginal Engagement Plan for initiation and environmental assessment stage of this Project.

PROJECT EXPERIENCE – OIL & GAS

Papua New Guinea Liquified Natural Gas Project, 2009 - 2011
Papua New Guinea

Stakeholder Engagement Coordinator for public participation field program for the development of natural gas reserves in Papua New Guinea. Lead and then managed field teams in an awareness and issues identification program. Program targeted communities in the Southern Highlands, Gulf and National Capital District provinces of Papua New Guinea. Public participation responsibilities included capacity development, materials development, facilitating community open houses. Management responsibilities included organizing team logistics for mobilization in the field, ensuring team safety and security and guiding, motivating and evaluating team members.

Northland Cogeneration Facility at Redpath Sugar Environmental Assessment, 2009
Toronto, Ontario

Developed and carried out a public participation and agency consultation programs, including developing materials for Open Houses, managing a stakeholder issue and comment tracking database and facilitating a public meeting and Open House. Prepared interim consultation reports and assisted the client in responding to public concerns.

Royal Windsor Energy Centre Environmental Assessment, 2009
Mississauga, Ontario

Developed and carried out a public participation and agency consultation programs, including developing materials for Open Houses and managing a stakeholder issue and comment tracking database. Prepared interim consultation reports, the consultation section of the Environmental Assessment and assisted the client in responding to public concerns.

Sluse Road Peaking Station Environmental Assessment, 2008
East Gwillimbury, Ontario

Assisted in carrying out a public participation and agency consultation program, including developing materials for Open Houses for this 230 MW peaking station environmental assessment. Assisted in reporting the outcome of the Open Houses and public response to the Project.

PROJECT EXPERIENCE – WASTE

Region of Waterloo Waste Management Strategy, 2011 – present
Region of Waterloo, Ontario

Oversaw and provided strategic advice on the engagement program for the development of the Region of Waterloo Waste Management Strategy.

City of Barrie Landfill Reclamation Engineering Project, 2011 - 2012
Barrie, Ontario

Advised client on strategies to inform and engage neighbours about ongoing reclamation work at the landfill and the short and long term affects that are associated with this work. Facilitated public participation activities and reviewed materials.

City of Barrie Sustainable Waste Management Strategy, 2010 - 2012
Barrie, Ontario

Developed a Public Participation Program to assist the City of Barrie in incorporating community perspectives into the development of their long term solid waste management plan. Advised City on various strategies to engage public, facilitate meaningful discussion and incorporate feedback into the development of the strategy. Facilitated public participation activities such as community liaison committee meetings, open houses and workshops. Oversaw the development of materials for all activities.

City of Guelph Organic Waste Processing Facility, 2009
Guelph, Ontario

Assisted in developed and carried out a public participation program, including developing materials for Open Houses and managing a stakeholder issue and comment tracking database. Prepared interim consultation reports and assisted the client in responding to public concerns. Public participation activities and reporting are ongoing.

PROJECT EXPERIENCE – MANUFACTURING

AM Dofasco Alternative Standards Application, 2008 - 2010
Hamilton, Ontario

Developed a public participation and agency consultation program, that included public notification strategies, open house organization and public participation materials development. Carried out the public participation program and reported the outcome of the public participation activities. Assisted in the writing and submission of the preliminary Alternative Standards Application.

U.S. Steel Canada Alternative Standards Applications, 2008
Hamilton and Nanticoke, Ontario

Developed a public participation and agency consultation program that included public notification strategies, open house organization and public participation materials development for two U.S. Steel Canada plant locations. Carried out the public participation program and reported the outcome of the public participation activities. Assisted in the writing and submission of the preliminary Alternative Standards Application.

TRAINING

Planning for Effective Public Participation Course
International Association for Public Participation, October 2008

Communications for Effective Public Participation Course
International Association for Public Participation, July 2009

Techniques for Effective Public Participation Course
International Association for Public Participation, July 2009

PROFESSIONAL AFFILIATIONS

Member of International Association for Public Participation

MURRAY G. ROBERTSON



PROFESSIONAL PROFILE

Licensed land agent. A seasoned professional with over 29 years of marketing, stakeholder engagement, Aboriginal consultation, community relations, surface rights and negotiation.

A motivated, energetic and goal-oriented people-person experienced in building positive working relationships with stakeholder communities and customers.

Proven ability to supervise, mentor and develop professional relationships with junior staff, stakeholder engagement consultants and Operations Staff.

Action - Results - Completion Management Style, focused on cycle-time reductions and cost-effective stakeholder engagement strategies designed to obtain license to operate.

Focus: Seeking to excel in a surface rights/stakeholder coordinator role that will draw upon my drive to succeed and my skills in stakeholder management, surface rights, marketing and sales.

WORK EXPERIENCE

AltaLink L.P. **2008- 2011**

Stakeholder Engagement Specialist – Responsible for project management, stakeholder engagement, marketing and public relations for the company's stakeholder community including includes First Nations, municipal Governments, landowners and industry.

Compton Petroleum Corporation **2003- 2008**

Senior Landman, Project Coordinator - Responsible for acquisition of Crown land and fee simple lands in five strike areas. This included engagement with Government, regulators, First Nations, landowner groups, other companies and stakeholder consultants.

BP Canada Energy Company **2001- 2003**

Landman – Work involved surface rights, public relations and safety programs for provincial government, municipal government and regulator audiences.

BC Gas/Terasen Southern Crossing Pipeline Project **1999 – 2001**

Public information meetings / Acquisition of right of way / Pipeline construction Supervisor/ Restoration and damage settlement

Harvest Medical Agencies **1995 – 1999**

Business Owner - Responsible for business development, marketing and sales relationships

Smith & Nephew Richards Medical Canada **1992 – 1995**

Surgical sales representative and marketer for several orthopedic product lines.

MURRAY G. ROBERTSON

7870 Spring Bank Way SW
Calgary, AB T3H 4J8
E-mail: montana2@telus.net
Cell: 403.826.6842

Imperial Metals Corporation – Vancouver **1987 – 1992**

Oil and Gas Land Manager, negotiator and administrator

Westburne Petroleum & Minerals Ltd. – Calgary **1982 – 1987**

Surface Land Manager

Can – Am Land/Maverick Land 1981 – 1982

Surface Land Broker

EDUCATION

University of Calgary, Physical Education Program **1978 -1980**

Lakehead University *Thunder Bay*, BA, Social Sciences **1975 - 1976**

Confederation College *Thunder Bay*, Social Worker Diploma **1972 - 1974**

HONOURS

University Varsity Athlete: Hockey and Track and Field

1980 Olympics: Carded Athlete

Vancouver Triathlon: Winner, 1987

PROFESSIONAL DEVELOPMENT

Too numerous to mention. Includes:

IAP2 Certification

P. Land Professional Certification

Cross- Cultural Awareness Training

ASSOCIATIONS

International Association for Public Participation (IAP2)

Canadian Association of Petroleum Landman member (CAPL)

International Right of Way Association member

Robert A. Mattei



BACKGROUND

Thirty-Eight (38) years experience providing project management, construction management, electrical engineering and design, technical consulting services and project execution support. Services include providing support for any or all project phases including development, design and engineering, construction, commissioning, and plant operations. Subject Matter Expert support services provided for all generation projects.

ELECTRIC POWER INDUSTRY EXPERIENCE

- Solar Power - Solar Photovoltaic, Canadian Solar Solutions solar panels
- Wind Power - Wind turbines; Vestas V90 - 3MW (DVAR Master Controller), GE 1.5MW ESS
- Fossil Power – Natural Gas Fired, Simple Cycle, Combined Cycle, Co-Generation, Coal and Oil fired
- Nuclear Power – Pressurized Water Reactor (PWR) and Boiling Water Reactor (BWR)
- Telecommunications – Data Centers, Central Office Switch Buildings, and Wireless Sites

PROFESSIONAL EXPERIENCE SUMMARY

- TransCanada Corporation - 450-1st Street S.W., Calgary, Alberta T2P 5H1

  - *Management Consultant, Nine Photovoltaic Projects Combined Capacity 86 MWs (November 2011 - Present)* Providing project consulting management and technical support services for the design, engineering, construction, commissioning and interconnection requirements.

  - *Management Consultant, Cartier- Gros Morne Phase I 101MWs Wind Power Project (November 2011 - Present)* Providing project consulting support services to the owner's group.

  - *Project Manager/Owner's Engineer, Kibby Wind Power Project (March 2010 to December 2011)* Provided consulting services to the Kibby Wind Power Project.: Services provided include: Project Management, Engineering, Design, Construction, Commissioning and matters relating to Jurisdictional Authorities' Interconnection requirements.

- Calpine Corporation - 717 Texas Avenue Houston, TX 77002

  - *Director, Engineering (February 2006 to February 2010);* Operations support responsibilities for Calpine's seventy-six (76) natural gas fired simple cycle, combined cycle, cogeneration and geothermal power plants throughout the U.S. Operations support includes outage support for planned and unplanned outages. Corporate Program Manager for over six hundred (600) large power transformers and other critical electrical equipment. Provided Operations support for compliance with NERC regulatory interconnection requirements for protective relaying (Maintenance, Testing and Documentation).

    Also, in responsible charge of the following organizations within the Engineering and Construction Department:

    - Electrical Engineering,
    - I&C Engineering,
    - Predictive Maintenance, and
    - Metering and Monitoring.

- Responsible for providing Electrical and I&C Engineering support during the development, engineering, construction, and commissioning of new power plant projects. Additional responsibilities extend to providing AE oversight and on-site electrical and I&C engineering support, construction management and contractor support across all Calpine's gas fired plants.

- *Manager, Electrical Engineering (2005 to 2006);* Responsible for providing first line electrical and I&C engineering support during the development, construction, and commissioning of new construction power plant projects, including on-site electrical and I&C construction management, AE oversight, on-site electrical contractor assistance to establish scope and work packages for the craft, responses to RFI's, and providing efficient work processes and methods for craft labor to install electrical raceway systems, cable pulling and wiring terminations.

- *Sr. Project Engineer/Electrical and I&C Construction Manager (2003 to 2005);* Provided AE oversight and on-site electrical and I&C construction management for the following projects: Columbia Combined Cycle Power Plant 606 MW (2x1) , Pastoria I Combined Cycle Power Plant 500MW (2x1), Pastoria II Combined Cycle Power Plant 250MW (1x1), and Fox Combined Cycle Power Plant 560MW (2x1).

➢ WRMS Engineering – 1556 Parkside Drive, Walnut Creek, CA 94596

- *Eastern Operations Manager (2000 to 2003);* Responsible for Telecommunications and Data Center Project Development and Operations support services for a Fortune 500 Company. Projects included Virginia Gateway Data Center, Distributive Generation Projects, Wireless Building Risk Assessments, Growth and Improvement Projects, Operating Expense Reduction Projects, Reliability Improvement Projects (e.g. Redwood City CA- Data Center).

➢ Shaw Stone and Webster Group - 100 Technology Center Drive, Stoughton, MA 02072

- *Principal Electrical Engineer (2000);* Responsible for electrical engineering and design of Shaw Entergy Joint Venture Standard Reference Design Project; Natural Gas Combined Cycle (2x1) and Pha Lai 2 coal fired units, Vietnam Coal fired 600MW Power Plant.

- *Lead Electrical Engineer (1998 to 2000);* Responsible for project electrical engineering and design of Calpine Rumford, ME Combined Cycle, 265 MW Power Plant (1x1) and Calpine Tiverton, RI Combined Cycle 265MW Power Plant (1x1, including electrical construction management after the engineering and design was completed.

- *Project Manager/Project Engineer (1997 to 1998);* Responsible for project engineering and project management of *Telecommunications MCI*; construction of $8.5 million, 25,000 sq ft telecommunication's switch expansion project, including a multi-discipline team consisting of architectural, electrical, mechanical, and structural disciplines.

- *Principal Electrical Engineer (1994 to 1997);* Responsible for electrical engineering and design of a Fortune 500 Telecommunications Company $1,000,000,000 switching center infrastructure improvement program at more than 145 central office switching centers across the United States, requiring management of a team of 75 engineers and designers to develop and implement capital projects to improve the reliability of the infrastructure supporting the national communication network. The program established infrastructure reliability criteria based on service reliability targets, documented existing design conditions using intelligent computer aided design drawings.

- *Electrical Division Staff Supervisor, Nuclear Projects (1990 to 1994);* Responsible for various nuclear project technical assignments involving design basis calculations and plant modifications upgrades etc: Commonwealth Edison's 10 Nuclear Plants provided engineering support; Braidwood, Byron, Clinton, Dresden, LaSalle, Limerick, Oyster Creek, Peach Bottom, Quad Cities, and Zion; TVA Bellefonte Nuclear Power Plant, 1256 MW (PWR), Fire Safe Shut- down Analysis; Comanche Peak Nuclear Power Plant, 1,150MW (PWR), Texas Utilities; South Texas Project, Two Pressurized Water Reactors (PWR's) 2,700MW; North Anna Nuclear Power Plant, Pressurized Water Reactor (PWR) 790MW; Pilgrim Nuclear Power Plant 690 MW, Boiling Water Reactor (BWR).

- *Lead Electrical Engineer – (1985 to 1990);* Responsible for project electrical engineering and design and on-site construction support for Beaver Valley Unit #2; Nuclear Power Plant 846MW, Pressurized Water Reactor (PWR), as well as operations support for plant modifications and upgrade projects for Beaver Valley Unit #1, Nuclear Power Plant 892 MW Pressurized Water Reactor (PWR).

- *Assistant Lead Electrical Engineer (1979 to 1985);* Responsible for electrical engineering and design, and on-site construction support, for Millstone Unit #3, Nuclear Power Plant 1150 MW, Pressurized Water Reactor (PWR).

- *Design Engineer – (1974 to 1979);* Responsible for electrical raceway, cabling, and wiring system designs for Shoreham Nuclear Power Plant 820MW Boiling Water Reactor (BWR).

- *Design Engineer - (1973 to 1974);* Responsible for electrical raceway, cabling, and wiring system designs Canal Electric, Two Units 1200MW Oil Fired.

- *Design Engineer - (1972);* Responsible for electrical raceway, cabling, wiring system designs, and vendor submittal review and comment for Maine Yankee Nuclear Power Plant 900MW Pressurized Water Reactor (PWR).

- *Subject Matter Expert (SME), Various Nuclear Projects;* Fire protection and safe shutdown analysis for compliance with the requirements of Federal Law (10 CFR50 Appendix R) Fire Protection Safe Shut-down analysis

- *Subject Matter Expert (SME), Electric Power Research Institute (EPRI);* Prepared technical design criteria for the development of Technology Transfer to the Republic of China.

- *Subject Matter Expert (SME*), *Massachusetts Institute of Technology Graduate School of Engineering;* Provided technical assistance, analyzing electrical type accidents at commercial U.S. nuclear power plants.

Education / Training

B.S., Electrical Engineering - University of Massachusetts – 1970
Framingham State College – Massachusetts State Teaching Certificate
Shaw Stone and Webster Education Courses; Technical Writing, Progressive Discipline, Electrical Engineering Applications, and Electrical Design Applications

Professional Affiliations

IEEE- Institute of Electrical and Electronic Engineers – Member
IEEE- Power Engineering Society - Member

Ryan McFadden

Work Experience

Senior Aboriginal Relations Advisor, Aboriginal & Tribal Relations

TransCanada Pipelines Limited **Calgary - (July 2012 to Present)**

- Coordinate and lead Aboriginal engagement teams for major projects across different business units. Project areas include: west coast power development and LNG, gas to liquids pipeline conversion projects across Canada, and eastern natural-gas-fired generation (Napanee Generation Station).
- Conduct Aboriginal risk due diligence for pipeline acquisitions.

Regulatory and Stakeholder Relation Coordinator

Canadian Natural Resources Limited **Calgary - (July 2011 to July 2012)**

- Developed and led stakeholder engagement programs for thermal in-situ oil sands (SAGD) projects in NE Alberta (Grouse and Kirby In-Situ Oil Sands Projects)
- Managed regulatory process with Provincial government and industry regulatory authority for thermal in-situ projects

Senior Coordinator, Consultation & Negotiations

Aboriginal Relations & Negotiations, BC Hydro **Vancouver (Nov 2006 to June 2011)**

- Lead coordinator to over 45 First Nations and Tribal Councils in SE and NE Regions of BC. Responsible for developing and leading legally defensible consultation workplans to support capital program and to fulfill the Crown's duty to consult.
- Manage diverse team of consultants, senior professionals, records management staff and legal counsel to prepare consultation materials, gather traditional use information, develop contracts, relationship protocols, and benefit agreements.

Policy and Economic Development Consultant - Katzie First Nation

Ryan McFadden Consulting Ltd. **Vancouver (2005 to 2006)**

- Acted as band representative for commercial contract and joint-venture negotiations. Responsible for developing business, procurement and contracting opportunities to create Aboriginal joint-venture partnerships to provide support services for the Golden Ears Bridge development project. Aboriginal joint-ventures included: security, archaeology, environmental monitoring, safety officers, and water taxi. Katzie-Coast Marine recognized at the BC Aboriginal Business Awards - Outstanding Business Achievement Award 2010.

Policy and Economic Development Consultant - Kwanlin Dun First Nation

MacArthur West Management Consulting **Whitehorse (2004 to 2005)**

- Project Manager tasked with developing action plan to assist Kwanlin Dun implement self-government agreement.
- Created new governance model, policies and procedures, and coordinated core funding to improve governance and fiscal planning. Efforts included extensive interviews with Chief and Council, community and government stakeholders. Changes led to improved fiscal

accountability, sustainable programs, and coordination between social and economic organizations.

Internships

Research Manager - Wildland Urban Interface (WUI) Risk Assessment Project

City of Calgary Parks Department / Calgary Fire Department Calgary (Summer 2004)

- Research Manager tasked with project initiation, planning and research to determine WUI fire risk potential for City of Calgary. Engaged in extensive interviews with stakeholders and industry experts. Research led to Capstone project (thesis) which won several awards. Findings and recommendations have been adopted by Calgary Fire Department and materials have been used for public education.

Research Assistant

Western Economic Diversification Canada Edmonton (Summer 2003)

- Research Assistant tasked with reviewing and adjudicating funding proposals to support business development and community economic development in rural and urban areas throughout the four western provinces. Drafted policy, briefing notes, and prepared information for Deputy Minister

Research Assistant - Recruiting Assessment Project

City of Calgary Police Department, Research and Development Unit Calgary (2002)

- Research Assistant tasked with identifying issues associated with attrition, retention, and recruiting. Research led to complete overhaul of recruiting practices, updated internet information and new approach to attracting high calibre recruits. Recommendations can still be found on Calgary Police Service recruiting website

Education & Training

Presented at the Vancouver Board of Trade - 2011 Aboriginal Opportunities Forum: *Making the Grade - Education and Skills training*

Presented at the BC Hydro Construction Services All Managers Meeting 2011 – *Working with First Nations: Who Owns the Relationship*

Authentic Leadership Training	BC Hydro	2010-2011
Negotiations Skills Training	The Banff Centre	2009
Master's in Public Policy (MPP)	Simon Fraser University	2003-2005

- Graduated with Distinction
- Recipient of Canadian Association of Programs in Public Administration (CAPPA) Award for Outstanding Public Policy Work

Applied Policy Studies Degree Mount Royal University 1998-2003

- Graduated with a fourth-year grade point average of 3.81
- Minor in geology and earth sciences

BC Wildland Fire Fighter 1998-2001

LARRY SCHEUERMAN

PROJECT ROLE:

MANAGER ENERGY PROJECTS DEVELOPMENT

QUALIFICATIONS:

- Brooks Senior High School
- CGSB Certified Level II Industrial Radiographer Trade Certification
- Mohawk College Ultrasonics Level 1
- WIC Training Modules Welding Technology and Inspection 1-21
- ISO 9000 Auditor Training
- Various Safety and Industry Training
- Karass Negotiation Training
- Miscellaneous Management Training

EXPERIENCE HISTORY:

TransCanada Pipelines Limited
January 2012 – Present
Manager Energy Projects Development

- Manage a team of engineers and project management professionals responsible for technical development of compression and energy projects through proposal and definition phases.

TransCanada Pipelines Limited
June 2008 – 2011
Project Manager Power Development

- Multiple development projects both thermal and renewable including the 900 MW GTA SW project

TransCanada Pipelines Limited
November 2007 – 2008
Manager Field Operations Airdrie North

- Manage a staff of 20 field operations staff in the daily operation and maintenance of 5 compressor stations, 140 measurement facilities and several hundred kilometers of large diameter pipeline.

TransCanada Pipelines Limited
January 2001 – 2007
Commercial Manager Contracts

- Develop pro forma contract documents for use by Power Development Engineering;
- Know and understand the supply market for major equipment and contractor services required for the construction of new co-generation facilities in North America;

- Negotiate and form EPC contracts and major Equipment purchase contracts for construction projects;
- Negotiate and resolve any construction claims or other contractual issues which arise during or after construction;
- Manage various aspects project development process up to award of all construction contracts

TransCanada Pipelines Limited
April 2000 – January 2001
Construction Strategy Leader

- Set up and implement construction strategies for mainline PL construction and ML maintenance programs and TransCanada Energy Power Plant Construction. This work involved significant negotiations and strategic planning with both union and non-union construction contractors.
- Negotiation and Resolution of Construction claims for both pipelines and facilities.

TransCanada Pipelines Limited
August 1999 – April 2000
Contracts Manager International Project Development

- Construction contract negotiation and formation for international construction projects, primarily in Brazil and Mexico.

TransCanada Pipelines Limited
January 1997 – August 1999
Construction Strategy Leader

- Set up and implement construction strategies for mainline PL construction. Several million dollars have been cut from the cost of Construction projects by the implementation of strategies such as negotiated price projects, long term contracts, sole source and target price contracts.
- Negotiation and Resolution of Construction claims for both pipelines and facilities

TransCanada Pipelines Limited
December 1995 – October 1996
Nova Gas International GasAndes Project

- Change existing training modules to meet the needs of Nova Gas International for use on the GasAndes Project.
- Implement the training of GasAndes Inspection staff. Review and accept contractor construction procedures.
- Construction supervisor on the SanAlfonso Portion of the Gas Andes project. Duties include land owner and community group negotiations, construction supervision of two major river crossings, resolution of constructability problems including modification of existing designs, micro routing of the line and selection of river crossing locations. Close liaison with environmentalist and land owners to insure minimal impact in environmentally sensitive areas of the project.

TransCanada Pipelines Limited
August 1995 – November 1995
Contractor Quality Implementation Coordinator

- Drafting of a Quality Manual for use by Nova Gas Transmission Contractors.
- Work with Nova Gas Transmission Contractors to the implementation of Contractor managed quality programs on pipeline construction projects.

TransCanada Pipelines Limited
1994 – 1995
Acting Team Leader Construction Management

- Duties including Monitor Coach and Manage a team of Construction Inspectors.
- Forecast and manage manpower and training requirements for Construction staff.
- Implement, negotiate and monitor changes in Scope/Circumstance for construction projects.

TransCanada Pipelines Limited
1992 – 1994
Welding Specialist

- Welding and NDT problem solving.
- Work with design to develop and test welding procedures and evaluate potential new welding processes.
- Reviewing and approving technical qualifications of potential contractors.
- Review and advice on new technological developments related to pipeline or facility construction.
- Training and supervision NGTL technical inspectors.
- Represent construction management on in house ISO development.
- Develop a ISO based quality manual for Construction Management.

TransCanada Pipelines Limited
1989 – 1992
Senior Welding Inspector

- Senior welding inspector on 400+ kilometers of large diameter pipeline. This includes Manual SMAW welded projects and Semi Automatic GMAW welded projects primarily CRC Evans system.
- Project duties have also included most other pipeline inspection functions.
- Conduct a technical evaluation and inspect the welding on 10 Km of NPS 30" line welded with the Saturnax Auto weld system on the Peninsular Gas Utilization Project in Malaysia.

NOVACORP International Consulting Inc.
1987 – 1998

- Procedure development and monitoring of all phases of welding and Non Destructive Testing on 700 Kilometers of NPS 24 and 36 on shore pipeline and 112 Kilometers of offshore pipeline on the USSR Turkey Natural Gas Pipeline

Russell Ultra Sound NDT Services Ltd.
1977 – 1987
Title and Department

- Industrial radiography on various pipelines and facilities in Alberta
  Complete management of all NDT services related to Calgary based operations. This includes new office start up, sales, bidding and management of NDT staff.

CHRISTINE CINNAMON
Environmental Manager, TransCanada Corporation
Power Generation Development and Operations

Christine Cinnamon is an Environmental Manager with over 15 years of experience in a technical role at TransCanada and has been responsible for a variety of duties specifically relating to environment, health and safety issues and security/emergency procedures. Her role has included direct support of the Energy side of the business from both policy and compliance standpoints, in both Business Unit support and in Corporate Policy development and implementation. She has been extensively involved in the development and environmental permitting process of over 2200 MW of existing or temporary Power Generation Projects in Eastern Canada and the United States. Currently she is responsible for the permitting and associated public consultation of an extensive amount of new or potential power projects, including wind, solar and natural gas generation, in various stages of development or operation in Ontario, Quebec and Maine. Her role in business development includes assessment of permitting risks and strategies for new proposed projects in the power generation area as well as the analysis of risks associated with potential acquisitions. Her duties include the overall management of permitting processes, involving the drafting, review, and revision of documents for presentation to federal, provincial/State and municipal regulatory agencies and operational issues related to environment, safety and health issues. Christine is also extensively involved in policy work at provincial and federal levels of government, through individual consultation as well as through committee involvement at several key Industry Organizations. Air emissions monitoring and control technologies have been a focus for her in representing the Company at these forums, and as a personal interest, and she has both presented and co-published material on the subject at a national level.

Christine has been integral in the development and implementation of stakeholder relations plans, with training in media and public relations. This has required successful coordination with various internal departments such as Government Relations, Public Affairs, Communications, Community Relations, Land and Aboriginal Relations. She has been comfortable representing the Company to media and large audiences (sometimes hostile) in a number of Provincial/State and National forums through various speaking engagements and regulatory processes, including public meetings and adjudicated hearings, both in English and French. Her interpersonal and communication skills have been key in the successful development of interdepartmental and external stakeholder relationships. She has enjoyed managing and working with employees directly reporting to her locally and across Canada. She is also currently mentoring two junior environmentally-focused individuals.

Christine's responsibilities have included:

- Completed environmental permitting for the construction/expansion/acquisition of 8 power plants in Ontario, 1 in Quebec, 1 in New Brunswick, 1 in British Columbia and 1 in Maine, including Tunis

(43MW-natural gas), North Bay (40MW-natural gas), Nipigon (42MW-natural gas), Kapuskasing (48MW-natural gas), Calstock (35MW biomass), Cobourg (110MW portable natural gas), Bécancour (550MW-natural gas), Grandview (80MW-natural gas), Williams Lake (72MW-biomass), Portlands Energy Centre (550MW-natural gas), Halton Hills (683MW-natural gas) and Kibby (132MW-wind); continued to provide transition support into operations as well as ongoing operational support

- Currently involved in environmental permitting for the construction of several new power projects including an expansion to the Kibby project (30 MW of wind generation in Maine) and responsible for TransCanada representation in permitting of 9 solar generation projects in Ontario (to be acquired upon completion of construction – total of 86 MW)
- Previously involved in environmental permitting for numerous wind projects, including Cartier (7 wind projects totaling 739.5MW); Belwood (50MW-wind) and Romney (170MW-wind)
- Communication and coordination with federal, provincial/State and municipal regulatory agencies, representing TransCanada's interests
- Review and revision of TransCanada's environment and safety policies and procedures to reflect issues related to the operation of power plants and new legislation
- Support Power Project Managers/Directors with environmental reporting requirements, both internal and regulatory, as well as with various aspects of siting and planning of projects
- Conduct environmental due diligence related to project development and acquisitions, including risk analysis and cost estimation
- Review engineering design and process (operations) specifications with respect to compliance with all applicable environmental, health and safety legislation as well as overall acceptability
- Conduct and respond to audits in all areas of health, safety and environment at the project level
- Extensively involved in the development of an ISO 14001 compliant HSE management system at the corporate level
- Responsible for safety and health reporting both internally and to external agencies (i.e. WSIB), including involvement in the development and implementation of an Incident Management Process
- Attending Member of the following:
  - Environment Committee, Ontario Energy Association (previously Chair for four years)
  - Environmental Assessment Caucus, Canadian Wind Energy Association
  - Board of Directors, ECO Canada (Environmental Careers Organization of Canada) – Vice Chair; Management Committee - Chair
  - National Steering Committee for Environmental Labour Market Information – Industry Representative
  - University of Toronto Masters of Science (Environmental Studies) Advisory Board – ECO Canada Board Representative

- ECO Industry Partnership Network with the Toronto District School Board – Chair
- Air and Waste Management Association Board, Ontario Chapter – Industry Representative

EDUCATION/PROFESSIONAL DESIGNATIONS

- Bachelor of Science (Agriculture) Honours, Major in Environmental Biology University of Guelph (1996)
- Canadian Certified Environmental Practitioner, Obtained designation in 2005 and recently recertified (2011) as Environmental Professional under the Management category
- Completed Intermediate level Director Education Program (2010), Canadian Board Diversity Council

Rebecca McElhoes

Highlights of Stakeholder Engagement Program Development and Management Skills

- Strategic Community Relations/Stakeholder Engagement Planning
- Stakeholder Engagement Program Implementation and Management in various regulatory jurisdictions
- Issues Management/Stakeholder Advice and Counsel
- Materials Development
- Leadership, Mentoring, Team-building
- Event Planning

Stakeholder Engagement Work Experience

TransCanada, Calgary, AB July 2001 to date
Community Relations Advisor

- Participated in the development of a Best Practices Manual for TransCanada Community Relations Practitioners (2002)
    - Led consultation with key internal stakeholders and users
    - Researched external best practices
    - Developed Community Relations sample plans, templates, checklists
- Lead the development and implementation of stakeholder engagement programs for complex energy infrastructure projects (pipe and power), including:
    - Strategic planning
    - Scheduling, Budgeting
    - Issue Identification/Management
    - Acquisition and Management of Consultants
    - Working on multi-disciplined teams
    - Identification and management of stakeholder risks
    - Counsel and Advise on complex stakeholder issues and outreach approaches
- Provide leadership and counsel to Calgary and regionally based Community and Aboriginal Relations practitioners

TransCanada, Airdrie, AB January 1998 to July 2001
Community and Aboriginal Relations Liaison
Rocky Mountain Region

- Developed and implemented regional Community and Aboriginal Relations plans
- Developed and implemented regional Public Awareness program

- Provided leadership and direction to local Community Relations committee and participated in local leadership and emergency management teams.
- Managed local media relations
- Developed local strategic Community Investment program and led local CI team
- Managed regional Community and Aboriginal Relations issues
- Developed and implemented Stakeholder Engagement plans for regional pipeline projects
- Represented TransCanada on regional oil and gas multi-stakeholder groups (synergy groups)
- Co-Chaired active regional multi-stakeholder group

Education

Bachelor of Arts
Major in Communications
Simon Fraser University, Burnaby, British Columbia 1995

Diploma in Journalism
Mount Royal University, Calgary, Alberta 1991

Professional Development

- Member, IABC, 1999 – present
- Attended Boston College, IABC, IAP2 professional development conferences, 1999 to present
- Member of Calgary-based Community Relations Peer Group, 2005 to present
- Member of Communications group in Synergy Alberta, a provincial non-profit society supporting Alberta synergy groups, 2005/2006
- Participated in and co-chaired numerous Oil and gas multi-stakeholder synergy groups between 1998 and 2003

Art Cunningham

A senior professional with 25 years of experience providing expert advice in the field of Aboriginal and tribal relations for TransCanada, a leading energy company in North America.

A current and former Board member of many non-profit organizations in Canada

Experience

Senior Aboriginal / Tribal Relations Policy Advisor - TransCanada, Calgary, 1982-Present

TransCanada owns and operates transmission and energy facilities throughout Canada and the United States, which intersect with over 150 Aboriginal communities in Canada and over 40 tribes in the United States, representing approximately 30 diverse cultural groups. The Senior Policy Advisor role involves:

- developing and implementing corporate policy and principles on Aboriginal and Tribal Relations
- providing senior-level advice to the executive and the management on issues and trends
- designing, planning and managing corporate and project-specific negotiations with Aboriginal communities and tribes
- developing internal corporate capacity and departmental structure to support positive Aboriginal and tribal relationships including in the areas of Traditional Knowledge, business and employment
- providing advice and mentorship on corporate agreements and negotiations

Children and Family Services, Calgary Alberta, 1999 - Present

As a Governor within the organization, I oversee the successful delivery of support and services to children, youth, adults and families residing in the City of Calgary and surrounding regions. This includes:

- providing advice in the development of policy and initiatives for Aboriginal families
- providing advice in the development of organizational capacity and departmental structure

Calgary Chamber of Commerce, Aboriginal Opportunities Committee, 1994 - Present

As a current member and former Chair of the Calgary Aboriginal Opportunities Committee, my focus has been on developing relationships with Aboriginal communities on behalf of the business community of Calgary. As such, I have:

- advised in the development of the document “How to do business in Aboriginal communities”
- assisted in the development of a unique program leading to the creation of opportunities for employment for Aboriginal people

Senator, Calgary Friendship Centre, 2005 - Present

Provide advice and guidance to the Friendship Centre, consistent with their mandate of creating positive understanding between Aboriginal and non Aboriginal communities.

Calgary Aboriginal Women's Shelter, 2003 - 2008

Governor of the Calgary Aboriginal Women's Shelter whose mandate is the protection of women against family violence.

Circle for Aboriginal Relations (CFAR), 2003 - Present

A founding member and long-standing Board member for CFAR, an Aboriginal relations organization committed to the development of qualified Aboriginal liaison practitioners.

Education

- Technical designation in the trades of electrician and corrosion technologist - 1982
- Leadership courses in the disciplines of mediation and facilitation - 1990 - Present

Awards

- I received the Chief David Crowchild Memorial Award in 1997. This prestigious award is bestowed upon persons who create bridges of understanding between Aboriginal and Non-Aboriginal people.
- I was also recognized by the International Rotary Foundation when they awarded me the Paul Harris Fellowship Award for contributions to the community.
- In 2005, I received the Alberta Centennial Medal for outstanding service to the people and province of Alberta.
- In 2006, the Métis Nation of Alberta recognized me for success in the corporate world

CARL LETWIN



PROFILE

Eight years of comprehensive experience in the oil and gas land industry. Self directed with strong decision making skills. An effective leader with sound business sense who creates positive results for all parties involved in the negotiation of successful land contracts. A proven ability to coordinate and provide leadership for large projects from start to finish in a timely manner.

EXPERIENCE

Senior Land Representative (2011-2013)
TransCanada PipeLines Limited

- Provide senior level leadership for large pipeline and regulatory projects
- Build effective and positive relationships with stakeholders, industry peers, consultants and project team members via excellent communication and written skills
- Prepare a sound budget and detailed execution plan for each project
- Guide projects through the National Energy Board regulatory process
- Demonstrate effective negotiation skills when dealing with challenging land related issues

Surface Land Coordinator (2007-2010)
Encana Corporation, *Calgary, Alberta*

- Senior level experience with oil and gas project coordination and the acquisition of surface rights via land access agreements
- Delegate and prioritize large projects to external land brokers, external survey companies, internal land administrators, internal land agents, and the appropriate construction personnel
- Provide expert advice on challenging land access issues
- Facilitate negotiations of Surface Leases and Pipeline Right of Ways with landowners and other stakeholders, including landowner advocates, lawyers, ERCB staff, and representatives of municipalities and counties within Alberta
- Develop comprehensive budgets for Surface Land projects, approve external invoices, and prepare cost estimates
- Collaborate with internal colleagues to develop processes to improve corporate efficiencies
- Approve Surface Land packages for wellsite, pipeline, and facility applications to the Energy and Resources Conservation Board.

Surface Land Agent (2004-2007)
***Maverick Land Consultants**, Calgary, Alberta*

- Responsible for the acquisition of oil and gas Surface Leases and Right of Way Agreements
- Negotiate successful land contracts with landowners on behalf of various oil and gas firms in a financially accountable manner
- Proficient with research of land values/rates through the use of surface land integrated management (SLIM) software, consultation with industry colleagues, and internet searches
- Coordinate with land administrators to ensure that all documents are complete for field acquisition
- Provide clients with updated information on current field files and advise on terms of settlement
- Extensive knowledge in many industry regulations with a specialization in the Directive 56 (Energy Development Application and Schedules)
- Participation in Appropriate Dispute Resolution (ADR) meetings, E.U.B. non-routine applications and Surface Rights Board hearings

Surface Land Administrator (2004)
***Maverick Land Consultants**, Calgary, Alberta*

- Preparation of documents for surface acquisition and public notification for Freehold and Crown lands
- Ensure all "land" related industry regulations are met to obtain an Alberta Energy Utilities Board License or Permit
- Skilled at use of SLIM (land management program) and Microsoft Office
- Worked effectively with many levels of land personnel in a fast paced environment

EDUCATION AND PROFESSIONAL AFFILIATIONS

International Right of Way Association
Registered member of Chapter 48 (2011-2013)

Petroleum Joint Venture Analyst Certificate
Mount Royal University (2010)

Canadian Association of Petroleum Landmen
Attended courses through this Association including (PSL) Industry Activity and Mitigation of Groundwater Effects, (PSL) Farm and Ranching Practices, (PSL) Fundamentals of Surface Agreements, and (PSL) Mitigating the Challenges of ERCB D56 Non-Routine Applications.(2009-2010)

Land 745 Land Agent Licensing
Olds College (2005)

Petroleum Land Contract Administration Certificate
Mount Royal College (2004)

Bachelor of Arts Degree
University of Manitoba (1995)

LESLIE JEANNE THOMAS
[redacted]

Career Objective

To utilize my accumulated skills and experience in a workplace environment that provides opportunities to mentor and support others and chances to challenge and educate myself.

Qualification Summary

- Thirty plus years of various responsibilities in mineral, contracts and surface land. The majority being a variety of roles in surface.
- Strong working knowledge of land acquisition and administration for wells, pipelines and related facilities, wind power and gas storage.
- Ability to successfully supervise, manage and coach employees.
- Extensive knowledge of provincial and federal regulations and legislations.

Professional Experience
Work History

Manager, Land Administration – TransCanada PipeLines Limited
October 2009 to present
Specific responsibilities:

- Understanding how to engage and influence Company staff and senior management in significant issues that affect the land department.
- Continually reassessment of the applicability of all land programs, practices and agreements in relation to the current climate of regulatory change and stakeholder expectations.
- Managing land programs to ensure that practices comply with all corporate policies as well as federal and provincial legislative and regulatory requirements.
- Representing TransCanada at industry and regulatory forums, workshops and organizational committees, and providing expert witness testimony regarding TransCanada's practices, policies and programs.
- Leading the research, analysis and implementation of legislation and regulation which impacts Land across all Canadian jurisdictions.
- Maintaining a working knowledge of the federal and provincial regulatory regimes.
- Leading, motivating, mentoring, coaching and counseling a team of more than 20.
- Managing the analysis, interpretation and drafting of land agreements and documents.
- Providing leadership, expertise and direction in the management and resolution of complex land-related issues.

- Managing forecasting and budget preparation for the Land department and annual payment program.

Senior Land Contracts Analyst – TransCanada PipeLines Limited
January 2009 to October 2009

- Identification, analysis and resolution of complex land/legal issues.
- Preparation and development of land agreements.
- Mentoring junior land staff.
- Supervision of external land brokers.
- Monitoring legislative and regulatory changes.
- Handle queries from land team, field representatives, third parties, project managers and others.
- Support development and maintenance of department processes and procedures.

Manager, Land – AltaGas Ltd.
January 2001 – January 2009

- Supervision, mentoring and training of department staff.
- Coordination of internal and external processes and staff for construction projects with land involvement.
- Development and continued improvement of department processes and services.
- Addressed internal and external queries, concerns and questions.
- Prepared, reviewed and approved land documents.
- Input data records.
- Prepared reports for department and management.
- Participated in meetings and presentations.
- Researched and provided updates to department and corporation with regard to industry, regulatory and legislative process and policy changes and additions.
- Participated in high level due diligence for acquisition and divestiture projects.
- Managed the department budget.
- Reviewed and approved invoices, cheque requests and annual rental payments.

Surface Land Coordinator – Newport Petroleum Corporation 1998-2000

- Coordinated and supervised external land agents and surveyors for new construction projects and related issues.
- Provided support and information to engineers, field staff, construction group and management as it relates to land acquisition, compliance and ongoing administration.
- Reviewed, approved and administered of land acquisition packages.
- Reviewed, approved and processed annual rental payments.
- Day to day administration of land records and documents.
- Mentoring junior team members.
- Addressed internal and external questions, concerns and comments.

- Monitored regulatory and legislative updates, external processes and best practices.
- Prepared and administered internal policies, procedures and best practices.
- Developed and maintained relations with stakeholders, landowners, regulatory bodies and third parties.
- Processed joint venture and third party invoices.
- Supported mineral administrators.

Senior Land Administrator – ELAN Energy Inc. 1997-1998

- Supported landmen, engineers, field staff, construction and land manager in land acquisition.
- Reviewed and administered land acquisition packages.
- Day to day administration of land records and documents.
- Addressed all third party requests.
- Handled internal and external surface land queries and concerns.
- Monitored regulatory and legislative updates.
- Participated in development of internal processes and procedures.
- Built and maintained relationships with stakeholders, landowners and third parties.
- Reviewed and prepared annual rental payments.
- Administered acquisition and divestitures.

Land Administrator – NOVA Gas Transmission Ltd. 1996-1997

- Supported land agents, land group members, field staff and project managers.
- Reviewed and administered land packages.
- Day to day administration of land records and documents.
- Handled internal and external questions and concerns.
- Administered on-going file maintenance.
- Built and maintained relationships with stakeholders, landowners and third parties.

Land Analyst – Norcen Energy Resources Limited 1987 – 1996

- Supported landmen, engineers, field staff, drilling and land team.
- Administered Land Contracts and mineral land files.
- Prepared and processed all land acquisition and divestiture documentation.
- Reviewed and administered land packages.
- Administered land records and documents.
- Coordinated external land agents and surveyors in land acquisitions.
- Processed third party requests.
- Land Department filing.
- Reviewed and approved annual rental payments.
- Input file data and maintained file records.
- Built and maintained relationships with industry peers, landowners and third parties.

- Researched and developed knowledge of applicable legislation and regulations.
- Created processes and procedures.
- Supported receptionist with phone coverage.
- Processed assignment and novations and notice of assignments.
- Prepared acquisition and divestiture documents. Participated in due diligence reviews.

Land Administrator – Murphy Oil Company Ltd. 1980 – 1987

- Assisted landmen with project administration.
- Administered all surface and mineral land documentation.
- Filed all land documentation.
- Input and maintained land records.
- Prepared annual lease payments.
- Administered Alberta Land Title accounts.
- Processed all third party requests and related documents.
- Prepared acquisition and divestiture documents.
- Handled landowner queries and questions.

Clerk Typist – University of Calgary/Ambulatory Care Centre 1979 – 1980

Computer Skills

- Proficient in Word, Access, CGI Landman, Qbyte Land, Qbyte FM, Excel, Windows, Accumap, Powerpoint, LSAS, Internet, Spin 2, AFE Navigator, EGIS.
- Participated in research, analysis and implementation of several land systems.

Training and Certification

SAIT: Land Administration Certification Program (first roll out).
CAPL: Surveying and Surface Rights Board Applications, Introduction to Petroleum Land Administration, Oil & Gas Law, Surface Rights, Alberta P&NG Regulations, CAPL Operating Procedure, Torrens System & Freehold Mineral Lease, Conflict Resolution, Farming & Ranching Practices.
CAPLA: B.C. Regulations & Tenure, Administration of Freehold Mineral Rights, B.C. Surface Rights, Administration of Indian Oil & Gas Lands, Alberta Crown; Transfer & P&NG Lease Administration, Administration of Surface Rights in Alberta, Freehold Lessor Estates, Administration of ERCB D56 & D60, U.S. Land Administration, Saskatchewan P&NG Rights, B.C. P&NG Rights,
University of Calgary – Environmental Management Overview
Mount Royal University - Professional Business Communications Certificate of Completion (one course remaining)

Affiliations

Canadian Association of Petroleum Land Administration (CAPLA)
Canadian Association of Petroleum Landmen (CAPL)

“Exhibit G”

Isolux Corsán Amazon Transmission Line Project

In 2008, Isolux Corsán won a competitive auction administered by Brazil's National Agency of Electric Energy (**ANEEL**)[1] to develop, construct and operate 1,191 km of 500 kV and 230 kV high voltage lines connecting Manaus (the capital of the State of Amazonas) and Macapá (the capital of the State of Amapá) with the country's National Interconnected System[2] (the "SIN"). The following provides an overview of the project.

1. Transmission Line Auction in Brazil

In 2000, ANEEL introduced an auction system for the development and operation of transmission lines to stimulate competition in the transmission sector. The auctions included the participation of private companies.

1.1 Lots A and B of the Auction ANEEL 004/2008

In October 2008, ANEEL awarded Isolux Corsán lots A and B of the Auction ANEEL 004/2008 (the "**Amazon Transmission Auction**"). The project is part of the interconnection Tucuruí – Macapá – Manaus ("**Linhão Interconnection**"), comprised of lots A, B and C of the Amazon Transmission Auction. Together with the other stretches of the Linhão Interconnection, the project enables the interconnection of vast regions in the states of Pará, Amapá and Amazonas with the **SIN**. The Linhão Interconnection has capacity to transport about 2,400 MW, enough capacity to meet anticipated demand for the city of Manaus until 2025. This interconnection will increase the reliability of energy supply to the northern region of Brazil and reduce tariffs to consumers and costs to Brazil's entire electricity sector.

1.1.1 Importance of the Project

Linhão Interconnection is an important milestone in the Brazilian energy sector and represents a priority in the Brazilian Growth Acceleration Program ("**PAC**")[3]. The project also offers positive external benefits to the Brazilian economy by reducing expenditures on the Fossil Fuel Consumption Account ("**CCC**")[4] and by contributing to:

- greater reliability of the electrical system in the area by reducing dependence on oil;
- meeting the power demand of previously isolated communities in the Amazon region and helping spur their economic development;

[1] ANEEL: is the National Agency of Electric Energy which is responsible for regulating and supervising the production, transmission and sale of electricity in accordance with the Policies and Guidelines of the Federal Government. Website: www.aneel.gov.br

[2] SIN: is an integrated system of coordination and control of generation and transmission of energy in Brazil. It is composed of companies from the regions: South, Southeast, Midwest, Northeast and part of the North of the country. This system encompasses 96.6% of the energy production capacity of Brazil.

[3] PAC: released in 2007, is a Brazilian federal Government program that encompasses a set of economic policies which aim to accelerate Brazil's economic growth through public investments mainly in infrastructure.

[4] CCC: the "Conta Consumo de Combustíveis Fósseis", in force since 1993, raises monies to fund diesel thermoelectric generation from isolated areas (concentrated in the North region of the country).

- reducing subsidies for fossil fuel power generation, thereby reducing power costs for all consumers in Brazil.

2. Project description

The Linhão Interconnection is divided into three Lots: A, B and C. Isolux Corsán is responsible for the development, construction and operation and maintenance of transmission facilities for Lots A and B. Lot A, known as Linhas de Xingu Transmissora de Energia ("**LXTE**"), is approximately 509 km of transmission lines between Tucuruí and Jurupari (see Figure 1). Lot B, known as Linhas de Macapá Transmissora de Energia ("**LMTE**"), is approximately 681 km of transmission lines between Macapá and Oriximiná (see Figure 3). LXTE and LMTE are collectively referred to as the "Amazon Project".

The following is a technical summary of the LXTE and LMTE lines:

(i) LXTE:

- 500kV transmission line Tucuruí – Xingu (double circuit), with an extension of 265 km
- 500kV transmission line Xingú – Jurupari (double circuit), with an extension of 244 km
- Extension of 500kV Tucuruí Substation
- 500kV Xingú Substation, including 4 Series Capacitor Banks to compensate the reactance of the lines
- 500/230 kV Jurupari Substation , including:
    - 900 MVA transformation 500/230 kV
    - Static Var Compensation of +-200 MVAR
    - 2 Series Capacitor Banks to compensate the reactance of the lines
    - 2 Series Capacitor Banks to compensate the reactance of the lines (included in Lot B)

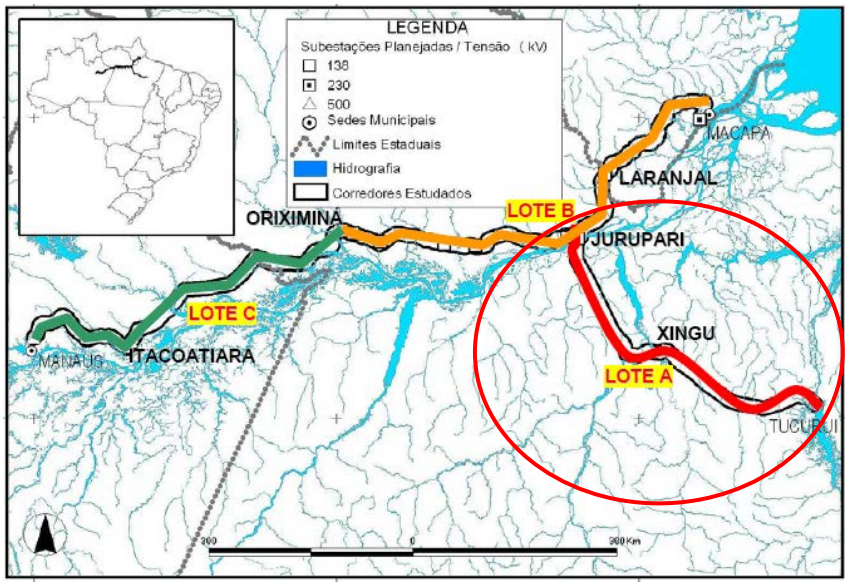


Figure 1: LXTE
Source: ANEEL

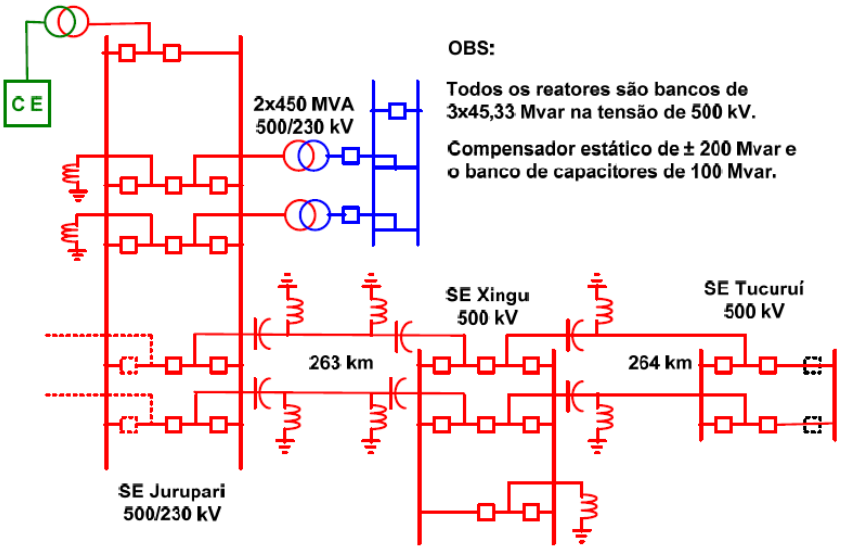


Figure 2: LXTE Substations location
Source: ANEEL

(ii) LMTE:

- 500kV transmission line Oriximiná– Juruparí (double circuit), with an extension of 350 km
- 230kV transmission line Jurupari– Laranjal (double circuit), with an extension of 105 km
- 230kV transmission line Laranjal – Macapá (double circuit), with an extension of 226 km
- 500/138 kV Oriximiná Substation including:
    - 2 Series Capacitor Banks to compensate the reactance of the lines
    - 150 MVA transformation 500/138 kV
    - Static Var Compensation of +-200 MVAR
- 230/69 kV Laranjal Substation including 200 MVA Transformation 230/69 kV
- 230/69 kV Macapá Substation including 450 MVA transformation 230/69 kV
    - Static Var Compensation of +-100 MVAR

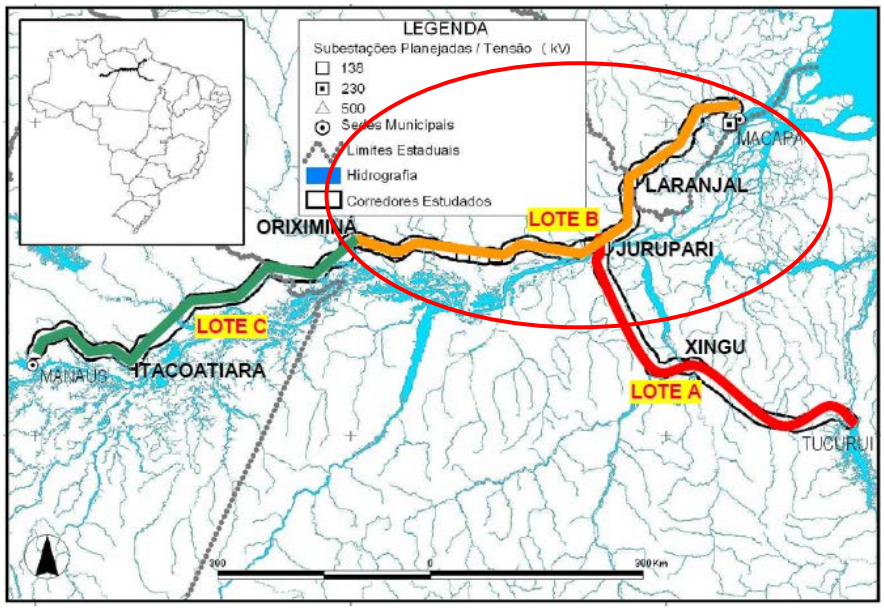


Figure 3: LMTE
Source: ANEEL

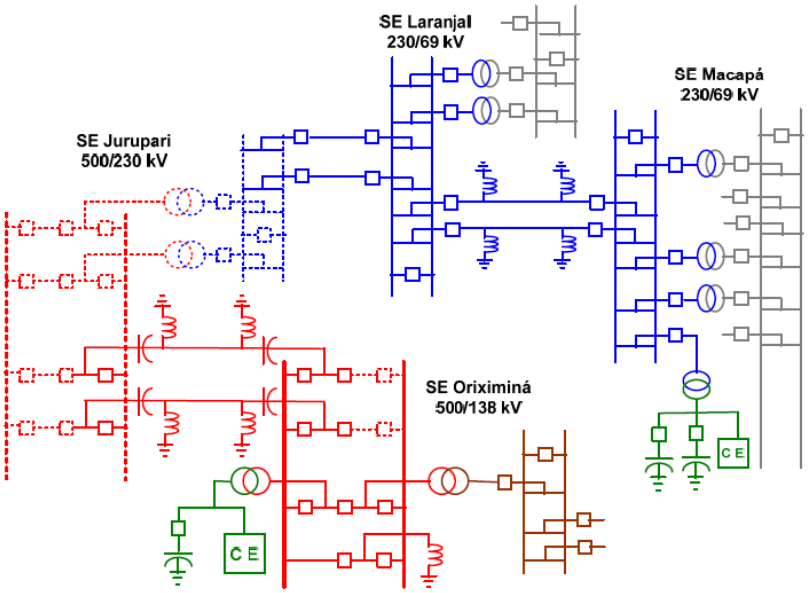


Figure 4: LMTE Substations location
Source: ANEEL

The following figure shows the Amazon Project, lots A and B of ANEEL 004/2008:

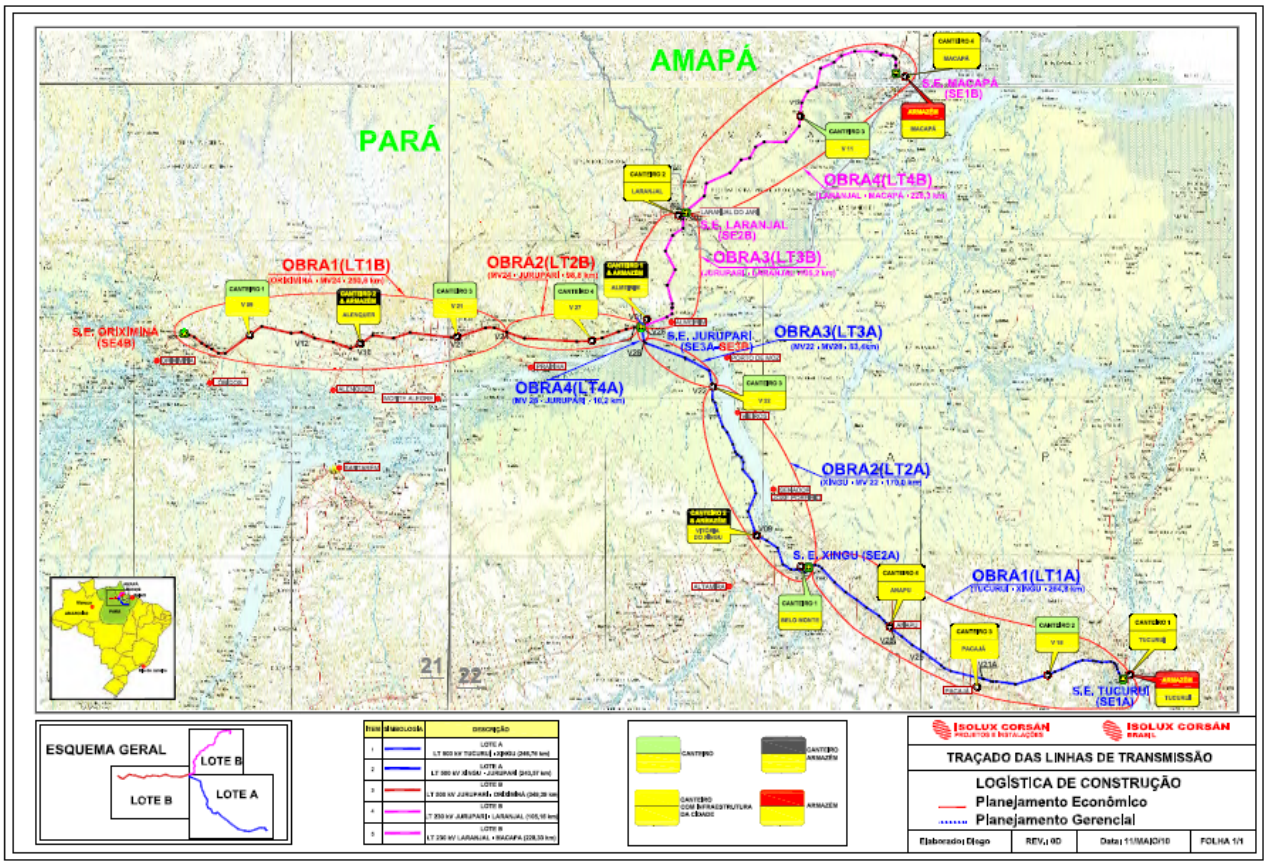


Figure 5: Lots A and B_ANEEL 004/2008
Source: Isolux Ingeniería

3. Challenges of the project

The major challenges Isolux has faced during project development are:

1. Obtaining environmental permits and approvals;
2. Crossing the Amazon River;
3. Erecting 70 km of line in submerged areas (areas flooded near the Amazon River);
4. Vegetation removal (approximately 10,000,000 m^3 timber); and
5. Logistics and transportation issues.

3.1. LXTE and LMTE Environmental process

Due to construction in the protected Amazon region, environmental issues were magnified through all stages of the Amazon Project.



In Brazil, developers who are responsible for a transmission line project that involves construction, installation and/or operation (even with no new significant environmental impact) must obtain the following environmental licenses required by federal environmental regulation:

1) *Preliminary License*
- Local studies
- Environmental studies
- Public Inquiry

2) *Installation License*
- Preparation of Environmental Basic Project (PBA)
- Necessary to commence construction

3) *Operating License*
- Oversight by IBAMA to ensure environmental compliance during construction

In August 2008, the environmental licensing process for transmission lines was initiated. In accordance with applicable legislation, Isolux hired a specialized consultant, *JGP Consultoria*, to proceed with the preparation of an Environmental Impact Study ("**EIA**") and Environmental Impact Report ("**RIMA**", together with the EIA, the "**Studies**"). These Studies assessed the impact of the development of a linear project in the Amazon and specifically its potential physical, socioeconomic and cultural impacts. Based on these Studies, it was possible to assess potential impacts from construction and operation and propose measures to mitigate and/or compensate for potential impacts.

The Studies were submitted for analysis and approval by the applicable licensing agencies. Also, the Studies were made public through hearings held in affected communities. The hearings were used to explain the Amazon Project, the Studies' findings and proposed mitigation/compensation measures. Following this process, the Amazon Project received a Preliminary License ("**LP**").

Next, Isolux filed a Preparation of Environmental Basic Project ("**PBA**"), which outlined 27 environmental programs aimed at preventing, controlling and compensating for impacts, as well as contributing to the preservation of the quality of the environment and the socioeconomic dynamics of the region. The PBA was approved and Isolux was issued the Environmental Installation License ("**LI**") needed to begin construction works.

The lengthy environmental assessment and licensing process for this complex project was due to the following:

- Complexity of the environmental studies needed to analyze the extraordinary biodiversity of the region and assess impacts;
- The need to optimize the route of the line in order to minimize interference in the areas of preserved vegetation;
- Develop a construction process to address physical and environmental challenges, especially erecting towers for crossing the Amazon River;
- Crossing conservation areas: the lines cross two important conservation areas. The authorization to cross these areas was only released by ICMBio[5] after consent of the management council and publication of a decree that provides procedures for authorization of projects in conservation areas;
- Addressing proximity to traditional communities: the LXTE transmission line is about 5 km from the limits of the Trocará indigenous tribal area. Isolux worked closely with the aboriginal communities to develop strategies and programs to mitigate the environmental impacts caused by the line.

3.1.1.1. The Project environmental impact

Ultimately the environmental impact of constructing the Amazon Project was deemed of low intensity. This was due to the careful consultation and planning undertaken by Isolux to minimize interference with the environment. Among other things, Isolux designed and engineered the project so as to:

- Adjust the transmission line's route to:
  - prioritize already anthropized areas such as pastures that were devoid of forest or native vegetation;
  - minimize interference in forested areas, drainage, wetlands, etc.;
  - increase proximity to highways (163/PA BR 254, BR 156 and BR 230 - transamazônica) so as to reduce the need for construction of service and access roads.

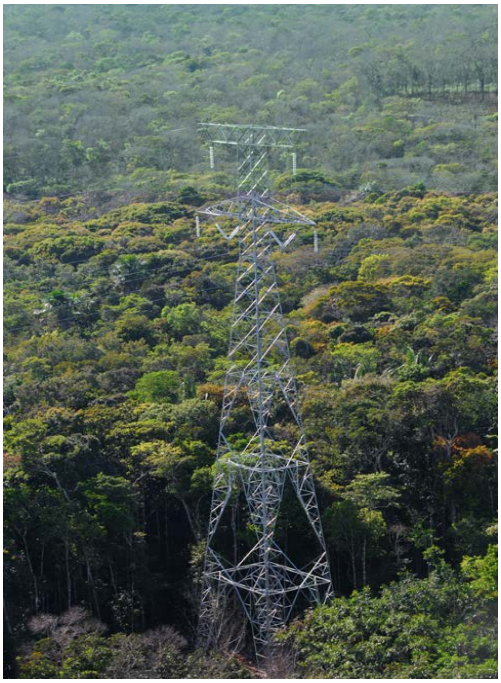
- Optimize service road incursions: building new service roads can cause very significant environmental harm. Therefore, Isolux minimized the construction of new service roads and in places where construction was necessary, it optimized construction by:
  - minimizing interference in forested areas;
  - minimizing routes on slopes or uneven reliefs;
  - minimizing intensity of earthworks in natural drainage areas;
  - utilized existing roads and river transport.

- Adopt studies and guidelines to minimize the need for the removal of native vegetation in ROWs: in order to mitigate the effects on native vegetation and wildlife, several criteria were adopted:

[5] ICMBio: the Institute carries out the mandate of the National System of Conservation Units, with the authority to propose, implement, manage, protect, monitor and supervise prescribed conservation areas. Website: www.icmbio.gov.br

- Using dual circuit structures and vertical disposition with lower horizontal distance between circuits; this reduced the service areas for mounting and lifts, as well as cable laying;
- Revising the locations of the towers on the line route for protection of watersheds, riparian forests, and Permanent Preservation Areas.

4. Amazon's Project expropriations



The Amazon Project traverses approximately 1,256 properties (556 properties by LXTE transmission line and 700 properties by LMTE transmission line). The process to constitute the Right of Way resulted in 97% of affected owners being compensated through amicable negotiations; only 20 landowners (approx. 3%) were subjected to expropriation proceedings (DUP – 13-05-2009).



5. Construction

The project is being executed by the Brazilian construction affiliate of Isolux Corsán.

The Engineering, Procurement and Construction Contract ("**EPC Contract**") is a turnkey contract with scheduled and fixed prices, which means that delivery time and price are guaranteed by the company's EPC contractor.

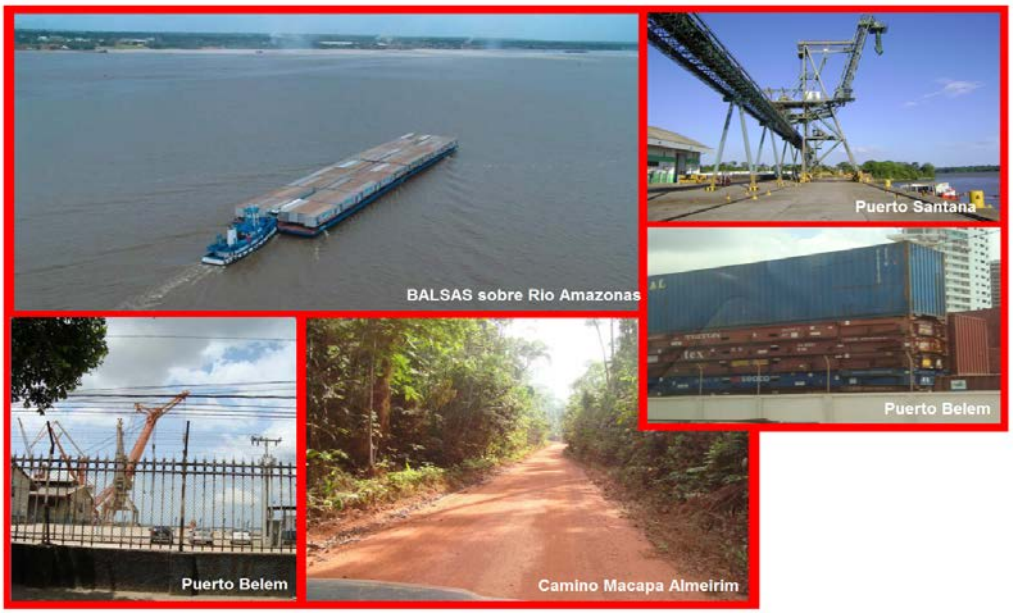
Isolux Corsán has extensive experience constructing such projects, having successfully built 13 other transmission projects in Brazil, the large majority with early operation

start dates and with an excellent operational history.

The construction of the Amazon project has significant challenges given the unique construction and environmental complexity and demands involved.

The existing challenges in construction are:

- The increase in tower's height to overcome, among other things, the rainforest canopy that reaches 60 meters high;
- Rainy periods, typical of the Amazon region between the months of January and July that impede construction activities; and
- A variety of difficulties in the construction area (jungle, tropical rainforest, etc.).



One of the most complex areas is the 'Alagado', a flooded area (approximately 70 km) near the Amazon river with a variable water level throughout the year.



Because of the variable water levels, personnel access and transporting equipment to this area is very complicated.

During the rainy season the access to this area is achieved by barges.



During the dry season, conventional access to this area is impossible due to the mud. The only way to access the Alagado during this period is by constructing wood platforms.



Foundations in 'Alagado' area are constructed by driving metallic tubes that are concreted later. This work is done from barges.







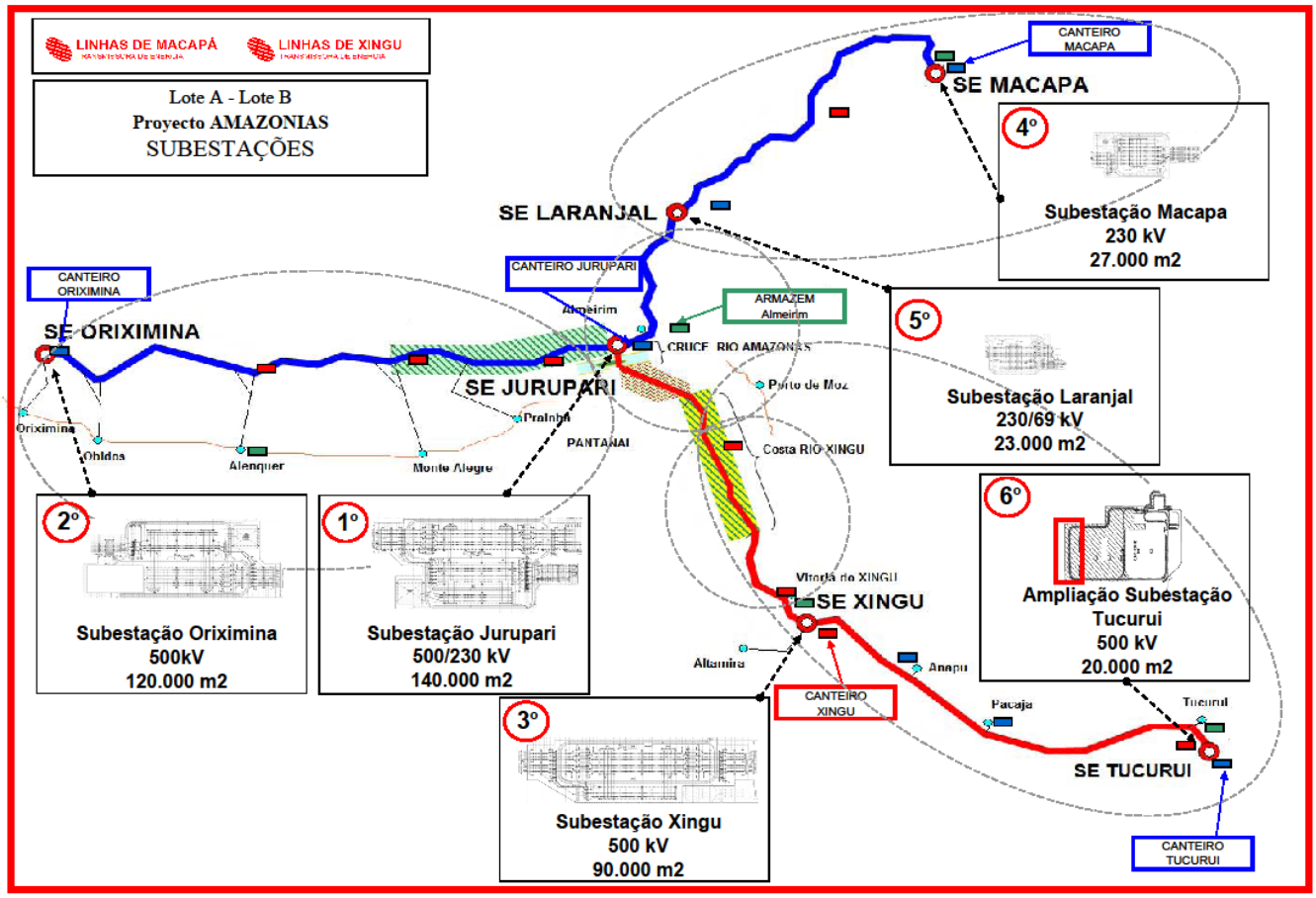
One of the unique challenges encountered was the need to cross the Amazon River, which is 2 km wide and impossible to traverse without the deployment of towers in the middle of the river. During the feasibility studies, several crossing alternatives were studied, taking

into account the distance to be traversed, geomorphological instability of the islands to be used as crossing points. After extensive and complex analysis, Isolux engineers determined that the only viable alternative was to use the Juruparí Island as crossing; this was done to overcome the gap of more than 2,000m while maintaining a minimum height of 75 meters from the water surface, in order to not interfere with the heavy boat traffic of the region.



The project presents other unique challenges such as:

- The magnitude of the substations.
-



The main challenges for the construction of the substations are: the necessary surface area, the difficult access, the earth movements, the logistics from point of view of personnel (accommodations, meals, etc.), equipment and materials (transportation from the river, construction of ports, etc.) and the coordination with the main equipment manufactures.



Transport of transformers to Jurupari's substation



Transport of materials to Jurupari's substation

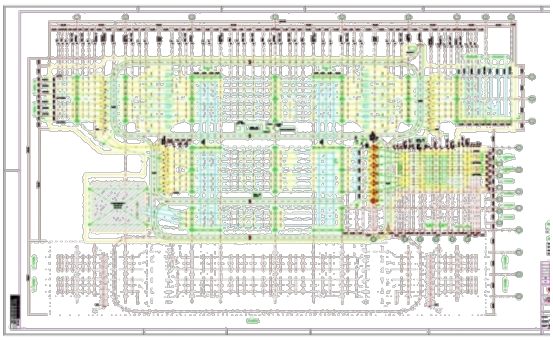




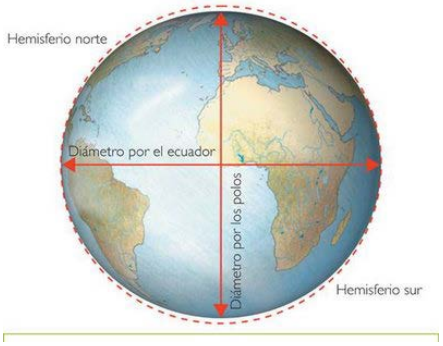


The Juruparí Substation has a footprint 48 times the size of a standard football field

Juruparí Substation	240,000 m^2 (600m x 400m)
Football field	5,000 m^2 (100m x 50m).

times  =  x 48

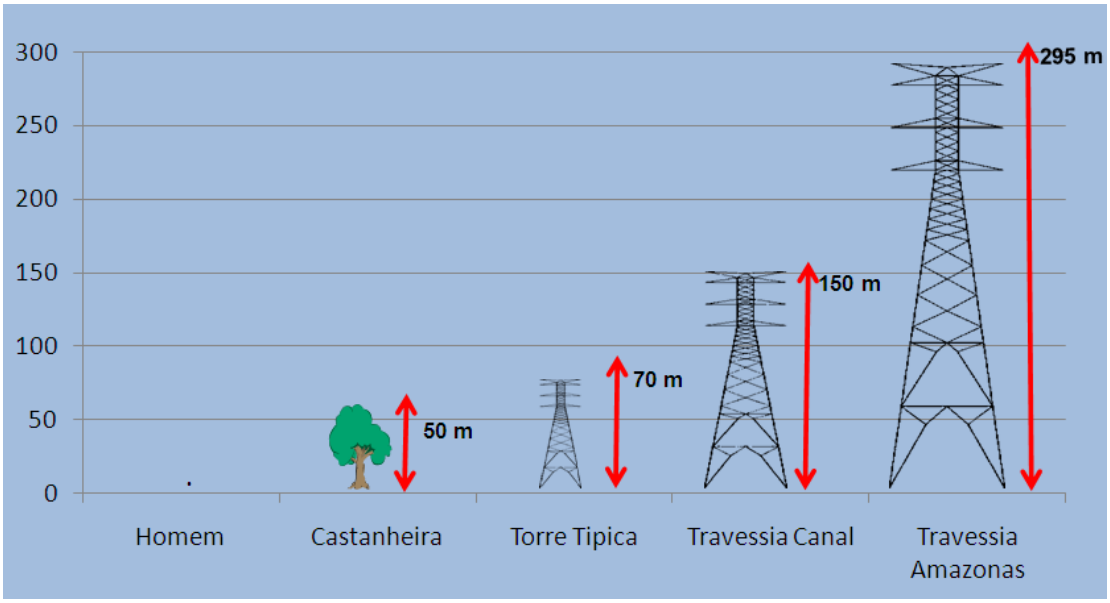
For the stringing of 12,000 km of transmission lines Isolux required 26,000 km of aluminum cable, equivalent to more than half the earth's circumference.



Earth circumference = 40,000km

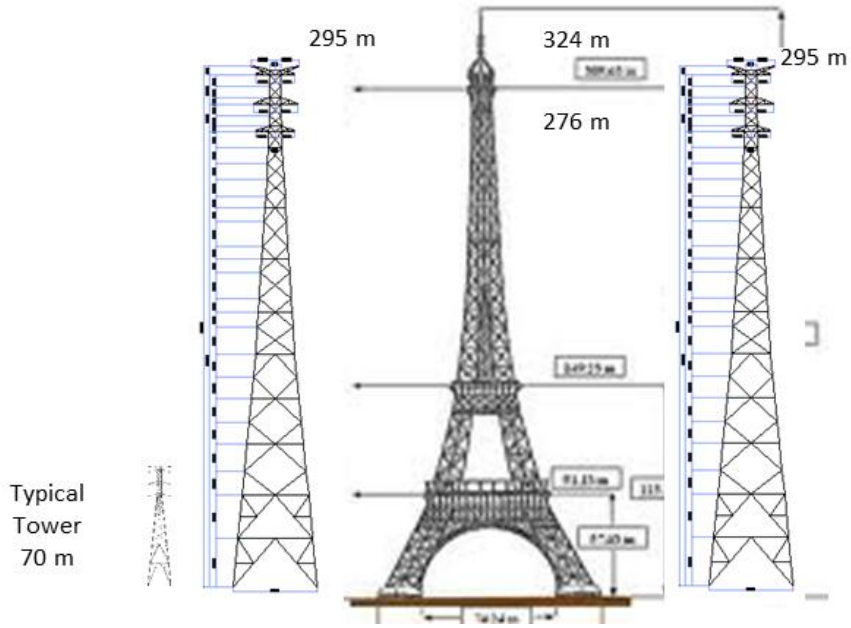
To construct the project's transmission towers, Isolux had to procure 55,000 metric tonnes of steel.

For the reasons explained above, to cross the Amazon River (width 2,000m) Isolux constructed transmission towers 295m high (approximately the height of the Eiffel Tower and almost 4 times the height of a typical transmission tower (70m)).



River's width (2,000m):





At this height, the Amazon's transmission towers are the highest in Brazil and are among the five highest transmission towers in the world (according to the publication issued by CIGRE) – only in China are there taller transmission towers.

Due to this extraordinary height, the crossing towers are identified in the world market as "Extra High Towers", and their engineering, supply and assembly are restricted to a very limited amount of qualified firms, with proven experience.

The following photos show the complexity of constructing in the Amazon's river crossing:



Foundation of a tower from the Amazon's river crossing



Dimensions of a tower from the Amazon's river crossing



Dimensions of a tower from the Amazon's river crossing



Dimensions of a tower from the Amazon's river crossing



Dimensions of a tower from the Amazon's river crossing

The average number of direct jobs during construction is 2,200 reaching 4,200 employees in periods of high construction. During construction, twelve construction sites were built to assist workers; and more than 700 mechanized vehicles (including cars, trucks, buses, cranes, boats, barges, vehicles, earth-moving equipment, tending equipment, ambulances, etc.) are being used.

“Exhibit H”

2011 | ANNUAL REPORT

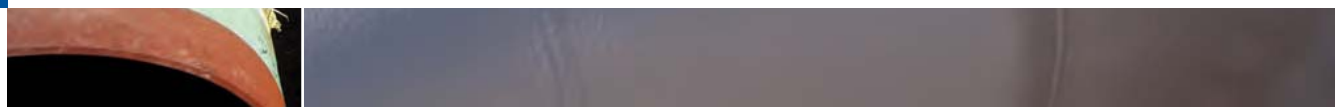


DELIVERING CRITICAL ENERGY INFRASTRUCTURE

TransCanada
In business to deliver



DELIVERING CRITICAL ENERGY INFRASTRUCTURE



It's been said the results you achieve will be in direct proportion to the effort you apply. Through the efforts of TransCanada's 4,400 employees, much was achieved in 2011, right across North America.

The company's capital program is nearly 50 per cent complete, with $10 billion in assets becoming operational since the second quarter of 2010. These assets are doing what they were designed to do: produce predictable, sustainable earnings and cash flow growth for our shareholders, while delivering energy safely and reliably to customers across North America.

TransCanada has $49 billion in blue-chip energy infrastructure assets and we have a presence in seven Canadian provinces, 33 U.S. States and Mexico.

We operate one of North America's largest natural gas pipeline networks – 68,500 kilometres (42,500 miles) – tapping into virtually every major gas supply basin on the continent. We deliver 20 per cent of the natural gas consumed in North America each and every day.

TransCanada is the third-largest natural gas storage provider on the continent with 380 billion cubic feet of capacity.

We are Canada's largest private sector power generator. Our company has 19 power plants in Canada and the U.S. that produce 10,800 megawatts of electricity. We can produce enough power to meet the needs of nearly 11 million homes.

In the summer of 2010, we broadened our asset base to include a very significant entrance into the oil transportation business with the start of commercial operations on our Keystone pipeline system, delivering a reliable source of crude oil to U.S. refineries. The system expanded in 2011 with completion of the Cushing Extension.

All are long-life assets that are critical to the needs of millions of people who rely on us to deliver their energy safely and reliably every day.

We remain focused on doing the right thing and doing things right as we have done for decades to ensure we maintain the trust of the communities where we work. It is important we remain grounded in our values of integrity, responsibility, innovation and collaboration, as they will continue to be our guide to navigate the path forward.

The safety of the public, our employees and our contractors has been a core value at TransCanada for 60 years. We strive to eliminate all incidents that could impact people, the environment or our corporate assets through continuous improvement of our health, safety and environmental performance. ■

PIPELINES

Natural Gas Pipelines

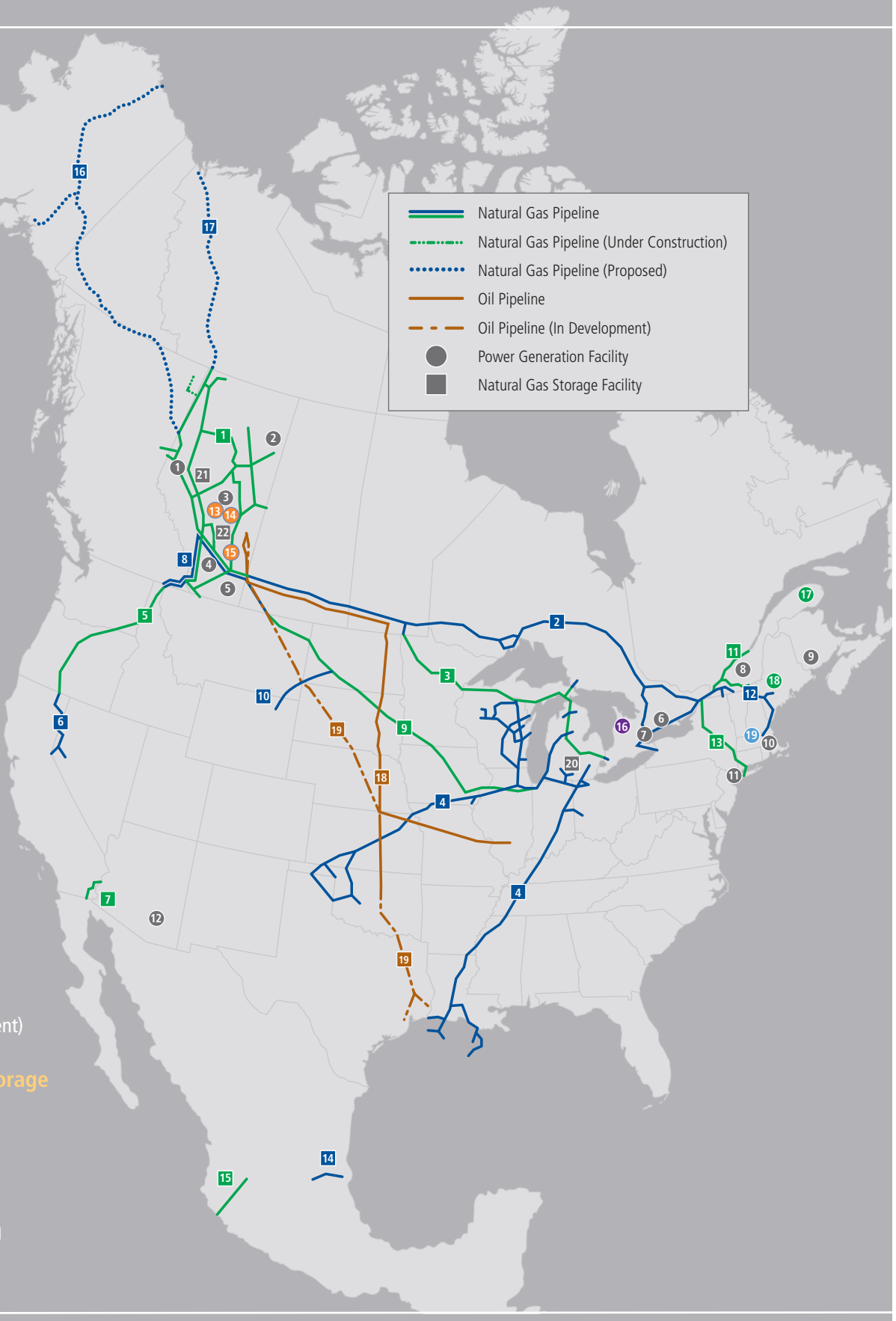
1. Alberta System
2. Canadian Mainline
3. Great Lakes (69%)
4. ANR
5. GTN (83.3%)
6. Tuscarora (33.3%)
7. North Baja (33.3%)
8. Foothills
9. Northern Border (16.7%)
10. Bison (83.3%)
11. TQM (50%)
12. Portland (61.7%)
13. Iroquois (44.5%)
14. Tamazunchale
15. Guadalajara
16. Alaska Pipeline Project (proposed)
17. Mackenzie Gas Project (proposed by producers)

Oil Pipeline

18. Keystone
19. Keystone XL (in development)

Regulated Natural Gas Storage

20. ANR Natural Gas Storage



All assets wholly owned except as noted

ENERGY

Natural Gas Power Generation

1. Bear Creek
2. MacKay River
3. Redwater
4. Carseland
5. Cancarb
6. Portlands Energy (50%)
7. Halton Hills
8. Bécancour
9. Grandview
10. Ocean State Power
11. Ravenswood
12. Coolidge

Coal Power Purchase Arrangements

13. Sundance A PPA
14. Sundance B PPA (50%)
15. Sheerness PPA

Nuclear Power Generation

16. Bruce Power
    (Bruce A – 48.8%, Bruce B – 31.6%)

Wind Power Generation

17. Cartier Wind (62%)
    4 of 5 stages complete
18. Kibby Wind

Hydro Power Generation

19. TC Hydro

Unregulated Natural Gas Storage

21. Edson
22. CrossAlta (60%)





TransCanada's capital program is delivering results

A STRONG FOUNDATION IS IN PLACE

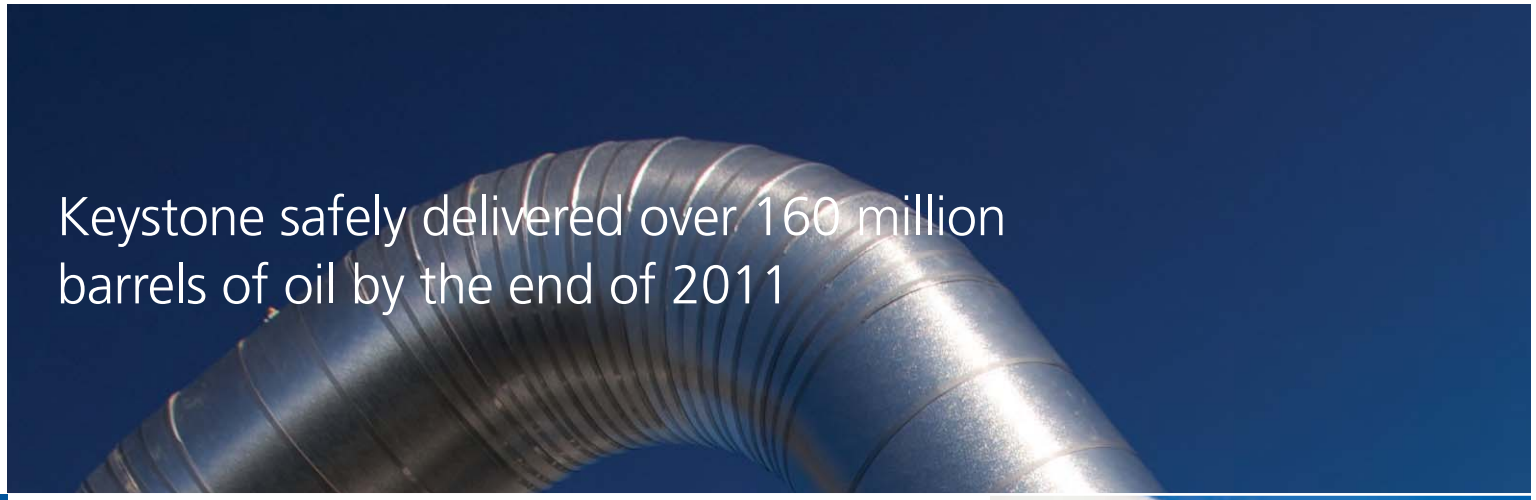


As TransCanada continues to progress its capital program, the specific projects that came into service in 2011 include: the Keystone Pipeline System Cushing Extension, the Bison and Guadalajara natural gas pipelines, extensions and expansions of the Alberta System, the Coolidge Generating Station in Arizona and additional phases of the Cartier Wind project.

These new operating assets are critical North American infrastructure and have become an important part of our growing asset base. In addition, we continue to focus on enhancing the value of existing assets by maximizing revenue and minimizing costs. This means increasing throughput on our pipelines, maximizing the availability and output of our power plants and minimizing the cost of our operations.

These are simple concepts we put into practice every day.

Incremental earnings from these new assets and improved results from our core businesses contributed to a significant year-over-year increase in our earnings. For the year ending December 31, 2011, we reported comparable earnings of $2.23 per share, which is a 13 per cent increase over the $1.97 per share we reported in 2010. Funds generated from operations were $3.7 billion, which is a 10 per cent increase over last year, a clear indication our strategy is working. ■



Keystone safely delivered over 160 million barrels of oil by the end of 2011

OIL PIPELINES







The Keystone pipeline system, which began transporting oil to the U.S. Midwest in the summer of 2010, achieved a key milestone early in 2011 with the start of deliveries to refineries in Cushing, Oklahoma.

Along with this accomplishment, TransCanada successfully signed contracts for thousands of additional barrels from the Bakken fields in Montana and North Dakota and oil from Cushing, along with oil flowing from Western Canada through the proposed Houston lateral pipeline. These commitments involve an investment of approximately US$800 million and will increase the capacity of Keystone XL to 830,000 barrels per day (bbl/d) and total capacity to approximately 1.4 million bbl/d. The entire Keystone system has secured long-term, firm contracts in excess of 1.1 million bbl/d.

Keystone will serve as a growth platform to transport more barrels to market. By 2020, oil production in the Western Canada Sedimentary Basin is expected to increase by 1.5 million bbl/d to more than four million bbl/d. By 2025, total supply is expected to grow by another million barrels per day. TransCanada has taken advantage of this opportunity as the Keystone system has contracted the lion's share of this growth over the next four to five years. Keystone XL has the potential to move approximately one-third of total Canadian exports to the U.S., 10 per cent of total U.S. imports and almost 250,000 bbl/d of domestic U.S.-produced oil.

The regulatory approval process for Keystone XL continued to advance in 2011 with the release of a Final Environmental Impact Statement in August. It concluded the pipeline would have minimal impact on the environment. The over three-year review of Keystone XL has become the most detailed and comprehensive environmental review ever undertaken for a cross-border pipeline.

The U.S. Department of State suspended the finalization of the review for Keystone XL in November 2011, stating that alternative routes needed to be defined that avoided the Nebraska Sandhills.

On January 18, 2012, the State Department denied a Presidential Permit for Keystone XL. Facing a 60-day legislative-imposed decision deadline, the Department said it did not have sufficient time to obtain the information necessary to assess whether the project, in its current state, was in the national interest of the United States.

TransCanada is working collaboratively with the State of Nebraska and Nebraska's Department of Environmental Quality to define a new route through the State.

Our commitment to the project remains and the company will re-apply for a Presidential Permit in 2012. We expect the 10,000 pages of data and analysis compiled since 2008 would be used in any future regulatory review, potentially speeding up final approval. We are focused on Keystone XL beginning to ship oil in early 2015.

The company continues to strongly believe that Keystone XL is in the national interest of the United States, as it would allow Americans to move closer toward achieving North American energy security while creating thousands of much-needed jobs. ■



NATURAL GAS PIPELINES



North American demand for natural gas is expected to grow by about 20 billion cubic feet per day (Bcf/d) over the next 15 years largely due to an increased demand for power. TransCanada expects both conventional and unconventional natural gas will be needed to meet the increase in demand and to offset an expected 20 per cent annual decline in existing production. We are well positioned to connect all existing sources of supply in North America, as well as new sources, to growing markets across the continent. Our pipeline network connects into virtually every major natural gas supply basin and provides our customers with unparalleled access to premium markets.

This vast network became even larger early in 2011 with the US$630 million Bison pipeline beginning operations. The 487-kilometre (303-mile) natural gas pipeline is TransCanada's first line to access gas produced in the U.S. Rocky Mountain region. Bison connects to the Northern Border pipeline system and provides options to producers in Wyoming's Powder River Basin and to consumers in the U.S. Midwest. Bison has an initial capacity of 407 million cubic feet per day (MMcf/d) and is easily expandable.

Construction of the Alberta System's $275 million Horn River natural gas pipeline project began in March 2011 and is expected to begin shipping gas in the second quarter of 2012. TransCanada plans to extend this pipeline by 100 kilometres (62 miles) at a cost of $230 million. The extension adds additional initial contractual commitments of 100 MMcf/d expected to begin in 2014, with volumes increasing to 300 MMcf/d by 2020. The currently contracted volumes for Horn River, including the extension, are expected to total 900 MMcf/d by 2020.

Construction of a $60 million, 24-kilometre (15-mile) extension of the Groundbirch pipeline began in August 2011 and is expected to be completed in April 2012. Contracts are in place for 250 MMcf/d of natural gas.

TransCanada continues to develop new natural gas pipeline infrastructure in British Columbia and Alberta. Several



applications have been filed with the National Energy Board (NEB) requesting approval for expansions of the Alberta System to accommodate requests to bring additional natural gas to market. The company has approvals for $910 million in new projects, with $810 million worth of pipeline infrastructure awaiting an NEB decision.

Ongoing business with Western Canadian producers has resulted in contracts from both the Montney and Horn River shale gas formations for 3.4 Bcf/d from northwestern Alberta and northeastern B.C. by 2014.

TransCanada's continental reach continued to expand in the summer of 2011 with the completion of Mexico's US$360 million Guadalajara pipeline. The entire capacity of the 310-kilometre (193-mile) natural gas pipeline is contracted with Mexico's state-owned electric company Comisión Federal de Electricidad. The Guadalajara project connects to a regasification facility near Manzanillo. It has the capacity to transport 500 MMcf/d of natural gas to a nearby power plant, along with the ability to deliver 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara.

TransCanada continued its work in 2011 toward the development of a longer-term plan to ensure there is a competitive toll structure for the Canadian Mainline. That work culminated in the filing in September of a comprehensive proposal to restructure services and tolling on the Mainline. The proposal responded to significant changes that have occurred over the last few years in natural gas supply, demand and transportation in North America with the advent of U.S. shale gas growth. The filing would achieve significantly reduced tolls for 2012 and 2013 compared to existing levels and is expected to enhance the overall competitiveness of Western Canadian gas and the Canadian Mainline.

The Mainline remains a critical component of the North American gas delivery system. Total deliveries averaged 5.2 Bcf/d for 2011, making it the largest gas transportation system on the continent. ■

ENERGY



TransCanada's energy portfolio is well positioned to prosper in a carbon-constrained world







Between 2010 and 2013, TransCanada will add 2,600 megawatts (MW) of capacity to our energy portfolio by investing $5 billion in numerous projects that are expected to generate sustainable earnings and cash flow.

In May 2011, we added 575 MW of capacity with the start of operations at our Coolidge Generating Station in Arizona. The US$500 million facility was completed on time and on budget. The Arizona-based Salt River Project utility signed a 20-year power purchase arrangement (PPA) to buy all of the power produced at the Coolidge facility.

In Canada, construction continues on the five-stage, 590-MW Cartier Wind project in Québec. The 101-MW first phase of the Gros-Morne and 58-MW Montagne-Sèche wind farm projects began producing power in November 2011. The 111-MW Gros-Morne phase two is expected to be operational in December 2012. These are the fourth and fifth Québec-based wind farms of Cartier Wind, which is 62 per cent owned by TransCanada. All of the power produced by Cartier Wind is sold under a 20-year PPA to Hydro-Québec.

The refurbishment of Units 1 and 2 at the Bruce Power nuclear facility in Ontario continues to progress and the two units are now being prepared to begin delivering power to Ontario's electrical grid. Unit 2 is expected to begin operations in the first quarter of 2012, while Unit 1 is on target to start producing power in the third quarter. TransCanada's share of the total capital cost is expected to be $2.4 billion. Once the refurbishment is complete, Bruce Power will be the world's largest nuclear facility, providing more than 6,200 MW or about 25 per cent of Ontario's power. This emissions-free power is sold under long-term PPAs with the Ontario Power Authority.

2011 ended with the announcement that TransCanada is entering the solar power business. The company agreed to purchase nine Ontario solar projects with a combined capacity of 86 MW. All nine projects in the $470 million deal have 20-year PPAs with the Ontario Power Authority. Each of the projects will be purchased after they begin producing power and meet certain milestones.

TransCanada's energy portfolio is well positioned to prosper in an increasingly carbon-constrained world as our diverse and growing fuel mix includes 52 per cent natural gas, 23 per cent nuclear, 15 per cent coal, five per cent wind and five per cent hydro. ■

BUILDING RELATIONSHIPS











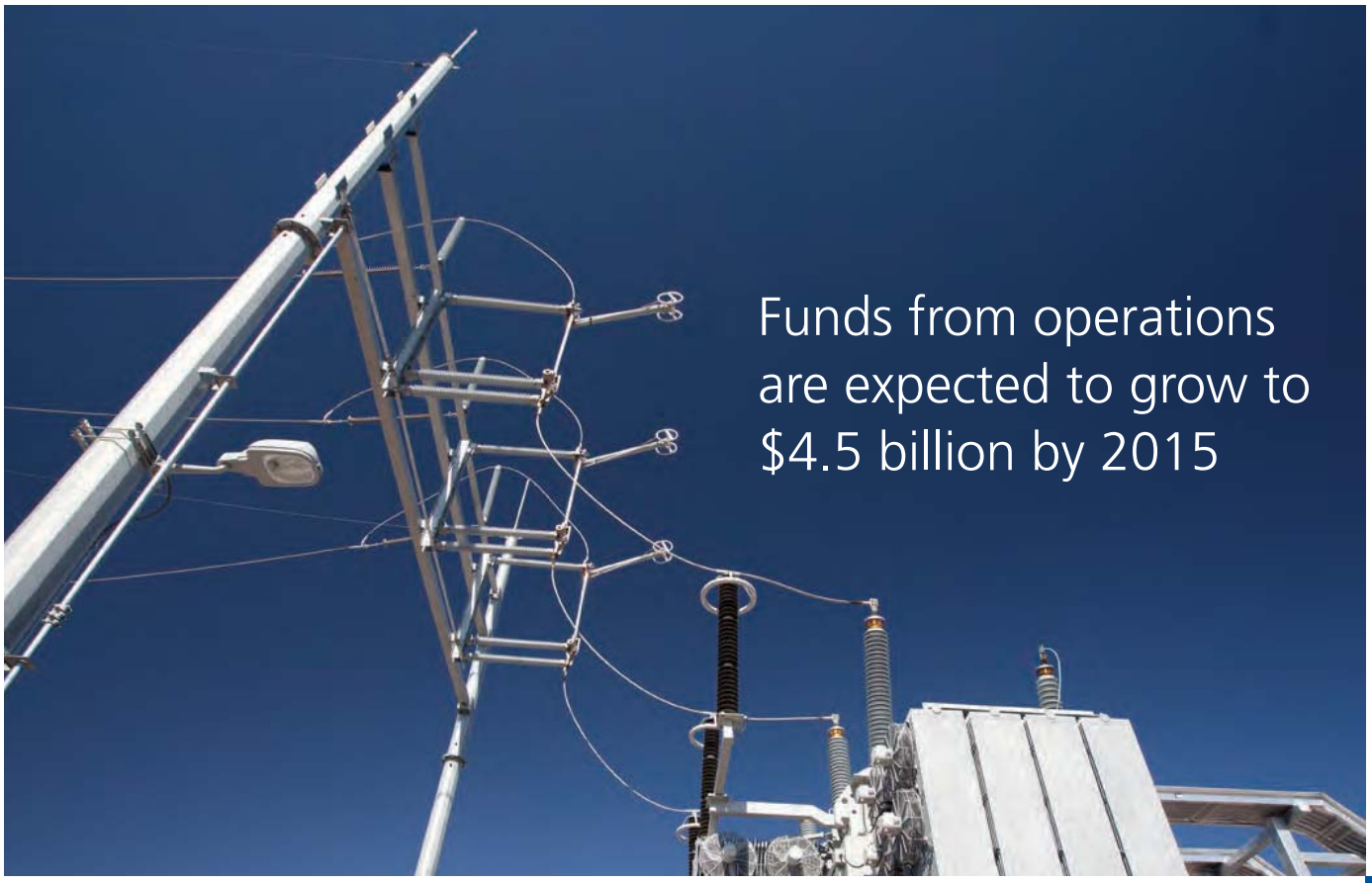
At TransCanada, our reputation matters. We recognize that excellence in stakeholder engagement helps deliver value and ensures we do so in a socially and environmentally responsible manner. Our four core values of integrity, collaboration, responsibility and innovation are at the heart of our commitment to stakeholder engagement. These values guide us in our interactions with our stakeholders.

TransCanada generally defines stakeholders as those people or groups who significantly affect, or who may be affected by, our business activities. We strive to engage stakeholders early and often from project development through to operations and decommissioning. Engaging with stakeholders means listening, providing accurate information and responding to stakeholder interests in a prompt and consistent manner.

Our company will be an integral part of hundreds of communities across the continent for many years to come. We want to be considered a good neighbour from the start of a project until the day we reclaim the local environment. When planning a new project, we strive to involve those affected as soon as possible.

TransCanada's stakeholders are a diverse group, including landowners, regulatory officials, Aboriginal communities and Native American Tribes, local governments, emergency response agencies, and our industry peers. We use many tools to lay out our intentions to these stakeholders, gather their comments and seek solutions. We bring our respect and a clear sense of our long-term corporate responsibility to these important discussions. Typically, this approach works very well.

Our vision is to be a North American community infrastructure leader by helping build healthy, safe and vibrant communities where we live and work. We do this by forging meaningful partnerships in the non-profit and voluntary sector, which serve as community assets in empowering individuals and building strong communities. ■



MAINTAINING OUR FINANCIAL STRENGTH & FLEXIBILITY



By early 2015, we anticipate completing the remaining elements of our current capital program: Keystone XL, the Bruce re-start, the Cartier Wind project, the Canadian Solar power initiative and expansions and extensions to the Alberta System. As a result, we expect to generate $6.5 billion of EBITDA (earnings before interest, taxes, depreciation and amortization) by 2015 – 45 per cent from our natural gas transmission business, 30 per cent from energy and 25 per cent from oil pipelines. This is expected to translate into growth in funds from operations to $4.5 billion annually.

TransCanada has three very attractive and growing businesses in which to reinvest its annual cash flow: natural gas pipelines and storage, oil pipelines and power generation and transmission. Reinvestment will be done in a disciplined fashion and in a way that allows us to live within our means in order to deliver predictable and stable long-term earnings and cash flow growth.

We are well on our way to realizing our vision of becoming the leading energy infrastructure company in North America. ■

2011 FINANCIAL HIGHLIGHTS

Net Income Attributable to Common Shares | **$1.5 billion or $2.18 per share**

Comparable Earnings[(1)] | **$1.6 billion or $2.23 per share**

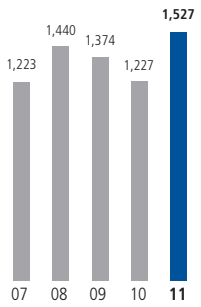
Comparable Earnings before Interest, Taxes, Depreciation and Amortization[(1)] | **$4.8 billion**

Funds Generated from Operations[(1)] | **$3.7 billion**

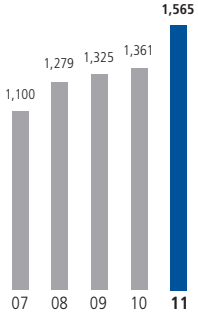
Capital Expenditures | **$3.3 billion**

Common Share Dividends Declared | **$1.68 per share**

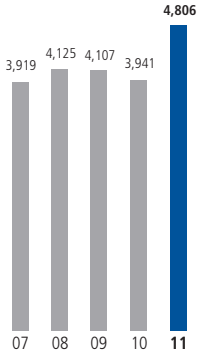
Net Income Attributable to Common Shares
(millions of dollars)



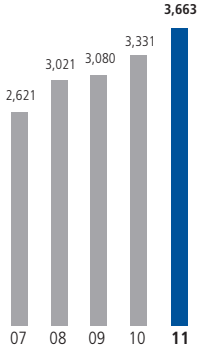
Comparable Earnings[(1)]
(millions of dollars)



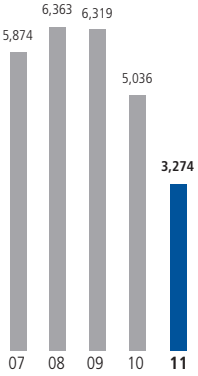
Comparable EBITDA[(1)]
(millions of dollars)



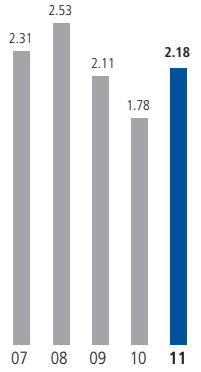
Funds Generated from Operations[(1)] (millions of dollars)



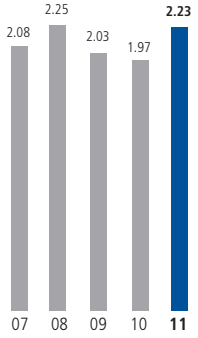
Capital Expenditures and Acquisitions (millions of dollars)



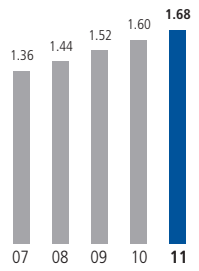
Net Income per Share – Basic (dollars)



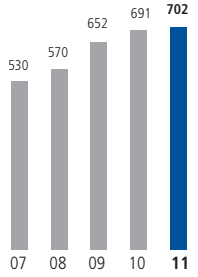
Comparable Earnings per Share[(1)] (dollars)



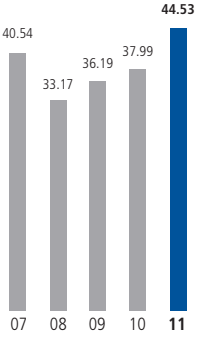
Dividends Declared per Share (dollars)



Common Shares Outstanding – Average
(millions of shares)



Market Price – Close Toronto Stock Exchange
(dollars)



(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles (GAAP). For more information see Non-GAAP Measures in the Management's Discussion and Analysis of the 2011 Annual Report.

Financial Highlights

Year ended December 31 (millions of dollars)	**2011**	2010	2009	2008	2007
Income					
Net income attributable to common shares	**1,527**	1,227	1,374	1,440	1,223
Cash Flow					
Funds generated from operations	**3,663**	3,331	3,080	3,021	2,621
Decrease/(increase) in operating working capital	**310**	(249)	(90)	135	63
Net cash provided by operations	**3,973**	3,082	2,990	3,156	2,684
Capital expenditures and acquisitions	**3,274**	5,036	6,319	6,363	5,874
Balance Sheet					
Total assets	**48,995**	46,794	43,841	39,414	30,330
Long-term debt	**17,632**	17,028	16,186	15,368	12,377
Junior subordinated notes	**1,009**	985	1,036	1,213	975
Preferred shares	**1,224**	1,224	539	–	–
Common shareholders' equity	**16,100**	15,503	15,220	12,898	9,785

Common Share Statistics Year ended December 31	**2011**	2010	2009	2008	2007
Net income per common share – basic	**$2.18**	$1.78	$2.11	$2.53	$2.31
– diluted	**$2.17**	$1.77	$2.11	$2.52	$2.30
Dividends declared per common share	**$1.68**	$1.60	$1.52	$1.44	$1.36
Common shares outstanding (millions)					
Average for the year	**701.6**	690.5	651.8	569.6	529.9
End of year	**703.9**	696.2	684.4	616.5	539.8

Chairman's Message



2011 was a strong year at TransCanada. We continue to experience the financial benefits of bringing $10 billion of assets into service since the spring of 2010. That progress will continue through 2012, with the completion of other major projects such as the re-start of two reactors at the Bruce nuclear facility.

Looking forward, we expect to invest an additional $12 billion in projects by the end of 2014 or early 2015. This will cap one of the largest capital programs in Canadian corporate history. TransCanada is widely recognized as a leader in the safe and reliable operation of North American energy infrastructure. It is known as a company that delivers on its promises and takes its responsibility toward all stakeholders seriously.

Notwithstanding that reputation, in 2011 the company became known by many for something more – the Keystone XL pipeline. Project opponents have used the pipeline as a lightning rod for a debate on society's use of fossil fuels, and specifically, Alberta's oil sands production. Seeing Keystone XL attacked in the media has been trying for our Board and for all TransCanada employees who take pride in the work they accomplish each and every day. The company has taken every opportunity to discuss the merits of the project in a factual, professional manner.

Experts forecast oil will be needed for decades and Keystone XL offers Americans an opportunity to receive a stable, secure supply of oil from domestic U.S. and Canadian production. This project makes sense, it has our full support and we remain confident it will ultimately be approved.

Our Board continues to be pleased with the transition of leadership at TransCanada from Hal Kvisle to Russ Girling. Russ's focus has remained on the strategies that he helped develop and have made the company successful in the past. He and the executive team have more than met the challenges the past year has presented and we expect that sets the stage for a great future.

Interestingly, our Board will also see noticeable transition between now and 2014. Six of our current directors will reach retirement age and leave the company over that period. The first two such individuals are Wendy Dobson and David O'Brien. Along with my fellow Board members, I would like to thank them for their many years of dedicated service to the company and our shareholders.

The overall scope of this renewal is unprecedented in TransCanada's history and I believe we will attract strong, new talent to provide the guidance and leadership necessary to move the company forward. After an extensive search, the Governance Committee nominated Paula Rosput Reynolds and Richard Waugh to be appointed to the Board.

I am confident Ms. Reynolds and Mr. Waugh, along with TransCanada's 4,400 employees, will continue to rise to the challenges ahead and build future successes for the company, to the benefit of our shareholders, partners and stakeholders.

On behalf of the Board of Directors;



S. Barry Jackson

Letter to Shareholders

Building and operating safe and reliable energy infrastructure – it is what we do and we do it well. Millions of people across North America rely on the energy we deliver every day, to heat their homes, cook their food and fuel their vehicles. We have done this successfully and responsibly for six decades. Our $49 billion of blue chip assets are essential to North Americans and we are well positioned to continue to meet the continent's growing energy needs for decades to come.



In 2011, TransCanada continued to successfully advance many of its strategic initiatives. While we experienced some disappointments, it is clear our strategy is working and we are seeing very tangible results of our discipline and focus. Our Company delivered a record $4.8 billion of EBITDA(1) (earnings before interest, taxes, depreciation and amortization) in 2011 versus $3.9 billion in 2010. This represents a year-over-year increase of $865 million. This growth in EBITDA(1) translated into comparable net income of $1.6 billion or $2.23 per share, a 13 per cent increase over 2010 earnings of $1.97 per share.

As a result of visible growth in cash flow and earnings, our Board of Directors again increased our annual dividend on our common shares in February 2012 by eight cents, an increase of five per cent. Since 2000, our dividend has risen steadily from 80 cents per share to $1.76 per share today, an average annual increase of seven per cent. We understand the value our shareholders place on a strong and growing dividend. Going forward, our goal is to continue to increase dividends in conjunction with sustainable growth in cash flow and earnings.

I would like to share with you some of the highlights of 2011, some of our challenges and the bright future we are building for your company. Our base businesses all continued to perform well in 2011 delivering predictable and steady contributions. We captured significant new shale gas supply in Western Canada, Marcellus in the eastern United States (U.S.) and gas from south central U.S. Our power business performed exceptionally well, primarily in the West, where we were well positioned to take advantage of tightening reserve margins and rising prices against a backdrop of robust growth in demand.

In February 2011, our Keystone pipeline system began oil deliveries to Cushing, Oklahoma. Since the start-up of first deliveries to Patoka and Wood River, Illinois in July 2010, Keystone has safely transported over 170 million barrels of Canadian oil to U.S. markets. TransCanada began recording EBITDA(1) from Keystone in February 2011 and over the 11-month period it contributed nearly $600 million.

We continued to successfully advance our large capital program in 2011. Over the past 18 months, we have brought into operation $10 billion of new projects. These were largely completed on time, within budget and with minimal work-related injury. The projects include the first two phases of Keystone, North Central Corridor, Groundbirch, Halton Hills, Coolidge, Kibby, additional phases of Cartier, Bison and Guadalajara.

Doing all of this safely and without injury is an imperative. The safety of our employees, contractors and the public is our first priority. In this same time period, our employees and contractors worked 25 million hours and we experienced a 20 per cent decline in our injury frequency rates, which continue to be among the lowest in our industry. While we are proud of this accomplishment, we know that we must continually

(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles (GAAP). For more information, see Non-GAAP Measures in the Management's Discussion and Analysis of the 2011 Annual Report.

improve our processes and procedures to ensure every employee and contractor goes home safe – every day – period.

We experienced some start-up issues on both the Keystone and Bison pipelines in 2011. Our teams responded well, confirming the effectiveness of our emergency response capabilities, which worked as planned, and the capacity of the company to ensure public safety, protect the environment, repair facilities and return to service safely – delivering the energy people need. This proven capability is truly a competitive advantage in a business that is increasingly in the public eye with ever rising standards of conduct. We embrace the challenge of continually improving our performance.

The Canadian Mainline remains a critical component of the North American natural gas pipeline network. That being said, the Mainline is being used differently as a result of the significant changes that have occurred in natural gas supply, demand and transportation in North America. In order to address those changes, we filed a comprehensive proposal with our regulator in 2011 to significantly reduce tolls and restructure services in a way that will enhance the competitiveness of the Mainline and the Western Canada Sedimentary Basin.

On Keystone XL, we remain focused on gaining approval for the US$7 billion project and proceeding with construction. A Final Environmental Impact Statement (FEIS) was issued in August 2011 that concluded the pipeline would have minimal impact on the environment.

On January 18, 2012, the State Department denied a Presidential Permit for Keystone XL. The decision was not based on the merits of the pipeline but rather that legislation introduced by Congress in December 2011, effectively to accelerate approval, did not allow for sufficient time to complete the required review. The State Department indicated that TransCanada can re-apply for a permit.

We are obviously very disappointed with the decision; however, TransCanada remains fully committed to the construction of Keystone XL. Plans are underway on a number of fronts to largely maintain the construction schedule. We will re-apply for a Presidential Permit and expect, given the already completed environmental work and supportive FEIS, a new application would be processed in an expedited manner to allow for an in-service date of late 2014/early 2015.

Shipper support for the project remains strong. In 2011, we signed long-term shipping contracts on Keystone XL to transport U.S.-produced oil to market from the Bakken formation in Montana and North Dakota and from Cushing, Oklahoma. In addition, we signed sufficient long-term contracts to support a new lateral pipeline to the large refining hub in Houston, Texas. These projects amount to a US$800 million incremental investment and increase the capacity of Keystone XL to 830,000 barrels per day. Today, the vast majority of Keystone's overall capacity is reserved with long-term, firm contracts – clear evidence of the market need for the pipeline.

In 2011, we made great progress on the Bruce Power refurbishment project with refuelling of both units and beginning the commissioning phase. Our current forecast is for Unit 2 to be fully operational in first quarter 2012 and Unit 1 fully operational in third quarter 2012. When back in service, these two units will deliver 1,500 MW of emissionless energy for the residents of Ontario for decades to come and produce very attractive and stable returns for our shareholders.

We took our first step into solar generation in 2011, with the $470 million acquisition of nine projects. This is a fast growing segment of the power market and I would expect several new opportunities to present themselves in the coming years.

As we bring an additional $12 billion of contracted assets into service over the next three years, we are positioned to deliver substantial growth in cash flow, earnings and dividends through 2015. Over the longer term, there will be significant opportunities to reinvest in our core businesses of natural gas pipelines and storage, oil pipelines and power infrastructure.

The International Energy Agency predicts investment in energy infrastructure of over $6 trillion will be needed in North America between 2010 and 2035. More specifically, an investment of about $3 trillion in power, $2 trillion in natural gas and $1.5 trillion in oil is required. That infrastructure is needed to fuel a growing economy and to replace aging assets with new and safe oil and gas pipelines and cleaner, more efficient power plants.

Today, we have a $50 billion portfolio of energy infrastructure projects being evaluated by a very capable business development team. They are focused on meeting the need to move shale and conventional gas within the continent and from frontier regions; attach growing crude oil production to key refining centres; and develop new power generation as the North American market revitalizes its aging infrastructure and evolves to a less carbon-intensive mix. These opportunities mesh extremely well with TransCanada's strategy, growth aspirations, existing presence and deep organizational capabilities.

While we don't expect to capture all of these opportunities, I am confident that these projects, combined with appropriate acquisitions, will provide us with the opportunity to continue to reinvest our substantial discretionary cash flow and grow the company for decades to come.

We will continue to face challenges – that is nothing new. Our 4,400 very highly skilled employees are experts in turning challenge into opportunity. I am extremely proud of their achievements in 2011 and the pride and care they take in operating this company – they are the reason for our success. I recognize that being in the media spotlight placed an additional burden on all of our employees this year and again I am proud of their value-driven, professional management of all issues that came their way. I thank them for their efforts this year and congratulate them on an outstanding job.

Going forward, I am confident in our strategy, our people and our assets. We will realize our vision of being the leading North American energy infrastructure company. In the process, we will continue to grow cash flow, earnings and dividends and build long-term sustainable value for our shareholders. I thank you for your continued support.



Russell K. Girling
President and Chief Executive Officer

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This Management's Discussion and Analysis (MD&A) dated February 13, 2012 should be read in conjunction with the accompanying audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2011 which are prepared in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2011. "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms not defined in this MD&A are defined in the Glossary of Terms in the Company's 2011 Annual Report.

TRANSCANADA OVERVIEW

With more than 60 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

Today, TransCanada is:

- One of the largest natural gas transmission companies in North America with a network of wholly- and partially-owned natural gas pipelines extending more than 68,500 kilometres (km) (42,500 miles), tapping into virtually all major gas supply basins;
- One of the continent's largest providers of natural gas storage and related services with approximately 380 billion cubic feet (Bcf) of storage capacity;
- The largest private sector power company in Canada and owns or has interests in over 10,800 megawatts (MW) of power generation in Canada and the United States (U.S.); and
- A significant player in the oil transmission business with the start up of the Keystone oil pipeline system and the large expansion opportunity to the U.S. Gulf Coast (Keystone XL).

In pursuing its vision to be the leading energy infrastructure company in North America, TransCanada continually strives to execute a large portfolio of attractive growth projects. Each of these new projects are large scale, long life assets supported by strong business fundamentals and long-term contracts that provide attractive and sustainable returns to shareholders over a long-term time horizon.

With assets of approximately $49 billion and a substantial growth portfolio, TransCanada believes it is well positioned to build on its track record of strong and sustainable earnings, cash flow and dividends. Since the spring of 2010, TransCanada has brought $10 billion of growth projects in service and is positioned to complete another $12 billion of new projects by the end of 2014.

TransCanada's 2011 Key Developments

The Company advanced its significant entry into the oil pipelines transmission business:

- Achieved full commercial operations in February 2011 on the sections of the Keystone crude oil pipeline system, extending from Hardisty, Alberta to Wood River and Patoka in Illinois (Wood River/Patoka) and from Steele City, Nebraska, to Cushing, Oklahoma (Cushing Extension) and recorded earnings before interest, taxes, depreciation and amortization (EBITDA) of $0.6 billion in Keystone's first eleven months of operations;
- Received a favourable Final Environmental Impact Statement (FEIS) in August from the U.S. Department of State (DOS) for Keystone XL;
- Secured commercial support for an extension and expansion of Keystone XL to provide crude oil transportation service from Hardisty, Alberta to Houston, Texas; and
- Received notice that the DOS had denied the Presidential Permit for Keystone XL, based on the DOS's position that it did not have sufficient time to receive and review additional information necessary to assess alternative routes that

would avoid the Sandhills region of Nebraska. TransCanada will submit a revised Presidential Permit application to the DOS.

The Company completed construction, placed in service and advanced the following initiatives in Natural Gas Pipelines, which included connecting new shale and unconventional natural gas supply:

- Continued to advance pipeline development projects on the Alberta System to transport new natural gas supply from the Horn River and Montney shale basins in northeastern British Columbia (B.C.) as well as the Deep Basin in Alberta:
  - Received approval from the National Energy Board (NEB) for the construction of natural gas pipeline projects on the Alberta System with capital costs totalling approximately $910 million including the $275 million Horn River pipeline; and
  - Filed additional pipeline development projects with the NEB costing approximately $810 million that included new agreements to further extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of $230 million.
- Placed in service:
  - The US$630 million Bison pipeline in January 2011, which delivers natural gas from the Powder River Basin in Wyoming to an interconnection with the Northern Border Pipeline; and
  - The US$360 million Guadalajara pipeline in June 2011, which transports natural gas from Manzanillo to Guadalajara in Mexico.
- Filed a comprehensive application, with the NEB in September 2011, to change the business structure and the terms and conditions of service for the Canadian Mainline to address tolls for 2012 and 2013;
- Closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$605 million, which included US$81 million or 25 per cent of GTN LLC debt outstanding; and
- Filed a supplemental application with the NEB to construct $130 million of new pipeline infrastructure on the Canadian Mainline to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets.

The Company completed, placed in service and advanced the following power generation assets in Energy:

- Placed in service the US$500 million Coolidge generation station in May 2011, capable of producing 575 MW;
- Completed construction and placed in service the Montagne-Sèche and phase one of the Gros-Morne wind farms in November 2011, capable of producing 159 MW of renewable energy;
- Executed an agreement in December 2011 for the purchase of nine Ontario solar projects, with a combined capacity of 86 MW, for approximately $470 million that are expected to come into service between late 2012 and mid-2013; and
- Continued to progress the $4.8 billion refurbishment and restart of two reactors at the Bruce Power nuclear facility in Ontario. TransCanada's expected net capital cost of the project is $2.4 billion. Fuelling of both Unit 1 and Unit 2 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.

The following are other key developments in Energy in 2012.

- Both units at Sundance A were not operational throughout 2011 and have been subject to force majeure and economic destruction claims by the asset owner. TransCanada has recorded revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the power purchase arrangement (PPA). An arbitration hearing is scheduled for April 2012 to hear both claims.

- Since July 2011, spot prices for capacity sales applicable to Ravenswood have been negatively impacted by the manner in which New York Independent System Operator (NYISO) has applied pricing rules for a new power plant in the New York City Zone J market. TransCanada has filed formal complaints with the Federal Energy Regulatory Commission (FERC) that are pending.
- TransCanada reached a formal agreement to use an arbitration process to settle the Oakville contract dispute resulting from the termination of a 20-year Clean Energy Supply contract with the Ontario Power Authority (OPA).

TransCanada's Businesses Are Organized Into Three Segments – Natural Gas Pipelines, Oil Pipelines and Energy

The Natural Gas Pipelines and Oil Pipelines businesses consist of large-scale natural gas and crude oil pipelines, respectively, primarily situated in Canada and the U.S. TransCanada is also the general partner of TC PipeLines, LP, a master limited partnership that owns interests in U.S. natural gas pipelines.

Natural Gas Pipelines

TransCanada's natural gas pipeline systems consist of a network of more than 57,000 km (35,500 miles) of wholly owned natural gas pipelines, and more than 11,500 km (7,000 miles) of partially owned natural gas pipelines. The network connects major natural gas supply basins and markets, transporting approximately 20 per cent of the natural gas consumed in North America or 14 Bcf of natural gas per day, which is delivered to local distribution companies, power generation facilities and other businesses in markets across North America. The Company's U.S. Natural Gas Pipelines include regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf.

TransCanada is also pursuing additional natural gas pipeline projects to diversify both the supply and market sides of this business and add incremental value to existing assets. Key areas of focus include greenfield development opportunities that connect TransCanada's natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies and that play a critical role in satisfying increased natural gas demand in North America especially for power generation. TransCanada continues to advance opportunities to optimize its existing natural gas pipelines systems to respond to the changing flow patterns of natural gas supply in North America.

Oil Pipelines

The Company's Keystone crude oil pipeline system currently operates on the Wood River/Patoka and the Cushing Extension sections and has a nominal design capacity of 591,000 barrels per day (bbl/d). With increasing production of crude oil in Alberta and new crude oil discoveries in the U.S., including the Bakken shale play in Montana and North Dakota, combined with growing demand for secure, reliable sources of energy, TransCanada has identified additional opportunities to develop new oil pipeline capacity.

The Company plans to expand and extend the existing system through Keystone XL which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

Energy

TransCanada's Energy segment primarily consists of a portfolio of essential power generation assets in select regions of Canada and the U.S., and unregulated natural gas storage assets in Alberta.

TransCanada owns, controls or is developing more than 10,800 MW of power generation, comprising a diverse portfolio that includes power sourced from natural gas, nuclear, coal, hydro, wind and solar assets. TransCanada's power business is primarily located in Canada in Alberta, Ontario and Québec, in the northeastern U.S. mainly in the New England states and New York, and in Arizona. The assets are largely underpinned by long-term tolling contracts or represent low-cost baseload generation and essential capacity.

From offices in Western Canada, Ontario and the northeastern U.S., TransCanada complements these assets by conducting wholesale and retail electricity marketing and trading throughout North America.

In addition to power generation assets in the Energy business, TransCanada owns or controls approximately 130 Bcf of unregulated natural gas storage capacity in Alberta, or approximately one-third of all storage capacity in the province. Combined with the regulated natural gas storage in Michigan included in the Natural Gas Pipelines segment, TransCanada provides natural gas storage and related services for approximately 380 Bcf of capacity.

TRANSCANADA'S STRATEGY

TransCanada's vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where it has or can develop a significant competitive advantage. TransCanada's key strategies continue to evolve with the Company's growth and development and its changing business environment. TransCanada's corporate strategy integrates four fundamental value-creating activities:

- **Maximize the full-life value of TransCanada's infrastructure assets and commercial positions**
- **Commercially develop and physically execute new asset investment programs**
- **Cultivate a focused portfolio of high-quality development options**
- **Maximize TransCanada's competitive strengths**

Maximize the full-life value of TransCanada's infrastructure assets and commercial positions
TransCanada relies on a low-risk business model to maximize the full-life value of existing assets and commercial positions. The Company's pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flows and earnings. In Energy, highly efficient, large-scale power generation facilities supply power markets through long-term power purchase and sale agreements and low-volatility, shorter-term commercial arrangements. TransCanada's growing investments in natural gas, nuclear, wind, hydro-power, and solar generating facilities demonstrate the Company's commitment to clean, sustainable energy. Long-life infrastructure assets and long-term commercial arrangements are expected to continue as cornerstones of TransCanada's business model.

Commercially develop and physically execute new asset investment programs
TransCanada's expertise, scale and financial capacity enable access to attractive commercial, financing and input cost arrangements that influence the quality of projects, notably the current $12 billion capital program. These projects are expected to provide further contributions to the Company's earnings over the next three years as they are put in service. Success in this capital program requires effective performance in engineering and in project set-up and delivery. It also requires expert regulatory, legal and financing support, as well as outstanding operational set-up. TransCanada's model for managing construction risks and maximizing capital productivity helps ensure disciplined attention to quality, cost and schedule that produces superior service for its customers and quality returns to shareholders. Many of these functional capabilities also create the basis for successful acquisition and integration of new energy and pipeline facilities, an important dimension of the growth strategy.

Cultivate a focused portfolio of high-quality development options
The Company's core regions within North America are the focus of pipelines and energy growth initiatives. TransCanada will continue to pursue opportunities to connect long-life shale and conventional natural gas resources in Western and Northern Canada, as well as Alaska, the U.S. Rockies, the U.S. Midcontinent and the U.S. Gulf Coast supply regions. TransCanada will also continue to pursue opportunities to connect growing crude oil volumes from the Alberta oil sands and U.S. sources, including the Bakken formation in Montana and North Dakota, to preferred North American markets. The Company will continue to assess energy infrastructure acquisition opportunities that complement its existing pipeline network and provide access to new supply and market regions. In Energy, the Company will continue to focus on low-cost, long-life baseload power generating and natural gas storage assets supported by firm, long-term contracts with reputable and creditworthy counterparties. Selected opportunities will be advanced to full development and construction when market conditions are appropriate and project risks are manageable.

Maximize TransCanada's competitive strengths

TransCanada continues to build competitive strength in areas that directly drive long-term shareholder value. At the core of the Company's competitive advantage are powerful capabilities in strategy development, implementation, and continuous improvement. The Company relies on its scale, presence, operating capabilities, leadership and teams to compete effectively and deliver outstanding value to customers. A disciplined approach to capital investment combined with access to sizeable amounts of competitive-cost capital allows the Company to create significant shareholder value from its large capital projects. TransCanada recognizes that constructive relationships with key customers and stakeholders are critically important in the long-term energy infrastructure business. TransCanada values its reputation for consistent financial performance and long-term financial stability. The Company clearly communicates its financial performance to equity and debt investors, providing insight into both value upside and business risks. We work to sustain the trust and support of our long-term investors and to attract new investors who see long-term value in our disciplined approach to the energy infrastructure business. The Company continues to identify and build on all aspects of competitive strength.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE-YEAR CONSOLIDATED FINANCIAL DATA

(millions of dollars except per share amounts)	**2011**	2010	2009
Income Statement			
Revenues	**9,139**	8,064	8,181
Comparable EBITDA[1]	**4,806**	3,941	4,107
Net Income Attributable to Common Shares	**1,527**	1,227	1,374
Comparable Earnings[1]	**1,565**	1,361	1,325
Per Share Data			
Net Income per Common Share			
Basic	**$2.18**	$1.78	$2.11
Diluted	**$2.17**	$1.77	$2.11
Comparable Earnings per Common Share[1]	**$2.23**	$1.97	$2.03
Dividends Declared			
Per Common Share	**$1.68**	$1.60	$1.52
Per Series 1 Preferred Share[2]	**$1.15**	$1.15	$0.29
Per Series 3 Preferred Share[2]	**$1.00**	$0.80	–
Per Series 5 Preferred Share[2]	**$1.10**	$0.65	–
Cash Flows			
Funds Generated from Operations[1]	**3,663**	3,331	3,080
Decrease/(Increase) in Operating Working Capital	**310**	(249)	(90)
Net Cash Provided by Operations	**3,973**	3,082	2,990
Capital Expenditures	**3,274**	5,036	5,417
Acquisitions, Net of Cash Acquired	**–**	–	902
Balance Sheet			
Total Assets	**48,995**	46,794	43,841
Total Long-Term Liabilities	**24,326**	23,220	21,959

[1] Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable Earnings, Comparable Earnings per Common Share and Funds Generated from Operations.

[2] The Company issued Series 1, 3 and 5 preferred shares in September 2009, March 2010 and June 2010, respectively, rounded to nearest cent.

HIGHLIGHTS

Earnings

- Net Income Attributable to Common Shares was $1.5 billion or $2.18 per share in 2011 compared to $1.2 billion or $1.78 per share, respectively, in 2010.
- TransCanada's Comparable Earnings in 2011 were $1.6 billion or $2.23 per share, a 13 per cent increase on a per share basis compared to the $1.4 billion or $1.97 per share reported in 2010.

Cash Flow

- Funds Generated from Operations were $3.7 billion in 2011, an increase of $0.4 billion or 10 per cent from $3.3 billion in 2010.
- TransCanada invested $3.3 billion in its Natural Gas Pipelines, Oil Pipelines and Energy capital projects in 2011, including the following:
  - capital expenditures of $0.9 billion for Natural Gas Pipelines projects, including expansion of the Alberta System and completion of Bison and Guadalajara;
  - capital expenditures of $1.2 billion for Keystone; and
  - capital expenditures of $1.1 billion for Energy projects, including the refurbishment and restart of Bruce A Units 1 and 2, completion of Coolidge and construction of Cartier Wind, including completion of Montagne-Sèche and phase one of the Gros-Morne project.
- In 2011, TransCanada issued approximately $1.6 billion of long-term debt and $200 million of common shares, primarily comprising the following:
  - in December 2011, TC PipeLines, LP made a draw of US$300 million on its senior revolving credit facility;
  - in November 2011, the issuance of $750 million of medium-term notes;
  - in June 2011, TC PipeLines, LP issued US$350 million of senior notes; and
  - in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of approximately 5 million common shares from treasury in lieu of making cash dividend payments totalling $202 million.

Balance Sheet

- Total assets increased by $2.2 billion to $49.0 billion in 2011 from 2010, primarily due to investments in capital projects, described above.
- TransCanada's Equity Attributable to Controlling Interests increased by $0.6 billion to $17.3 billion in 2011 from 2010.

Dividends

- On February 13, 2012, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares by five per cent to $0.44 per share from $0.42 per share for the quarter ending March 31, 2012. This was the twelfth consecutive year in which the common share dividend was increased. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2012, and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2012.

Refer to the Results of Operations and Liquidity and Capital Resources sections in this MD&A for further discussion of these highlights.

Reconciliation of Non-GAAP Measures

Year ended December 31, 2011 *(millions of dollars)*	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**2,967**	**587**	**1,338**	**(86)**	**4,806**
Depreciation and amortization	**(986)**	**(130)**	**(398)**	**(14)**	**(1,528)**
Comparable EBIT	**1,981**	**457**	**940**	**(100)**	**3,278**
Other Income Statement Items					
Comparable interest expense					**(939)**
Interest expense of joint ventures					**(55)**
Comparable interest income and other					**60**
Comparable income taxes					**(595)**
Net income attributable to non-controlling interests					**(129)**
Preferred share dividends					**(55)**
Comparable Earnings					**1,565**
Specific items (net of tax):					
Risk management activities[1]					**(38)**
Net Income Attributable to Common Shares					**1,527**

Year ended December 31, 2011 *(millions of dollars except per share amounts)*	2011
Comparable Interest Expense	**(939)**
Specific item:	
Risk management activities[1]	**2**
Interest Expense	**(937)**
Comparable Interest Income and Other	**60**
Specific item:	
Risk management activities[1]	**(5)**
Interest Income and Other	**55**
Comparable Income Taxes	**(595)**
Specific item:	
Risk management activities[1]	**22**
Income Taxes Expense	**(573)**
Comparable Earnings per Common Share	**$2.23**
Specific item (net of tax):	
Risk management activities[1]	**(0.05)**
Net Income per Common Share	**$2.18**

Reconciliation of Non-GAAP Measures

Year ended December 31, 2010 *(millions of dollars)*	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,915	–	1,125	(99)	3,941
Depreciation and amortization	(977)	–	(377)	–	(1,354)
Comparable EBIT	1,938	–	748	(99)	2,587

Other Income Statement Items	
Comparable interest expense	(701)
Interest expense of joint ventures	(59)
Comparable interest income and other	94
Comparable income taxes	(400)
Net income attributable to non-controlling interests	(115)
Preferred share dividends	(45)
Comparable Earnings	1,361
Specific items (net of tax):	
Valuation provision for MGP	(127)
Risk management activities[1]	(7)
Net Income Attributable to Common Shares	1,227

Year ended December 31, 2010 *(millions of dollars except per share amounts)*	**2010**
Comparable Income Taxes	(400)
Specific items:	
Valuation provision for MGP	19
Risk management activities[1]	1
Income Taxes Expense	(380)
Comparable Earnings per Common Share	$1.97
Specific items:	
Valuation provision for MGP	(0.18)
Risk management activities[1]	(0.01)
Net Income per Common Share	$1.78

Reconciliation of Non-GAAP Measures

Year ended December 31, 2009 *(millions of dollars)*	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	3,093	–	1,131	(117)	4,107
Depreciation and amortization	(1,030)	–	(347)	–	(1,377)
Comparable EBIT	2,063	–	784	(117)	2,730

Other Income Statement Items	
Comparable interest expense	(954)
Interest expense of joint ventures	(64)
Comparable interest income and other	121
Comparable income taxes	(406)
Net income attributable to non-controlling interests	(96)
Preferred share dividends	(6)
Comparable Earnings	1,325
Specific items (net of tax):	
Dilution gain from reduced interest in TC PipeLines, LP	18
Risk management activities[1]	1
Income tax adjustments	30
Net Income Attributable to Common Shares	1,374

Year ended December 31, 2009 *(millions of dollars except per share amounts)*	**2009**
Comparable Income Taxes	(406)
Specific items:	
Dilution gain from reduced interest in TC PipeLines, LP	(11)
Income tax adjustments	30
Income Taxes Expense	(387)
Comparable Earnings per Common Share	$2.03
Specific items:	
Dilution gain from reduced interest in TC PipeLines, LP	0.03
Risk management activities[1]	–
Income tax adjustments	0.05
Net Income per Common Share	$2.11

[1] For the year ended *(millions of dollars)*

	2011	2010	2009
Risk Management Activities Gains/(Losses):			
U.S. Power derivatives	**(48)**	2	–
Canadian Power derivatives	**(3)**	–	–
Natural Gas Storage proprietary inventory and derivatives	**(6)**	(10)	1
Interest rate derivatives	**2**	–	–
Foreign exchange derivatives	**(5)**	–	–
Income taxes attributable to risk management activities	**22**	1	–
Risk Management Activities	**(38)**	(7)	1

RESULTS OF OPERATIONS

TransCanada had Net Income Attributable to Common Shares of $1,527 million or $2.18 per share in 2011 compared to $1,227 million or $1.78 per share and $1,374 million or $2.11 per share in 2010 and 2009, respectively.

Comparable Earnings in 2011, 2010 and 2009 were $1,565 million or $2.23 per share, $1,361 million or $1.97 per share and $1,325 million or $2.03 per share, respectively. Comparable Earnings in 2011 excluded $38 million of net unrealized after-tax losses ($60 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings in 2010 excluded a $127 million after-tax ($146 million pre-tax) valuation provision for advances to the Aboriginal Pipeline Group (APG) for the Mackenzie Gas Project (MGP) and $7 million of net unrealized after-tax losses ($8 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings in 2009 excluded $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, an $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced interest in TC PipeLines, LP following a public offering of TC PipeLines, LP common units in fourth quarter 2009 and a $1 million net unrealized after-tax gain ($1 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $204 million or $0.26 per share in 2011 compared to 2010 and included the following:

- increased Comparable Earnings Before Interest and Taxes (EBIT) from Natural Gas Pipelines primarily due to incremental earnings from Bison and Guadalajara which were placed in service in January 2011 and June 2011, respectively, lower general, administrative and support costs as well as lower business development spending, partially offset by lower revenues from certain U.S. Pipelines and the negative impact of a weaker U.S. dollar;
- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;
- increased Comparable EBIT from Energy primarily due to higher realized power prices for Western Power and incremental earnings from Halton Hills and Coolidge, partially offset by lower contributions from Bruce B, Natural Gas Storage and U.S. Power;
- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service, and higher interest expense as a result of U.S. dollar-denominated debt issuances in June and September 2010, partially offset by gains on derivatives used to manage the Company's exposure to rising interest rates in 2011 compared to losses incurred in 2010 and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;
- decreased Comparable Interest Income and Other primarily due to lower realized gains in 2011 compared to 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income;
- increased Comparable Income Taxes primarily due to higher pre-tax earnings in 2011 and higher positive income tax adjustments in 2010 compared to 2011;
- increased Non-Controlling Interests due to the sale of a 25 per cent interest in GTN LLC and Bison LLC to TC PipeLines, LP in May 2011 and the reduction in the Company's ownership interest in TC PipeLines, LP; and
- increased Preferred Share Dividends recorded on preferred shares issued in 2010.

Comparable Earnings increased $36 million and decreased $0.06 per share in 2010 compared to 2009. The increase in Comparable Earnings was primarily due to increased capitalized interest relating to Keystone and other capital projects. This increase was partially offset by decreased EBIT from Natural Gas Pipelines and Energy as discussed later. The decrease in Comparable Earnings on a per share basis reflected the issuance of 58.4 million common shares in second quarter 2009 and common shares issued in 2010 and 2009 under the Company's DRP.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is significantly offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The

average exchange rate to convert a U.S. dollar to a Canadian dollar for the year ended December 31, 2011 was 0.99 (2010 –1.03; 2009 – 1.14).

Summary of Significant U.S. Dollar-Denominated Amounts

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
U.S. Natural Gas Pipelines Comparable EBIT[1]	**786**	710	682
U.S. Oil Pipelines Comparable EBIT[1]	**301**	–	–
U.S. Power Comparable EBIT[1]	**164**	187	78
Interest on U.S. dollar-denominated long-term debt	**(734)**	(680)	(645)
Capitalized interest on U.S. capital expenditures	**116**	290	123
U.S. non-controlling interests and other	**(192)**	(164)	(132)
	441	343	106

[1] Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBIT.

FORWARD-LOOKING INFORMATION

This MD&A contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

- anticipated business prospects;
- financial performance of TransCanada and its subsidiaries and affiliates;
- expectations or projections about strategies and goals for growth and expansion;
- expected cash flows;
- expected costs;
- expected costs for projects under construction;
- expected schedules for planned projects (including anticipated construction and completion dates);
- expected regulatory processes and outcomes;
- expected outcomes with respect to legal proceedings, including arbitration;
- expected capital expenditures;
- expected operating and financial results; and
- expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

- inflation rates, commodity prices and capacity prices;
- timing of debt issuances and hedging;
- regulatory decisions and outcomes;

- arbitration decisions and outcomes;
- foreign exchange rates;
- interest rates;
- tax rates;
- planned and unplanned outages and utilization of the Company's pipeline and energy assets;
- asset reliability and integrity;
- access to capital markets;
- anticipated construction costs, schedules and completion dates; and
- acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

- the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits;
- the operating performance of the Company's pipeline and energy assets;
- the availability and price of energy commodities;
- amount of capacity payments and revenues from the Company's energy business;
- regulatory decisions and outcomes;
- outcomes with respect to legal proceedings, including arbitration;
- counterparty performance;
- changes in environmental and other laws and regulations;
- competitive factors in the pipeline and energy sectors;
- construction and completion of capital projects;
- labour, equipment and material costs;
- access to capital markets;
- interest and currency exchange rates;
- weather;
- technological developments; and
- economic conditions in North America.

Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC).

Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this MD&A or otherwise, whether as a result of new information, future events or otherwise, except as required by law.

NON-GAAP MEASURES

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, EBITDA, Comparable EBITDA, EBIT, Comparable EBIT, Comparable Interest Expense and Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning as prescribed by CGAAP. They are, therefore, considered to be non-GAAP measures and may not be comparable to similar

measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other and Income Taxes, respectively, and are adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing derivatives. The risk management activities which TransCanada excludes from Comparable Earnings provide effective economic hedges but do not meet the specific criteria for hedge accounting treatment and, therefore, changes in their fair values are recorded in Net Income each year. The unrealized gains or losses from changes in the fair value of these derivative contracts and natural gas inventory in storage are not considered to be representative of the underlying operations in the current period or the positive margin that will be realized upon settlement. As a result, these amounts have been excluded in the determination of Comparable Earnings.

The Reconciliation of Non-GAAP Measures table in this MD&A presents a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares. Comparable Earnings per Common Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the year.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Summarized Cash Flow table in the Liquidity and Capital Resources section in this MD&A.

OUTLOOK

TransCanada's corporate strategy is to maximize the full-life value of its existing assets and commercial positions, and to pursue long-term growth opportunities that add long-term shareholder value while focusing on its core strengths in its pipelines and energy businesses in North America. In 2012 and beyond, TransCanada expects that its net income and operating cash flow combined with a strong balance sheet and its proven ability to access capital markets will provide the financial resources needed to complete its current $12 billion capital expenditure program, which includes Keystone XL and the Bruce Power restarts, to continue pursuing additional long-term growth opportunities and to create additional value for its shareholders. This strategy will be executed with the same discipline and deliberate manner that characterized TransCanada's capital expenditure program in previous years.

TransCanada expects a positive impact on its 2012 earnings from assets that were placed in service in 2011 such as the Guadalajara natural gas pipeline, the Coolidge power facility and two Cartier Wind farm projects, from Keystone's Wood River/Patoka and Cushing Extension sections that began recording earnings in 2011, and from assets that are

expected to be placed in service in 2012, such as Bruce Power Units 1 and 2. TransCanada expects that as these assets are placed in service, its consolidated earnings for the year will be somewhat offset by a corresponding reduction in capitalized interest.

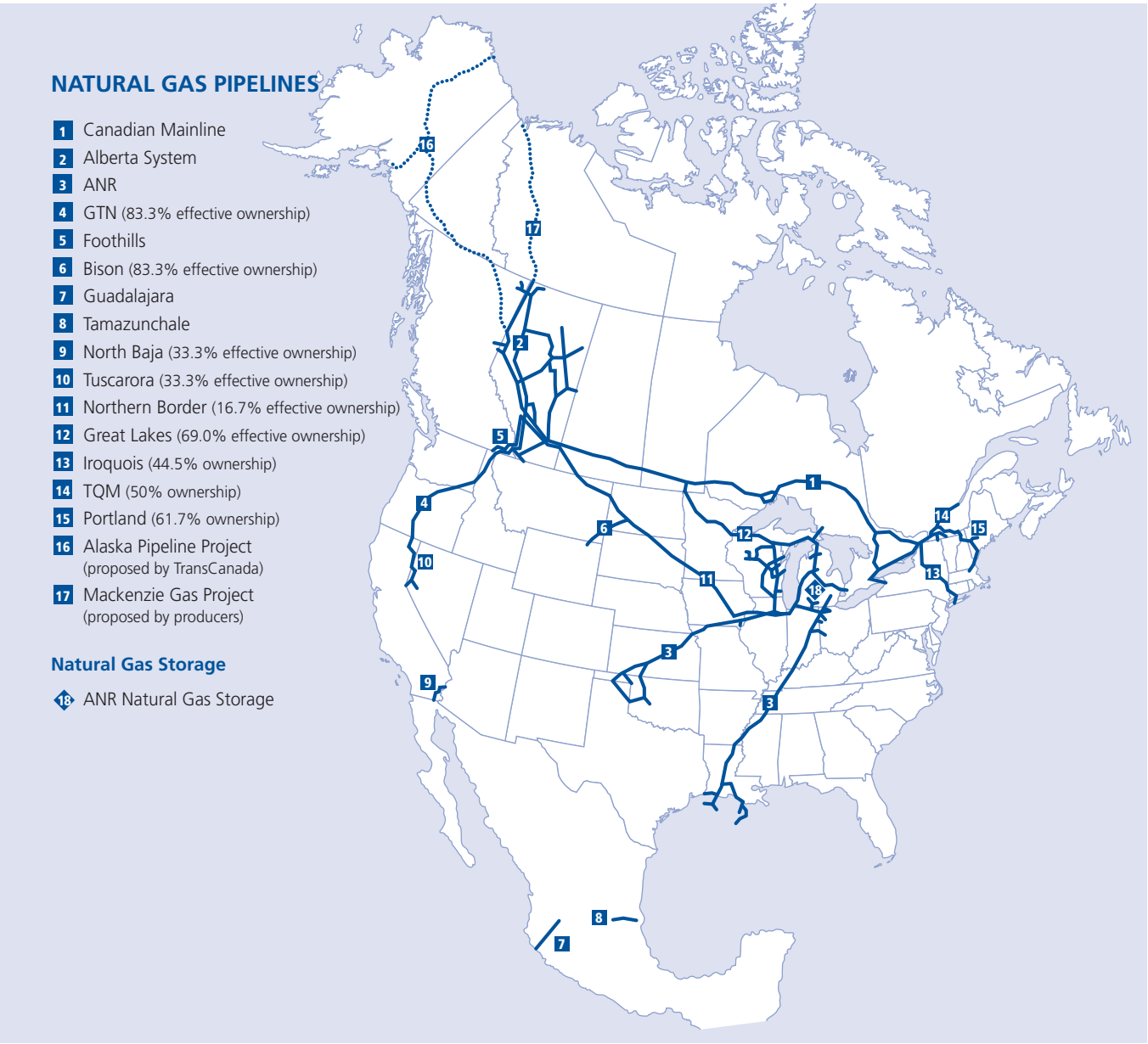
Natural Gas Pipelines' EBIT in 2012 will be affected by decisions made by applicable regulatory authorities, and the timing thereof, including the Canadian Mainline 2012 Tolls Application and Restructuring Proposal (Restructuring Proposal), as well as the establishment and expiry of long-term contracts, other variances in throughput volume, and rate settlements on its U.S. pipelines. Absent an NEB decision in 2012 with respect to Canadian Mainline 2012 tolls, EBIT from the Canadian Mainline will reflect the last approved rate of return on common equity (ROE) of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years.

Oil Pipelines EBIT in 2012 is expected to be higher than in 2011, primarily due to the impact of a full year of earnings being recorded on the Wood River/Patoka and Cushing Extension sections of Keystone compared to eleven months in 2011.

Energy's EBIT in 2012 is expected to be positively affected by assets that were placed in service during 2011 and assets that are expected to be placed in service in 2012. Energy's EBIT in 2012 could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York and outcome of the Sundance A PPA arbitration. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by fluctuations in commodity prices.

TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy businesses in the U.S. are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's Net Income. As new assets are placed in service in the U.S., this exposure is expected to increase as EBIT from U.S. operations increases. This impact will be partially offset by corresponding changes in the value of U.S. dollar-denominated interest expense. In addition, the Company expects to continue to use derivatives to manage its resultant net exposure to changes in U.S. dollar exchange rates.

The Company's results in 2012 may be affected by a number of factors and developments as discussed throughout this MD&A including, without limitation, the factors and developments discussed in the Forward-Looking Information and Business Risks sections for Natural Gas Pipelines, Oil Pipelines and Energy. Refer to the Outlook sections in this MD&A for further discussion on the outlook for Natural Gas Pipelines, Oil Pipelines and Energy.



NATURAL GAS PIPELINES

The following pipelines are owned 100 per cent by TransCanada unless otherwise stated.

CANADIAN MAINLINE The Canadian Mainline is a 14,101 km (8,762 miles) natural gas transmission system in Canada that extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

ALBERTA SYSTEM The Alberta System is a 24,373 km (15,145 miles) natural gas transmission system in Alberta and Northeast B.C. that connects with the Canadian Mainline and Foothills natural gas pipelines and with third-party natural gas pipelines.

ANR ANR is a 16,656 km (10,350 miles) natural gas transmission system that extends from producing fields located in the Texas and Oklahoma panhandle regions, from the offshore and onshore regions of the Gulf of Mexico, and from the U.S. midcontinent region to markets located mainly in Wisconsin, Michigan, Illinois, Indiana and Ohio. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total working capacity of 250 Bcf.

GTN Owned 75 per cent by TransCanada and 25 per cent by TC PipeLines, LP, GTN is a 2,178 km (1,353 miles) natural gas transmission system that transports WCSB and Rocky Mountain-sourced natural gas to third-party natural gas pipelines and markets in Washington, Oregon and California, and connects with Tuscarora. TransCanada operates GTN and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

FOOTHILLS Foothills is a 1,241 km (771 miles) transmission system in Western Canada carrying natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

BISON Owned 75 per cent by TransCanada and 25 per cent by TC PipeLines, LP, Bison is a 487 km (303 miles) natural gas pipeline that was placed in service in January 2011 and connects supply from the Powder River Basin in Wyoming to Northern Border in North Dakota. TransCanada operates Bison and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

GUADALAJARA Guadalajara is a 310 km (193 miles) natural gas pipeline from Manzanillo to Guadalajara in Mexico.

TAMAZUNCHALE Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi.

NORTH BAJA Owned 100 per cent by TC PipeLines, LP, North Baja is a natural gas transmission system extending 138 km (86 miles) from Ehrenberg, Arizona to Ogilby, California and connecting with a third-party natural gas pipeline system in Mexico. TransCanada operates North Baja and effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

TUSCARORA Owned 100 per cent by TC PipeLines, LP, Tuscarora is a 491 km (305 miles) pipeline system transporting natural gas from GTN at Malin, Oregon to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

NORTHERN BORDER Owned 50 per cent by TC PipeLines, LP, Northern Border is a 2,265 km (1,407 miles) natural gas transmission system serving the U.S. Midwest. TransCanada operates Northern Border and effectively owns 16.7 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by TC PipeLines, LP, Great Lakes is a 3,404 km (2,115 miles) natural gas transmission system serving markets in Eastern Canada and the U.S. Northeast and Midwest regions. TransCanada operates Great Lakes and effectively owns 69.0 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

IROQUOIS Owned 44.5 per cent by TransCanada, Iroquois is a 666 km (414 miles) pipeline system that connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the northeastern U.S.

TQM Owned 50 per cent by TransCanada, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline near the Québec/Ontario border, transports natural gas to markets in Québec, and connects with Portland. TQM is operated by TransCanada.

PORTLAND Owned 61.7 per cent by TransCanada, Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. Portland is operated by TransCanada.

TRANSGAS Owned 46.5 per cent by TransCanada, TransGas is a 344 km (214 miles) natural gas pipeline system extending from Mariquita to Cali in Colombia.

GAS PACIFICO/INNERGY Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

ALASKA PIPELINE PROJECT The Alaska Pipeline Project is a proposed natural gas pipeline and a proposed treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the treatment plant at Prudhoe Bay, Alaska to Alberta. TransCanada also commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the LNG option, that would extend from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska. TransCanada has entered into an agreement with ExxonMobil to jointly advance these projects.

MACKENZIE GAS PROJECT The Mackenzie Gas Project is a proposed natural gas pipeline extending 1,196 km (743 miles) that would connect northern onshore natural gas fields with North American markets. TransCanada has the right to acquire an equity interest in the project.

NATURAL GAS PIPELINES – HIGHLIGHTS

- Comparable EBIT from Natural Gas Pipelines was $2.0 billion in 2011, an increase of $0.1 billion from $1.9 billion in 2010.
- The Company invested $0.9 billion in Natural Gas Pipelines capital projects in 2011 primarily related to growth on the Alberta System and construction of the Guadalajara pipeline.
- In January 2011, the Bison natural gas pipeline was placed in service.
- In June 2011, the Company's US$360 million, 307 km (191 miles) Guadalajara natural gas pipeline went into service. This pipeline has capacity to transport 500 million cubic feet per day (MMcf/d) of natural gas to a power plant and 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara.
- The Alberta System growth continues through new connections of supply primarily in the Horn River and Montney shale basins in B.C. as well as the Deep Basin in Alberta. In 2011, the NEB approved the construction of natural gas pipeline projects for the Alberta System with a capital cost of approximately $910 million, including the approval to construct the Horn River pipeline with an estimated capital cost of $275 million and an in-service date of second quarter 2012. In addition, Pipeline projects with a total capital cost of approximately $810 million are still awaiting NEB decisions. The Company executed new agreements to further extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of $230 million. Subject to regulatory approval this extension is projected to commence service in 2014.
- In September 2011, TransCanada filed, with the NEB, the Restructuring Proposal, a comprehensive application to change the business structure and the terms and conditions of service for the Canadian Mainline including a 7.0 per cent after-tax weighted average cost of capital (ATWACC) fair return, revised depreciation rates and other parameters to address tolls for 2012 and 2013. The application also includes components that affect the Alberta System and Foothills. The NEB decision for this filing is expected in late 2012 or early 2013.
- In November 2011, TransCanada refiled an application with the NEB including supplemental information to construct $130 million of new pipeline infrastructure on the Canadian Mainline to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets.
- In May 2011, TransCanada closed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$605 million plus closing adjustments, which included US$81 million or 25 per cent of GTN LLC debt outstanding.

NATURAL GAS PIPELINES – RESULTS

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Canadian Natural Gas Pipelines			
Canadian Mainline	**1,058**	1,054	1,133
Alberta System	**742**	742	728
Foothills	**127**	135	132
Other (TQM, Ventures LP)	**50**	50	59
Canadian Natural Gas Pipelines Comparable EBITDA[1]	**1,977**	1,981	2,052
Depreciation and amortization	**(722)**	(715)	(714)
Canadian Natural Gas Pipelines Comparable EBIT[1]	**1,255**	1,266	1,338
U.S. Natural Gas Pipelines (in U.S. dollars)			
ANR	**312**	314	300
GTN[2]	**131**	171	170
Great Lakes[3]	**101**	109	120
TC PipeLines, LP[2][4][5]	**101**	99	90
Iroquois	**67**	67	68
Bison[5]	**49**	–	–
Portland[6]	**22**	22	22
International (Tamazunchale, Guadalajara, TransGas, Gas Pacifico/INNERGY)[7]	**77**	42	52
General, administrative and support costs[8]	**(9)**	(31)	(17)
Non-controlling interests[9]	**202**	173	153
U.S. Natural Gas Pipelines Comparable EBITDA[1]	**1,053**	966	958
Depreciation and amortization	**(267)**	(256)	(276)
U.S. Natural Gas Pipelines Comparable EBIT[1]	**786**	710	682
Foreign exchange	**(8)**	24	105
U.S. Natural Gas Pipelines Comparable EBIT[1] (in Canadian dollars)	**778**	734	787
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[1]	**(52)**	(62)	(62)
Natural Gas Pipelines Comparable EBIT[1]	**1,981**	1,938	2,063
Summary:			
Natural Gas Pipelines Comparable EBITDA[1]	**2,967**	2,915	3,093
Depreciation and amortization	**(986)**	(977)	(1,030)
Natural Gas Pipelines Comparable EBIT[1]	**1,981**	1,938	2,063
Specific items:			
Valuation provision for MGP[10]	**–**	(146)	–
Dilution gain from reduced interest in TC PipeLines, LP[11]	**–**	–	29
Natural Gas Pipelines EBIT[1]	**1,981**	1,792	2,092

[1] Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.

(2) Results reflect TransCanada's direct ownership of 75 per cent of GTN effective May 2011 when 25 per cent was sold to TC PipeLines, LP, and 100 per cent prior to that date. GTN's results also include North Baja until July 2009, when North Baja was sold to TC PipeLines, LP.

(3) Represents TransCanada's 53.6 per cent direct ownership interest.

(4) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. Results reflect TransCanada's indirect effective ownership interest of 8.3 per cent in each of GTN and Bison effective May 2011. Effective November 18, 2009, TC PipeLines, LP's results reflected TransCanada's effective ownership in TC PipeLines, LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in TC PipeLines, LP was 42.6 per cent. From January 1, 2009 to June 30, 2009, TransCanada's ownership interest in TC PipeLines, LP was 32.1 per cent.

(5) Results reflect TransCanada's direct ownership of 75 per cent of Bison effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison went into service.

(6) Portland's results reflect TransCanada's 61.7 per cent ownership interest.

(7) Includes Guadalajara effective June 2011.

(8) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines, including $17 million for the start up of Keystone in 2010.

(9) Non-controlling interests reflects Comparable EBITDA for the 66.7 per cent and 38.3 per cent portions of TC PipeLines, LP and Portland, respectively, not owned by TransCanada.

(10) In 2010, the Company recorded a valuation provision of $146 million for its advances to the APG for the MGP.

(11) As a result of TC PipeLines, LP issuing common units to the public in July 2009, the Company's ownership interest in TC PipeLines, LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of $29 million was realized.

Natural Gas Pipelines' Comparable EBIT was $1,981 million in 2011 compared to $1,938 million in 2010. Comparable EBIT in 2010 excluded a $146 million valuation provision for the Company's advances to the APG for the MGP. Comparable EBIT in 2009 was $2,063 million excluding the $29 million dilution gain resulting from TransCanada's reduced interest in TC PipeLines, LP, which occurred as a result of the public issuance of common units by TC PipeLines, LP in November 2009.

Wholly Owned Canadian Natural Gas Pipelines Net Income

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Canadian Mainline	**246**	267	273
Alberta System	**200**	198	168
Foothills	**22**	27	23

NATURAL GAS PIPELINES – FINANCIAL ANALYSIS

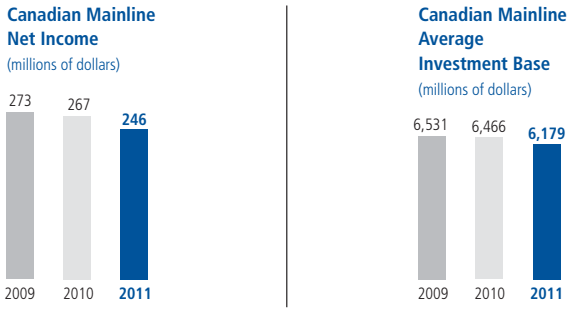
Canadian Mainline The Canadian Mainline is regulated by the NEB under the *National Energy Board Act (Canada)*. The NEB sets tolls that provide TransCanada with the opportunity to recover the costs of transporting natural gas, including a return on average investment base. The Canadian Mainline's EBITDA and net income are affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

The Canadian Mainline operated under a five-year tolls settlement from 2007 through 2011. The cost of capital reflected an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent. The tolls settlement established certain elements of the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. All other cost elements of the revenue requirement were treated on a flow-through basis. The settlement also allowed for performance-based incentive arrangements that the Company believes were mutually beneficial to TransCanada and its customers.

The Canadian Mainline's net income of $246 million in 2011 was $21 million lower compared to 2010 as a result of a lower ROE of 8.08 per cent in 2011 compared to 8.52 per cent in 2010 and a lower average investment base, partially offset by higher incentive earnings. Net income in 2010 was $6 million lower compared to 2009. This decrease was primarily due to lower OM&A incentive earnings as a result of cost-sharing with customers and an ROE of 8.52 per cent in 2010 compared to 8.57 per cent in 2009.

The Canadian Mainline's Comparable EBITDA was $1,058 million in 2011 compared to $1,054 million and $1,133 million in 2010 and 2009, respectively. EBITDA variances reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Capital Expenditures for the Canadian Mainline were $65 million in 2011 compared with $50 million and $61 million in 2010 and 2009, respectively.



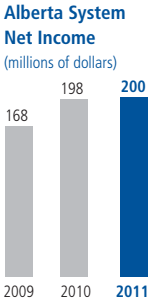
Alberta System The Alberta System is also regulated by the NEB, which approves the Alberta System's tolls and revenue requirement. The Alberta System's EBITDA and net income are affected by changes in the investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

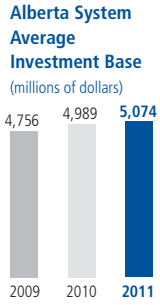
The Alberta System currently operates under the 2010 - 2012 Revenue Requirement Settlement approved by the NEB in September 2010. The 2010 - 2012 Revenue Requirement Settlement established an ROE of 9.70 per cent on deemed common equity of 40 per cent and included an annual fixed amount of $174 million for certain OM&A costs. Variances between actual and agreed-to OM&A costs accrue to TransCanada. All other cost elements of the revenue requirement are treated on a flow-through basis. In 2009, the Alberta System operated under the 2008 - 2009 Revenue Requirement Settlement approved by the Alberta Utilities Commission (AUC) in December 2008. The Alberta System was regulated by the AUC until April 2009.

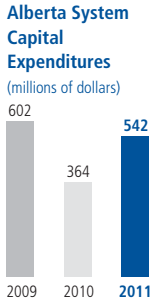
The 2008 - 2009 Revenue Requirement Settlement established fixed amounts for ROE, income taxes and certain OM&A costs. Variances between actual costs and those agreed to in the settlement accrued to TransCanada, subject to an ROE and income tax adjustment mechanism that accounted for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement were treated on a flow-though basis.

The Alberta System's net income of $200 million in 2011 was $2 million higher compared to 2010. The increase is primarily due to higher earnings as a result of a growing average investment base. Net income in 2010 was $30 million higher than in 2009. This increase reflected an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 compared to the earnings achieved under the settlement in place in 2009 and a higher average investment base, partially offset by lower incentive earnings. The increase in average investment base from 2009 to 2011 reflects capital expenditures to expand capacity in response to growing customer demand for service.

The Alberta System's Comparable EBITDA of $742 million in 2011 was consistent with 2010. Comparable EBITDA in 2010 was $14 million higher than 2009. EBITDA variances from the Alberta System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.







Foothills The Foothills System's net income of $22 million in 2011 was $5 million lower compared to 2010. The decrease was primarily due to lower earnings from a lower average investment base and lower OM&A incentive earnings. Net income in 2010 was $4 million higher than 2009, due to a Foothills 2010 settlement agreement, which established an ROE of 9.70 per cent on deemed common equity of 40 per cent for 2010 through 2012. Results in 2009 were based on the NEB ROE formula of 8.57 per cent on deemed common equity of 36 per cent.

The Foothills System's Comparable EBITDA of $127 million in 2011 was $8 million lower compared to 2010. Comparable EBITDA in 2010 was $3 million higher than 2009. EBITDA variances from the Foothills System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Other Canadian Natural Gas Pipelines Comparable EBITDA from Other Canadian Natural Gas Pipelines of $50 million in 2011 was consistent with 2010 and was $9 million lower than 2009 primarily due to an adjustment in 2009 as a result of the NEB's decision with respect to TQM cost of capital for 2007 and 2008.

ANR ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company, which is a FERC regulated entity that owns and operates certain storage fields in Michigan, has rates that were established pursuant to a settlement approved by the FERC that were effective beginning in 1990. ANR Storage Company is currently subject to a review, initiated by the FERC in late 2011, of its existing rates.

ANR's EBITDA is affected by the contracting and pricing of its existing transportation and storage capacity, expansion projects, delivered volumes and incidental commodity sales, as well as by costs for providing various services, which include OM&A costs and property taxes. Due to the seasonal nature of its business, ANR's volumes and revenues are generally higher in the winter months.

ANR's Comparable EBITDA in 2011 was US$312 million, a decrease of US$2 million compared to 2010. The decrease was primarily due to higher OM&A costs partially offset by higher transportation revenues, a settlement with a counterparty and incidental commodity sales. Comparable EBITDA in 2010 of US$314 million increased US$14 million compared to 2009, primarily due to lower OM&A costs, partially offset by lower contracted firm long-haul transportation sales and storage revenues.

GTN GTN is regulated by the FERC and is operated in accordance with tariffs that establish maximum and minimum rates for various services. GTN is permitted to discount or negotiate rates on a non-discriminatory basis. In 2011, GTN

negotiated a settlement for new rates with its customers in lieu of filing a rate case. The FERC approved the settlement agreement in November 2011 for new rates effective January 1, 2012. The settlement includes a four-year moratorium during which GTN and the settling parties are prohibited from taking certain actions, including making any filings to adjust rates prior to December 31, 2015. The settlement also requires GTN to file for new rates that are to be effective January 1, 2016.

GTN's EBITDA is affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types as well as by variations in the costs of providing services, which include OM&A costs and property taxes.

GTN's Comparable EBITDA from TransCanada's direct investment was US$131 million in 2011, a decrease of US$40 million compared to 2010. The decrease was primarily due to TransCanada's May 2011 sale of a 25 per cent interest in GTN to TC PipeLines, LP and decreased revenue. Comparable EBITDA in 2010 increased US$1 million compared to 2009, primarily due to lower OM&A costs and incremental proceeds accrued in 2010 relating to bankruptcy distributions from Calpine, partially offset by the impact of selling North Baja to TC PipeLines, LP in July 2009 and the write-off of costs in 2010 related to an unsuccessful information systems project.

Other U.S. Natural Gas Pipelines Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US$610 million in 2011 compared to $481 million in 2010. The increase was primarily due to the start of commercial operations of Bison and Guadalajara pipelines in January 2011 and June 2011, respectively, as well as the 25 per cent sale of TransCanada's ownership interest in GTN to TC PipeLines, LP in May 2011. Other contributing factors were lower general, administrative and support costs in 2011, partially offset by lower Great Lakes revenues in 2011. Comparable EBITDA in 2010 decreased US$7 million from 2009, primarily due to lower Great Lakes revenues.

Business Development Natural Gas Pipelines' Business Development Comparable EBITDA loss from business development expenses was $52 million in 2011 compared to $62 million in 2010. This improvement of $10 million was primarily due to lower business development costs associated with the Alaska Pipeline Project as a result of increased reimbursement by the State of Alaska to 90 per cent from 50 per cent effective July 31, 2010. Comparable EBITDA loss of $62 million in 2010 was consistent with 2009.

Depreciation and Amortization Depreciation and Amortization for Natural Gas Pipelines was $986 million in 2011, an increase of $9 million from 2010. The increase was primarily due to the start-up of Bison and Guadalajara partially offset by lower depreciation for Great Lakes as a result of the lower depreciation rate in Great Lakes' 2010 rate settlement. Depreciation and Amortization decreased $53 million in 2010 from 2009 primarily due to a weaker U.S. dollar in 2010 and lower depreciation for Great Lakes as a result of its 2010 rate settlement.

NATURAL GAS PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Introduction Opportunities for North American natural gas pipeline infrastructure are impacted by the developments in the natural gas exploration and production sector. Rapidly increasing supply of hydrocarbons from shale and other tight or low permeability resource plays, particularly in the past five years, are transforming the domestic natural gas market. These resource plays are being further developed due to the recent wide-spread application of horizontal drilling together with multi-stage hydraulic fracturing (fracking) that is reshaping the natural gas industry. For example, North America has evolved from having numerous projects and proposals in various stages of development for liquefied natural gas (LNG) import facilities as recently as five years ago to the current situation where both the Canadian and U.S. regulators have issued and are considering additional LNG export licenses due to the significant increase in North American natural gas supply.

The abundance of supply resulting in relatively low natural gas prices across North America is supportive of increased reliance on natural gas to meet growing energy demands. A shift to increased natural gas fired power generation is also emerging in the U.S. and Canada. Numerous proposals for development of LNG export facilities from North America is another example of the evolution of the natural gas industry. Persistently high oil prices, particularly relative

to North America natural gas prices, have resulted in increased deployment of capital for the exploration and production of liquid-rich hydrocarbon basins, which also tend to produce associated natural gas. A recent announcement by the Mexican government to change its procurement strategy away from LNG imports to infrastructure improvements that facilitate increased access to natural gas supply from the U.S. is further evidence of the increased confidence in the availability of supply at stable prices across North America.

The evolution of the natural gas market is also driving changes to traditional flow patterns across the continental pipeline grid resulting in reassessment of the use and repurposing of existing assets. TransCanada's portfolio of North American natural gas pipeline infrastructure is well positioned to capture investment opportunities from growing natural gas supply as well as opportunities to connect new markets while satisfying increasing demand for natural gas within existing markets.

The following are significant initiatives by TransCanada to capture opportunities in the evolving natural gas industry in North America:

Canadian Mainline In September 2011, TransCanada filed the Restructuring Proposal, a comprehensive application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline. The application included the following components:

- Extension of the Alberta System footprint to points on the Canadian Mainline in Saskatchewan, and on the Foothills System in Saskatchewan and B.C., thereby reducing the cost to transport gas from the Western Canada Sedimentary Basin (WCSB) to markets served by the Canadian Mainline.
- Lower depreciation expense and therefore lower tolls resulting from adjustments to the economic planning horizons for the three Canadian Mainline segments and a reallocation of accumulated depreciation to better match consumed service value for each segment.
- Changes to toll design, services, and pricing resulting in higher revenues and lower overall tolls.
- A 7.0 per cent ATWACC fair return which is equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent.

In October 2011, TransCanada filed supplementary information on cost of service and the proposed tolls for 2012 and 2013. These applied-for tolls result in a 2012 toll of $1.29 per gigajoule for transportation from Nova Inventory Transfer to the Dawn, Ontario delivery point, which is 38 per cent lower than the comparable toll charged in 2011.

The Restructuring Proposal was developed by TransCanada as an innovative and balanced response to recent and dramatic changes in the business environment of natural gas supply, demand and transportation in North America. The application is intended to enhance the long-term economic viability and sustainability of the Canadian Mainline and the WCSB. A decision regarding the Restructuring Proposal is expected in late 2012 or early 2013.

TransCanada re-filed an application with the NEB in November 2011 that included supplemental information for approval to construct $130 million of new pipeline infrastructure on the Canadian Mainline, to receive Marcellus shale basin gas at the Niagara Falls receipt point for further transportation to Eastern markets. Subject to regulatory approval to construct the facilities, deliveries from Niagara Falls are expected to begin at a rate of 230 MMcf/d in November 2012 and then increase to 350 MMcf/d by November 2013, which may require a subsequent application for additional facilities.

Alberta System The Alberta System's Horn River natural gas pipeline project was approved by the NEB in January 2011 and commenced construction in March 2011, with a targeted completion date of second quarter 2012 and an estimated capital cost of $275 million. In addition, the Company executed an agreement to extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of $230 million. As a result of the extension, additional contractual commitments of 100 MMcf/d are expected to commence in 2014 with volumes increasing to 300 MMcf/d by 2020. An application requesting approval to construct and operate this extension was filed with the NEB in October 2011. The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 MMcf/d by 2020.

In June 2011, the NEB approved the construction and operation of a 24 km (15 miles) extension of the Groundbirch natural gas pipeline. Construction commenced in August 2011 with an expected in-service date of April 1, 2012 and an estimated cost of approximately $60 million. The project is required to serve 250 MMcf/d of new transportation contracts.

TransCanada continues to advance pipeline development projects in B.C. and Alberta to transport new natural gas supply. The Company has filed applications with the NEB requesting approval for expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. TransCanada has incremental firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeast B.C. by 2014. Further requests for additional volumes on the Alberta System from the northwest portion of the WCSB have been received. In 2011, including the projects discussed above, the NEB has approved natural gas pipeline projects with capital costs of approximately $910 million. Further pipeline projects with a total capital cost of approximately $810 million are awaiting NEB decision. In addition, infrastructure to connect WCSB supply to markets continues to be pursued particularly to support further development of Alberta oil sands production and to supply proposed LNG export facilities on the Pacific Coast.

The Alberta System filed an application in October 2011 with the NEB to implement a new business model to restructure the commercial terms applied to existing natural gas liquids entering the Alberta System. The Natural Gas Liquids Extraction Model (NEXT) implementation date is proposed to be effective November 1, 2013. NEXT is designed to address the inequities caused by the current extraction convention, and improve the competitiveness of the Alberta System and the WCSB.

Commercial integration of the Alberta System and ATCO Pipelines system commenced in October 2011. Under the Agreement, the combined facilities of the two systems are commercially operated as a single transmission system and transportation service is provided to customers by NOVA Gas Transmission Ltd. (NGTL) pursuant to NGTL's Tariff and suite of rates and services. This agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of NGTL and ATCO Pipelines. The final stage in this integration project is the swapping of certain pipeline assets of equal value. An application to the NEB for approval of the asset swaps is anticipated in the first quarter 2012.

Canadian Mainline, Alberta System and Foothills 2012 Tolls TransCanada filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as the currently approved 2011 final tolls. In addition, TransCanada filed for interim 2012 tolls on the Alberta System and annual tolls for Foothills to be effective January 1, 2012. These tolls have also been approved on an interim basis pending the outcome of the NEB's decision on the Restructuring Proposal.

U.S. Pipelines In May 2011, TransCanada closed the sale of a 25 per cent interest in each of GTN and Bison to TC PipeLines, LP for an aggregate purchase price of US$605 million, which included US$81 million or 25 per cent of GTN's debt plus customary closing adjustments.

GTN GTN executed a settlement agreement with its shippers for new transportation rates to be effective January 2012 through December 2015. The settlement agreement was filed in August 2011 and approved by the FERC in November 2011.

Northern Border Northern Border operates pursuant to maximum long-term mileage-based rates and seasonal short-term transportation rates approved by the FERC in a January 2007 rate case settlement. A moratorium on the filing of future rate cases under National Gas Act Sections 4 or 5 expired on January 1, 2010. Northern Border is required to file a rate case on or before December 31, 2012.

Tuscarora Tuscarora Gas Transmission filed a settlement agreement with the FERC in December 2011 that concluded a review of Tuscarora's currently effective rates. The agreement, subject to the FERC approval, will lower shippers' reservation and transportation charges, and preclude another rate case until 2014.

ANR In September 2011, ANR Pipeline Company filed an application with the FERC to sell its offshore Gulf of Mexico assets and certain related onshore facilities to its wholly-owned subsidiary, TC Offshore LLC. At the same time, TC Offshore LLC requested authorization from the FERC to acquire, own and operate those facilities under the FERC's regulations. These filings are currently pending before the FERC and a decision is expected in second or third quarter 2012.

Alaska Pipeline Project The Alaska Pipeline Project team continues to work with shippers to resolve conditional bids received as part of the project's open season and is working toward the FERC application deadline of October 2012 for the Alberta option that would extend from Prudhoe Bay to points near Fairbanks and Delta Junction, and then to the Alaska-Canada border, where the pipeline would connect with a new pipeline in Canada. The pipeline in Canada would extend from the Alaska-Canada border to link up with pipeline systems near Boundary Lake, Alberta, providing the capability of transporting natural gas into the continental U.S. TransCanada has commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the LNG option, that would require a pipeline from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska. TransCanada has entered into an agreement with Exxon Mobil Corporation (ExxonMobil) to jointly advance the project.

The Mackenzie Gas Project The MGP received its Certificate of Public Convenience and Necessity in March 2011, marking the end of the Federal regulatory process. The proponents of the 1,196 km, 30 inch pipeline, with an initial capacity of 1.2 Bcf/d, continue to seek the Canadian government's support for an acceptable fiscal framework which would allow the project to progress.

Mexico The Guadalajara Pipeline in Mexico began commercial operations in June 2011. The US$360 million, 310 km (193 miles) project has capacity to transport 500 MMcf/d of natural gas to a power plant and 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara. The pipeline is secured under 25-year contracts with the Comisión Federal de Electricidad (CFE), Mexico's federal government owned electrical power company. In 2011, natural gas shipments were limited to support testing and commissioning efforts at the power plant. TransCanada and the CFE have agreed to add a US$60 million compressor station to the pipeline that is expected to be operational in early 2013.

NATURAL GAS PIPELINES – BUSINESS RISKS

Natural Gas Supply, Markets and Competition TransCanada faces competition at both the supply and market ends of its natural gas pipeline systems. This competition comes from other natural gas pipelines accessing supply basins, including the WCSB, and markets served by TransCanada's pipelines as well as from natural gas supplies produced in certain basins not directly served by the Company. Growth in supply and pipeline infrastructure has increased competition throughout North America. Production has increased in the U.S., driven primarily by shale gas, as well as in the WCSB. After declining over the past four years, WCSB production showed signs of recovery in 2011. Lower-cost shale gas in the U.S. has resulted in an increase in competition between supply basins, changes to traditional flow patterns and an increase in supply choices for customers. This change has contributed to a trend of continued reduction in long-haul, long-term firm contracted capacity and a shift to shorter-distance, short-term firm and interruptible contracts on many natural gas pipelines.

Although TransCanada has diversified its natural gas supply sources, many of its North American natural gas pipelines and its transmission infrastructure remain dependent on supply from the WCSB. TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Western Canada to domestic and export markets. The Alberta System, however, faces competition for connection to supply, particularly in northeast B.C., where the largest new source of natural gas has access to two existing pipeline companies with infrastructure in the area.

The Canadian Mainline, with its primary source of supply being the WCSB, also seeks opportunities to increase market share in Canadian domestic markets. However, TransCanada expects to continue to face competition for both the eastern domestic markets and in particular, the northeastern U.S export markets. Consumers in the northeastern U.S. generally have access to natural gas through numerous delivery and supply options. Eastern markets that

historically received Canadian supplies only from TransCanada's systems are now able to receive supplies from new natural gas pipelines that source U.S. and Atlantic Canada supplies. In recent years, the Canadian Mainline has experienced reductions in volumes originating at the Alberta border and in Saskatchewan, which have been partially offset by increases in volumes originating at points east of Saskatchewan. These reductions in both volumes and distance transported have resulted in an increase in Canadian Mainline tolls per unit that adversely affects its competitive position.

ANR's directly connected natural gas supply is primarily sourced from the U.S. Gulf Coast and midcontinent regions which are also served by competing interstate and intrastate natural gas pipelines. The sale of pipeline transportation capacity in the U.S. Gulf Coast region is highly competitive given the extensive natural gas pipeline network in this region. ANR must also compete for supply from interconnects with pipelines originating within the growing U.S. midcontinent shale gas formations and the U.S. Rockies production regions. Lower natural gas prices could result in reduced drilling activity and slow the rate of supply growth that has been fuelling investments in pipeline infrastructure additions in the U.S. midcontinent which could limit the number of incremental pipeline investment opportunities in the future.

ANR competes for market share with other natural gas pipelines and storage operators in its primary markets in the U.S. Midwest. As transportation capacity has become more abundant due to major pipeline additions over the past few years, lower natural gas prices that result in less available supply could negatively affect the value of pipeline capacity. The value of ANR's natural gas storage services is based on market conditions, which could become unfavourable resulting in reduced rates and terms.

GTN is primarily supplied with natural gas from the WCSB and competes with other interstate pipelines providing natural gas transportation services to markets in the U.S. Pacific Northwest, California and Nevada. These markets also have access to supplies from natural gas basins in the Rocky Mountains and the U.S. Southwest. Historically, natural gas supplies from the WCSB have been competitively priced against supplies from the other regions serving these markets. Increased competing supply sources could negatively affect the transportation value on GTN. Pacific Gas and Electric Company, GTN's largest customer, received California Public Utilities Commission approval to commit to capacity on a competing pipeline out of the U.S. Rockies basin to the California border that went in service in July 2011.

Great Lakes and Northern Border are subject to annual contract renewals and can experience demand changes related to seasonal market conditions. To the extent the capacity on these pipelines is contracted, utilization does not impact revenue significantly. Both pipelines compete for natural gas transportation customers with pipelines that transport gas exiting the WCSB. An increase in competition in the key markets served by TransCanada's pipeline systems could arise from new ventures or expanded operations from existing competitors. For Great Lakes, the combination of growing supply from the Rockies, Mid-Continent and Marcellus shale developments reaching Dawn, Ontario through both new and available pipeline capacity, as well as reduced demand due to the economic environment, has the potential to maintain competitive pressures on WCSB supply into the Midwest. For example, if the transport of natural gas from those other supply basins to Dawn becomes more economical on competitive pipeline routes, then those supplies could reach the eastern zone of Great Lakes' market area and displace Great Lakes' long-haul volumes.

Demand for Pipeline Capacity Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Demand and supply in new locations often creates opportunities for new infrastructure, but it may also change flow patterns and potentially impact utilization of existing assets. For example, the proposed LNG export facilities on the west coast of B.C. have the potential to reduce demand for capacity on pipelines that transport WCSB supply to other markets. TransCanada's pipelines may be challenged to sell available transportation capacity as transportation contracts expire on its existing pipeline assets, as they have, for example, on the Great Lakes system in fourth quarter 2011. TransCanada expects its U.S. natural gas pipelines to become more exposed to the potential for revenue variability due to rapidly evolving supply dynamics, competition and trends toward shorter term contracting by shippers.

Demand for a pipeline's capacity is ultimately the key driver that enables the transportation services to be sold. There are four key factors that influence demand for pipeline capacity. They are the price of gas that influences the amount of supply, basin on basin competition that influences where the supply will be developed, technology that influences the cost and pace of development of the resource play, and price basis differentials that drive what markets the supply will flow to. The risks associated with each of these four factors are considered below.

Gas Price
The price of natural gas is a key driver for development and exploration of the resource. The current low gas prices in North America may slow drilling activities that in turn diminishes production levels, particularly in dry gas fields where the extra revenue generated from the entrained liquids is not available.

Basin on Basin Competition
Large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of the necessary pipeline infrastructure. Therefore, basin on basin competition impacts the extent and timing of a resource play development that in turn drives changing dynamics for demand of pipeline capacity.

Technology
The increased supply of natural gas in North America is primarily due to the application of technology to shale and tight gas plays that include both horizontal drilling and fracking. There is growing regulatory and public scrutiny over the impacts of fracking. Changes to the practices of fracking through changes in regulations could impact the costs and pace of development of natural gas plays.

Basis Differentials
In the period 2008 to 2011, there was more capacity added to the continental pipeline network than in any prior period in the history of the industry. Gas supply basins that were once constrained such as the U.S. Rockies and East Texas now have an overabundance of export capacity. As well, the recent focus on the development of shale gas basins has led to declines in conventional supply basins and unutilized capacity on many pipelines. These factors have led to contraction of regional basis differentials, the differences in market prices paid for natural gas between different gas receipt and delivery points, which has led to changes in the way many pipeline systems are being used. As a result, many pipeline companies are moving to restructure their business models, rate designs and services to adapt to the changing flow dynamics.

Regulatory Risk Regulatory decisions continue to have an impact on the financial returns from existing investments in TransCanada's natural gas pipelines and are expected to have a similar impact on financial returns from future investments. TransCanada manages this risk through rate applications and negotiated settlements, where possible.

Regulations and decisions issued by U.S. regulatory bodies, particularly the FERC, the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Transportation, may also have an impact on the financial performance of TransCanada's U.S. pipelines. TransCanada continually monitors existing as well as proposed regulations to manage potential impacts to its U.S. pipelines.

Pipeline Abandonment Cost Risk Through the Land Matters Consultation Initiative (LMCI), the NEB is addressing several significant issues relating to future pipeline abandonment costs for Canadian regulated pipelines. During the LMCI process, the NEB provided several key guiding principles including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the system. Based on the NEB's direction, the earliest that collection of funds for future pipeline abandonment costs through cost-of-service tolls on Canadian regulated pipelines could begin would be 2015.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and management of risks in the Natural Gas Pipelines business.

NATURAL GAS PIPELINES – OUTLOOK

The WCSB remains an important supply basin for TransCanada's pipeline infrastructure, however, the Company's portfolio of pipelines across North America has broadened its supply source to include many other prolific and emerging supply areas.

TransCanada expects there will be excess natural gas pipeline capacity from the WCSB to markets outside Western Canada for the foreseeable future as a result of capacity expansions on natural gas pipelines over the past 15 years, competition from other pipelines and supply basins, and significant growth in natural gas consumption within Alberta driven primarily by oil sands development and electricity generation requirements.

The WCSB has an ultimate remaining conventional resource estimate of 126 trillion cubic feet. In addition, the ultimate potential of the basin has been vastly improved due to the advent of economic access to shale gas and tight gas. Over its history, the WCSB's ultimate potential has primarily reflected the economic productivity of the conventional resource base. The recent additions of unconventional resources together with the increasing economic viability of low quality conventional resources as a result of new drilling and completion technology, has in TransCanada's view, more than doubled the technically accessible resource base of the WCSB.

WCSB production is expected to increase slightly in 2012. Despite reduced overall drilling levels across the WCSB, the dramatic increases in initial productivity resulting from horizontally drilled wells, in combination with a renewed focus on associated natural gas liquids, has significantly offset the anticipated negative supply impact associated with reduced levels of conventionally drilled vertical wells. Drilling activity has increased in northwestern Alberta and northeastern B.C. as producers develop projects to access deeper multi-zone gas plays, shales and tight sands utilizing horizontally-drilled wells in combination with fracking techniques. Recently, shale gas production in northeastern B.C. has emerged as a significant natural gas supply source. TransCanada forecasts approximately 5 Bcf/d of total production from the Montney and Horn River shale gas sources by 2020, however, achieving this level will depend on natural gas prices as well as producer economics in the basin. The production from these two natural gas supply regions is currently approximately 1.5 Bcf/d.

The outlook for demand driven infrastructure for WCSB supply within Western Canada remains positive with continued growth expected in Alberta oil sands development and coal conversion to natural gas for power generation. In addition, in the second half of this decade, there is also potential for additional new markets in the Asia-Pacific region for WCSB gas, connecting to new LNG terminals which are proposed along the west coast of B.C. to export Canadian gas.

Demand for WCSB-sourced natural gas in Eastern Canada and the U.S. Northeast decreased in 2011, largely as a result of a diversification of supply sources. However, demand for natural gas in TransCanada's key eastern markets served by the Canadian Mainline is expected to increase over time, particularly to meet the expected growth in natural gas-fired power generation.

In the U.S., TransCanada expects that unconventional production will continue to grow from established shale gas plays in eastern Texas, northwestern Louisiana, Arkansas, southwestern Oklahoma and the Appalachian region. The Marcellus shale basin continues to grow and with new pipeline infrastructure coming on-stream, is changing the dynamics for gas flows into and out of the U.S. Northeast. In addition, development of the Utica shale basin (predominantly in Ohio) is in its infancy. This basin has significant potential to become another major natural gas supply source. Production focus has shifted in the near term toward more oil and liquids-rich hydrocarbon production, which is expected to increase associated natural gas supply in Texas, North Dakota and other areas. Supply from coalbed methane and tight gas sands in the U.S. Rockies is also expected to grow. The resulting anticipated growth in U.S. supply should provide additional opportunities for TransCanada's U.S. pipelines. U.S. demand growth is expected to be driven primarily by increased use of natural gas for power generation and industrial growth, as well as LNG exports in the second half of the decade.

TransCanada continues to seek opportunities in Mexico to further develop natural gas infrastructure opportunities. TransCanada will leverage the experience and expertise gained on its Guadalajara and Tamazunchale pipelines and

intends to participate in the $10 billion program recently announced by the Mexican government to expand its natural gas transmission infrastructure.

TransCanada will continue to focus on operational excellence and collaboration with all stakeholders to achieve negotiated settlements and provision of services that will increase the value of the Company's business.

Earnings Canadian Natural Gas Pipelines' earnings are affected by changes in investment base, ROE, capital structure and terms of toll settlements or other toll proposals as approved by the NEB, with the most significant variables being ROE, capital structure and investment base. Absent an NEB decision in 2012 with respect to Canadian Mainline 2012 tolls, earnings from the Canadian Mainline will be lower than in 2011 as results will reflect the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years. The Company expects continued growth of the Alberta System investment base as new supply in northeastern B.C. and western Alberta continues to be developed and connected to the Alberta System. TransCanada also anticipates a modest level of investment in its other Canadian natural gas pipelines but expects a continued net decline in the average investment bases of these pipelines as annual depreciation outpaces capital investment, the result of which would have the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian natural gas pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

The ability to recontract unsold capacity on TransCanada's U.S. pipelines and to sell capacity at attractive rates is influenced by prevailing market conditions and competitive factors, including competing natural gas pipelines and supply from other natural gas sources in these markets. EBIT from U.S. Natural Gas Pipelines' operations is also affected by the level of OM&A costs, regulatory decisions and changes in foreign currency exchange rates.

In addition, Natural Gas Pipelines' EBIT is expected to be affected by costs to develop new pipeline projects, including the Alaska Pipeline Project.

Capital Expenditures Total capital spending for natural gas pipelines was $0.9 billion in 2011. Capital spending for the Company's wholly owned pipelines is expected to be approximately $1.0 billion in 2012.

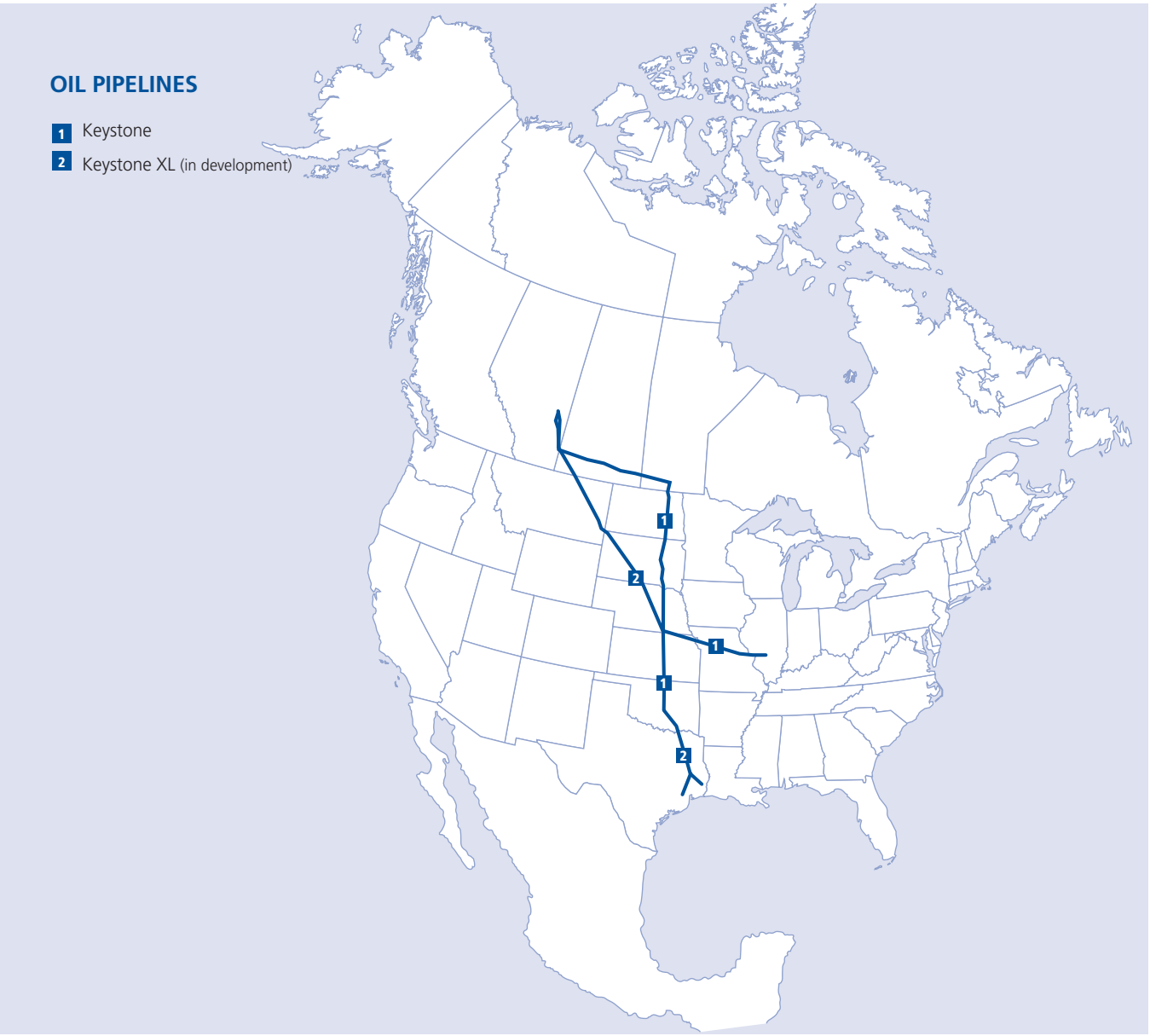
NATURAL GAS THROUGHPUT VOLUMES

(Bcf)	**2011**	2010	2009
Canadian Mainline[1]	**1,887**	1,666	2,030
Alberta System[2]	**3,517**	3,447	3,538
ANR	**1,706**	1,589	1,575
Foothills	**1,289**	1,446	1,205
Northern Border	**971**	902	706
Great Lakes	**830**	804	727
GTN	**679**	802	797
Iroquois	**317**	343	355
TQM	**154**	151	164
Ventures LP	**150**	144	145
Bison[3]	**105**	–	–
North Baja	**92**	60	96
Tamazunchale	**57**	52	54
Gas Pacifico	**46**	51	62
Portland	**36**	36	37
Tuscarora	**33**	35	34
TransGas	**26**	30	28

(1) Canadian Mainline's throughput volumes reflect physical deliveries to domestic and export markets. Customer contracting patterns have changed in recent years therefore the Company uses physical deliveries to measure system utilization. Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2011 were 1,160 Bcf (2010 – 1,228 Bcf; 2009 – 1,579 Bcf).

(2) Field receipt volumes for the Alberta System in 2011 were 3,622 Bcf (2010 – 3,471 Bcf; 2009 – 3,578 Bcf) and includes three months of ATCO Pipelines receipts consistent with the commercial integration of NGTL and ATCO Pipelines effective October 1, 2011.

(3) Effective January 14, 2011.



OIL PIPELINES

KEYSTONE

Keystone is a 3,467 km (2,154 miles) wholly owned and operated crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Company plans to expand and extend the oil pipeline system to the U.S. Gulf Coast (Keystone XL) which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

OIL PIPELINES – HIGHLIGHTS

- Wood River/Patoka and Cushing Extension sections of Keystone achieved full commercial operations in February 2011. The Company recorded EBITDA of $587 million in its first eleven months of operations.
- In August 2011, a favourable FEIS was received from the DOS for Keystone XL.
- The Company secured commercial support for an extension and expansion of Keystone XL to provide crude oil transportation service from Hardisty, Alberta to Houston, Texas, increasing total long-term firm contracts on Keystone to in excess of 1.1 million bbl/d for an average term of approximately 18 years.
- In January 2012, the DOS denied TransCanada's application requesting a Presidential Permit to construct Keystone XL based on the DOS's position that they did not have sufficient time to receive and review additional information necessary to assess alternative routes that would avoid the Sandhills region of Nebraska. The Company will reapply for a Presidential Permit for Keystone XL.

OIL PIPELINES – RESULTS

Year ended December 31[1] *(millions of dollars)*	2011
Canadian Oil Pipelines Comparable EBITDA[2]	**210**
Depreciation and amortization	**(49)**
Canadian Oil Pipelines Comparable EBIT[2]	**161**
U.S. Oil Pipelines Comparable EBITDA[2] (in U.S. dollars)	**383**
Depreciation and amortization	**(82)**
U.S. Oil Pipelines Comparable EBIT[2]	**301**
Foreign exchange	**(3)**
U.S. Oil Pipelines Comparable EBIT[2] (in Canadian dollars)	**298**
Oil Pipelines Business Development Comparable EBITDA and EBIT[2]	**(2)**
Oil Pipelines Comparable EBIT[2]	**457**
Summary:	
Oil Pipelines Comparable EBITDA[2]	**587**
Depreciation and amortization	**(130)**
Oil Pipelines Comparable EBIT[2]	**457**

[1] Results reflect eleven months of operations.

[2] Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

OIL PIPELINES – FINANCIAL ANALYSIS

Keystone is a 3,467 km (2,154 miles) wholly owned and operated crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Company plans to expand and extend the existing system through Keystone XL which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

The Marketlink projects would transport crude oil sourced from U.S. basins to refining markets in the Cushing, Oklahoma region and the U.S. Gulf Coast on facilities that form part of Keystone XL. The proposed Bakken Marketlink project would transport U.S. crude oil from Baker, Montana to Cushing and the proposed Cushing Marketlink project would transport crude oil from Cushing to Port Arthur and Houston, Texas.

Oil Pipelines Comparable EBIT for the year ended 2011 was $457 million. EBITDA from Keystone is primarily generated from payments received under long-term commercial arrangements for committed capacity that are not dependent on actual throughput. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental EBITDA. In February 2011, the Company began recording EBITDA for the Wood River/Patoka and Cushing Extension sections.

Although the Wood River/Patoka section commenced commercial operations in June 2010, cash flows other than general, administrative and support costs were capitalized until February 2011. As a condition of the NEB's approval to begin operations, the Wood River/Patoka section operated at a reduced maximum operating pressure (MOP) on the Canadian conversion segment of the pipeline, which did not allow the pipeline to run at design pressure and reduced throughput capacity below the initial nominal capacity of 435,000 bbl/d. After additional in-line inspections were completed, the NEB removed the MOP restriction in December 2010 and the required operational modifications were completed in late January 2011 allowing the system to operate at its design pressure and throughput capacity.

Operating Statistics

Year ended December 31[1]	2011
Delivery volumes (thousands of barrels)[2]	
Total	**137,384**
Average	**411**

[1] Results reflect eleven months of operations.

[2] Delivery volumes reflect physical deliveries.

OIL PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Wood River/Patoka and Cushing Extension In late January 2011, work was completed to allow the Wood River/Patoka section of the system to operate at its design pressure following the NEB's decision to remove the MOP restriction in December 2010. In February 2011, the Cushing Extension commenced commercial operations, extending the pipeline system to Cushing, Oklahoma and increasing nominal design capacity to 591,000 bbl/d.

In May 2011, revised fixed tolls came into effect for the Wood River/Patoka section of the system that reflected the final project costs for this section.

In June 2011, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order on Keystone as a result of two above-ground incidents in second quarter 2011 at pump stations in North Dakota and Kansas, both of which involved the release of crude oil. Following the incidents, TransCanada took immediate action to contain the crude oil releases and repair the facilities. The corrective action order required TransCanada to develop and submit a written restart plan which included steps to facilitate the proper clean up, investigation, and system improvements and modifications. The restart plan was approved by PHMSA in June 2011. In July and August 2011, work was performed on the Keystone system to improve system reliability. The work was completed as planned and resulted in reduced pipeline capacity during those two months, however, it did not have a significant impact on EBIT.

In 2010, three entities, each of which had entered into Transportation Service Agreements for the Cushing Extension, had filed separate Statements of Claim against certain of TransCanada's Keystone subsidiaries in the Alberta Court of

Queen's Bench, seeking declaratory relief, or alternatively, damages in varying amounts. All of the claims have been discontinued on a without-cost and without-liability basis.

Keystone XL The regulatory approval process for the U.S. portion of Keystone XL continued throughout 2011 and early 2012. Following an extensive environmental review process, the DOS, the lead agency for U.S. federal regulatory approvals, released its FEIS in August 2011. The FEIS found that the project would have no significant impact on the environment and that the proposed route would have the least environmental impact of the alternatives considered.

Following the issuance of the FEIS, the DOS initiated a 90-day National Interest Determination (NID) process. During the NID process, concern about the pipeline's impact on the Sandhills region of Nebraska was raised and on November 10, 2011, the DOS determined it necessary to identify and assess alternative routes that would avoid the Sandhills region in Nebraska in order to move forward with a decision on the Presidential Permit. The DOS indicated that the additional environmental review process including a public comment period on a supplement to the FEIS could be completed as early as first quarter 2013. In December 2011, the *Temporary Payroll Tax Cut Continuation Act* was approved by the U.S. Senate and the U.S. House of Representatives and signed into law by U.S. President Obama on December 23, 2011. The legislation required a final decision on the Keystone XL Presidential Permit by February 21, 2012.

On January 18, 2012, the DOS denied the Presidential Permit for Keystone XL, based on the DOS's position that it did not have sufficient time to receive and review additional information necessary to assess alternative routes that would avoid the Sandhills region of Nebraska. The DOS noted that its decision did not preclude TransCanada from submitting a subsequent Presidential Permit application for Keystone XL.

TransCanada is continuing to work with the State of Nebraska to determine the preferred route that avoids the Sandhills region in Nebraska. The Company will submit a revised Presidential Permit application to the DOS. Assuming regulatory approval is received by first quarter 2013, TransCanada believes it could have Keystone XL in service by early 2015. The Company continues to monitor political developments in the U.S. and the potential impact they may have on commencing construction of Keystone XL.

In December 2011, TransCanada announced that it had secured additional commercial support for Keystone XL following the successful conclusion of a binding open season offering long-term firm service for crude oil transportation from Hardisty, Alberta to Houston, Texas (Houston Lateral) increasing total long-term contracts on Keystone XL to in excess of 1.1 million bbl/d for an average term of approximately 18 years. The approximate US$600 million Houston Lateral project would involve the expansion of capacity through additional pump units increasing the capacity of Keystone XL to 830,000 bbl/d and the construction of an approximately 80 km (50 miles) pipeline extension from the proposed Keystone XL system. The Houston Lateral is expected to more than double the U.S. Gulf Coast refining market capacity directly accessible from the Keystone pipeline system to over four million bbl/d and is expected to be in service by early 2015, subject to regulatory approvals.

The capital cost of Keystone XL, including the Houston Lateral, is estimated to be approximately US$7.6 billion, with US$2.4 billion having been invested at December 31, 2011. Of the amount invested to date, approximately 60 per cent of the total represents purchased equipment and materials. The remaining capital cost amount is expected to be invested between now and the in-service date of the expansion, which is expected by early 2015. Capital costs related to the construction of Keystone XL are subject to capital cost risk and reward sharing mechanisms with Keystone's long-term committed shippers.

Marketlink Projects The Company is pursuing opportunities to transport growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to major U.S. refining markets. In 2010, the Company secured firm, five-year shipper contracts totalling 65,000 bbl/d for its proposed Bakken Marketlink project, which would transport U.S. crude oil from Baker, Montana to Cushing on facilities that form part of Keystone XL. The capital cost of the incremental facilities is expected to be approximately US$140 million and, pending regulatory approvals, commercial in service is anticipated in early 2015.

In fourth quarter 2011, TransCanada secured additional contractual support for the Cushing Marketlink project, which would transport crude oil from Cushing, Oklahoma to Port Arthur and Houston, Texas. The approximate US$50 million Cushing Marketlink project would use a portion of the Keystone XL facilities including the Houston Lateral. Pending

regulatory approvals, Cushing Marketlink is expected to begin shipping crude oil to Port Arthur and Houston in early 2015.

OIL PIPELINES – BUSINESS RISKS

Crude Oil Supply, Markets and Competition Alberta produces the majority of the crude oil in the WCSB and is the primary source of crude oil supply for Keystone. In 2011, the WCSB produced an estimated 2.7 million bbl/d, consisting of 1.1 million bbl/d of conventional crude oil and condensate, and 1.6 million bbl/d of Alberta oil sands crude oil. The production of conventional crude oil has been declining but has been offset by increases in production from new shale oil production including the Bakken and Cardium formations and from the oil sands. The Alberta Energy Resources Conservation Board estimated, in its June 2010 report, that there are approximately 170 billion barrels of remaining established reserves in the Alberta oil sands.

In June 2011, the Canadian Association of Petroleum Producers (CAPP) forecasted WCSB crude oil supply would increase to 3.5 million bbl/d by 2015 and to 4.5 million bbl/d by 2020, indicating future growth in Alberta crude oil production. CAPP estimated spending in the oil sands totalled $19 billion in 2011 and is expected to increase from that level in 2012.

Keystone has contracted a significant portion of its capacity under long-term commercial arrangements. Keystone will compete for spot market throughput with other crude oil pipelines from Alberta and for new long-term contracts as supply from the WCSB increases.

The Williston Basin, located primarily in North Dakota and Montana, is the primary source of crude oil supply for the Bakken Marketlink project. In 2011, the Williston Basin achieved production rates of nearly 530,000 bbl/d. TransCanada expects production levels will reach approximately 840,000 bbl/d by 2015 due to growth in Bakken shale oil production.

The Permian Basin, located primarily in western Texas, is the primary source of crude oil for the Cushing Marketlink project. Production in the Permian Basin connected to crude oil storage facilities at Cushing is more than 1.0 million bbl/d and has been growing since 2006.

The Bakken Marketlink and Cushing Marketlink projects have contracted a significant amount of capacity. Both projects would compete for spot market throughput with other crude oil pipelines in the Williston Basin, Rocky Mountain and U.S. midcontinent regions and for new long-term contracts as supply from connected basins increases.

The markets for crude oil served by TransCanada's Keystone pipeline system are primarily refiners in the U.S. Midwest, midcontinent and Gulf Coast regions. TransCanada competes with pipelines that deliver WCSB, Williston Basin and Permian Basin crude oil to these refiners through interconnections with other pipelines. Keystone also competes with U.S. domestically-produced crude oil and imported crude oil for refining markets in the U.S. Midwest, Midcontinent and Gulf Coast regions.

Regulatory Risk Regulations and decisions issued by Canadian and U.S. regulatory bodies, including the NEB, FERC, EPA, Army Corps of Engineers, various state regulators, U.S. Department of Transportation, PHMSA and DOS, may have a significant impact on the approval, construction, operational and financial performance of TransCanada's crude oil pipelines. TransCanada continuously monitors existing and proposed regulations to determine their possible impact on its Oil Pipelines business.

Pipeline Abandonment Cost Risk Keystone's Canadian facilities are subject to the NEB's LMCI process previously discussed in the Natural Gas Pipelines – Business Risks section in this MD&A. Future pipeline abandonment costs for Keystone's Canadian facilities are expected to be recovered in transportation tolls.

Throughput Risk TransCanada has secured long-term transportation contracts for most of Keystone's capacity. Payments received for this committed capacity are not dependent on actual throughput. Uncontracted capacity is offered to the market on a spot basis. Uncontracted throughput is dependent primarily on crude oil production levels, market competition for crude oil, refinery activity and variations in economic activity.

Plant Availability Optimizing and maintaining plant availability is essential to the success of the Oil Pipelines business. TransCanada has a proven history of achieving high levels of performance through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment and a skilled workforce. Unexpected plant outages will impact throughput capacity and may result in reduced contracted capacity payments and lower uncontracted transportation sales revenue.

Execution and Capital Cost Risk Capital costs related to the construction of Keystone are subject to a capital cost risk-and reward-sharing mechanism with Keystone's long-term committed shippers. This mechanism allows Keystone to adjust its tolls by a factor based on the percentage change in the capital cost of the project. Tolls on Keystone XL would be adjusted by a factor equal to 75 per cent of the percentage change in capital costs. Capital costs related to the construction of the Bakken Marketlink and Cushing Marketlink projects would not be subject to a capital cost risk-and reward-sharing mechanism with the shippers.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Oil Pipelines business.

OIL PIPELINES – OUTLOOK

North American crude oil demand is expected to remain relatively unchanged in the long term while the availability of foreign sources of supply to North America declines. TransCanada's Oil Pipelines business will continue to focus on contracting and delivering growing North American crude oil supply to key U.S. markets.

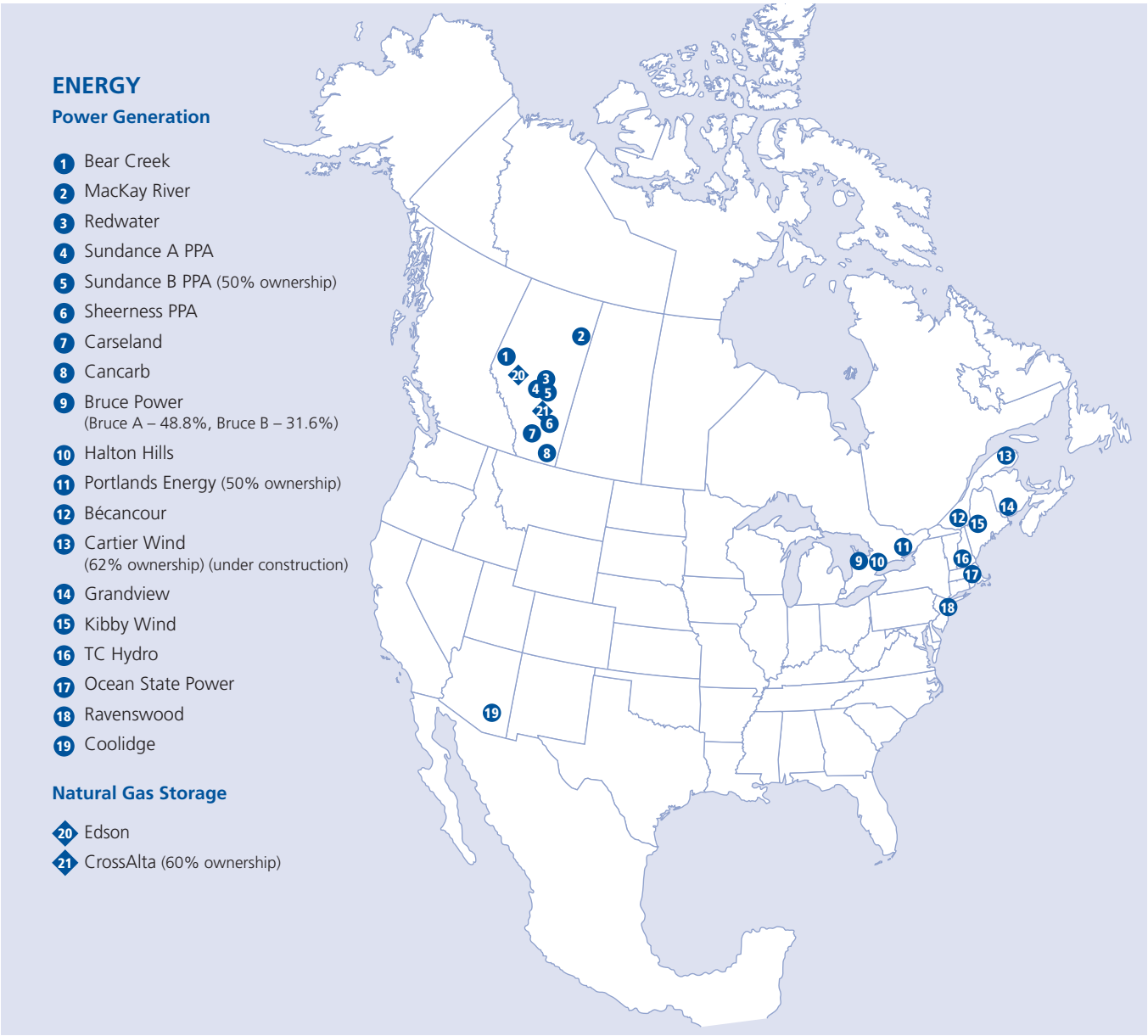
Producers continue to develop new crude oil supply in Western Canada. Several Alberta oil sands projects recently completed or under construction will begin to produce crude oil or will increase crude oil production in 2012 and 2013. Alberta oil sands production is forecast to increase to 2.3 million bbl/d by 2016 from 1.6 million bbl/d in 2011 and total Western Canada crude oil supply is projected to grow over the same period to 3.7 million bbl/d from 2.7 million bbl/d. The primary market for new crude oil production extends from the U.S. Midwest to the U.S. Gulf Coast and contains a large number of refineries that are capable of handling Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

The increase in WCSB crude oil exports from Alberta requires access to new markets, including international markets and markets in the U.S., that are currently served by foreign imports. TransCanada will continue to pursue additional opportunities to transport crude oil from Alberta to new markets.

Production in the Williston Basin is also growing and pipeline capacity in the region is constrained. Major markets for Williston Basin crude oil include the U.S. midcontinent and Midwest, and the U.S. Gulf Coast. TransCanada is competing with several other proposals to build pipeline capacity to transport crude oil supply from this region to U.S. refining centres. Capacity is constrained on the pipelines serving the crude oil storage facilities at Cushing. This situation periodically causes the price of West Texas Intermediate crude oil to be depressed relative to world prices. There are several competitive proposals to build pipeline capacity to transport oil supply from this region to the U.S. Gulf Coast. TransCanada will continue to compete for additional opportunities to transport Cushing crude oil to U.S. refining centres.

Earnings Oil Pipelines earnings in 2012 are expected to be higher than in 2011, primarily due to the impact of a full year of earnings being recorded for the Wood River/Patoka and Cushing Extension sections of Keystone compared to eleven months in 2011. Earnings are primarily generated by contractual arrangements for committed capacity that are not dependent on actual throughput. Uncontracted capacity offered to the market on a spot basis provides additional earnings opportunities. TransCanada expects earnings from its crude oil pipelines to increase as the proposed Keystone XL and Marketlink projects begin delivering crude oil. Once fully completed, TransCanada expects to record annual EBITDA of approximately US$1.7 billion, based on contracted volumes in place and assuming a full year of commercial operations servicing both the U.S. Midwest and Gulf Coast markets.

Capital Expenditures Total capital spending for Oil Pipelines in 2011 was $1.2 billion. Capital spending for Oil Pipelines in 2012 is expected to be approximately $0.9 billion, primarily due to contractual commitments associated with Keystone XL and expansion of Keystone's Hardisty, Alberta facilities.



ENERGY

The following Energy assets are owned 100 per cent by TransCanada unless otherwise stated.

BEAR CREEK An 80 MW natural gas-fired cogeneration plant located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant located near Redwater, Alberta.

SUNDANCE A&B TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA that expires in 2017. TransCanada also has a 50 per cent interest in ASTC Power Partnership, which has a PPA that expires in 2020, in place for 100 per cent of the production from the 706 MW Sundance B power facility. The Sundance facilities are located in south-central Alberta.

SHEERNESS TransCanada has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA that expires in 2020. The Sheerness plant is located in southeastern Alberta.

CARSELAND An 80 MW natural gas-fired cogeneration plant located near Carseland, Alberta.

CANCARB A 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TransCanada's adjacent facility, which produces thermal carbon black (a natural gas by-product).

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.8 per cent of Bruce A, which has four 750 MW reactors. Two of these reactors are currently operating and two are being refurbished. TransCanada owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired, combined-cycle power plant in Halton Hills, Ontario.

PORTLANDS ENERGY A 550 MW natural gas-fired, combined-cycle power plant located in Toronto, Ontario. The plant is 50 per cent owned by TransCanada.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec.

CARTIER WIND The 590 MW Cartier Wind farm consists of five wind power projects located in Québec and is 62 per cent owned by TransCanada. Baie-des-Sables, Anse-à -Valleau, Carleton, Montagne-Sèche and phase one of Gros-Morne wind farms are in service and have a total generating capacity of 479 MW. Construction continues on the 111 MW second phase of the Gros-Morne wind farm which is expected to be operational in December 2012.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick.

KIBBY WIND A 132 MW wind farm located in Kibby and Skinner Townships in Maine.

TC HYDRO TC Hydro has a total generating capacity of 583 MW and comprises 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OCEAN STATE POWER A 560 MW natural gas-fired, combined-cycle facility located in Burrillville, Rhode Island.

RAVENSWOOD A 2,480 MW multiple-unit generating facility located in Queens, New York, employing dual fuel-capable steam turbine, combined-cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power facility in Coolidge, Arizona, which was placed in service in second quarter 2011.

EDSON An underground natural gas storage facility connected to the Alberta System near Edson, Alberta. Edson's central processing system is capable of maximum injection and withdrawal rates of 725 MMcf/d of natural gas, and has a working storage capacity of approximately 50 Bcf.

CROSSALTA A 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. CrossAlta's central processing system is capable of maximum injection and withdrawal rates of 550 MMcf/d of natural gas. TransCanada owns 60 per cent of CrossAlta and, through an agreement made effective July 1, 2011, is now the operator of the facility.

ENERGY – HIGHLIGHTS

- Energy's Comparable EBIT was $940 million in 2011, an increase of $192 million from $748 million in 2010.
- In 2011, the Company invested $1.1 billion in Energy capital projects which are all supported by long-term contracts, including:
    - the 575 MW Coolidge generating facility, which was placed in service in May 2011;
    - construction of the two remaining wind farms at Cartier Wind, including completion of the 58 MW Montagne-Sèche project and the 101 MW phase one of the Gros-Morne project; and
    - the restart of Bruce Power Units 1 and 2.
- Refurbishment work on Bruce Power Units 1 and 2 reached significant milestones in 2011. Fuelling of both Units 1 and 2 has now been completed and the final phases of commissioning for Unit 2 are underway.
- In December 2011, an agreement was executed for the purchase of nine Ontario solar projects with a combined capacity of 86 MW, for approximately $470 million. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. It is anticipated that the projects will be placed in service between late 2012 and mid-2013.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Canadian Power		
Western Power		
Sheerness	756	Coal
Coolidge	575	Natural gas
Sundance A	560	Coal
Sundance B[1]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Halton Hills	683	Natural gas
Bécancour	550	Natural gas
Cartier Wind[2]	365	Wind
Portlands Energy[3]	275	Natural gas
Grandview	90	Natural gas
	1,963	
Bruce[4]	2,480	Nuclear
	7,079	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
Ocean State Power	560	Natural gas
Kibby Wind	132	Wind
	3,755	
Total Nominal Generating Capacity	10,834	

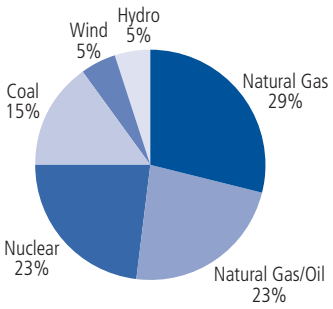
(1) Represents TransCanada's 50 per cent share of the Sundance B power plant output.

(2) Represents TransCanada's 62 per cent share of the total 590 MW project, including 111 MW under construction.

(3) Represents TransCanada's 50 per cent share of the total 550 MW facility.

(4) Represents TransCanada's 48.8 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B, including 733 MW for Bruce A Units 1 and 2.

Power by Fuel Source



ENERGY – RESULTS			
Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Canadian Power			
Western Power[1]	**489**	220	279
Eastern Power[2]	**314**	231	220
Bruce Power	**252**	298	352
General, administrative and support costs	**(43)**	(38)	(39)
Canadian Power Comparable EBITDA[3]	**1,012**	711	812
Depreciation and amortization	**(276)**	(242)	(227)
Canadian Power Comparable EBIT[3]	**736**	469	585
U.S. Power (in U.S. dollars)			
Northeast Power[4]	**314**	335	210
General, administrative and support costs	**(41)**	(32)	(40)
U.S. Power Comparable EBITDA[3]	**273**	303	170
Depreciation and amortization	**(109)**	(116)	(92)
U.S. Power Comparable EBIT[3]	**164**	187	78
Foreign exchange	**(4)**	7	8
U.S. Power Comparable EBIT[3] (in Canadian dollars)	**160**	194	86
Natural Gas Storage			
Alberta Storage	**89**	140	173
General, administrative and support costs	**(6)**	(8)	(9)
Natural Gas Storage Comparable EBITDA[3]	**83**	132	164
Depreciation and amortization	**(14)**	(15)	(14)
Natural Gas Storage Comparable EBIT[3]	**69**	117	150
Energy Business Development Comparable EBITDA and EBIT[3]	**(25)**	(32)	(37)
Energy Comparable EBIT[3]	**940**	748	784
Summary:			
Energy Comparable EBITDA[3]	**1,338**	1,125	1,131
Depreciation and amortization	**(398)**	(377)	(347)
Energy Comparable EBIT[3]	**940**	748	784

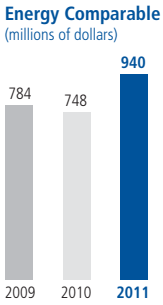
(1) Includes Coolidge effective May 2011.

(2) Includes Montagne-Sèche and phase one of Gros-Morne, Halton Hills, and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(4) Includes phase one and two of Kibby Wind effective October 2009 and October 2010, respectively.

ENERGY – FINANCIAL ANALYSIS



Energy's Comparable EBIT was $940 million in 2011 compared to $748 million in 2010 and $784 million in 2009.

Western Power As at December 31, 2011, Western Power owned or had the rights to approximately 2,600 MW of power supply in Alberta and the western U.S. from its three long-term PPAs, five natural gas-fired cogeneration facilities and a simple-cycle, natural gas peaking facility in Arizona.

The current operating power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, baseload, coal-fired generation through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration power plants with capacity ranging from 27 MW to 165 MW. This supply portfolio includes some of the lowest cost and most competitive power generation in the Alberta market area. The Sheerness and Sundance B PPAs expire in 2020, while the Sundance A PPA expires in 2017. As described further in the Energy – Opportunities and Developments section of this MD&A, no volumes were delivered under the Sundance A PPA in 2011. A portion of the expected output from the Western Power facilities is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas.

Western Power in Alberta relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced through the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is critical for optimizing Energy's return from its portfolio of power supply and managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market to ensure supply in case of unexpected plant outages. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where TransCanada would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices in Alberta, as at December 31, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 8,400 gigawatt hours (GWh) in 2012 and 6,200 GWh in 2013.

Western U.S. power assets consist of the 575 MW Coolidge Generating Station which was placed in service in May 2011. Coolidge power output is fully contracted under a 20 year PPA with the Salt River Project, a local Arizona utility.

Eastern Power Eastern Power owns approximately 2,000 MW of power generation capacity, including facilities under construction. Eastern Power's current operating power generation assets are Halton Hills, Bécancour, the in-service Cartier Wind farms, Portlands Energy and Grandview.

Halton Hills was placed in service in September 2010 and is fully contracted under a 20-year Clean Energy Supply contract with the OPA.

Bécancour's entire power output is supplied to Hydro-Québec under a 20-year power purchase contract expiring in 2026. Steam produced from this facility is sold to an industrial customer for use in commercial processes. Electricity generation at the Bécancour power plant has been suspended since January 2008 as a result of an agreement entered

into with Hydro-Québec. Under the agreement, while energy production and payments are suspended, TransCanada continues to receive capacity payments similar to those that would have been received under the normal course of operation.

The Montagne-Sèche and phase one of Gros-Morne Cartier Wind farms were placed in service November 2011, bringing the total generating capacity of the in-service Cartier Wind farms to 479 MW. Output from these wind farms is supplied to Hydro-Québec under 20-year power purchase contracts.

Portlands Energy was placed in service in April 2009. This facility is fully contracted under a 20-year Accelerated Clean Energy Supply contract with the OPA.

Grandview is located on the site of the Irving Oil refinery in Saint John, New Brunswick. TransCanada and Irving Oil are under a 20-year tolling arrangement, which expires in 2025, through which Irving Oil supplies fuel for the 90 MW plant and is contracted to purchase 100 per cent of the plant's heat and electricity output.

Eastern Power is focused on selling power under long-term contracts. Eastern Power sales volumes were 100 per cent sold under contract in 2011 and are expected to be fully contracted going forward.

Western and Eastern Canadian Power Comparable EBIT[1][2][3]

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Revenues			
Western power[2]	**1,081**	714	788
Eastern power[3]	**475**	330	281
Other[4]	**70**	84	86
	1,626	1,128	1,155
Commodity purchases resold			
Western power	**(538)**	(431)	(451)
Other[4][5]	**(9)**	(26)	(26)
	(547)	(457)	(477)
Plant operating costs and other	**(276)**	(220)	(179)
General, administrative and support costs	**(43)**	(38)	(39)
Comparable EBITDA[1]	**760**	413	460
Depreciation and amortization	**(163)**	(140)	(138)
Comparable EBIT[1]	**597**	273	322

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(2) Includes Coolidge effective May 2011.

(3) Includes Montagne-Sèche and phase one of Gros-Morne, Halton Hills, and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(4) Includes sales of excess natural gas purchased for generation and sales of thermal carbon black. The net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues.

(5) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics			
Year ended December 31	**2011**	2010	2009
Sales Volumes (GWh)			
Supply			
Generation			
Western Power[1]	**2,606**	2,373	2,334
Eastern Power[2]	**3,714**	2,359	1,550
Purchased			
Sundance A & B and Sheerness PPAs[3]	**7,909**	10,785	10,603
Other purchases	**1,112**	429	529
	15,341	15,946	15,016
Sales			
Contracted			
Western Power	**9,245**	10,211	9,944
Eastern Power	**3,714**	2,375	1,588
Spot			
Western Power	**2,382**	3,360	3,484
	15,341	15,946	15,016
Plant Availability[4]			
Western Power[1][5]	**97%**	95%	93%
Eastern Power[2][6]	**93%**	94%	97%

(1) Includes Coolidge effective May 2011.

(2) Includes Montagne-Séche and phase one of Gros-Morne, Halton Hills and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(3) No volumes were delivered under the Sundance A PPA in 2011.

(4) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(5) Excludes facilities that provide power to TransCanada under PPAs.

(6) Bécancour has been excluded from the availability calculation, as power generation at the facility has been suspended since 2008.

Western Power's Comparable EBITDA of $489 million and Power Revenues of $1,081 million in 2011 increased $269 million and $367 million, respectively, compared to 2010 primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year PPA in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 51 per cent to $77 per megawatt hour (MWh) in 2011 compared to $51 per MWh in 2010. Approximately 20 per cent of Western Power's sales volumes were sold in the spot market in 2011 compared to 25 per cent in 2010.

Western Power's Comparable EBITDA in 2011 included $156 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 are interruptions of supply in accordance with the terms of the PPA. Refer to the Opportunities and Developments section in this MD&A for further discussion on the dispute regarding the Sundance A outage.

Eastern Power's Comparable EBITDA of $314 million and Power Revenues of $475 million in 2011 increased $83 million and $145 million, respectively, compared to 2010. These increases were primarily due to the full year impact of incremental earnings from Halton Hills, which was placed in service in September 2010.

Western Power's commodity purchases resold of $538 million increased $107 million compared to 2010 due to increased direct sales to customers, higher PPA costs per MWh and higher volumes at Sheerness.

Plant Operating Costs and Other, which includes natural gas fuel consumed in power generation, of $276 million in 2011 increased $56 million from 2010 primarily due to incremental fuel consumed at Halton Hills.

Depreciation and amortization of $163 million increased $23 million in 2011 compared to 2010 primarily due to incremental depreciation from Halton Hills and Coolidge.

Western Power's Comparable EBITDA of $220 million and Power Revenues of $714 million in 2010 decreased $59 million and $74 million, respectively, compared to 2009 primarily due to lower overall realized power prices. Approximately 25 per cent of Western Power's sales volumes were sold in the spot market in 2010 compared to 26 per cent in 2009.

Eastern Power's Comparable EBITDA of $231 million and Power Revenues of $330 million in 2010 increased $11 million and $49 million, respectively, compared to 2009. These increases were primarily due to incremental earnings from Halton Hills and Portlands Energy, which went in service September 2010 and April 2009, respectively, partially offset by lower contracted revenue from the Bécancour facility.

Plant Operating Costs and Other of $220 million in 2010 increased $41 million from 2009 primarily due to incremental fuel consumed at Portlands Energy and Halton Hills.

Bruce Power Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and comprises Bruce A and Bruce B. Bruce A has four 750 MW reactors, two of which are being refurbished. The two units being refurbished are expected to resume commercial operations in first and third quarter 2012. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2011, TransCanada and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System (OMERS), each owned a 48.8 per cent interest in Bruce A (2010 and 2009 – 48.8 per cent). The remaining 2.4 per cent interest in Bruce A is owned by the Power Workers' Union Trust (PWU), the Society of Energy Professionals Trust (SEP) and the Bruce Power Employee Investment Trust. Bruce A subleases Units 1 to 4 from Bruce B. TransCanada, OMERS and Cameco Corporation each own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure. The remaining interest in Bruce B is owned by PWU and SEP.

The following Bruce Power financial results reflect TransCanada's proportionate share of the eight Bruce Power units, six of which were operating:

Bruce Power Results			
(TransCanada's proportionate share)			
Year ended December 31 *(millions of dollars unless otherwise indicated)*	**2011**	2010	2009
Revenues[1]	**817**	862	883
Operating expenses	**(565)**	(564)	(531)
Comparable EBITDA[2]	**252**	298	352
Bruce A Comparable EBITDA[2]	**98**	91	48
Bruce B Comparable EBITDA[2]	**154**	207	304
Comparable EBITDA[2]	**252**	298	352
Depreciation and amortization	**(113)**	(102)	(89)
Comparable EBIT[2]	**139**	196	263
Bruce Power – Other Information			
Plant availability[3]			
Bruce A	**90%**	81%	78%
Bruce B	**88%**	91%	91%
Combined Bruce Power	**89%**	88%	87%
Planned outage days			
Bruce A	**60**	60	56
Bruce B	**135**	70	45
Unplanned outage days			
Bruce A	**16**	64	82
Bruce B	**24**	34	47
Sales volumes (GWh)			
Bruce A	**5,475**	5,026	4,894
Bruce B	**7,859**	8,184	7,767
	13,334	13,210	12,661
Results per MWh			
Bruce A power revenues	**$66**	$65	$64
Bruce B power revenues[4]	**$54**	$58	$64
Combined Bruce Power revenues	**$57**	$60	$64

(1) Revenues include Bruce A fuel cost recoveries of $24 million in 2011 (2010 – $29 million; 2009 – $34 million).

(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(3) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(4) Includes revenues received under the floor price mechanism, from contract settlements as well as volumes and revenues associated with deemed generation.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased $46 million to $252 million in 2011 compared to 2010, primarily due to lower results at Bruce B. Comparable EBITDA in 2010 also included the net positive impact of a payment made in 2010 by Bruce B to Bruce A related to amendments made in 2009 to the agreements with the OPA. The net positive impact to TransCanada from the payment reflected TransCanada's higher percentage ownership in Bruce A.

TransCanada's proportionate share of Bruce A's Comparable EBITDA increased $7 million to $98 million in 2011 compared to 2010 primarily due to higher volumes as a result of a decrease in unplanned outage days, partially offset by the above-noted payment in 2010 from Bruce B.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $53 million to $154 million in 2011 compared to 2010. The decrease was primarily due to lower realized prices resulting from expiration of fixed-price contracts at higher prices, higher operating costs and lower volumes due to an increase in planned outage days. Bruce B results for 2010 included the above-noted payment to Bruce A.

Bruce Power's Depreciation and Amortization increased $11 million in 2011 compared to 2010 and $13 million in 2010 compared to 2009 primarily due to capital additions.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA of $298 million in 2010 decreased $54 million compared to 2009 due to lower realized prices and higher annual lease expense in 2010 for Bruce B, partially offset by higher volumes at both Bruce A and Bruce B and the positive net impact of the payment made in 2010 by Bruce B to Bruce A.

The Independent Electricity System Operator (IESO) periodically requires the curtailment of certain units at Bruce Power to address surplus baseload generation in Ontario. During these unit curtailments, Bruce power receives deemed generation payments at OPA contract prices. Lower sales volumes in 2009 compared to 2010 and 2011 reflected the impact of higher unit curtailments in 2009.

The overall plant availability percentage in 2012 is expected to be in the mid 70s for Bruce A Units 3 and 4. Bruce A commenced the approximate six month West Shift Plus outage on Unit 3 on November 6, 2011. Additional planned maintenance on one of the units at Bruce A is scheduled for the summer of 2012. Bruce B's overall plant availability is expected to be in the mid 90s for the four units in 2012. Planned maintenance on one of the units at Bruce B commenced in January 2012.

Bruce A

Under a contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh, adjusted annually for inflation on April 1. In addition, fuel costs are recovered from the OPA.

Bruce A Fixed Price

	per MWh
April 1, 2011 – March 31, 2012	$66.33
April 1, 2010 – March 31, 2011	$64.71
April 1, 2009 – March 31, 2010	$64.45

Bruce B

As part of Bruce Power's contract with the OPA, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1. Payments received under the floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues were subject to repayment in 2011, 2010 or 2009.

Bruce B Floor Price

	per MWh
April 1, 2011 – March 31, 2012	$50.18
April 1, 2010 – March 31, 2011	$48.96
April 1, 2009 – March 31, 2010	$48.76

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price. Bruce B's realized price decreased by $4 per MWh to $54 per MWh in 2011 compared to 2010, and by $6 per MWh to $58 per MWh in 2010 compared to 2009, and reflected revenues recognized from the floor price mechanism, contract settlements as well as volumes and revenues associated with deemed generation. The decreases reflected the expiration of higher-priced contracts entered into in previous years.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, consisting of Ravenswood, TC Hydro, Ocean State Power, and Kibby Wind. Ravenswood, located in Queens, New York, is a 2,480 MW natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts with total generating capacity of 583 MW. Ocean State Power, a 560 MW natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island and Kibby Wind is a 132 MW wind farm located in Maine. The first 66 MW phase of Kibby Wind was placed in service in October 2009 and the second 66 MW phase went in service in October 2010.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM Interconnection area (PJM) power markets. Exposure to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. At present, a series of voluntary forward auctions and a mandatory spot demand curve price setting process are used to determine the price paid to capacity suppliers. There are two annual six-month strip forward auctions and 12 monthly forward auctions in which buyer and seller participation is optional. All remaining available capacity is required to participate in a monthly spot auction in the final week prior to each capacity month. The spot auction clears at a price based on a downward-sloping demand curve, the parameters of which are determined by the NYISO and approved by the FERC. There are separate demand curves for each of three defined capacity zones: Long Island, New York City and Rest of State. The Ravenswood capacity is located in the New York City capacity zone. Refer to the Energy – Opportunities and Development section of this MD&A for more information.

The New England Power Pool relies on a Forward Capacity Market (FCM) to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. This capacity market operated on a transition basis from 2007 to 2009. During this period, Ocean State Power and TC Hydro received capacity transition payments under this mechanism as specified in the FERC-approved FCM settlement. Beginning in June 2010, the price paid for capacity was determined by annual competitive FCM auctions, which are held three years in advance of the applicable capacity year. Future auction results will be affected by actual versus projected demand, the pace of progress in developing new qualifying resources that bid into the auctions and other factors.

U.S. Power Comparable EBIT[1][2]			
Year ended December 31 *(millions of U.S. dollars)*	**2011**	2010	2009
Revenues			
Power[3]	**919**	1,090	742
Capacity	**227**	231	169
Other[3][4]	**80**	78	79
	1,226	1,399	990
Commodity purchases resold[3]	**(398)**	(543)	(309)
Plant operating costs and other[4]	**(514)**	(521)	(471)
General, administrative and support costs	**(41)**	(32)	(40)
Comparable EBITDA[1]	**273**	303	170
Depreciation and amortization	**(109)**	(116)	(92)
Comparable EBIT[1]	**164**	187	78

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(2) Includes phases one and two of Kibby Wind as of October 2009 and October 2010, respectively.

(3) Realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.

(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics[1]			
Year ended December 31	**2011**	2010	2009
Physical Sales Volumes (GWh)			
Supply			
Generation	**6,880**	6,755	5,993
Purchased	**6,018**	8,899	5,310
	12,898	15,654	11,303
Plant Availability[2]	**87%**	86%	79%

(1) Includes phases one and two of Kibby Wind as of October 2009 and October 2010, respectively.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

U.S. Power's Comparable EBITDA of US$273 million in 2011 decreased US$30 million compared to 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes, partially offset by new sales activity in PJM, an increase in the New York commercial customer base and incremental earnings from phase two of Kibby Wind which was placed in service in October 2010.

Physical sales volumes in 2011 have decreased compared to 2010 due to decreased demand as a result of unseasonable weather and reduced opportunities for wholesale contracts. As well, fewer physical transactions were used to cover power sales commitments during 2011, in favour of financial transactions, compared to 2010.

U.S. Power's Power Revenues of US$919 million in 2011 decreased US$171 million compared to 2010 primarily due to lower physical sales volumes and lower prices, partially offset by new sales activity in New York and PJM.

Capacity Revenue of US$227 million in 2011 decreased US$4 million compared to 2010. New York capacity revenues in the second half of 2011 were negatively impacted by low spot prices as a result of the price mitigation issue described further in the Energy – Opportunities and Developments section in this MD&A. Reduced capacity prices were partially offset by lower forced outage rates at Ravenswood.

Commodity Purchases Resold of $398 million in 2011 decreased US$145 million compared to 2010 primarily due to a decrease in the quantity of physical power purchased for resale under U.S. Power's power sales commitments to wholesale and industrial customers in New England, partially offset by higher realized prices on purchased power as well as new activity in the New York and PJM markets.

U.S. Power's Comparable EBITDA of US$303 million in 2010 increased US$133 million compared to 2009 primarily due to higher capacity revenues resulting from higher capacity prices partially offset by higher forced outage rates at Ravenswood, higher volumes of power sold in the New England and New York markets, higher realized prices on power sold and incremental earnings from Kibby Wind.

U.S. Power achieved plant availability of 87 per cent in 2011 compared to 86 per cent in 2010 and 79 per cent in 2009. Lower availability in 2009 was primarily due to an unplanned outage at Ravenswood Unit 30 from September 2008 to May 2009.

As at December 31, 2011, approximately 3,600 GWh or 30 per cent and 1,000 GWh or 10 per cent of U.S. Power's planned generation is contracted for 2012 and 2013, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage TransCanada owns or has rights to 129 Bcf of non-regulated natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta. TransCanada also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (MMcf/d)
Edson	50	725
CrossAlta[1]	41	550
Third-party storage	38	630
	129	1,905

[1] Represents TransCanada's 60 per cent ownership interest in CrossAlta. Working gas storage capacity can vary due to the amount of base gas in the facility.

The Company's natural gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Alberta-based storage will continue to serve market needs and could play an important role as additional gas supplies are connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TransCanada's Natural Gas Pipelines segment.

TransCanada manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

Market volatility creates arbitrage opportunities and TransCanada's storage facilities provide customers with the ability to capture value from short-term price movements. At December 31, 2011, TransCanada had contracted approximately 60 per cent of the total 129 Bcf of working gas storage capacity in 2012 and 20 per cent of storage capacity in 2013. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions are comprised of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TransCanada locks in future positive margins, effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in revenues. TransCanada records its proprietary natural gas inventory in storage at its fair value using a weighted average of forward prices for natural gas for the following four months, less selling costs. Changes in the fair value of inventory are recorded in revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings, as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage's Comparable EBITDA of $83 million in 2011 decreased $49 million compared to 2010 primarily due to decreased third party storage and proprietary revenues as a result of lower realized natural gas price spreads.

Natural Gas Storage's Comparable EBITDA of $132 million in 2010 decreased $32 million compared to 2009 primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas price spreads.

Business Development Business Development Comparable EBITDA losses from business development expenses of $25 million in 2011 decreased $7 million compared to 2010 and decreased $5 million in 2010 compared to 2009 primarily due to decreased development activity in 2011.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Bruce Power In accordance with terms of the Bruce Power Refurbishment Implementation Agreement (BPRIA) between Bruce Power and the OPA, Bruce A committed to refurbish and restart Units 1 and 2.

Refurbishment work on Units 1 and 2 reached significant milestones in 2011. Fuelling of both Unit 1 and Unit 2 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012. TransCanada's share of the total net capital cost is expected to be approximately $2.4 billion of which $2.3 billion was incurred as at December 31, 2011.

In February 2011, the BPRIA was amended to extend the suspension date for Bruce A Contingent Support Payments (CSP) from December 31, 2011 to June 1, 2012. The CSP received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A will be subject to spot market prices effective June 1, 2012 until the restart of both Units 1 and 2 is complete.

In November 2011, Bruce Power commenced the approximately six month West Shift Plus outage as part of the life extension strategy for Unit 3. Subject to regulatory approval, Unit 3 is expected to return to service in second quarter 2012.

Sundance A In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta Corporation (TransAlta) in January 2011. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated.

TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at December 31, 2011, of $77 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Oakville In October 2010, the Government of Ontario announced that it would not proceed with the $1.2 billion Oakville generating station, a 900 MW facility that TransCanada was intending to build, own, and operate further to a previously awarded 20-year Clean Energy Supply contract with the OPA. In third quarter 2011, TransCanada, the Government of Ontario and the OPA reached a formal agreement to use an arbitration process to settle the dispute resulting from termination of this contract. Pursuant to the arbitration agreement, the parties remain in discussions. TransCanada expects to be appropriately compensated for the economic consequences associated with the contract's termination.

Coolidge The US$500 million Coolidge generating station was placed in service in May 2011. Power from the 575 MW simple-cycle, natural gas-fired peaking facility located near Phoenix, Arizona is sold to the Salt River Project Agricultural Improvement and Power District under a 20-year PPA.

Cartier Wind In November 2011, the 58 MW Montagne-Sèche and the 101 MW first phase of the Gros-Morne Wind farm projects were placed in service. The 111 MW second phase of Gros-Morne is expected to be operational in December 2012. This will complete construction of the 590 MW Cartier Wind project in Québec. All of the power produced by Cartier Wind is sold under a 20-year PPA to Hydro-Québec.

Ontario Solar In December 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately $470 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. TransCanada anticipates the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Bécancour In June 2011, Hydro-Québec notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2012. Under the terms of the suspension agreement, Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TransCanada will continue to receive capacity payments under the agreement similar to those that would have been received under the normal course of operation while energy production and payments are suspended.

Ravenswood Since July 2011, spot prices for capacity sales in the New York Zone J market have been negatively impacted by the manner in which NYISO has applied pricing rules for a new power plant that recently began service in this market. TransCanada believes that this application of pricing rules by the NYISO is in direct contravention of a series of the FERC orders which direct how new entrant capacity is to be treated for the purpose of determining capacity prices. TransCanada and other parties have filed formal complaints with the FERC that are currently pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown.

During third quarter 2011, the demand curve reset process was completed following the FERC's acceptance of the NYISO's September 22, 2011 compliance filing. This resulted in increased demand curve rates that apply going forward

to 2014. Until the above noted NYISO actions relative to new unit pricing are resolved, capacity prices are expected to remain volatile.

Subsequent to closing the acquisition of Ravenswood in August 2008, TransCanada experienced a forced outage event related to Ravenswood's 981 MW Unit 30. The unit returned to service in May 2009. TransCanada has filed claims against the insurers to enforce its rights under the insurance policies and litigation proceedings are ongoing.

Power Transmission Line Projects In June 2011, Zephyr terminated the precedent agreements with its potential shippers as the parties were unable to resolve key commercial issues. In July 2011, one of Zephyr's potential shippers exercised its contractual rights to acquire 100 per cent of the Zephyr project from TransCanada.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices TransCanada operates in competitive power and natural gas markets in North America. Power and natural gas price volatility is caused by fluctuating supply and demand, and by general economic conditions. TransCanada's power generation facilities are exposed to commodity price volatility in its Western Power operations in Alberta and in its U.S. Power operations in New England and New York. Earnings from these businesses are generally correlated to the prevailing power supply demand conditions and the price of natural gas, as power prices are set by gas-fired power supplies the majority of the time. Extended periods of low gas prices will generally place downward pressure on earnings from these facilities. Western Power's Coolidge Generating Station and TransCanada's portfolio of assets in Eastern Canada have been fully contracted, and are therefore not subject to fluctuating commodity prices. Bruce Power's exposure to fluctuating power prices is discussed further below.

Sales of uncontracted power volumes into the spot market in Alberta and the U.S. northeast can be subject to price volatility, directly affecting earnings. To mitigate this risk, TransCanada commits a portion of its supply to medium-term to long-term sales contracts while retaining an amount of unsold supply to mitigate the financial impact of unexpected plant outages and to provide flexibility in managing the Company's portfolio of wholly owned assets. This unsold supply is subsequently sold under shorter-term forward arrangements or into the spot market and is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Under an agreement with the OPA, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price for all of its output. Bruce B also enters into third party fixed-price contracts where it receives the difference between the contract price and spot price. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA. All Bruce A output will be subject to spot market pricing effective June 1, 2012 until the restart of both Units 1 and 2 is complete.

Energy's natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons.

U.S. Power Capacity Payments The parameters that drive U.S. Power capacity prices are reset periodically and are affected by a number of factors including the cost of entering the market, available supply and fluctuations in forecast demand. With the downturn in the economy in recent years, there has been a decrease in demand that, combined with increased supply in these markets, has put downward pressure on capacity prices. In September 2011, the demand curve reset process for the New York Zone J market was completed for the 2011 to 2014 capacity periods, resulting in increased demand curve rates. These increases, however, were more than offset by the unexpected capacity price treatment applied to certain new entrants by NYISO in 2011, a matter that remains subject to a pending complaint lodged with the FERC. Refer to Energy – Opportunities and Development for more information.

Plant Availability Optimizing and maintaining plant availability is essential to the continued success of the Energy business. High levels of performance are achieved through the use of risk-based comprehensive preventative

maintenance programs, prudent operating and capital investment, and a skilled workforce. Further mitigation is provided through the contractual obligations to TransCanada of its power suppliers under the Sundance and Sheerness PPAs, including the payment of market-based penalties related to availability requirements and by certain sales contracts that share operating risks with the purchaser. In the event a PPA power supplier experiences a verified force majeure event, TransCanada is not entitled to receive market-based penalties for the duration of the verified force majeure event and the monthly capacity payments paid to the supplier are eliminated during the same period. Unexpected plant outages, including unexpected delays in ending planned outages, could result in lower plant output and sales revenue, reduced capacity payments and margins, and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TransCanada meets its contractual obligations.

Weather Extreme temperature and weather events in North America often create price volatility and variable demand for power and natural gas. These events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds impact the earnings of Energy's wind assets.

Hydrology TransCanada's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution, Capital Cost and Permitting Energy's construction programs in Québec and Ontario, including its investment in Bruce Power, are subject to execution, capital cost and permitting risks.

Regulation of Power Markets TransCanada operates in both regulated and deregulated power markets. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, unfair cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. TransCanada is an active participant in formal and informal regulatory proceedings and takes legal action where required.

Refer to the Risk Management and Financial Instruments and Other Risks sections in this MD&A for information on additional risks related to the Energy business.

ENERGY – OUTLOOK

The power supply/demand dynamic in Alberta is rapidly tightening. The 2011 average pool price rose to $77/MWh compared to $51/MWh in 2010, driven by unexpected plant outages and increased demand, especially in the peak periods. Increases in Alberta's power demand were a function of economic growth coming from the oil sands and natural gas industries plus population increases in the province. Over the next decade, further oil sands projects and the associated development are expected to drive continued strong Alberta economic growth. The Alberta Electric System Operator's forecasts indicate power demand growth rates of 3.2 per cent per year over the next 20 years and estimates that more than 11,000 MW of new generation will be required. This backdrop will provide an opportunity for TransCanada to participate in new generation and other power infrastructure projects. The current low gas price environment provides an opportunity for gas generation sources to be a very cost-competitive option to fill these anticipated generation needs.

Ontario's 2011 average power demand was down 0.5 per cent compared to 2010. New renewable energy projects came in service in 2011 and the IESO projects a further 2,500 MW of new and refurbished power supply additions by early 2013. This increase in supply, combined with lower natural gas prices plus weak 2011 Ontario economic growth of about two per cent resulted in a decrease in the year-over-year average hourly Ontario energy price from $36/MWh

in 2010 to $30/MWh in 2011. The IESO forecasts a return to power demand growth in 2012, however, future power demand growth rates are expected to be modest, as a full return of the energy intensive industries lost in the recession is not expected. TransCanada's existing energy assets in Ontario are largely insulated from changes in the market price of power through contracts with the OPA.

New England's average power demand fell slightly in 2011 while approximately 800 MW of new gas-fired power supply was added. This prevailing supply and demand environment, in addition to lower natural gas prices and weak 2011 economic growth, resulted in power prices down slightly on a year over year basis. The 2011 average ISO New England power price was US$47/MWh compared to the 2010 average of about US$50/MWh. ISO New England forecasts a return to power growth of about one per cent per year in the coming years, based on modest economic growth.

New York City's average power demand dropped slightly in 2011 while approximately 550 MW of new gas-fired power supply was added. Under this supply/demand environment, coupled with lower natural gas prices, weak 2011 economic growth and continuing high New York City unemployment rates, power prices fell slightly on a year over year basis. The 2011 average NYISO New York City power price was US$51/MWh versus the 2010 average of about US$56/MWh. The NYISO forecasts a return to power demand growth of about one per cent per year in the coming years, based on modest population and economic growth.

Earnings TransCanada expects that results from its Energy operations in 2012 will be higher than those in 2011. There will be a positive earnings impact from a full year of Coolidge, Montagne-Sèche and the first phase of Gros-Morne, which all came in service during 2011. Additional earnings from Bruce Power will also be realized with the return to service of Unit 2, which is expected in first quarter 2012, followed by Unit 1 which is expected in third quarter 2012. It is also anticipated that the nine solar projects TransCanada agreed to purchase in late 2011 will come in service between late 2012 and mid-2013 pending certain conditions and approvals. Output from these plants, as well as a significant portion of output from Energy's other assets, has been sold under long-term contracts and provides a stable earnings base for the Energy business.

The Company expects the positive impact on earnings from the new assets coming in service could be tempered by results from U.S. Power if capacity prices in New York remain at low levels, and Gas Storage, where storage spreads are expected to remain at low levels throughout 2012. In addition, earnings from Bruce A will be impacted by the West Shift Plus outage on Unit 3, which commenced on November 6, 2011 and is expected to last six months. Energy earnings in 2012 will also be impacted by fluctuations in Alberta power prices.

Certain regulatory and arbitration outcomes that are expected to be resolved in 2012 may also have a significant impact on Energy results. Specifically, actions taken by the FERC related to New York capacity prices, and resolution to the arbitration processes underway on Sundance A and Oakville may have a material financial impact on Energy earnings in 2012.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2012 EBIT. Refer to the Energy – Business Risks section in this MD&A for a complete discussion of these and other factors affecting the Energy Outlook.

CORPORATE

Corporate had a Comparable EBIT loss of $100 million in 2011 compared to losses of $99 million and $117 million in 2010 and 2009, respectively. The losses in 2011 were consistent with 2010 and the decrease in the loss in 2010 compared to 2009 was primarily due to lower support services and other corporate costs.

OTHER INCOME STATEMENT ITEMS

COMPARABLE INTEREST EXPENSE

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Comparable Interest on long-term debt[1]			
Canadian dollar-denominated	**490**	514	548
U.S. dollar-denominated	**734**	680	645
Foreign exchange	**(7)**	20	92
	1,217	1,214	1,285
Other interest and amortization	**24**	74	27
Capitalized interest	**(302)**	(587)	(358)
Comparable Interest Expense	**939**	701	954

[1] Includes interest on Junior Subordinated Notes.

Comparable Interest Expense increased in 2011 by $238 million to $939 million compared to 2010. This increase was primarily due to decreased capitalized interest upon placing Keystone and Coolidge in service in 2011 and Halton Hills in service in the latter part of 2010. Comparable Interest on long-term debt increased in 2011 compared to 2010 primarily due to new debt issues of US$1.0 billion in September 2010 and US$1.25 billion in June 2010. This was offset by the impact of a weaker U.S. dollar and the decrease in interest expense on Canadian dollar-denominated debt from debt maturities. Other Interest and Amortization Expense in 2011 was positively affected by increased gains from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates.

Comparable Interest Expense in 2010 decreased $253 million to $701 million from $954 million in 2009. Interest on Canadian dollar-denominated debt decreased in 2010 compared to 2009 primarily due to debt maturities. Interest on U.S. dollar-denominated debt increased in 2010 compared to 2009 due to new debt issues of US$1.0 billion in September 2010, US$1.25 billion in June 2010 and US$2.0 billion in January 2009, partially offset by the impact of a weaker U.S. dollar. Other Interest and Amortization Expense in 2010 was negatively affected by additional financing charges on committed credit facilities and increased losses from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates. Interest Expense was positively impacted by higher capitalization of interest in 2010 relating to the Company's larger capital spending program primarily for the construction of Keystone and refurbishment and restart of Bruce A Units 1 and 2.

Comparable Interest Income and Other was $60 million in 2011 compared to $94 million and $121 million in 2010 and 2009, respectively. The decrease in 2011 compared to 2010 was primarily due to lower gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. The decrease in 2010 compared to 2009 was primarily due to the positive impact of a weakening U.S. dollar on the translation of U.S. dollar working capital balances throughout each year and gains in 2010 on derivatives used to manage foreign exchange fluctuations.

Comparable Income Taxes were $595 million, $400 million and $406 million in 2011, 2010, and 2009, respectively. The increase of $195 million in 2011 compared to 2010 was primarily due to increased pre-tax earnings and higher positive income tax adjustments in 2010 compared to 2011. In 2011 and 2010, the Company recorded a benefit in Current

Income Taxes with an offsetting provision in Future Income Taxes as a result of bonus depreciation for U.S. income tax purposes on the Bison pipeline which was placed in service in January 2011 and the Wood River/Patoka and Cushing Extension sections of Keystone which were placed in operational service in June 2010 and February 2011, respectively. The decrease of $6 million in 2010 compared to 2009 was primarily due to increased pre-tax earnings offset by higher positive income tax adjustments in 2010.

Non-Controlling Interests were $129 million in 2011 compared to $115 million and $96 million in 2010 and 2009, respectively. The $14 million increase in 2011 compared to 2010 was primarily due to the sale of a 25 per cent interest in GTN and Bison to TC PipeLines, LP and reduction in the Company's ownership interest in TC PipeLines, LP in May 2011 partially offset by the impact of a weaker US dollar in 2011. The increase in 2010 compared to 2009 was primarily due to increased TC PipeLines, LP earnings as a result of higher revenues from Northern Border and the acquisition by TC PipeLines, LP of North Baja, partially offset by the impact of a weaker US dollar in 2010.

LIQUIDITY AND CAPITAL RESOURCES

TransCanada believes that its financial position remains sound as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TransCanada's liquidity is underpinned by predictable cash flow from operations, available cash balances and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2012, October 2016, October 2012 and February 2013, respectively. These facilities also support the Company's three commercial paper programs. In addition, at December 31, 2011, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada-operated affiliates was $0.1 billion with maturity dates in 2012 and 2016. As at December 31, 2011, TransCanada had capacity of $2.0 billion, $1.25 billion and US$4.0 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

SUMMARIZED CASH FLOW

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Funds generated from operations[1]	**3,663**	3,331	3,080
Decrease/(Increase) in operating working capital	**310**	(249)	(90)
Net Cash Provided by Operations	**3,973**	3,082	2,990

[1] Refer to the Non-GAAP Measures section in this MD&A for further discussion of Funds Generated from Operations.

HIGHLIGHTS

Investing Activities

- Capital expenditures and acquisitions, including assumed debt, totalled approximately $15 billion over the three-year period ending December 31, 2011.

Dividends

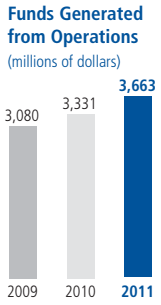
- TransCanada's Board of Directors declared a $0.44 per common share dividend for the quarter ending March 31, 2012, an increase of five per cent over the previous dividend amount. The Board of Directors also declared regular quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2012 and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2012.

CASH FLOW AND CAPITAL RESOURCES

Cash Generated from Operations

Net Cash Provided by Operations was $4.0 billion in 2011 compared to $3.1 billion and $3.0 billion in 2010 and 2009, respectively. Net Cash Provided by Operations reflects Funds Generated from Operations, net of changes in operating working capital.

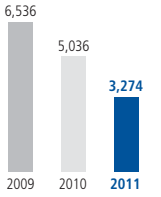
Funds Generated from Operations



Funds Generated from Operations were $3.7 billion in 2011 compared to $3.3 billion and $3.1 billion in 2010 and 2009, respectively. The increase in 2011 compared to 2010 was primarily due to increased cash from earnings. This increase was net of lower current income tax benefits from bonus depreciation for U.S. tax purposes recognized in 2011 compared to 2010. The increase in 2010 compared to 2009 was primarily due to the current income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed in service in June 2010.

As at December 31, 2011, TransCanada's current liabilities were $5.9 billion and current assets were $3.6 billion resulting in a working capital deficiency of $2.3 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations, access to the unutilized committed revolving bank lines in excess of $4.0 billion, discussed above, as well as its ongoing access to capital markets.

Investing Activities



Capital expenditures totalled $3.3 billion in 2011 compared to $5.0 billion in 2010 and $5.4 billion in 2009. Expenditures in 2011, 2010 and 2009 related primarily to the completion of the Wood River/Patoka and Cushing Extension Sections of Keystone, advancement of Keystone XL, the refurbishment and restart of Units 1 and 2 at Bruce A, construction of other new pipeline and power facilities, and the expansion and maintenance of existing pipelines.

In August 2009, the Company purchased ConocoPhillips' remaining interest of approximately 20 per cent in Keystone for US$553 million plus the assumption of US$197 million of short-term debt. In the first seven months of 2009, TransCanada solely funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million.

Financing Activities

In 2011, TransCanada issued Medium-Term Notes of $500 million and $250 million maturing in 2021 and 2041, respectively, and US$350 million of Senior Notes due in 2021. The Company also made draws totalling US$0.5 billion on existing facilities and retired or repaid $1.3 billion of long-term debt.

In 2011, the Company's proportionate share of joint venture long-term debt issued and repaid was $48 million and $102 million, respectively. In addition, Notes Payable decreased by $218 million in 2011.

At December 31, 2011, total committed revolving and demand credit facilities of $5.1 billion were available to support the Company's commercial paper programs and for general corporate purposes. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving, extendible TransCanada PipeLines Limited (TCPL) credit facility, maturing October 2016. The facility was fully available at December 31, 2011 and supports TCPL's Canadian commercial paper program;

- a US$300 million committed, syndicated, revolving credit facility maturing February 2013. At December 31, 2011, this facility was fully available. This facility is part of an initial US$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility established in 2007 which has since been reduced through term loan repayments of US$200 million in August 2011 and US$500 million in January 2012;
- a US$1.0 billion committed, syndicated, revolving, extendible TransCanada Keystone Pipeline, LP credit facility, maturing November 2012. The facility was fully available at December 31, 2011 and supports a TCPL USA U.S. dollar commercial paper program dedicated to funding a portion of capital expenditures for Keystone;
- a US$1.0 billion committed, syndicated, revolving, extendible TCPL USA credit facility, maturing October 2012. The facility was fully available at December 31, 2011 and supports a TCPL U.S. dollar commercial paper program that was established in December 2011; and
- demand lines totalling $802 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2011, the Company had used approximately $468 million of these demand lines for letters of credit.

In May 2011, TransCanada sold a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for a total transaction value of US$605 million, which included US$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively. Subsequent to the transaction, TransCanada's ownership in TC PipeLines, LP decreased to 33.3 per cent due to TC PipeLines, LP's public issuance of common units as discussed under the heading 2011 Equity Financing Activities in this section.

The Company believes it has the capacity to fund its existing capital program through internally-generated cash flow, continued access to capital markets and liquidity underpinned by in excess of $4 billion of committed credit facilities. TransCanada's financial flexibility is further bolstered by opportunities for portfolio management, including an ongoing role for TC PipeLines, LP.

2011 Long-Term Debt Financing Activities

In November 2011, the Company issued Medium-Term Notes of $500 million and $250 million maturing in 2021 and 2041, respectively, and in June 2011, TC Pipelines, LP issued US$350 million of Senior Notes due in 2021. The Company also made draws totalling US$0.5 billion on existing facilities and retired or repaid $1.3 billion of long-term debt.

2011 Equity Financing Activities

In November 2011, TransCanada filed a base shelf prospectus in Canada and the U.S. qualifying the issuance of up to $2.0 billion of common shares, preferred shares and/or subscription receipts until December 2013. The shelf replaced the base shelf prospectus filed in September 2009. No securities have been issued under the November 2011 base shelf prospectus.

In May 2011, TC PipeLines, LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. As part of this offering, TransCanada made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in TC PipeLines, LP and did not purchase any other units. As a result of the common units offering, TransCanada's ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent.

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The Company reserves the right to satisfy its DRP obligations by issuing common shares from treasury at a discount of up to five per cent or by purchasing shares on the open market. Commencing with the dividends declared in April 2011, common

shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. In 2011, dividends of $202 million were paid (2010 – $378 million; 2009 – $254 million) through the issuance of 5 million (2010 – 11 million; 2009 – 8 million) common shares from treasury in accordance with the DRP.

Dividends

Cash dividends on common shares of $961 million were paid in 2011 (2010 – $710 million; 2009 – $722 million). In addition, cash dividends of $55 million were paid on preferred shares in 2011 (2010 – $44 million). The increase in common share cash dividends paid in 2011 was primarily due to the Company's decision to satisfy its DRP obligations with market purchased shares instead of treasury shares effective April 2011, as discussed above, and an increase in the per share dividend amount in 2011. The decrease in common share dividends paid in cash in 2010 from 2009 was primarily due to increased participation in the DRP in lieu of cash dividends, which grew to $378 million in 2010 from $254 million in 2009, partially offset by a greater number of shares outstanding and an increase in the per share dividend amount in 2010.

The increase in preferred share dividends paid in 2011 from 2010 was primarily due to a full year of preferred share dividend payments in 2011 on preferred shares issued in March and June 2010. The increase in preferred share dividends paid in 2010 from 2009 was primarily due to a full year of preferred share dividend payments in 2010 on preferred shares issued in September 2009 and the preferred share issuances in 2010.

In February 2012, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.44 per share from $0.42 per share for the quarter ending March 31, 2012. This was the twelfth consecutive year in which the dividend was increased, resulting in a per share dividend that has more than doubled since 2000. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2012 and $0.275 per Series 5 preferred share for the three-month period ended April 30, 2012.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2011, the Company had $18.6 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes, compared to $17.9 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes at December 31, 2010. TransCanada's share of the total long-term debt of joint ventures, including capital lease obligations, was $0.8 billion at December 31, 2011, compared to $0.9 billion at December 31, 2010. Total Notes Payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $1.9 billion at December 31, 2011 and $2.1 billion at December 31, 2010. TransCanada has also provided certain pro-rata guarantees related to the capital lease and performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS

Year ended December 31 *(millions of dollars)*	Total	Payments Due by Period: Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	20,204	950	1,926	2,467	14,861
Capital lease obligations	194	18	42	57	77
Operating leases[2]	735	79	152	143	361
Purchase obligations	9,152	1,650	2,905	1,568	3,029
Other long-term liabilities reflected on the balance sheet	911	17	35	39	820
	31,196	2,714	5,060	4,274	19,148

[1] Includes Junior Subordinated Notes and Long-Term Debt of Joint Ventures, excluding capital lease obligations.

[2] Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2052 with an option to renew certain lease agreements for one to 10 years.

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability among other factors. TransCanada's share of power purchased under the PPAs in 2011 was $394 million (2010 – $363 million; 2009 – $384 million).

At December 31, 2011, scheduled principal repayments and interest payments related to long-term debt and the Company's proportionate share of the long-term debt of joint ventures were as follows:

PRINCIPAL REPAYMENTS

Year ended December 31 *(millions of dollars)*	Total	Payments Due by Period: Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009	–	–	–	1,009
Long-term debt of joint ventures	628	15	52	156	405
	20,204	950	1,926	2,467	14,861

INTEREST PAYMENTS

Year ended December 31 *(millions of dollars)*	Total	Payments Due by Period: Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes[1]	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

[1] Payments were calculated assuming the notes would be redeemed after 10 years.

At December 31, 2011, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]

Year ended December 31 *(millions of dollars)*	Total	Payments Due by Period: Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Natural Gas Pipelines					
Transportation by others[2]	482	130	133	108	111
Capital expenditures[3][4]	250	248	2	–	–
Other	1	1	–	–	–
Oil Pipelines					
Capital expenditures[3][5]	992	98	894	–	–
Other	48	4	8	8	28
Energy					
Commodity purchases[6]	5,121	666	1,201	1,221	2,033
Capital expenditures[3][7]	290	234	56	–	–
Other[8]	1,928	254	587	231	856
Corporate					
Information technology and other	40	15	24	–	1
	9,152	1,650	2,905	1,568	3,029

(1) The amounts in this table exclude funding contributions to pension plans.

(2) Rates are based primarily on known 2011 levels. Beyond 2011, demand rates are subject to change. The purchase obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow.

(3) Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund capital projects with cash from operations, the issuance of senior debt and, if required, subordinated capital, and through portfolio management.

(4) Capital expenditures primarily relate to the construction costs of the Alberta System expansion, Guadalajara and other natural gas pipeline projects.

(5) Capital expenditures primarily relate to Keystone XL.

(6) Commodity purchases include fixed and variable components and excludes derivatives. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(7) Capital expenditures primarily relate to TransCanada's share of the construction and development costs of Bruce Power and Cartier Wind.

(8) Includes estimates of certain amounts that are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation. This includes the purchase obligation for Ontario Solar.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Potential future commitments are discussed in the Opportunities and Developments sections for Natural Gas Pipelines, Oil Pipelines and Energy in this MD&A.

In 2012, TransCanada expects to make funding contributions of approximately $119 million to its defined benefit pension plans (DB Plan) and approximately $31 million to the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. In addition to these contributions, the Company expects to provide a

$48 million letter of credit in 2012 to the DB Plan. In 2011, the Company made total cash funding contributions of $93 million and provided a $27 million letter of credit to the DB Plan. TransCanada's proportionate share of cash funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2012 is approximately $73 million and $7 million, respectively, compared to total contributions of $59 million in 2011.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2013. Based on current market conditions, TransCanada expects funding requirements for these plans to continue at the anticipated 2012 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2012 net benefit cost is expected to increase from 2011 primarily due to a lower projected discount rate. However, future net benefit costs and the amount of funding contributions will be dependent on various factors, including investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2. TransCanada's share of these signed commitments is $95 million. The Company expects $88 million and $7 million to be paid in 2012 and 2013, respectively.

Ontario Solar

In December 2011, an agreement was announced for the purchase of nine Ontario solar projects with a combined capacity of 86 MW, for approximately $470 million. TransCanada will purchase each project once construction and acceptance testing are completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. It is anticipated that the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2011, the Company had accrued approximately $49 million (2010 – $59 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta in January 2011. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated. TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012. TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC, have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $863 million at December 31, 2011. The fair value of these Bruce Power guarantees at December 31, 2011 is estimated to be $29 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these assurances was estimated at December 31, 2011 to range from $182 million to a maximum of $498 million. The fair value of these guarantees at December 31, 2011 is estimated to be $7 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with financial risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity and natural gas. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate operational and price risks in its asset portfolio.

- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and on these forward contracts are not representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's net income. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated interest expense.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the foreign exchange rate exposures of the Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10 billion (US$9.8 billion) (2010 – $9.8 billion (US$9.8 billion)) and a fair value of $12.7 billion (US$12.5 billion) (2010 – $11.3 billion (US$11.4 billion)). At December 31, 2011, $79 million (December 31, 2010 – nil)

was included in Other Current Assets, $66 million (December 31, 2010 – $181 million) was included in Intangibles and Other Assets, $15 million (December 31, 2010 – nil) was included in Accounts Payable, and $41 million (December 31, 2010 – nil) was included in Deferred Amounts for the fair value of the forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability)

	2011		2010	
December 31 *(millions of dollars)*	**Fair Value[1]**	**Notional or Principal Amount**	Fair Value[1]	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2018)	**93**	**US 3,850**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2012)	**(4)**	**US 725**	2	US 100
	89	**US 4,575**	181	US 2,900

[1] Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open positions will not exceed the reported VaR. The VaR methodology is a statistically calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the regulated natural gas pipelines as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2011 (2010 – $12 million).

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring

exposures against these limits, using contract netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts receivable and other, and Available for sale assets in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2011, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2011, the Company had a credit risk concentration of $274 million (2010 – $317 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

In August 2011, the Company received final distributions of 2.1 million common shares, as a result of previous claims in the 2005 Calpine Corporation bankruptcy. These shares were sold into the open market resulting in total pre-tax gains of $30 million, of which the Company had accrued pre-tax gains of $15 million in 2010. In 2008, the Company had received 15.5 million common shares which were sold into the open market for $279 million. Claims by NGTL and Foothills PipeLines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in 2008 and 2009 and were passed onto the shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section of this note.

At December 31, 2011, the Company had unutilized committed revolving bank lines of US$1.0 billion, US$1.0 billion, US$300 million and $2.0 billion maturing in October 2012, November 2012, February 2013 and October 2016, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms and recently initiated a commercial paper program in the U.S.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2011, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Equity. Net debt comprises Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 *(millions of dollars)*	**2011**	2010
Notes payable	**1,863**	2,081
Long-term debt	**18,567**	17,922
Junior subordinated notes	**1,009**	985
Cash and cash equivalents	**(654)**	(660)
Net Debt	**20,785**	20,328
Equity attributable to non-controlling interests	**1,465**	1,157
Equity attributable to controlling interests	**17,324**	16,727
Total Equity	**18,789**	17,884
	39,574	38,212

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates and applying a discounted cash flow valuation model. The fair value of power and natural gas derivatives, and of available for sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

December 31 *(millions of dollars)*	**2011** **Carrying Amount**	**2011** **Fair Value**	2010 Carrying Amount	2010 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**765**	**765**	764	764
Accounts receivable and other[2][3]	**1,576**	**1,620**	1,555	1,595
Available for sale assets[2]	**23**	**23**	20	20
	2,364	**2,408**	2,339	2,379
Financial Liabilities[1][3]				
Notes payable	**1,880**	**1,880**	2,092	2,092
Accounts payable and deferred amounts[4]	**1,536**	**1,536**	1,436	1,436
Accrued interest	**373**	**373**	367	367
Long-term debt	**18,567**	**23,757**	17,922	21,523
Junior subordinated notes	**1,009**	**1,027**	985	992
Long-term debt of joint ventures	**822**	**940**	866	971
	24,187	**29,513**	23,668	27,381

(1) Consolidated Net Income in 2011 included losses of $13 million (2010 – losses of $8 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At December 31, 2011, the Consolidated Balance Sheet included financial assets of $1,265 million (2010 – $1,271 million) in Accounts Receivable, $41 million (2010 – $40 million) in Other Current Assets and $293 million (2010 – $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for $350 million (2010 – $250 million) of Long-Term Debt that is adjusted to fair value.

(4) At December 31, 2011, the Consolidated Balance Sheet included financial liabilities of $1,494 million (2010 – $1,406 million) in Accounts Payable and $42 million (2010 – $30 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2011:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Notes payable	1,880	1,880	–	–	–
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009	–	–	–	1,009
Long-term debt of joint ventures	822	33	94	213	482
	22,278	2,848	1,968	2,524	14,938

[1] The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2011, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

December 31 *(all amounts in millions unless otherwise indicated)*	2011 Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$213**	**$176**	**$3**	**$22**
Liabilities	**$(212)**	**$(212)**	**$(14)**	**$(22)**
Notional Values				
Volumes[3]				
Purchases	**23,500**	**103**	**–**	**–**
Sales	**23,158**	**82**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**684**
U.S. dollars	**–**	**–**	**US 1,269**	**US 250**
Cross-currency	**–**	**–**	**47/US 37**	**–**
Net unrealized (losses)/gains in the year[4]	**$(3)**	**$(50)**	**$(4)**	**$1**
Net realized gains/(losses) in the year[4]	**$58**	**$(74)**	**$10**	**$10**
Maturity dates	**2012-2018**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$42**	**$3**	**$–**	**$13**
Liabilities	**$(277)**	**$(22)**	**$(38)**	**$(1)**
Notional Values				
Volumes[3]				
Purchases	**17,188**	**8**	**–**	**–**
Sales	**9,217**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**US 91**	**US 600**
Cross-currency	**–**	**–**	**136/US 100**	**–**
Net realized losses in the year[4]	**$(150)**	**$(17)**	**$–**	**$(16)**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2012-2015**

(1) All derivative financial instruments in the held for trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on held for trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million. In 2011, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2011, Net Income included losses of $3 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2011, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2011. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Derivative financial instruments held for trading					
Assets	414	282	123	9	–
Liabilities	(460)	(292)	(151)	(17)	–
Derivative financial instruments in hedging relationships					
Assets	217	121	91	5	–
Liabilities	(408)	(208)	(135)	(50)	(15)
	(237)	(97)	(72)	(53)	(15)

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2010			
December 31 (all amounts in millions unless otherwise indicated)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values				
Volumes[3]				
Purchases	15,610	158	–	–
Sales	18,114	96	–	–
Canadian dollars	–	–	–	736
U.S. dollars	–	–	US 1,479	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year[4]	$(32)	$27	$4	$43
Net realized gains/(losses) in the year[4]	$77	$(42)	$36	$(74)
Maturity dates	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	$112	$5	$–	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values				
Volumes[3]				
Purchases	16,071	17	–	–
Sales	10,498	–	–	–
U.S. dollars	–	–	US 120	US 1,125
Cross-currency	–	–	136/US 100	–
Net realized losses in the year[4]	$(9)	$(35)	$–	$(33)
Maturity dates	2011-2015	2011-2013	2011-2014	2011-2015

[1] All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

[2] Fair values equal carrying values.

[3] Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

[4] Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2010, Net Income included a gain of $1 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2010, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 *(millions of dollars)*	**2011**	2010
Current		
Other current assets	**404**	273
Accounts payable	**(502)**	(337)
Long Term		
Intangibles and other assets *(Note 9)*	**213**	374
Deferred amounts *(Note 11)*	**(352)**	(282)

Derivative Financial Instruments of Joint Ventures

Included in the Derivative Financial Instruments Summary tables are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power derivatives was $35 million at December 31, 2011 (2010 – $48 million). These contracts mature from 2012 to 2018. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 2,979 GWh at December 31, 2011 (2010 – 3,772 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 1,595 GWh at December 31, 2011 (2010 – 2,322 GWh).

Derivatives in Cash Flow Hedging Relationships

Information about how derivatives and hedging activities affect the Company's financial position, financial performance and cash flows is as follows:

	Cash Flow Hedges							
	Power		Natural Gas		Foreign Exchange		Interest	
Year ended December 31 *(millions of Canadian dollars, pre-tax)*	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Change in fair value of derivative instruments recognized in OCI (effective portion)	**(252)**	(79)	**(59)**	(26)	**5**	10	**(1)**	(137)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**61**	(7)	**100**	(21)	**–**	–	**43**	32

Credit Risk Related Contingent Features

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2011, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2010 – $92 million), for which the Company has provided collateral of $28 million (2010 – $4 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2011, the Company would have been required to provide additional collateral of $82 million (2010 – $88 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative financial instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets are included in this category. Long-dated commodity prices are derived with a third-party modelling tool that uses market fundamentals to derive long-term prices.

There were no transfers between Level I and Level II in 2011 or 2010. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 *(millions of dollars, pre-tax)*	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Natural Gas Inventory	**–**	–	**29**	49	**–**	–	**29**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**–**	–	**35**	28	**–**	–	**35**	28
Foreign exchange contracts	**11**	10	**131**	179	**–**	–	**142**	189
Power commodity contracts	**–**	–	**244**	269	**2**	5	**246**	274
Gas commodity contracts	**124**	93	**55**	56	**–**	–	**179**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**–**	–	**(23)**	(47)	**–**	–	**(23)**	(47)
Foreign exchange contracts	**(13)**	(11)	**(89)**	(54)	**–**	–	**(102)**	(65)
Power commodity contracts	**–**	–	**(465)**	(299)	**(15)**	(8)	**(480)**	(307)
Gas commodity contracts	**(208)**	(178)	**(26)**	(15)	**–**	–	**(234)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**23**	20	**–**	–	**–**	–	**23**	20
	(63)	(66)	**(109)**	166	**(13)**	(3)	**(185)**	97

The following table presents the net change in the Level III fair value category:

(millions of dollars, pre-tax)	Derivatives[1]
Balance at December 31, 2009	(2)
New contracts[2]	(16)
Settlements	(3)
Transfers into Level III[3]	3
Transfers out of Level III[3][4]	(38)
Change in unrealized gains recorded in Net Income	14
Change in fair value of derivative instruments recorded in OCI	39
Balance at December 31, 2010	(3)
New contracts[2]	**1**
Settlements	**1**
Transfers out of Level III[3][4]	**(1)**
Change in unrealized gains recorded in Net Income	**1**
Change in fair value of derivative instruments recorded in OCI	**(12)**
Balance at December 31, 2011	**(13)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) At December 31, 2011, the total amount of net gains included in Net Income attributable to derivatives that were entered into during the year and still held at the reporting date was nil (2010 – $1 million).

(3) Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable.

(4) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2011.

OTHER RISKS

Development Projects and Acquisitions

TransCanada continues to focus on growing its Natural Gas Pipelines, Oil Pipelines and Energy operations through greenfield development projects and acquisitions. TransCanada capitalizes costs incurred on certain of its projects during the development period prior to construction when the project meets specific criteria and is expected to proceed through to completion. The related capital costs of a project that does not proceed through to completion are expensed at the time it is discontinued to the extent that these costs and underlying materials cannot be utilized on another project. There is a risk with respect to TransCanada's acquisition of assets and operations that certain commercial opportunities and operational synergies may not materialize as expected and that the assets would subsequently be subject to an impairment write-down.

Asset Commissioning

Although each of TransCanada's newly-constructed assets goes through rigorous acceptance testing prior to being placed in service, there is a risk that these assets will have lower than expected availability or performance, especially in their first year of operations.

Operational and Other Business Risks

There are a number of operating risks associated with TransCanada's pipelines and energy businesses including: labour disputes; the breakdown or failure of equipment; acts of terror; and catastrophic events such as natural disasters. The occurrence or continuance of any of these events could impact earnings through the costs associated with remediation or a reduction in revenues.

The Company has established emergency response plans to address certain unplanned events, which include an ongoing program to provide local emergency responders with the information and training necessary to ensure their preparedness for responding to events. TransCanada maintains a comprehensive insurance program to mitigate the risk of potential losses arising from operational risks and other potential losses related to its business. In certain circumstances, not all events will be covered by insurance, which may have an adverse effect on the Company's operations, earnings, cash flow and financial position.

Health, Safety and Environment Risk Management

Health, safety and environment (HSE) are top priorities in all of TransCanada's operations and business activities. These areas are guided by the Company's HSE Commitment Statement, which outlines guiding principles for a safe and healthy environment for TransCanada's employees, contractors and the public, and for TransCanada's commitment to protect the environment. All employees are responsible for the Company's HSE performance. The Company is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to the public and the environment. The Company is committed to continually improving its HSE performance, and to promoting safety on and off the job in the belief that all occupational injuries and illnesses are preventable. TransCanada endeavours to do business with companies and contractors that share its perspective and expectation on HSE performance and will influence them to improve their collective performance and culture. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with its stakeholders.

The HSE Committee of TransCanada's Board of Directors monitors compliance with the Company's HSE corporate policy through regular reporting. TransCanada's integrated HSE management system is modeled after the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001; and the Occupational Health and Safety Assessment Series (OHSAS 18001) for occupational health and safety. TransCanada's HSE management system conforms to external industry consensus standards and voluntary regulatory programs and complies with applicable legislated requirements and various other internal management systems. Resources are focused on the areas of significant risk to the organization's HSE business activities. Management is informed regularly of all important and/or significant HSE operational issues and initiatives through formal reporting and incident management processes. TransCanada's HSE management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in 2009 and did not identify any material issues. The HSE management system is subject to ongoing internal and external review to ensure that it remains effective as circumstances change.

As one of TransCanada's priorities, safety is an integral part of the way its employees work. In 2011, one of the Company's objectives was to sustain health and safety performance year over year. Overall, the Company's safety frequency rates in 2011 continued to be better than most industry benchmarks.

The safety and integrity of the Company's existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. The Company expects to spend approximately $322 million in 2012 for pipeline integrity on the pipelines it operates, an increase of approximately $78 million over 2011 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are treated on a flow-through basis and, as a result, these expenditures have no impact on TransCanada's earnings. Under the Keystone

contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on TransCanada's earnings. TransCanada's pipeline safety record in 2011 continued to be better than industry benchmarks. TransCanada experienced two pipeline breaks in 2011 on its operated pipelines. The first break occurred in a remote part of Northern Ontario on the Canadian Mainline pipeline system. The second break occurred in a remote part of Wyoming on the Bison pipeline system.

Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is slightly higher than previous years due to increased spending to repair damage from the high flow events of 2011 caused by Hurricane Irene.

Environment

TransCanada's facilities are subject to stringent federal, state, provincial, and local environmental statutes and regulations governing environmental protection, including, but not limited to, air emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements and/or the issuance of orders respecting future operations. TransCanada has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements.

At December 31, 2011, TransCanada recorded liabilities of approximately $69 million (2010 – $84 million) for remediation obligations and compliance costs associated with certain environmental regulations. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

The Company owns assets in four regions, Alberta, Québec, B.C., and the Northeastern U.S., where regulations exist to address industrial greenhouse gas (GHG) emissions. TransCanada has procedures in place to comply with these regulations.

In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHG emissions over an intensity threshold level are required to reduce the intensity of GHG emissions by 12 per cent below an average baseline. TransCanada's Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TransCanada has certain rights under the PPAs. TransCanada has a program in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls paid by customers. Some of the compliance costs from the Company's power generation facilities in Alberta are recovered through market pricing and contract flow-through provisions. TransCanada has estimated and recorded GHG emissions related costs of $13 million for 2011 (2010 – $22 million), after contracted cost recovery.

In Québec, the natural gas distributor collects the hydrocarbon royalty on behalf of the provincial government through a green fund contribution charge on gas consumed. In 2011, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility's power generation.

The carbon tax in B.C., which came into effect in mid-2008, applies to carbon dioxide (CO_2) emissions from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax in 2011 were approximately $3 million (2010 – $4 million). The cost per tonne of CO_2 will be increased in July 2012 to $30 from $25.

States in the northeastern U.S. that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators effective in January 2009. Under the RGGI, both the Ravenswood and OSP generation facilities were required to submit allowances following the end of the first compliance period on December 31, 2011. TransCanada participated in the quarterly auctions of allowances for the Ravenswood and Ocean

State Power generation facilities and incurred related costs of $4 million in 2011 (2010 – $5 million). These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

TransCanada is not aware of any material outstanding orders, claims or lawsuits against it in relation to the release or discharge of any material into the environment or in connection with environmental protection.

Environmental risks from TransCanada's operating facilities typically include: air emissions, GHG emissions; potential impacts on land, including land reclamation or restoration following construction; the use, storage and release of hydrocarbons or other chemicals; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge.

The Company's operations are subject to various environmental laws and regulations that establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties. It is not possible for the Company to estimate the amount and timing of all future expenditures related to environmental matters due to:

- uncertainties in estimating pollution control and clean up costs, including at sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new contaminated sites or additional information at existing contaminated sites;
- the uncertainty in quantifying the Company's liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement of them; and
- the potential for litigation on existing or discontinued assets.

The impact of new or proposed federal, state, and/or provincial safety and environmental laws, regulations, guidelines and enforcement in Canada and the U.S. on TransCanada's business is not yet certain. TransCanada makes assumptions about possible expenditures for safety and environmental matters based on current laws and regulations and interpretations thereof. If the laws or regulations or the interpretation thereof changes, the Company's assumptions may change. Incremental costs may or may not be recoverable under existing rate structures or commercial agreements. Proposed changes in environmental policy, legislation or regulation are routinely monitored by TransCanada, and where the risks are potentially large or uncertain, the Company works independently or through industry associations to comment on proposals.

Regulation of air pollutant emissions under the *U.S. Clean Air Act* and state regulations continue to evolve. A number of EPA initiatives could lead to impacts ranging from requirements to install enhanced emissions control equipment, to additional administrative and reporting requirements. At this time, there is insufficient detail to accurately determine the potential impacts of these initiatives. While the majority of the proposals are not expected to be material to TransCanada, the Company anticipates additional future costs related to the monitoring and control of air emissions.

In addition to those climate change policies already in place, there are also federal, regional, state, and provincial initiatives currently in development. While recent political and economic events may significantly affect the scope and timing of new policies, TransCanada anticipates that most of the Company's facilities in Canada and the U.S. are or will be subject to federal and/or regional climate change regulations to manage industrial GHG emissions.

In August 2011, the Canadian government published the first sector specific draft regulation that will impact industrial GHG emissions. This proposed regulation is focused on the coal-fired generation of electricity and requires a natural gas performance standard for all coal-fired facilities reaching the end of their economic life. The draft regulation is expected to come into effect in July 2015. This process is not expected to pose a significant risk or financial impact to TransCanada's existing facilities and may present opportunities for new power generation investment. Additional sectors,

including the natural gas-fired generation of electricity and upstream oil and gas facility sectors, are expected to begin consultations with Environment Canada.

The Western Climate Initiative (WCI) continues to work toward implementing a regional cap-and-trade program. California and Québec are the only WCI members with cap and trade regulations. In December 2011, the Government of Québec adopted the "Regulation respecting the cap-and-trade system for greenhouse gas emission allowances". The initial phase of the cap and trade system will begin January 1, 2013. The regulation will have a limited impact on TransCanada's Bécancour power generation facility and natural gas pipeline assets. With respect to California, the Air Resources Board adopted a cap and trade regulation in October 2011. The regulation is divided into two phases: the first, beginning in 2013, will include all major industrial sources and electricity utilities; the second, starting in 2015, will cover distributors of transportation fuels, natural gas and other fuels. The regulation may impact the Company's importation of electricity into the state.

Future Abandonment Costs

Depending on specific operating jurisdictions, the Company may have obligations to abandon its facilities in accordance with applicable laws and regulations.

To the extent legal obligations exist and can be reasonably estimated, the Company recognizes the fair value of a liability for asset retirement obligations (ARO), which is accreted through changes to operating expenses. The Company recorded ARO associated with the retirement of certain power generation facilities, natural gas pipelines and transportation facilities, and natural gas storage systems. The estimates or assumptions required to calculate ARO include scope of abandonment and reclamation activities, inflation rates, discount rates and timing of asset retirements. By their nature, these assumptions are subject to measurement uncertainty. The Company has determined that the scope and timing of asset retirements related to its U.S. regulated natural gas pipelines, oil pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded amounts for ARO related to these assets, with the exception of certain abandoned facilities.

The NEB's LMCI deals with pipeline abandonment, including related financial issues. The goal of this initiative is for all pipeline companies regulated under the *National Energy Board Act* (Canada) to begin collecting and setting aside funds to cover future abandonment costs by mid-2014. In its May 2009 decision, the NEB established several filing deadlines relating to the financial issues, including deadlines for preparing and filing an estimate of the abandonment costs to be used to begin collecting funds, developing a proposal for collecting these funds through tolls or some other satisfactory method and developing a proposed process to set aside the funds collected. TransCanada filed its estimates of abandonment costs for its Canadian oil and natural gas pipelines in November 2011, as required by the NEB decision. These costs would be recovered from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The specific toll impacts have not yet been determined as they will be the subject of a subsequent NEB filing in late 2012. In addition, as the actual timing of retirements for the assets is indeterminable, the Company has not recorded amounts for ARO.

For the foreseeable future, the Company intends to operate and maintain these assets as long as supply and demand exists for hydroelectric power generation, natural gas and oil. The Company continues to evaluate its obligations related to future abandonment costs and to monitor developments that could impact the amounts it records.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As at December 31, 2011, an evaluation of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer

concluded that, as at December 31, 2011, the design and operation of TransCanada's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in reports filed with, or submitted to, securities regulatory authorities is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure and were effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's Annual Report on Internal Control over Financial Reporting

Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with CGAAP, including a reconciliation to U.S. generally accepted accounting principles (U.S. GAAP).

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting was effective as at December 31, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2011, there was no change in TransCanada's internal control over financial reporting that materially affected or is reasonably likely to materially affect TransCanada's internal control over financial reporting.

CEO and CFO Certifications

TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2011 reports filed with the SEC and the Canadian securities regulators.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

To prepare financial statements that conform with CGAAP, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses, since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. TransCanada regularly assesses the assets and liabilities associated with these estimates and assumptions. A summary of TransCanada's significant accounting policies can be found in Note 2 to the Consolidated Financial Statements. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact on the Company's financial information.

Rate-Regulated Accounting

The Company accounts for the impacts of rate regulation in accordance with CGAAP. The following three criteria must be met to use these accounting principles:

- the rates for regulated services or activities must be established by or subject to approval by a regulator;
- the regulated rates must be designed to recover the cost of providing the services or products; and

- it must be reasonable to assume that rates set at levels to recover the cost can be charged to and collected from customers in view of the demand for services or products and the level of direct and indirect competition.

The Company's management believes all three of these criteria have been met with respect to each of the regulated natural gas pipelines accounted for using rate-regulated accounting (RRA) principles. The most significant impact from the use of these accounting principles is that the timing of recognition of certain Natural Gas Pipelines expenses and revenues in the regulated businesses may differ from that otherwise expected under CGAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls. At December 31, 2011, the Company reported regulatory assets of $0.2 billion and $1.4 billion in Other Current Assets and Regulatory Assets, respectively (2010 – $0.3 billion and $1.5 billion, respectively), and regulatory liabilities of $0.1 billion and $0.3 billion in Accounts Payable and Regulatory Liabilities, respectively (2010 – $0.1 billion and $0.3 billion, respectively).

Financial Instruments and Hedges

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at fair value. Subsequent measurement of the financial instruments is based on their classification as held for trading, available for sale, held-to-maturity investments, loans and receivables, and other financial liabilities.

Held for trading derivative financial assets and liabilities consist of swaps, options, forwards and futures with changes in the fair value recorded in Net Income. The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications with changes in the fair value recorded in Other Comprehensive (Loss)/Income (OCI). Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as loans and receivables and are measured at amortized cost using the effective interest method, net of any impairment. The Company does not have any held-to-maturity investments. Other financial liabilities consist of liabilities not classified as held for trading and are recognized at amortized cost using the effective interest method.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination or cancellation.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item. Changes in fair value of the hedged and hedging items are recognized in Net Income.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive (Loss)/Income (AOCI) are reclassified to Net Income during the periods when the variability in cash flows of the hedged item affects Net Income. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it is probable the anticipated transaction will not occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation in Canada. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains and losses are refunded to or collected from the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its investment in a foreign operation.

The fair value of financial instruments and hedges, where fair value does not approximate carrying value, is primarily derived from market values adjusted for credit risk, which can fluctuate widely from period to period. Since the changes in fair value are recorded through earnings in certain circumstances, fluctuations can result in variability in Net Income.

Depreciation and Amortization Expense

TransCanada's Plant, Property and Equipment are depreciated on a straight-line basis over their estimated useful lives once they are ready for their intended use. The estimation of useful lives requires management's judgement regarding the period of time the assets will be in use based on third-party engineering studies, experience and industry practice. The initial payment for the Company's PPAs is deferred and amortized on a straight-line basis over the terms of the contracts, which expire in 2017 and 2020.

Natural gas pipeline and compression equipment is depreciated at annual rates ranging from one per cent to six per cent. Oil pipeline and pumping equipment is depreciated at annual rates ranging from approximately two per cent to 2.5 per cent. Metering and other plant equipment are depreciated at various rates. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated by major component on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to 20 per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other Energy equipment is depreciated at various rates. Corporate Plant, Property and Equipment are depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Depreciation and Amortization Expense in 2011 was $1,528 million (2010 – $1,354 million; 2009 – $1,377 million) and was recorded in Natural Gas Pipelines, Oil Pipelines, Energy and Corporate. In Natural Gas Pipelines, depreciation rates are approved by regulators when applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery of depreciation through rates charged to customers, a change in the estimate of the useful lives of plant, property and equipment in the Natural Gas Pipelines segment will have no material impact on TransCanada's Net Income but will directly affect Funds Generated from Operations. PPA amortization expense of $58 million was included in Energy's Depreciation and Amortization expense for 2009 through 2011.

Impairment of Long-Lived Assets and Goodwill

The Company reviews long-lived assets such as plant, property and equipment, as well as intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

At December 31, 2011, the Company reported Goodwill of $3.7 billion (2010 – $3.6 billion). Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial test is done by comparing the fair value of the operations, which includes goodwill, to the book value of each reporting unit. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- discount rates;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies; and
- regulatory changes.

Significant changes in these assumptions could affect the Company's requirement to record an impairment charge. In addition to the above noted estimates and assumptions used by the Company in its fair value determinations, the realization of Ravenswood's fair value is partially dependent on a favourable resolution of the NYISO actions relating to capacity prices as described further in Energy – Opportunities and Developments. An unfavourable outcome could have a negative effect on the estimated fair value and may, in future periods, result in an impairment of a portion of the US$834 million Goodwill balance relating to Ravenswood at December 31, 2011 (2010 – US$834 million).

ACCOUNTING CHANGES

CHANGES IN ACCOUNTING POLICIES FOR 2011

Business Combinations

Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, expensing of acquisition costs, and increased disclosure. Adoption of this standard had no effect on the financial statements as at and for the year ended December 31, 2011.

Consolidated Financial Statements and Non-Controlling Interests

Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of net income between the controlling and non-controlling interests. Changes resulting fromt he adoption of Sections 1601 and 1602 were applied retrospectively.

FUTURE ACCOUNTING CHANGES

U.S. GAAP

The CICA's Accounting Standards Board previously announced that Canadian publicly accountable enterprises were required to adopt International Financial Reporting Standards (IFRS) effective January 1, 2011, with the exception of certain qualifying entities historically using RRA that were given a one year deferral from adopting IFRS. TransCanada is a qualifying entity for these purposes and has deferred the adoption of IFRS. The Company has prepared its consolidated financial statements for 2011 in accordance with CGAAP in order to continue using RRA.

In the application of CGAAP, TransCanada follows specific accounting guidance under U.S. GAAP unique to rate-regulated businesses. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under CGAAP in order to

appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The International Accounting Standards Board has concluded that the development of RRA under IFRS requires further analysis and TransCanada does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As a registrant with the SEC, TransCanada has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The financial reporting impact of TransCanada adopting U.S. GAAP is disclosed in Note 25 of the Consolidated Financial Statements. The differences between CGAAP and U.S. GAAP are consistent with those reported by the Company in its annual "Reconciliation to United States GAAP" as filed in prior years. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting framework.

Fair Value Measurement

In May 2011, the Financial Accounting Standards Board (FASB) issued amended guidance on fair value measurements, which updated some of the existing measurement guidance and included enhanced disclosure requirements under U.S. GAAP. This guidance is effective for interim and annual periods beginning after December 15, 2011. Adoption of these amendments is expected to result in an increase in the qualitative and quantitative disclosures regarding Level 3 measurements, however, the Company expects no material effect on the financial statements.

Intangibles – Goodwill and Other

In September 2011, the FASB issued new guidance on testing goodwill for impairment which simplifies an entity's testing for goodwill impairment under U.S. GAAP by permitting an entity to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount, as a basis for determining whether it is required to proceed to the two-step quantitative goodwill impairment test. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Adoption is not expected to impact the financial statements.

Balance Sheet Offsetting/Netting

In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting agreement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosures regarding financial instruments which are subject to offsetting as described in this amendment.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

(unaudited) *(millions of dollars except per share amounts)*	2011 Fourth	2011 Third	2011 Second	2011 First
Revenues	**2,360**	**2,393**	**2,143**	**2,243**
Net Income Attributable to Common Shares	**375**	**384**	**353**	**415**
Share Statistics				
Net income per share – basic and diluted	**$0.53**	**$0.55**	**$0.50**	**$0.59**
Dividend declared per common share	**$0.42**	**$0.42**	**$0.42**	**$0.42**

(unaudited) *(millions of dollars except per share amounts)*	2010 Fourth	2010 Third	2010 Second	2010 First
Revenues	2,057	2,129	1,923	1,955
Net Income Attributable to Common Shares	269	377	285	296
Share Statistics				
Net income per share – basic and diluted	$0.39	$0.54	$0.41	$0.43
Dividend declared per common share	$0.40	$0.40	$0.40	$0.40

[1] The selected quarterly consolidated financial data has been prepared in accordance with GAAP.

Factors Affecting Quarterly Financial Information

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Oil Pipelines, which consists of the Company's investment in a regulated crude oil pipeline, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, capacity prices and payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that affected EBIT and Net Income in 2011 and 2010 were as follows:

- ***Fourth Quarter 2011*** EBIT excluded net unrealized after-tax gains of $9 million ($9 million pre-tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- ***Third Quarter 2011*** Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of $47 million pre-tax ($33 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Second Quarter 2011*** Natural Gas Pipelines' EBIT included incremental earnings from Guadalajara, which was placed in service in June 2011. Energy's EBIT included incremental earnings from Coolidge, which was placed in service in May 2011. EBIT included net unrealized losses of $5 million pre-tax ($4 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***First Quarter 2011*** Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of Keystone in February 2011. EBIT included net unrealized losses of $17 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Fourth Quarter 2010*** Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after-tax) valuation provision for advances to the APG for the MGP. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of $22 million pre-tax ($12 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Third Quarter 2010*** Natural Gas Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 - 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized gains of $4 million pre-tax ($3 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Second Quarter 2010*** Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of $58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.
- ***First Quarter 2010*** Energy's EBIT included net unrealized losses of $49 million pre-tax ($32 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

FOURTH QUARTER 2011 HIGHLIGHTS

Reconciliation of Non-GAAP Measures

Three months ended December 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines		Oil Pipelines		Energy		Corporate		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Comparable EBITDA	**739**	737	**179**	–	**295**	301	**(29)**	(33)	**1,184**	1,005
Depreciation and amortization	**(251)**	(241)	**(35)**	–	**(100)**	(103)	**(4)**	–	**(390)**	(344)
Comparable EBIT	**488**	496	**144**	–	**195**	198	**(33)**	(33)	**794**	661
Other Income Statement Items										
Comparable interest expense									**(251)**	(173)
Interest expense of joint ventures									**(15)**	(15)
Comparable interest income and other									**8**	61
Comparable income taxes									**(123)**	(103)
Net income attributable to non-controlling interests									**(33)**	(33)
Preferred share dividends									**(14)**	(14)
Comparable Earnings									**366**	384
Specific items (net of tax):										
Valuation provision for MGP									**–**	(127)
Risk management activities[1]									**9**	12
Net Income Attributable to Common Shares									**375**	269

Three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	**2011**	2010
Comparable Interest Income and Other	**8**	61
Specific item:		
Risk management activities[1]	**35**	–
Interest Income and Other	**43**	61
Comparable Income Taxes	**(123)**	(103)
Specific items:		
Valuation provision for MGP	**–**	19
Risk management activities[1]	**–**	(10)
Income Taxes Expense	**(123)**	(94)
Comparable Earnings per Common Share	**$0.52**	$0.55
Specific items (net of tax):		
Valuation provision for MGP	**–**	(0.18)
Risk management activities[1]	**0.01**	0.02
Net Income per Common Share	**$0.53**	$0.39

[1] Three months ended December 31

(unaudited)(millions of dollars)	**2011**	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**(33)**	24
Natural Gas Storage proprietary inventory and derivatives	**7**	(2)
Foreign exchange derivatives	**35**	–
Income taxes attributable to risk management activities	**–**	(10)
Risk Management Activities	**9**	12

Comparable Earnings in fourth quarter 2011 were $366 million or $0.52 per share compared to $384 million or $0.55 per share for the same period in 2010. Comparable Earnings in fourth quarter 2011 excluded net unrealized after-tax gains of $9 million ($9 million pre-tax) (2010 – $12 million after-tax gains; $22 million pre-tax) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in fourth quarter 2010 also excluded the $127 million after tax ($146 million pre-tax) valuation provision on advances to the APG for the MGP.

Comparable Earnings decreased $18 million or $0.03 per share in fourth quarter 2011 compared to the same period in 2010 and included the following:

- decreased Comparable EBIT from Natural Gas Pipelines reflecting lower incentive earnings from the Canadian Mainline and the Alberta System and lower revenues from certain U.S. Pipelines partially offset by incremental earnings from Bison and Guadalajara which were placed in service in January and June 2011, respectively;
- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;
- decreased Comparable EBIT from Energy reflecting lower Bruce A and B volumes and higher operating costs as well as lower realized prices at Bruce B, lower contributions from U.S. Power and lower Natural Gas Storage revenues partially offset by higher realized prices in Western Power and incremental earnings from the start-up of Coolidge in May 2011;
- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service in 2011;
- decreased Comparable Interest Income and Other, reflecting higher realized losses in 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income compared to gains in 2010; and
- increased Comparable Income Taxes due to higher positive income tax adjustments which reduced income taxes in fourth quarter 2010.

TransCanada's Net Income Attributable to Common Shares was $375 million or $0.53 per share in fourth quarter 2011 compared to $269 million or $0.39 per share in fourth quarter 2010.

Natural Gas Pipelines' Comparable EBIT was $488 million in fourth quarter 2011 compared to $496 million for the same period in 2010. Comparable EBIT in 2010 excluded a $146 million pre-tax valuation provision on advances to the APG for the MGP.

Canadian Mainline's net income in fourth quarter 2011 decreased $11 million to $60 million compared to the same period in 2010. This decrease was primarily due to lower incentive earnings, a lower ROE as determined by the NEB of 8.08 per cent in 2011 compared to 8.52 per cent in 2010, as well as a lower average investment base.

The Alberta System's net income of $51 million in fourth quarter 2011 decreased $2 million compared to the same period in 2010. The lower net income was primarily due to lower incentive earnings, partially offset by the positive impact of a higher average investment base.

Canadian Mainline's Comparable EBITDA of $262 million in fourth quarter 2011 decreased $7 million compared to the same period in 2010. The Alberta System's Comparable EBITDA was $185 million in fourth quarter 2011 compared to $194 million for the same period in 2010. EBITDA from the Canadian Mainline and the Alberta System includes net income variances discussed above as well as flow through items which do not affect net income.

ANR's Comparable EBITDA in fourth quarter 2011 was US$73 million compared to US$76 million for the same period in 2010. The decrease in fourth quarter 2011 was primarily due to higher OM&A costs.

GTN's Comparable EBITDA in fourth quarter 2011 from TransCanada's direct investment was US$26 million compared to US$45 million for the same period in 2010. The decrease was primarily due to TransCanada's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011 and lower revenues.

The Bison pipeline was placed in service on January 14, 2011. TransCanada's portion of Comparable EBITDA from its direct investment was US$14 million in fourth quarter 2011. EBITDA reflects TransCanada's 75 per cent direct interest in Bison subsequent to the sale of a 25 per cent interest in Bison to TC PipeLines, LP in May 2011 and 100 per cent prior to that date.

Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US$145 million in fourth quarter 2011 compared to US$128 million for the same period in 2010. The increases were primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011. In addition, lower general, administrative and support costs increased EBITDA in fourth quarter 2011, offset by lower earnings from Great Lakes and Portland.

Natural Gas Pipelines' Depreciation and Amortization increased $10 million in fourth quarter 2011 compared to the same period in 2010 primarily due to the Guadalajara and Bison pipelines being placed in service in 2011.

Natural Gas Pipelines' Business Development Comparable EBITDA losses, resulting from business development expenses, decreased $6 million in fourth quarter 2011 compared to the same period in 2010 primarily due to decreased business development costs related to the Alaska Pipeline Project. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TransCanada's joint venture partner in developing the Alaska Pipeline Project.

Oil Pipelines Comparable EBIT in fourth quarter 2011 was $144 million. At the beginning of February 2011, the Company commenced recording EBITDA for the Wood River/Patoka section of Keystone following the NEB's decision to remove the MOP restriction along the conversion section of the system and completion of the required operational modifications. The Cushing Extension was also placed in service at that time.

Energy's Comparable EBIT was $195 million in fourth quarter 2011 compared to $198 million for the same period in 2010.

Western Power's Comparable EBITDA of $143 million and Power revenues of $294 million in fourth quarter 2011 increased $95 million and $114 million, respectively, compared to the same period in 2010, primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year PPA in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 65 per cent to $76 per MWh in fourth quarter 2011 compared to $46 per MWh in fourth quarter 2010.

Western Power's Comparable EBITDA in fourth quarter 2011 included $57 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA.

Eastern Power's Comparable EBITDA of $87 million and Power Revenues of $125 million in fourth quarter 2011 increased $10 million and $12 million, respectively, compared to the same period in 2010 primarily due to higher Bécancour contractual earnings.

TransCanada's proportionate share of Bruce A's Comparable EBITDA decreased $34 million to a loss of $1 million in fourth quarter 2011 compared to EBITDA of $33 million in fourth quarter 2010. The decrease was primarily due to lower volumes reflecting the November 6, 2011 commencement of the approximate six-month West Shift Plus planned outage as part of the life extension strategy for Unit 3.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $32 million to $34 million in fourth quarter 2011 compared to $66 million in fourth quarter 2010 due to higher operating costs, lower volumes due to increased planned outage days and lower realized prices resulting from the expiry of fixed-price contracts at higher prices.

U.S. Power's Comparable EBITDA in fourth quarter 2011 of US$32 million decreased US$27 million compared to the same period in 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes partially offset by new sales activity in PJM.

Natural Gas Storage's Comparable EBITDA in fourth quarter 2011 was $23 million compared to $37 million for the same period in 2010. The decrease of $14 million in Comparable EBITDA in fourth quarter 2011 was primarily due to decreased proprietary natural gas and third party storage revenues as a result of lower realized natural gas price spreads.

Comparable Interest Expense in fourth quarter 2011 increased $78 million to $251 million from $173 million in fourth quarter 2010. The increase primarily reflected lower capitalized interest upon placing Keystone and other new assets in service in 2011.

Comparable Interest Income and Other in fourth quarter 2011 decreased $53 million to $8 million from income of $61 million in fourth quarter 2010. The decrease in fourth quarter reflected realized losses in 2011 compared to gains in 2010 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable Income Taxes were $123 million in fourth quarter 2011 compared to $103 million for the same period in 2010. The increase was primarily due to higher positive income tax adjustments that reduced income taxes in fourth quarter 2010 compared to 2011.

SHARE INFORMATION

At February 8, 2012, TransCanada had 704 million issued and outstanding common shares, and had 22 million Series 1, 14 million Series 3 and 14 million Series 5 issued and outstanding first preferred shares that are convertible to 22 million Series 2, 14 million Series 4 and 14 million Series 6 preferred shares, respectively. In addition, there were seven million outstanding options to purchase common shares, of which five million were exercisable as at February 8, 2012.

OTHER INFORMATION

Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for 2007 to 2011 is found under the heading "Five Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AFUDC	Allowance for funds used during construction
Alaska Pipeline Project	A proposed natural gas pipeline extending from Prudhoe Bay, Alaska to either Alberta or Valdez, Alaska
Alberta System	A natural gas transmission system in Alberta and B.C.
AOCI	Accumulated Other Comprehensive (Loss)/Income
ANR	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and U.S. midcontinent region to markets located primarily in Wisconsin, Michigan, Illinois, Indiana and Ohio, and regulated underground natural gas storage facilities in Michigan
APG	Aboriginal Pipeline Group
ARO	Asset retirement obligation
ATWACC	After-tax weighted average cost of capital
AUC	Alberta Utilities Commission
B.C.	British Columbia
bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A natural gas pipeline extending from the Powder River Basin in Wyoming to Northern Border in North Dakota
Bison LLC	Bison Pipeline LLC
BPC	BPC Generation Infrastructure Trust
BPRIA	Bruce Power Refurbishment Implementation Agreement
Bruce A	A partnership interest in a nuclear power generation facility consisting of Units 1 to 4 of Bruce Power
Bruce B	A partnership interest in a nuclear power generation facility consisting of Units 5 to 8 of Bruce Power
Bruce Power	A nuclear power generation facility located northwest of Toronto, Ontario (Bruce A and Bruce B, collectively)
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant and the Cancarb thermal carbon black facility in Medicine Hat, Alberta
CAPP	Canadian Association of Petroleum Producers
Carseland	A natural gas-fired cogeneration plant near Carseland, Alberta
Cartier Wind	Five wind farms in Gaspé, Québec, four plus the first phase of the fifth which are operational and phase two of the fifth under construction
CFE	Comisión Federal de Electricidad
CGAAP	Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station in Coolidge, Arizona
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
CSP	Contingent Support Payments
Cushing Extension	A crude oil pipeline extending from Steele City, Nebraska to Cushing, Oklahoma
DB Plans	Defined benefit pension plans
DC Plans	Defined contribution pension plans
DOS	U.S. Department of State
DRP	Dividend Reinvestment and Share Purchase Plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization

Edson	An underground natural gas storage facility near Edson, Alberta
EPA	Environmental Protection Agency (U.S.)
ExxonMobil	Exxon Mobil Corporation
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
Fracking	Multi-stage hydraulic fracturing
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
Grandview	A natural gas-fired cogeneration plant in Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
GTN	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GTN LLC	Gas Transmission Northwest LLC
Guadalajara	A natural gas pipeline in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant in Halton Hills, Ontario
HOEP	Hourly Ontario energy price
HSE	Health, safety and environment
IASB	International Accounting Standards Board
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
ISO	International Organization for Standardization
Keystone	The crude oil pipeline system which extends from Hardisty, Alberta to the U.S. markets and includes the Wood River/Patoka, the Cushing Extension and Keystone XL
Keystone XL	A proposed extension and expansion of the Keystone oil pipeline to the U.S. Gulf Coast, which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the expansion of existing facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometre(s)
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Project (MGP)	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
MMcf/d	Million cubic feet per day
MOP	Maximum operating pressure
MW	Megawatt(s)
MWh	Megawatt hours
NCC	North Central Corridor
NEB	National Energy Board
NEXT	Natural Gas Liquids Extraction Model
NGTL	NOVA Gas Transmission Ltd.
NID	National Interest Determination

North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan to the U.S. Midwest
NYISO	New York Independent System Operator
OCI	Other Comprehensive (Loss)/Income
OM&A	Operating, maintenance and administration
OMERS	Ontario Municipal Employees Retirement System
OPA	Ontario Power Authority
Ocean State Power	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM Interconnection (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
Portland	A natural gas transmission system extending from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A natural gas-fired, combined-cycle power plant in Toronto, Ontario
PPA	Power purchase arrangement
PWU	Power Workers' Union Trust
Ravenswood	A natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant near Redwater, Alberta
Restructuring Proposal	Canadian Mainline 2012 Tolls Application and Restructuring Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
RRA	Rate-regulated accounting
SEC	Securities and Exchange Commission (U.S.)
SEP	Society of Energy Professionals Trust
Sheerness	A coal-fired power generating facility near Hanna, Alberta
Sundance A	A coal-fired power generating facility near Wabamun, Alberta
Sundance B	A coal-fired power generating facility near Wabamun, Alberta
Tamazunchale	A natural gas pipeline in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets in New Hampshire, Vermont and Massachusetts
TC Keystone	TransCanada Keystone Pipeline, LP
Tcf	Trillion cubic feet
TCPL	TransCanada PipeLines Limited
TCPL USA	TransCanada PipeLine USA Ltd.
TQM	A natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with Portland
TransAlta	TransAlta Corporation
TransCanada or the Company	TransCanada Corporation
TransGas	A natural gas transmission system extending from Mariquita to Cali in Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
U.S. GAAP	U.S. generally accepted accounting principles
VaR	Value-at-Risk
Ventures LP	A natural gas transmission system in Alberta supplying natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Wood River/Patoka	A crude oil pipeline extending from Hardisty, Alberta to U.S. markets at Wood River and Patoka in Illinois
Zephyr	A proposed power transmission line project originating in Wyoming and terminating in Nevada

Report of Management

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP) and include amounts that are based on estimates and judgements. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2011 to that in 2010, and highlights significant changes between 2010 and 2009. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal controls over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting are effective as of December 31, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with CGAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.



Russell K. Girling
President and
Chief Executive Officer



Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 13, 2012

Independent Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the accompanying consolidated financial statements of TransCanada Corporation, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, the consolidated statements of income, comprehensive income, accumulated other comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada Corporation as at December 31, 2011 and 2010 and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2011 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 13, 2012

TRANSCANADA CORPORATION
CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2011**	2010	2009
Revenues	**9,139**	8,064	8,181
Operating and Other Expenses			
Plant operating costs and other	**3,449**	3,114	3,213
Commodity purchases resold	**941**	1,017	831
Depreciation and amortization	**1,528**	1,354	1,377
Valuation provision for MGP (Note 9)	**–**	146	–
	5,918	5,631	5,421
Financial Charges/(Income)			
Interest expense (Note 13)	**937**	701	954
Interest expense of joint ventures (Note 14)	**55**	59	64
Interest income and other	**(55)**	(94)	(121)
	937	666	897
Income before Income Taxes	**2,284**	1,767	1,863
Income Tax Expense/(Recovery) (Note 12)			
Current	**209**	(141)	30
Future	**364**	521	357
	573	380	387
Net Income	**1,711**	1,387	1,476
Net Income Attributable to Non-Controlling Interests (Note 16)	**129**	115	96
Net Income Attributable to Controlling Interests	**1,582**	1,272	1,380
Preferred Share Dividends (Note 18)	**55**	45	6
Net Income Attributable to Common Shares	**1,527**	1,227	1,374
Net Income per Common Share (Note 17)			
Basic	**$2.18**	$1.78	$2.11
Diluted	**$2.17**	$1.77	$2.11

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Net Income	**1,711**	1,387	1,476
Other Comprehensive Income/(Loss), Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**113**	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	**(73)**	89	258
Change in fair value of derivative instruments designated as cash flow hedges[3]	**(203)**	(141)	75
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	**127**	(7)	(15)
Other Comprehensive Loss	**(36)**	(239)	(153)
Comprehensive Income	**1,675**	1,148	1,323
Comprehensive Income Attributable to Non-Controlling Interests	**140**	121	103
Comprehensive Income Attributable to Controlling Interests	**1,535**	1,027	1,220
Preferred Share Dividends	**55**	45	6
Comprehensive Income Attributable to Common Shares	**1,480**	982	1,214

(1) Net of income tax recovery of $29 million in 2011 (2010 – $65 million expense; 2009 – $92 million expense).

(2) Net of income tax recovery of $28 million in 2011 (2010 – $37 million expense; 2009 – $124 million expense).

(3) Net of income tax recovery of $104 million in 2011 (2010 – $95 million recovery; 2009 – $7 million expense).

(4) Net of income tax expense of $77 million in 2011 (2010 – $21 million expense; 2009 – $9 million expense).

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED CASH FLOWS

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Cash Generated from Operations			
Net income	**1,711**	1,387	1,476
Depreciation and amortization	**1,528**	1,354	1,377
Future income taxes (Note 12)	**364**	521	357
Employee future benefits funding in excess of expense (Note 20)	**(3)**	(69)	(111)
Valuation provision for MGP (Note 9)	**–**	146	–
Other	**63**	(8)	(19)
	3,663	3,331	3,080
Decrease/(increase) in operating working capital (Note 22)	**310**	(249)	(90)
Net cash provided by operations	**3,973**	3,082	2,990
Investing Activities			
Capital expenditures (Note 4)	**(3,274)**	(5,036)	(5,417)
Deferred amounts and other	**(14)**	(384)	(594)
Acquisitions, net of cash acquired (Note 23)	**–**	–	(902)
Net cash used in investing activities	**(3,288)**	(5,420)	(6,913)
Financing Activities			
Dividends on common and preferred shares (Notes 17 and 18)	**(1,016)**	(754)	(728)
Distributions paid to non-controlling interests	**(131)**	(112)	(100)
Notes payable (repaid)/issued, net	**(218)**	474	(244)
Long-term debt issued, net of issue costs	**1,622**	2,371	3,267
Repayment of long-term debt	**(1,272)**	(494)	(1,005)
Long-term debt of joint ventures issued	**48**	177	226
Repayment of long-term debt of joint ventures	**(102)**	(254)	(246)
Common shares issued, net of issue costs	**58**	26	1,820
Preferred shares issued, net of issue costs	**–**	679	539
Partnership units of subsidiary issued, net of issue costs (Note 23)	**321**	–	193
Net cash (used in)/provided by financing activities	**(690)**	2,113	3,722
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**6**	(8)	(110)
Increase/(Decrease) in Cash and Cash Equivalents	**1**	(233)	(311)
Cash and Cash Equivalents Beginning of year	**764**	997	1,308
Cash and Cash Equivalents End of year	**765**	764	997

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2011**	2010
ASSETS		
Current Assets		
Cash and cash equivalents	**765**	764
Accounts receivable	**1,265**	1,271
Inventories	**416**	425
Other	**1,194**	870
	3,640	3,330
Plant, Property and Equipment (Note 5)	**38,262**	36,244
Goodwill (Note 6)	**3,650**	3,570
Regulatory Assets (Note 7)	**1,405**	1,512
Intangibles and Other Assets (Note 9)	**2,038**	2,138
	48,995	46,794
LIABILITIES		
Current Liabilities		
Notes payable (Note 10)	**1,880**	2,092
Accounts payable	**2,659**	2,272
Accrued interest	**373**	367
Current portion of long-term debt (Note 13)	**935**	894
Current portion of long-term debt of joint ventures (Note 14)	**33**	65
	5,880	5,690
Regulatory Liabilities (Note 7)	**303**	314
Deferred Amounts (Note 11)	**805**	694
Future Income Taxes (Note 12)	**3,788**	3,398
Long-Term Debt (Note 13)	**17,632**	17,028
Long-Term Debt of Joint Ventures (Note 14)	**789**	801
Junior Subordinated Notes (Note 15)	**1,009**	985
	30,206	28,910
EQUITY		
Controlling interests	**17,324**	16,727
Non-controlling interests (Note 16)	**1,465**	1,157
	18,789	17,884
	48,995	46,794

Commitments, Contingencies and Guarantees (Note 24)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:



Russell K. Girling
Director



Kevin E. Benson
Director

TRANSCANADA CORPORATION

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE (LOSS)/INCOME

(millions of dollars)	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at January 1, 2009	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(471)	–	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	258	–	258
Change in fair value of derivative instruments designated as cash flow hedges[3]	–	77	77
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	–	(24)	(24)
Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(180)	–	(180)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	89	–	89
Change in fair value of derivative instruments designated as cash flow hedges[3]	–	(137)	(137)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	–	(17)	(17)
Balance at December 31, 2010	(683)	(194)	(877)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**113**	**–**	**113**
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	**(73)**	**–**	**(73)**
Change in fair value of derivative instruments designated as cash flow hedges[3]	**–**	**(204)**	**(204)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4][5]	**–**	**117**	**117**
Balance at December 31, 2011	**(643)**	**(281)**	**(924)**

(1) Net of income tax recovery of $29 million in 2011 (2010 – $65 million expense; 2009 – $92 million expense).

(2) Net of income tax recovery of $28 million in 2011 (2010 – $37 million expense; 2009 – $124 million expense).

(3) Net of income tax recovery of $104 million in 2011 (2010 – $95 million recovery; 2009 – $7 million expense).

(4) Net of income tax expense of $77 million in 2011 (2010 – $21 million expense; 2009 – $9 million expense).

(5) Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net Income in 2012 are estimated to be $181 million ($116 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED EQUITY

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Common Shares			
Balance at beginning of year	**11,745**	11,338	9,264
Shares issued under dividend reinvestment plan (Note 17)	**202**	378	254
Shares issued on exercise of stock options (Note 17)	**64**	29	28
Proceeds from shares issued under public offering, net of issue costs (Note 17)	**–**	–	1,792
Balance at end of year	**12,011**	11,745	11,338
Preferred Shares			
Balance at beginning of year	**1,224**	539	–
Shares issued under public offering, net of issue costs (Note 18)	**–**	685	539
Balance at end of year	**1,224**	1,224	539
Contributed Surplus			
Balance at beginning of year	**331**	328	279
Issuance of stock options, net of exercises	**1**	3	2
Increased ownership in TC PipeLines, LP (Note 23)	**–**	–	47
Dilution gain from TC PipeLines, LP units issued (Note 23)	**30**	–	–
Balance at end of year	**362**	331	328
Retained Earnings			
Balance at beginning of year	**4,304**	4,186	3,827
Net income attributable to controlling interests	**1,582**	1,272	1,380
Common share dividends	**(1,180)**	(1,109)	(1,015)
Preferred share dividends	**(55)**	(45)	(6)
Balance at end of year	**4,651**	4,304	4,186
Accumulated Other Comprehensive (Loss)/Income			
Balance at beginning of year	**(877)**	(632)	(472)
Other comprehensive loss	**(47)**	(245)	(160)
Balance at end of year	**(924)**	(877)	(632)
Equity Attributable to Controlling Interests	**17,324**	16,727	15,759
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,157**	1,174	1,194
Net income attributable to non-controlling interests			
TC PipeLines, LP	**101**	87	66
Preferred share dividends of subsidiary	**22**	22	22
Portland	**6**	6	8
Other comprehensive income attributable to non-controlling interests	**11**	6	7
Sale of TC PipeLines, LP units			
Proceeds, net of issue costs	**321**	–	193
Decrease in TransCanada's ownership	**(50)**	–	(29)
Distributions to non-controlling interests	**(131)**	(112)	(100)
Foreign exchange and other	**28**	(26)	(187)
Balance at end of year	**1,465**	1,157	1,174
Total Equity	**18,789**	17,884	16,933

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy company which operates in three business segments, Natural Gas Pipelines, Oil Pipelines and Energy, each of which offers different products and services.

Natural Gas Pipelines
The Natural Gas Pipelines segment consists of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities. Through its Natural Gas Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta and northeastern British Columbia (B.C.) (Alberta System);
- a natural gas transmission system extending from producing fields primarily located in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets primarily located in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale); and
- a natural gas transmission system in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco (Guadalajara).

Through its Natural Gas Pipelines segment, TransCanada operates and has ownership interests in natural gas pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in eastern Canada and the northeastern and midwestern United States (U.S.) (Great Lakes);
- a 75 per cent direct ownership interest in a natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border (GTN);
- a 75 per cent direct ownership interest in a natural gas transmission system extending from the Powder River Basin in Wyoming to Northern Border in North Dakota (Bison);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec, to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec and to the Portland system (TQM); and
- a 33.3 per cent controlling interest in TC PipeLines, LP, which has the following ownership interests in pipelines operated by TransCanada:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 69 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 16.7 per cent effective ownership interest through TC PipeLines, LP;
  - a 25 per cent interest in GTN, in which TransCanada has a combined 83.3 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 25 per cent interest in Bison, in which TransCanada has a combined 83.3 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California at the Mexico/California border (North Baja), in which TransCanada has a 33.3 per cent effective ownership interest through TC PipeLines, LP; and
  - a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon, to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 33.3 per cent effective ownership interest through TC PipeLines, LP.

TransCanada does not operate but has ownership interests in natural gas pipelines and natural gas marketing activities as follows:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system extending from Mariquita to Cali in Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

Oil Pipelines
The Oil Pipelines segment consists of a wholly owned and operated crude oil pipeline system extending from Hardisty, Alberta to U.S. markets at Wood River and Patoka in Illinois (Wood River/Patoka), and from Steele City, Nebraska to Cushing, Oklahoma (Cushing Extension). The Company plans to expand and extend this oil pipeline system to the U.S. Gulf Coast (Keystone XL) which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone.

The proposed Marketlink projects will connect additional oil supply sourced from U.S. basins to facilities which form part of Keystone XL and provide transportation services accessing refining markets in the Cushing, Oklahoma region and the U.S. Gulf Coast. The proposed Bakken Marketlink project would transport U.S. crude oil from Baker, Montana to Cushing and the proposed Cushing Marketlink project would transport crude oil from Cushing to Port Arthur and Houston, Texas.

Energy
The Energy segment primarily consists of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- a natural gas-fired, combined-cycle power plant in Halton Hills, Ontario (Halton Hills);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired peaking facility located near Phoenix, Arizona (Coolidge);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine (Kibby Wind);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a waste-heat fuelled power plant and the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas storage facility near Edson, Alberta (Edson); and
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

TransCanada does not operate but has ownership interests in power generation plants as follows:

- a 48.8 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau, Carleton, Montagne-Sèche and Gros-Morne wind farms in Gaspé, Québec (Cartier Wind). All wind farms are in service with the exception of the second phase of Gros-Morne, which is currently under construction; and
- a 50 per cent interest in a natural gas-fired, combined-cycle plant in Toronto, Ontario (Portlands Energy).

TransCanada also has long-term power purchase arrangements (PPA) in place for:

- 756 megawatts (MW) of generating capacity from the Sheerness power facility near Hanna, Alberta;
- a 50 per cent interest in ASTC Power Partnership, which has a PPA in place for 100 per cent of the production from the Sundance B power facilities near Wabamun, Alberta; and
- 100 per cent of the production of the Sundance A power facilities near Wabamun, Alberta.

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP) as discussed further in Note 3. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

In Canada, regulated natural gas pipelines and oil pipelines are subject to the authority of the National Energy Board (NEB) of Canada. In the U.S., natural gas pipelines, oil pipelines and regulated storage assets are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). The Company's natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in these rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses under CGAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls.

The NEB and the FERC regulate construction and operations of Keystone; however, RRA is not applicable to Keystone and, as a result, the regulators' decisions regarding operations and tolls on Keystone generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Canadian Natural Gas Pipelines

Revenues from Canadian natural gas pipelines subject to rate regulation are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include an appropriate return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are periodically subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than otherwise required to account for the incentives. Revenues are recognized on firm contracted capacity over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to the NEB's decision on rates for a specified period reflect the NEB's last approved return on equity. Adjustments to revenue are recorded when the NEB decision is received.

U.S. Natural Gas Pipelines

Revenues from U.S. natural gas pipelines subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's U.S. natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made.

Oil Pipelines

The Company's oil pipeline revenues are generated from the transportation of crude oil and contractual arrangements for committed capacity. Transportation revenues are recognized in the period the product is delivered. Transportation revenues are based on actual volumes and reflect adjustments to rates to reflect under-recovery or over-recovery of certain transportation costs. Revenues earned from contracted capacity arrangements are recognized in the period in which the capacity is made available.

Energy

i) Power

Revenues from the Company's power business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, which are earned monthly, and revenues earned through the use of energy derivative contracts. The accounting for energy derivative contracts is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory in storage, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's Cash and Cash Equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts and fuel, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory in storage at fair value, measured using a weighted average of forward prices for the following four months, which represents the estimated withdrawal period, less selling costs. To record inventory at fair value, TransCanada has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of proprietary natural gas inventory in storage are reflected in Inventories and in Revenues.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates. The cost of overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets in Plant, Property and Equipment. The equity component of AFUDC is a non-cash item. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Oil Pipelines

Plant, property and equipment for oil pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from approximately two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction. When oil pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy

Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other equipment is depreciated at various rates. The cost of overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When Energy retires plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Corporate

Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as plant, property and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate the asset might be impaired. An initial test is done by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The PPAs under which TransCanada buys power are accounted for as operating leases. The initial payments for the Company's PPAs were recognized in Intangibles and Other Assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. A portion of these PPAs has been subleased to third parties under terms and conditions similar to the PPAs. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Stock Options

TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. The contractual life of options granted in 2003 and thereafter and of options granted prior to 2003 is seven years and 10 years, respectively. The Company uses the Black-Scholes model to determine fair value of the options on their grant date. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration, and if not previously vested, upon resignation or retirement of the option holder or upon termination of the option holder's employment. Stock options become null and void upon forfeiture. The Company records compensation expense over the three-year vesting period, assuming a 15 per cent forfeiture rate, with an offset to Contributed Surplus. This charge is reflected in the Corporate segment. Upon exercise of stock options, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The Company uses the liability method of accounting for income taxes. This method requires the recognition of future income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at the period-end exchange rates and revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive Income/(Loss) (OCI).

Exchange gains and losses on monetary assets and liabilities are recorded in income except for exchange gains and losses on the foreign currency debt related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at fair value. Where possible, fair value is determined by reference to quoted market prices. In the absence of quoted prices, other pricing and valuation techniques are used that maximize the use of observable data. The entity's own credit risk and the credit risk of its counterparties are taken into consideration when measuring the fair value of financial assets and financial liabilities. Subsequent measurement of financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments, and loans and receivables. Financial liabilities are classified as held for trading or as other financial liabilities.

Held for trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading when it is entered into with the intention of generating a profit. The Company has not designated any of its non-derivative financial assets or liabilities as held for trading. Commodity held for trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Realized gains and losses on derivatives used to manage the Company's operating assets are presented on a net basis in Revenues. Changes in the fair value of interest rate held for trading instruments are recorded in Interest Expense and changes in the fair value of foreign exchange rate held for trading instruments are recorded in Interest Income and Other. Realized gains and losses are included in the same financial statement category as their underlying position upon settlement of the financial instrument.

The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in any of the other three classifications. TransCanada's available for sale financial instruments include fixed-income securities held for self-insurance.

These instruments are accounted for initially at their fair value and changes to fair value are recorded through OCI. Gains and losses from the settlement of available for sale financial assets is included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as loans and receivables and are measured at amortized cost using the effective interest method, net of any impairment. The Company's loans and receivables include trade accounts receivable, interest-bearing and non-interest-bearing third-party loans, and notes receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest costs are included in Interest Expense and in Interest Expense of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the balance sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected normal purchase, sale or usage requirements. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are recorded separately, they are included in Net Income.

The recognition of gains and losses on the derivatives used to manage the Canadian natural gas regulated pipelines exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of RRA are deferred in Regulatory Assets or Regulatory Liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair value of its portion of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Documentation is prepared at the inception of each hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company performs an assessment of effectiveness at the inception of the contract and at each reporting date. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination or cancellation.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Interest Expense, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive (Loss)/Income (AOCI) are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it is probable the anticipated transaction will not occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation in Canada. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities. When the hedges are settled, the realized gains or losses are refunded to or collected from the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its net investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are utilized. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and recorded in Revenues.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-employment benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-employment benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 3 ACCOUNTING CHANGES

Changes in Accounting Policies for 2011

Business Combinations

Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, expensing of acquisition costs, and increased disclosure. Adoption of this standard had no effect on the financial statements as at and for the year ended December 31, 2011.

Consolidated Financial Statements and Non-Controlling Interests
Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of net income between the controlling and non-controlling interests. Changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

United States Generally Accepted Accounting Principles
The CICA's Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises were required to adopt International Financial Reporting Standards (IFRS) effective January 1, 2011, with the exception of certain qualifying entities historically using RRA that were given a one year deferral from adopting IFRS. TransCanada is a qualifying entity for these purposes and has deferred the adoption of IFRS. The Company has prepared its consolidated financial statements for 2011 in accordance with CGAAP in order to continue using RRA.

In the application of CGAAP, TransCanada follows specific accounting guidance under United States generally accepted accounting principles (U.S. GAAP) unique to rate-regulated businesses. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under CGAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The International Accounting Standards Board has concluded that the development of RRA under IFRS requires further analysis and TransCanada does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As a registrant with the U.S. Securities and Exchange Commission, TransCanada has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The financial reporting impact of TransCanada adopting U.S. GAAP is disclosed in Note 25 "United States Accounting Principles and Reporting". The differences between CGAAP and U.S. GAAP are consistent with those reported by the Company in its annual "Reconciliation to United States GAAP" as filed in prior years. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting framework.

Fair Value Measurement
In May 2011, the Financial Accounting Standards Board (FASB) issued amended guidance on fair value measurements, which updated some of the existing measurement guidance and included enhanced disclosure requirements under U.S. GAAP. This guidance is effective for interim and annual periods beginning after December 15, 2011. Adoption of these amendments is expected to result in an increase in the qualitative and quantitative disclosures regarding Level 3 measurements, however, the Company expects no material effect on the financial statements.

Intangibles – Goodwill and Other
In September 2011, the FASB issued new guidance on testing goodwill for impairment which simplifies an entity's testing for goodwill impairment under U.S. GAAP by permitting an entity to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount, as a basis for determining whether it is required to proceed to the two-step quantitative goodwill impairment test. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Adoption is not expected to impact the financial statements.

Balance Sheet Offsetting/Netting
In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting agreement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosures regarding financial instruments which are subject to offsetting as described in this amendment.

NOTE 4 SEGMENTED INFORMATION

Commencing in February 2011, TransCanada began recording earnings related to the Wood River/Patoka and Cushing Extension sections of Keystone.

During 2010, the Company began recognizing a separate segment, Oil Pipelines. Also during that period, Wood River/Patoka began delivering oil but at reduced operating pressure due to regulatory restrictions. As a result, the Company continued to classify Wood River/Patoka as under construction along with the Cushing Extension and Keystone XL. At December 31, 2010, Keystone capital costs were net of $99 million of operating cash flows relating to Wood River/Patoka.

Year ended December 31, 2011 (millions of dollars)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,500**	**827**	**3,812**	**–**	**9,139**
Plant operating costs and other	**(1,533)**	**(240)**	**(1,590)**	**(86)**	**(3,449)**
Commodity purchases resold	**–**	**–**	**(941)**	**–**	**(941)**
Depreciation and amortization	**(986)**	**(130)**	**(398)**	**(14)**	**(1,528)**
	1,981	**457**	**883**	**(100)**	**3,221**
Interest expense					**(937)**
Interest expense of joint ventures					**(55)**
Interest income and other					**55**
Income tax expense					**(573)**
Net Income					**1,711**
Net Income Attributable to Non-Controlling Interests					**(129)**
Net Income Attributable to Controlling Interests					**1,582**
Preferred Share Dividends					**(55)**
Net Income Attributable to Common Shares					**1,527**

Year ended December 31, 2010 (millions of dollars)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Revenues	4,373	–	3,691	–	8,064
Plant operating costs and other[1]	(1,458)	–	(1,557)	(99)	(3,114)
Commodity purchases resold	–	–	(1,017)	–	(1,017)
Depreciation and amortization	(977)	–	(377)	–	(1,354)
Valuation provision for MGP	(146)	–	–	–	(146)
	1,792	–	740	(99)	2,433
Interest expense					(701)
Interest expense of joint ventures					(59)
Interest income and other					94
Income tax expense					(380)
Net Income					1,387
Net Income Attributable to Non-Controlling Interests					(115)
Net Income Attributable to Controlling Interests					1,272
Preferred Share Dividends					(45)
Net Income Attributable to Common Shares					1,227

[1] In 2010, Natural Gas Pipelines included $17 million of general, administrative and support costs relating to Keystone.

Year ended December 31, 2009 (millions of dollars)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Revenues	4,729	–	3,452	–	8,181
Plant operating costs and other	(1,607)	–	(1,489)	(117)	(3,213)
Commodity purchases resold	–	–	(831)	–	(831)
Depreciation and amortization	(1,030)	–	(347)	–	(1,377)
	2,092	–	785	(117)	2,760
Interest expense					(954)
Interest expense of joint ventures					(64)
Interest income and other					121
Income tax expense					(387)
Net Income					1,476
Net Income Attributable to Non-Controlling Interests					(96)
Net Income Attributable to Controlling Interests					1,380
Preferred Share Dividends					(6)
Net Income Attributable to Common Shares					1,374

TOTAL ASSETS

December 31 (millions of dollars)	**2011**	2010
Natural Gas Pipelines	**23,669**	23,629
Oil Pipelines	**9,439**	8,501
Energy	**14,276**	12,966
Corporate	**1,611**	1,698
	48,995	46,794

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Revenues[1]			
Canada – domestic	**4,836**	4,368	5,079
Canada – export	**1,087**	838	756
United States and other	**3,216**	2,858	2,346
	9,139	8,064	8,181

[1] Revenues are attributed based on the country in which the product or service originated.

December 31 (millions of dollars)	**2011**	2010
Plant, Property and Equipment		
Canada	**22,349**	21,561
United States and other	**15,913**	14,683
	38,262	36,244

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Natural Gas Pipelines	**935**	1,196	965
Oil Pipelines	**1,204**	2,696	2,939
Energy	**1,127**	1,129	1,487
Corporate	**8**	15	26
	3,274	5,036	5,417

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2011			2010		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Natural Gas Pipelines[1]						
Canadian Mainline						
Pipeline	**8,785**	**4,958**	**3,827**	8,768	4,730	4,038
Compression	**3,362**	**1,765**	**1,597**	3,385	1,651	1,734
Metering and other	**383**	**175**	**208**	381	167	214
	12,530	**6,898**	**5,632**	12,534	6,548	5,986
Under construction	**28**	**–**	**28**	14	–	14
	12,558	**6,898**	**5,660**	12,548	6,548	6,000
Alberta System						
Pipeline	**6,701**	**3,062**	**3,639**	6,528	2,917	3,611
Compression	**1,778**	**1,109**	**669**	1,707	1,045	662
Metering and other	**931**	**409**	**522**	909	378	531
	9,410	**4,580**	**4,830**	9,144	4,340	4,804
Under construction	**368**	**–**	**368**	71	–	71
	9,778	**4,580**	**5,198**	9,215	4,340	4,875
ANR						
Pipeline	**858**	**47**	**811**	858	96	762
Compression	**510**	**72**	**438**	507	74	433
Metering and other	**576**	**81**	**495**	548	74	474
	1,944	**200**	**1,744**	1,913	244	1,669
Under construction	**20**	**–**	**20**	7	–	7
	1,964	**200**	**1,764**	1,920	244	1,676
Joint Ventures and Others						
GTN	**1,612**	**370**	**1,242**	1,557	319	1,238
Great Lakes	**1,581**	**741**	**840**	1,540	698	842
Foothills	**1,630**	**1,005**	**625**	1,650	975	675
Northern Border	**1,288**	**644**	**644**	1,252	608	644
Other[2]	**3,132**	**720**	**2,412**	2,913	633	2,280
	9,243	**3,480**	**5,763**	8,912	3,233	5,679
	33,543	**15,158**	**18,385**	32,595	14,365	18,230
Oil Pipelines						
Keystone						
Pipeline	**4,904**	**80**	**4,824**	–	–	–
Pumping equipment	**1,502**	**38**	**1,464**	–	–	–
Tanks and other	**548**	**15**	**533**	–	–	–
	6,954	**133**	**6,821**	–	–	–
Under construction[3]	**2,433**	**–**	**2,433**	8,184	–	8,184
	9,387	**133**	**9,254**	8,184	–	8,184
Energy						
Nuclear[4]	**1,712**	**630**	**1,082**	1,586	536	1,050
Natural Gas – Ravenswood	**1,799**	**220**	**1,579**	1,710	144	1,566
Natural Gas – Other[5]	**3,337**	**708**	**2,629**	2,767	588	2,179
Hydro	**620**	**90**	**530**	599	69	530
Wind[6]	**843**	**88**	**755**	659	65	594
Natural Gas Storage	**454**	**78**	**376**	423	67	356
Other	**163**	**94**	**69**	160	96	64
	8,928	**1,908**	**7,020**	7,904	1,565	6,339
Under construction – Nuclear[7]	**3,217**	**–**	**3,217**	2,678	–	2,678
Under construction – Other[8]	**308**	**–**	**308**	728	–	728
	12,453	**1,908**	**10,545**	11,310	1,565	9,745
Corporate	**129**	**51**	**78**	125	40	85
	55,512	**17,250**	**38,262**	52,214	15,970	36,244

(1) In 2011, the Company capitalized $23 million (2010 – $35 million) relating to the equity portion of AFUDC for natural gas pipelines with a corresponding amount recorded in Interest Income and Other.

(2) Includes in service assets of Bison, Tamazunchale, Portland, Iroquois, TQM, North Baja, Guadalajara, Tuscarora and Ventures LP, and under construction amounts of $33 million (2010 – $899 million). Bison went in service in January 2011 and Guadalajara went in service in June 2011.

(3) Includes $2.4 billion at December 31, 2011 (2010 – $1.4 billion) relating to Keystone XL which remains subject to regulatory approvals.

(4) Includes assets under capital lease relating to Bruce Power.

(5) Includes facilities with long-term PPAs that are accounted for as operating leases, including Coolidge which went in service in May 2011. The cost and accumulated depreciation of these facilities were $605 million and $34 million, respectively, at December 31, 2011 (2010 – $89 million and $19 million, respectively). Revenues of $53 million were recognized in 2011 (2010 and 2009 – $15 million) through the sale of electricity under the related PPAs.

(6) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011.

(7) Nuclear assets under construction primarily includes expenditures for the refurbishment and restart of Bruce A.

(8) Other Energy assets under construction at December 31, 2011 includes amounts for the second phase of the Gros-Morne wind farm (Cartier Wind).

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

(millions of dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2010	2,891	872	3,763
Foreign exchange rate changes	(144)	(49)	(193)
Balance at December 31, 2010	2,747	823	3,570
Foreign exchange rate changes	**62**	**18**	**80**
Balance at December 31, 2011	**2,809**	**841**	**3,650**

NOTE 7 RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's Canadian regulated pipelines are typically set through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated natural gas pipelines have generally been subject to a cost-of-service model wherein forecasted costs, including a return on capital, determine the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Alberta System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

In October 2009, the NEB issued a decision that its RH-2-94 Decision, which established a rate of return on common equity (ROE) formula that had formed the basis of determining tolls for natural gas pipelines under NEB jurisdiction since 1995, would no longer be in effect. The decision meant a company's cost of capital will now be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. The decision has affected TransCanada's NEB regulated pipelines. However, the Canadian Mainline continues to base its return on the RH-2-94 ROE formula in accordance with the terms of the current Canadian Mainline tolls settlement, described below.

Canadian Mainline
In 2011, the Canadian Mainline operated under its five-year settlement, which was effective January 1, 2007 to December 31, 2011. The Canadian Mainline's cost of capital for establishing tolls under the settlement reflects ROE as determined by the NEB's RH-2-94 ROE formula on a deemed common equity of 40 per cent. The allowed ROE in 2011 for the Canadian Mainline was 8.08 per cent (2010 – 8.52 per cent). The balance of the capital structure is comprised of short and long-term debt.

The settlement also established the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. Variances between actual OM&A costs and those agreed to in the settlement accrued fully to TransCanada from 2007 to 2009. Variances in OM&A costs were shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements. In 2009, the NEB approved an adjustment account, which was established to reduce tolls in 2010 under a settlement with stakeholders. In accordance with the terms of the settlement, balances in the adjustment account are to be amortized at the composite depreciation rate and included in tolls beginning in 2011.

In September 2011, the NEB approved the Canadian Mainline's interim tolls as final for 2011, including TransCanada's proposal to carry forward any revenue variances into the determination of 2012 tolls. However, the NEB determined that TransCanada's inclusion of certain elements in the proposed 2011 revenue requirement derived in accordance with the 2007-2011 settlement will be examined with TransCanada's 2012-2013 Tolls Application before a final decision is rendered on the 2011 revenue requirement.

Alberta System
In September 2010, the NEB approved the Alberta System's 2010-2012 Revenue Requirement Settlement Application. The settlement provides for a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixes certain annual OM&A costs during the term. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada. All other costs are treated on a flow-through basis.

Foothills
In June 2010, TransCanada reached an agreement to establish a cost of capital for Foothills that reflects a 9.70 per cent ROE on a deemed common equity of 40 per cent for 2010 to 2012. A component of OM&A is fixed, subject to the terms of the B.C System/Foothills Integration Settlement, and variances between actual and fixed amounts were shared with customers up to and including June 2011 when the OM&A savings cap was reached.

TQM
In November 2010, the NEB approved TQM's multi-year settlement with its interested parties regarding its annual revenue requirements for 2010 to 2012. As part of the settlement, the annual revenue requirement comprises fixed and flow-through components. The fixed component includes certain OM&A costs, return on rate base, depreciation and municipal taxes. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations
TransCanada's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* (NGA) and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR
ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company, which is another FERC regulated entity that owns and operates storage fields in Michigan, has rates that were established pursuant to a settlement approved by the FERC that were effective beginning in 1990. ANR Storage Company is currently subject to a review, initiated by the FERC in late 2011, of its existing rates.

In 2011, ANR Pipeline Company filed an application with the FERC to sell its offshore Gulf of Mexico assets and certain related onshore facilities to its wholly owned subsidiary, TC Offshore LLC. At the same time, TC Offshore LLC requested authorization from the FERC to acquire, own and operate those facilities under the FERC's regulations. These filings are currently pending before the FERC and a decision is expected in second or third quarter 2012.

GTN
GTN is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2008. That settlement required GTN to file a rate case within seven years of the effective date. In November 2011, the FERC approved, without modification, GTN's new settlement with its shippers regarding GTN's rates, terms and

conditions of service which will become effective January 1, 2012. This new settlement provides for a four year moratorium during which GTN and the settling parties are prohibited from taking certain actions under the NGA, including filings to adjust rates. GTN is required to file for new rates to be effective January 1, 2016.

Great Lakes
Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. Great Lakes rates were established pursuant to a settlement approved by the FERC in July 2010. The settlement included a moratorium on participants and customers from initiating a NGA Section 5 rate case to adjust rates prior to November 1, 2012. In addition, Great Lakes is required to file a NGA Section 4 general rate case no later than November 1, 2013.

Bison
Bison is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. Bison is permitted to discount or negotiate these rates on a non-discriminatory basis. Bison's rates were established pursuant to its initial certificate to construct and operate the pipeline that initiated service in January 2011.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2011**	2010	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Future income taxes[1]	**1,178**	1,256	n/a
Operating and debt-service regulatory assets[2]	**172**	237	1
Adjustment account[3]	**82**	85	31
Other[4]	**151**	174	n/a
	1,583	1,752	
Less: Current portion included in Other Current Assets	**178**	240	
	1,405	1,512	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**184**	200	1 - 18
Operating and debt-service regulatory liabilities[2]	**135**	98	1
Other[4]	**123**	150	n/a
	442	448	
Less: Current portion included in Accounts Payable	**139**	134	
	303	314	

(1) These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

(2) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2011 would have been $102 million higher (2010 – $51 million higher) had these amounts not been recorded as regulatory assets and liabilities.

(3) A regulatory adjustment account of $85 million was established and agreed upon by Canadian Mainline stakeholders to reduce tolls in 2010. Amortization of the adjustment account commenced in 2011 at the composite depreciation rate.

(4) Pre-tax operating results in 2011 would have been $4 million lower (2010 – $28 million higher) had these amounts not been recorded as regulatory assets and liabilities.

(5) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, CGAAP would have required the inclusion of these unrealized gains or losses in Net Income.

NOTE 8 JOINT VENTURE INVESTMENTS

(millions of dollars)	Ownership Interest as at December 31, 2011	TransCanada's Proportionate Share				
		Income before Income Taxes Year Ended December 31			Net Assets December 31	
		2011	2010	2009	**2011**	2010
Natural Gas Pipelines						
Northern Border[1]		**75**	69	47	**429**	389
Iroquois	44.5%	**40**	40	44	**181**	181
TQM	50.0%	**17**	16	22	**82**	85
Other	Various	**14**	16	17	**32**	36
Energy						
Bruce A	48.8%	**33**	35	3	**3,537**	3,011
Bruce B	31.6%	**77**	138	236	**493**	505
ASTC Power Partnership	50.0%	**84**	41	34	**58**	61
Portlands Energy	50.0%	**33**	33	24	**313**	335
CrossAlta	60.0%	**23**	45	55	**81**	73
Cartier Wind[2]	62.0%	**27**	24	26	**518**	355
Other	Various	**7**	8	4	**50**	42
		430	465	512	**5,774**	5,073

[1] The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2011, TransCanada had an ownership interest in TC PipeLines, LP of 33.3 per cent (2010 and 2009 – 38.2 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 16.7 per cent (2010 and 2009 – 19.1 per cent).

[2] TransCanada proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The Montagne-Sèche project and phase one of the Gros-Morne wind farm were placed in service in November 2011.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Income			
Revenues	**1,668**	1,643	1,632
Plant operating costs and other	**(974)**	(913)	(856)
Depreciation and amortization	**(212)**	(208)	(196)
Interest expense and other	**(52)**	(57)	(68)
Proportionate Share of Joint Venture Income before Income Taxes	**430**	465	512

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Cash Flows			
Operating activities	**733**	678	455
Investing activities	**(827)**	(722)	(651)
Financing activities[1]	**99**	51	130
Effect of foreign exchange rate changes on cash and cash equivalents	**2**	(1)	(17)
Proportionate Share of Increase/(Decrease) in Cash and Cash Equivalents of Joint Ventures	**7**	6	(83)

[1] Financing activities included cash outflows resulting from distributions paid to TransCanada of $486 million in 2011 (2010 – $475 million; 2009 – $252 million) and cash inflows resulting from capital contributions paid by TransCanada of $633 million in 2011 (2010 – $601 million; 2009 – $864 million).

December 31 (millions of dollars)	**2011**	2010
Balance Sheet		
Cash and cash equivalents	**111**	104
Other current assets	**433**	438
Plant, property and equipment	**6,430**	5,704
Intangibles and other assets/(deferred amounts), net	**26**	14
Current liabilities	**(437)**	(387)
Long-term debt	**(789)**	(801)
Future income taxes	**–**	1
Proportionate Share of Net Assets of Joint Ventures	**5,774**	5,073

NOTE 9 INTANGIBLES AND OTHER ASSETS

December 31 (millions of dollars)	**2011**	2010
Employee benefit plans (Note 20)	**499**	473
PPAs[1]	**482**	539
Loans and advances[2]	**224**	241
Fair value of derivative contracts (Note 21)	**213**	374
Future income tax assets (Note 12)	**133**	112
Margin calls	**104**	76
Equity investments[3]	**41**	78
Other	**342**	245
	2,038	2,138

(1) The following amounts related to PPAs are included in Intangibles and Other Assets:

	2011			2010		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
Sheerness	**585**	**234**	**351**	585	195	390
Sundance A	**225**	**148**	**77**	224	133	91
Sundance B	**110**	**56**	**54**	110	52	58
PPAs	**920**	**438**	**482**	919	380	539

Amortization expense for the PPAs was $58 million for the year ended December 31, 2011 (2010 and 2009 – $58 million). The expected annual amortization expense in each of the next five years is $58 million. The $77 million net book value related to Sundance A is expected to remain fully recoverable under the terms of the PPA regardless of the outcome of the arbitration process discussed in Note 24 "Commitments, Contingencies and Guarantees".

(2) As at December 31, 2011, TransCanada held a $265 million (2010 – $281 million) note receivable from the seller of Ravenswood which bears interest at 6.75 per cent and matures in 2039. This represents the long–term portion of that note.

(3) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

Advances to Aboriginal Pipeline Group

The Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TransCanada have an agreement governing TransCanada's role in the Mackenzie Gas Project (MGP). The project, if successful, would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories to the northern border of Alberta, where it would connect to the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs.

The MGP proponents continue to pursue the required regulatory approvals for the project and the Canadian government's support of an acceptable fiscal framework. In December 2010, the NEB released a decision granting approval of the project's application for a Certificate of Public Convenience and Necessity. The approval contained 264 conditions including the requirement to file an updated cost estimate and report on the decision to construct by the end of 2013 and, further, that construction must commence by December 31, 2015.

At December 31, 2010, due to uncertainty with respect to the project's ultimate commercial structure and fiscal framework, the timeframes under which the project would proceed and if and when the Company's advances to the APG will be repaid, a valuation provision of $146 million was recorded on the loan to the APG. Amounts advanced to the APG in furtherance of the MGP in 2011 have been expensed.

NOTE 10 NOTES PAYABLE

	2011		2010	
	Outstanding December 31	**Weighted Average Interest Rate per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate per Annum at December 31
	(millions of dollars)		(millions of dollars)	
Canadian dollars	**483**	**1.2%**	601	1.2%
U.S. dollars (2011 – US$1,373; 2010 – US$1,499)	**1,397**	**0.5%**	1,491	0.7%
	1,880		2,092	

Notes payable consists of commercial paper issued by TransCanada PipeLines Limited (TCPL), TransCanada PipeLine USA Ltd. (TCPL USA) and TransCanada Keystone Pipeline, LP (TC Keystone) and draws on line-of-credit and demand facilities.

At December 31, 2011, total committed revolving and demand credit facilities of $5.1 billion were available. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving, extendible TCPL credit facility, maturing October 2016. The facility was fully available at December 31, 2011. The cost to maintain the credit facility was $2 million in 2011 (2010 – $2 million; 2009 – $2 million);
- a US$300 million committed, syndicated, revolving TCPL USA credit facility, guaranteed by TransCanada and maturing February 2013. At December 31, 2011, this facility was fully available. This facility is part of an initial US$1.0 billion credit facility discussed in Note 13. The cost to maintain the credit facility was $1 million in 2011 (2010 – $1 million; 2009 – $1 million);
- a US$1.0 billion committed, syndicated, revolving, extendible TC Keystone credit facility, guaranteed by TCPL and TCPL USA and maturing November 2012. The facility was fully available at December 31, 2011. The cost to maintain the credit facility was $4 million in 2011 (2010 – $5 million; 2009 – $2 million);
- a US$1.0 billion committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL and maturing October 2012. At December 31, 2011, this facility was fully available. The cost to maintain the credit facility was $4 million in 2011 (2010 – $4 million); and
- demand lines totalling $802 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2011, the Company had used approximately $468 million of these demand lines for letters of credit.

NOTE 11 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2011**	2010
Fair value of derivative contracts (Note 21)	**352**	282
Employee benefit plans (Note 20)	**285**	251
Asset retirement obligations (Note 19)	**68**	65
Other	**100**	96
	805	694

NOTE 12 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Current			
Canada	**211**	29	(70)
Foreign	**(2)**	(170)	100
	209	(141)	30
Future			
Canada	**138**	170	339
Foreign	**226**	351	18
	364	521	357
Income Tax Expense	**573**	380	387

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Canada	**1,175**	798	1,095
Foreign	**1,109**	969	768
Income before Income Taxes	**2,284**	1,767	1,863

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Income before Income Taxes	**2,284**	1,767	1,863
Federal and provincial statutory tax rate	**26.5%**	28.0%	29.0%
Expected income tax expense	**605**	495	540
Income tax differential related to regulated operations	**42**	8	39
Lower effective foreign tax rates	**(5)**	(36)	(63)
Tax rate and legislative changes	**–**	–	(30)
Income from equity investments and non-controlling interests	**(45)**	(40)	(37)
Other	**(24)**	(47)	(62)
Actual Income Tax Expense	**573**	380	387

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2011**	2010
Future Income Tax Assets		
Operating loss carryforwards	**905**	494
Financial instruments	**163**	108
Other post-employment benefits	**74**	75
Deferred amounts	**49**	42
Other	**141**	153
	1,332	872
Future Income Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and PPAs	**4,164**	3,439
Taxes on future revenue requirement	**299**	321
Unrealized foreign exchange gains on long-term debt	**133**	161
Pension benefits	**94**	96
Other	**107**	77
	4,797	4,094
Net Future Income Tax Liabilities	**3,465**	3,222

The above future tax amounts have been classified in the Consolidated Balance Sheet as follows:

December 31 (millions of dollars)	**2011**	2010[1]
Future Income Tax Assets		
Other current assets	**265**	93
Intangibles and other assets (Note 9)	**133**	112
	398	205
Future Income Tax Liabilities		
Accounts payable	**75**	29
Future income taxes	**3,788**	3,398
	3,863	3,427
Net Future Income Tax Liabilities	**3,465**	3,222

[1] Amounts relating to deferred tax assets and liabilities as at December 31, 2010 have been reclassified to conform with current year's presentation.

At December 31, 2011, the Company has recognized the benefit of unused non-capital loss carryforwards of $450 million (2010 – $42 million) for federal and provincial purposes in Canada, which expire from 2014 to 2031.

At December 31, 2011, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,119 million (2010 – US$1,320 million) for federal purposes in the U.S., which expire from 2028 to 2031.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased at December 31, 2011 by approximately $136 million (2010 – $105 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax refunds of $84 million, net of payments made, were received in 2011 (2010 – payments, net of refunds, of $53 million; 2009 – payments, net of refunds, of $83 million).

NOTE 13 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars)	Maturity Dates	2011 Outstanding December 31	2011 Interest Rate[1]	2010 Outstanding December 31	2010 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2014 to 2020	**873**	**10.9%**	872	10.9%
U.S. dollars (2011 and 2010 – US$600)	2012 to 2021	**608**	**9.5%**	595	9.5%
Medium-Term Notes					
Canadian dollars	2013 to 2041	**4,537**	**5.9%**	4,150	6.2%
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$8,626)[2]	2013 to 2040	**8,693**	**5.7%**	8,490	5.7%
		14,711		14,107	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2014 to 2024	**386**	**11.5%**	390	11.4%
U.S. dollars (2011 and 2010 – US$375)	2012 to 2023	**380**	**8.2%**	371	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	502	7.4%
U.S. dollars (2011 and 2010 – US$33)	2026	**33**	**7.5%**	32	7.5%
		1,301		1,295	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2011 – US$500; 2010 – US$700)	2012	**509**	**0.6%**	696	0.5%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$432)	2021 to 2025	**438**	**8.9%**	429	8.9%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$325)	2015 to 2035	**329**	**5.5%**	322	5.5%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2011 – US$363; 2010 – US$483)	2016	**366**	**1.6%**	480	0.8%
Senior Unsecured Notes					
U.S. dollars (2011 – US$350)	2021	**356**	**4.7%**	–	–
		722		480	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2011 – US$373; 2010 – US$392)	2018 to 2030	**379**	**7.8%**	389	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2011 – US$30; 2010 – US$31)	2012 to 2017	**31**	**4.4%**	31	4.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. dollars (2011 – US$147; 2010 – US$164)	2018	**147**	**6.1%**	161	6.1%
OTHER					
Senior Notes					
U.S. dollars (2011 – nil; 2010 – US$12)		**–**	**–**	12	7.3%
		18,567		17,922	
Less: Current Portion of Long-Term Debt		**935**		894	
		17,632		17,028	

(1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

(2) Includes fair value adjustments of $13 million (2010 – $8 million) for interest rate swap agreements on US$350 million of debt at December 31, 2011 (2010 – US$250 million).

(3) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2012 – $935 million; 2013 – $903 million; 2014 – $971 million; 2015 – $1,084 million; and 2016 $1,227 million.

In the normal course of business, TransCanada and various wholly owned subsidiaries also provide guarantees on behalf of the Company or wholly owned subsidiaries for debt owed to third parties. This is to facilitate the extension of sufficient credit to accomplish their intended commercial activity.

TransCanada PipeLines Limited

In November 2011, TCPL issued $500 million and $250 million of Medium-Term Notes maturing November 15, 2021 and November 15, 2041, respectively, and bearing interest at 3.65 per cent and 4.55 per cent, respectively.

In May 2011, TCPL retired $60 million of 9.50 per cent Medium-Term Notes.

In January 2011, TCPL retired $300 million of 4.3 per cent Medium-Term Notes.

In September 2010, TCPL issued US$1.0 billion of Senior Notes maturing October 1, 2020, and bearing interest at 3.80 per cent.

In June 2010, TCPL issued US$500 million and US$750 million of Senior Notes maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively.

In February 2010, TCPL retired US$120 million of 6.125 per cent Medium-Term Notes and in August 2010, TCPL retired $130 million of 10.50 per cent debentures.

In October 2009, TCPL retired $250 million of 10.625 per cent debentures.

In February 2009, TCPL issued $300 million and $400 million of Medium-Term Notes maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. Also in February 2009, TCPL retired $200 million of 4.10 per cent Medium-Term Notes.

In January 2009, TCPL issued US$750 million and US$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. Also in January 2009, TCPL retired US$227 million of 6.49 per cent Medium-Term Notes.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2011.

TransCanada PipeLine USA Ltd.

TCPL USA has an initial US$1.0 billion committed, unsecured, syndicated credit facility, guaranteed by TransCanada which was reduced to a US$800 million credit facility through a US$200 million term loan repayment in August 2011. The facility consists of a US$500 million five-year term loan maturing in 2012 and a US$300 million revolving facility maturing in February 2013, described further in Note 10. Included in Long-Term Debt was an outstanding balance of US$500 million on the term loan at December 31, 2011 (2010 – US$700 million) which was fully repaid in January 2012.

TC PipeLines, LP

In July 2011, TC PipeLines, LP increased its senior syndicated revolving credit facility to US$500 million and extended the maturity date to July 2016. In December 2011, TC PipeLines, LP repaid a maturing US$300 million term loan with a draw under this facility, and at December 31, 2011, US$363 million (2010 – US$8 million) was outstanding on the facility.

In June 2011, TC PipeLines, LP issued US$350 million of 4.65 per cent Senior Notes due 2021. The proceeds from the issuance were used to partially repay TC PipeLines, LP's term loan and borrowings under its senior revolving credit facility, and repay its bridge loan facility described below.

In May 2011, TC PipeLines, LP made draws of US$61 million on a bridge loan facility and US$125 million on its senior revolving credit facility to partially fund the acquisition of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) as further described in Note 23.

Interest Expense

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Interest on long-term debt	**1,154**	1,149	1,212
Interest on junior subordinated notes	**63**	65	73
Interest on short-term debt	**16**	15	10
Capitalized interest	**(302)**	(587)	(358)
Amortization and other financial charges[1]	**6**	59	17
	937	701	954

[1] Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates.

The Company made interest payments of $926 million in 2011 (2010 – $652 million; 2009 – $916 million) on long-term debt and junior subordinated notes, net of interest capitalized on construction projects.

NOTE 14 LONG-TERM DEBT OF JOINT VENTURES

		2011		2010	
Outstanding loan amounts (millions of dollars)	Maturity Dates	**Outstanding December 31[1]**	**Interest Rate[2]**	Outstanding December 31[1]	Interest Rate[2]
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$175)	2016 to 2021	**177**	**7.1%**	174	7.1%
Bank Facility					
U.S. dollars (2011 – US$62; 2010 – US$96)	2016	**62**	**1.6%**	94	0.5%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes					
U.S. dollars (2011 – US$169; 2010 – US$178)	2019 to 2027	**171**	**6.1%**	176	6.1%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**194**	**7.5%**	207	7.5%
Term Loan	2031	**88**	**7.1%**	90	7.1%
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2014 to 2017	**87**	**4.2%**	87	4.2%
Term Loan	2016	**30**	**2.2%**	35	1.6%
OTHER	2012 to 2016	**13**	**4.0%**	3	2.7%
		822		866	
Less: Current Portion of Long-Term Debt of Joint Ventures		**33**		65	
		789		801	

[1] Amounts outstanding represent TransCanada's proportionate share, except for Northern Border, which reflects a 50 per cent interest as a result of the Company fully consolidating TC PipeLines, LP.

[2] Interest rates are the effective interest rates except for those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TQM has two series of bonds which mature in 2014 and 2017, respectively. The bonds are secured by the pledge of a bond and promissory note of certain affiliated entities. All security interests with respect to the TQM bonds terminate on redemption or repayment of the series of bonds maturing in 2014.

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for a series of renewals commencing January 1, 2019. The first renewal is for a period of one year and each of 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2012 – $15 million; 2013 – $8 million; 2014 – $44 million; 2015 – $7 million; and 2016 – $149 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2012 – $18 million; 2013 – $20 million; 2014 – $22 million; 2015 – $26 million; and 2016 – $31 million.

In April 2010, Iroquois retired US$200 million of Series I bonds bearing interest at 9.16 per cent and issued US$150 million of bonds maturing in April 2020 and bearing interest at 4.96 per cent.

In September 2010, TQM retired $100 million of 7.53 per cent Series I bonds and $75 million of 3.906 per cent Series J bonds. In July 2010, TQM issued $100 million of bonds maturing in September 2017 and bearing interest at 4.25 per cent.

Sensitivity

A one per cent change in interest rates would have the following effect on Net Income assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on interest expense of variable interest rate debt	1	(1)

Interest Expense of Joint Ventures

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Interest on long-term debt	**34**	39	51
Interest on capital lease obligations	**22**	16	17
Short-term interest and other financial charges	**(1)**	4	(4)
	55	59	64

The Company's proportionate share of the interest payments by joint ventures was $31 million in 2011 (2010 – $42 million; 2009 – $41 million), net of interest capitalized on construction projects.

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $15 million in 2011 (2010 – $16 million; 2009 – $17 million).

NOTE 15 JUNIOR SUBORDINATED NOTES

		2011		2010	
Outstanding loan amount (millions of dollars)	Maturity Date	**Outstanding December 31**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2011 and 2010 – US$1,000)	2017	**1,009**	**6.5%**	985	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

NOTE 16 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the Consolidated Balance Sheet were as follows:

December 31 (millions of dollars)	**2011**	2010
Non-controlling interest in TC PipeLines, LP[1]	**997**	686
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland[2]	**79**	82
	1,465	1,157

The Company's non-controlling interests included in the Consolidated Income Statement were as follows:

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Non-controlling interest in TC PipeLines, LP[1]	**101**	87	66
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in Portland[2]	**6**	6	8
	129	115	96

(1) Effective May 3, 2011, the non-controlling interest in TC PipeLines, LP increased from 61.8 per cent to 66.7 per cent due to the issuance of equity to non-controlling interests in TC PipeLines, LP associated with the sale of 25 per cent interests in GTN LLC and Bison LLC pipelines from TransCanada to TC PipeLines, LP. The non-controlling interest in TC PipeLines, LP from November 18, 2009 to May 2, 2011 was 61.8 per cent, from July 1, 2009 to November 17, 2009 was 57.4 per cent, and from February 22, 2007 to June 30, 2009 was 67.9 per cent.

(2) The non-controlling interests in Portland as at December 31, 2011 represented the 38.3 per cent interest not owned by TransCanada (2010 and 2009 – 38.3 per cent).

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate per Share	Redemption Price per Share	**2011**	2010
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

The authorized number of preferred shares of TCPL issuable in each series is unlimited. All of the cumulative first preferred shares of TCPL are without par value.

On or after October 15, 2013, TCPL may redeem the Series U preferred shares at $50 per share, and on or after March 5, 2014, TCPL may redeem the Series Y shares at $50 per share.

Cash Dividends

Cash dividends of $22 million or $2.80 per share were paid on the Series U and Series Y preferred shares in each of 2011, 2010 and 2009.

In 2011, TransCanada received fees of $2 million from TC PipeLines, LP (2010 and 2009 – $2 million) and $7 million from Portland (2010 – $7 million; 2009 – $8 million) for services provided.

NOTE 17 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2009	616,471	9,264
Issuance of common shares[1]	58,420	1,792
Dividend reinvestment and share purchase plan	8,220	254
Exercise of options	1,248	28
Outstanding at December 31, 2009	684,359	11,338
Dividend reinvestment and share purchase plan	10,670	378
Exercise of options	1,201	29
Outstanding at December 31, 2010	696,230	11,745
Dividend reinvestment and share purchase plan	**5,371**	**202**
Exercise of options	**2,260**	**64**
Outstanding at December 31, 2011	**703,861**	**12,011**

[1] Net of underwriting commissions and future income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

In June 2009, TransCanada completed a public offering of 58.4 million common shares at a purchase price of $31.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.8 billion.

Net Income per Share

Net income per share is calculated by dividing Net Income Attributable to Common Shares by the weighted average number of common shares. During the year, the weighted average number of common shares of 701.6 million and 702.8 million (2010 – 690.5 million and 691.7 million; 2009 – 651.8 million and 652.8 million) were used to calculate basic and diluted earnings per share, respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2009	8,501	$29.10	6,461
Granted	1,191	$31.96	
Exercised	(1,248)	$21.22	
Forfeited	(170)	$35.58	
Outstanding at December 31, 2009	8,274	$30.56	6,212
Granted	1,367	$35.32	
Exercised	(1,201)	$22.04	
Forfeited	(34)	$27.35	
Outstanding at December 31, 2010	8,406	$32.57	6,458
Granted	**970**	**$38.02**	
Exercised	**(2,260)**	**$25.86**	
Forfeited	**(16)**	**$35.83**	
Outstanding at December 31, 2011	**7,100**	**$35.44**	**5,165**

Stock options outstanding were as follows:

December 31, 2011	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(thousands)		(years)	(thousands)		(years)
$21.43 to $31.93	**414**	**$26.32**	**4.3**	**379**	**$25.80**	**4.2**
$31.97 to $33.08	**1,496**	**$32.32**	**3.8**	**1,285**	**$32.38**	**3.7**
$35.08	**1,135**	**$35.08**	**5.2**	**559**	**$35.08**	**5.2**
$35.23	**1,001**	**$35.23**	**1.2**	**1,001**	**$35.23**	**1.2**
$36.26 to $38.10	**2,100**	**$37.86**	**5.2**	**1,011**	**$37.99**	**2.8**
$38.14 to $41.65	**954**	**$39.63**	**3.2**	**930**	**$39.58**	**3.1**
	7,100	**$35.44**	**3.5**	**5,165**	**$35.14**	**2.7**

An additional 4.4 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2011. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $2.94 for the year ended December 31, 2011 (2010 – $5.76; 2009 – $4.78). The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2011: four years of expected life (2010 and 2009 – four years); 2.1 per cent interest rate (2010 – 2.0 per cent; 2009 – 1.7 per cent); 14 per cent volatility (2010 – 27 per cent; 2009 – 29 per cent); and 4.3 per cent dividend yield (2010 – 4.7 per cent; 2009 – 5.2 per cent). Volatility is derived based on the historical volatility of the Company's shares. The amount expensed for stock options, with a corresponding increase in contributed surplus, was $5 million in 2011 (2010 and 2009 – $4 million).

The total intrinsic value of options exercised in 2011 was $34 million (2010 – $17 million; 2009 – $15 million). As at December 31, 2011, the aggregate intrinsic value of the total options exercisable was $48 million and the total intrinsic value of options outstanding was $64 million. In 2011, the 0.9 million (2010 – 1.5 million; 2009 – 1.2 million) shares that vested had a fair value of $42 million (2010 – $57 million; 2009 – $43 million).

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right that entitles certain holders to purchase two common shares of the Company for the price of one.

Cash Dividends

Cash dividends of $961 million, net of the Dividend Reinvestment and Share Purchase Plan (DRP), or $1.66 per common share were paid in 2011 (2010 – $710 million or $1.58 per common share; 2009 – $722 million or $1.50 per common share).

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The Company reserves the right to satisfy its DRP obligations by issuing common shares from treasury at a discount of up to five per cent or by purchasing shares on the open market. Commencing with the dividends declared in April 2011, common shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. In 2011, TransCanada issued 5.4 million (2010 – 10.7 million; 2009 – 8.2 million) common shares from treasury in accordance with the DRP in lieu of making cash dividend payments of $202 million (2010 – $378 million; 2009 – $254 million).

NOTE 18 PREFERRED SHARES

December 31	Number of Shares Authorized and Outstanding	Dividend Rate per Share	Redemption Price per Share	**2011**	2010
	(thousands)			(millions of dollars)[1]	(millions of dollars)[1]
Cumulative First Preferred Shares					
Series 1	22,000	$1.15	$25.00	**539**	539
Series 3	14,000	$1.00	$25.00	**343**	343
Series 5	14,000	$1.10	$25.00	**342**	342
				1,224	1,224

[1] Net of underwriting commissions and future income taxes.

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, for the initial five-and-a-half-year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter at a price of $25 per share plus all accrued and unpaid dividends.

The Series 5 preferred shareholders have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, for the initial five-year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter at a price of $25 per share plus all accrued and unpaid dividends.

The Series 3 preferred shareholders have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent.

In September 2009, TransCanada completed a public offering of 22 million Series 1 cumulative redeemable first preferred shares for gross proceeds of $550 million. The holders of the Series 1 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25 per share plus all accrued and unpaid dividends.

The Series 1 preferred shareholders have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

The preferred shareholders are eligible to participate in the Company's DRP.

Cash Dividends

In 2011, the Company made cash dividend payments of $25 million, net of DRP, or $1.15 per Series 1 preferred share (2010 – $24 million or $1.15 per share; 2009 – $6 million or $0.2875 per share), $14 million, net of DRP, or $1.00 per Series 3 preferred share (2010 – $11 million or $0.8041 per share) and $16 million, net of DRP, or $1.10 per Series 5 preferred share (2010 – $9 million or $0.3707 per share).

NOTE 19 ASSET RETIREMENT OBLIGATIONS

The scope and timing of asset retirements related to regulated oil and natural gas pipelines in the U.S. and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities. The Company has not recorded an amount for ARO related to the nuclear assets, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Through its Land Matters Consultation Initiative, the NEB is addressing several significant issues relating to future pipeline abandonment costs for Canadian regulated pipelines. In its May 2009 decision, the NEB established several filing deadlines relating to the financial issues, including deadlines for preparing and filing an estimate of the abandonment costs to be used to begin collecting funds. TransCanada filed its estimates of abandonment costs for its Canadian natural gas and oil pipelines on November 30, 2011, as required by the NEB decision. These estimates are expected to clarify the scope of ARO, however, the timing of retirements for these assets remains indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets.

ARO recognized in the Natural Gas Pipelines segment relates to non-regulated natural gas pipelines and regulated natural gas storage operations. The estimated undiscounted cash flows required to settle the ARO with respect to these operations were $63 million at December 31, 2011 (2010 – $62 million), calculated using an annual inflation rate ranging from 1.2 per cent to 4.0 per cent. The estimated fair value of this liability was $26 million at December 31, 2011 (2010 – $24 million) after discounting the estimated cash flows at rates ranging from 4.3 per cent to 11.0 per cent. At December 31, 2011, the expected timing of payment for settlement of the obligations ranged from 2012 to 2029.

ARO recognized in the Energy segment relates to certain power generation facilities and non-regulated natural gas storage facilities. The estimated undiscounted cash flows required to settle the ARO with respect to the Energy segment were $641 million at December 31, 2011 (2010 – $719 million), calculated using an annual inflation rate ranging from 2.0 per cent to 2.5 per cent. The estimated fair value of this liability was $43 million at December 31, 2011 (2010 – $42 million), after discounting the estimated cash flows at average rates ranging from 5.2 per cent to 6.8 per cent. During 2010, the economic life of certain Energy assets was extended after reviewing market trends and asset conditions. At December 31, 2011, the expected timing of payment for settlement of the obligations ranged from 2018 to 2061.

Reconciliation of Asset Retirement Obligations[1]

(millions of dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2010	24	87	111
New obligations and revisions in estimated cash flows	(1)	(47)	(48)
Accretion expense	1	2	3
Balance at December 31, 2010	24	42	66
New obligations and revisions in estimated cash flows	**–**	**(1)**	**(1)**
Accretion expense	**2**	**2**	**4**
Balance at December 31, 2011	**26**	**43**	**69**

[1] At December 31, 2011, ARO totalling $68 million (2010 – $65 million) and $1 million (2010 – $1 million) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 20 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover a significant majority of employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plans increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately eight years (2010 – eight years; 2009 – eight years).

The Company also provides its employees with a Savings Plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2011. Contributions to the Savings Plan and DC Plans are expensed as incurred. In 2011, the Company expensed $23 million (2010 and 2009 – $21 million) for the Savings Plan and DC Plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $93 million in 2011 (2010 – $127 million; 2009 – $168 million), including $23 million in 2011 (2010 and 2009 – $21 million) related to the Savings Plan and DC Plans. In addition to these cash payments, in 2011 the Company provided a $27 million letter of credit to the DB Plan.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2012, and the next required valuation will be as at January 1, 2013.

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,622**	1,476	**159**	150
Current service cost	**54**	50	**2**	2
Interest cost	**91**	89	**9**	9
Employee contributions	**4**	4	**1**	1
Benefits paid	**(71)**	(73)	**(9)**	(9)
Actuarial loss	**131**	95	**7**	8
Transfers	**–**	(8)	**–**	–
Foreign exchange rate changes	**5**	(11)	**1**	(2)
Benefit obligation – end of year	**1,836**	1,622	**170**	159
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,636**	1,447	**29**	27
Actual return on plan assets	**21**	177	**–**	3
Employer contributions	**62**	98	**8**	8
Employee contributions	**4**	4	**1**	1
Benefits paid	**(71)**	(73)	**(9)**	(9)
Transfers	**–**	(8)	**–**	–
Foreign exchange rate changes	**4**	(9)	**–**	(1)
Plan assets at fair value – end of year	**1,656**	1,636	**29**	29
Funded status – plan (deficit)/surplus	**(180)**	14	**(141)**	(130)
Unamortized net actuarial loss	**549**	345	**50**	42
Unamortized past service costs	**15**	18	**(3)**	(3)
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**384**	377	**(94)**	(91)

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Intangibles and Other Assets	**399**	380	**–**	–
Deferred Amounts	**(15)**	(3)	**(94)**	(91)
	384	377	**(94)**	(91)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Benefit obligation	**(1,836)**	(417)	**(170)**	(159)
Plan assets at fair value	**1,656**	391	**29**	29
Funded Status – Plan Deficit	**(180)**	(26)	**(141)**	(130)

The Company's expected funding contributions in 2012 are approximately $119 million for the DB Plans and approximately $31 million for the other benefit plans, Savings Plan and DC Plans. In addition to these contributions, the Company expects to provide a $48 million letter of credit in 2012 to the DB Plan.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2012	85	9
2013	90	9
2014	94	10
2015	99	10
2016	104	10
2017 to 2021	591	57

The rate used to discount pension and other post-employment benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2011. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-employment obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31	**2011**	2010	**2011**	2010
Discount rate	**5.05%**	5.55%	**5.10%**	5.65%
Rate of compensation increase	**3.15%**	3.20%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost were as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.55%**	6.00%	6.65%	**5.60%**	6.00%	6.50%
Expected long-term rate of return on plan assets	**6.95%**	6.95%	6.95%	**6.40%**	7.80%	7.75%
Rate of compensation increase	**3.10%**	3.20%	3.25%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

An 8.50 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2019 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	15	(13)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2011**	2010	2009	**2011**	2010	2009
Current service cost	**54**	50	45	**2**	2	2
Interest cost	**91**	89	89	**9**	9	9
Actual return on plan assets	**(21)**	(177)	(206)	**–**	(3)	(5)
Actuarial loss	**131**	95	107	**7**	8	10
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**255**	57	35	**18**	16	16
Difference between expected and actual return on plan assets	**(93)**	68	107	**(2)**	1	3
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(110)**	(86)	(101)	**(5)**	(6)	(8)
Difference between amortization of past service costs and actual plan amendments	**3**	4	4	**–**	–	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
	55	43	45	**13**	13	13

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

Asset Category

	Percentage of Plan Assets		Target Allocations
December 31	**2011**	2010	**2011**
Debt securities	**39%**	37%	**35% to 60%**
Equity securities	**61%**	63%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $2 million (0.1 per cent of total plan assets) and $4 million (0.2 per cent of total plan assets) at December 31, 2011 and 2010, respectively. Equity securities included the Company's common shares of $3 million (0.2 per cent of total plan assets) and $3 million (0.2 per cent of total plan assets) at December 31, 2011 and 2010, respectively.

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded.

The following table presents plan assets for DB Plans and other post-employment benefits measured at fair value, which have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets. In Level II, determination of the fair value of assets includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets is based on inputs that are not readily observable and are significant to the overall fair value measurement.

Asset Category	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
December 31 (millions of Canadian dollars)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Cash and cash equivalents	**25**	19	**–**	–	**–**	–	**25**	19	**1%**	1%
Equity Securities:										
Canadian	**374**	394	**95**	93	**–**	–	**469**	487	**28%**	29%
U.S.	**251**	225	**55**	117	**–**	–	**306**	342	**18%**	21%
International	**25**	31	**231**	199	**–**	–	**256**	230	**15%**	14%
Fixed Income Securities:										
Canadian Bonds:										
Federal	**–**	–	**303**	302	**–**	–	**303**	302	**18%**	18%
Provincial	**–**	–	**158**	127	**–**	–	**158**	127	**9%**	8%
Municipal	**–**	–	**4**	4	**–**	–	**4**	4	**–**	–
Corporate	**–**	–	**47**	64	**–**	–	**47**	64	**3%**	4%
U.S. Bonds:										
State	**–**	–	**29**	28	**–**	–	**29**	28	**2%**	2%
Corporate	**–**	–	**29**	19	**–**	–	**29**	19	**2%**	1%
International:										
Corporate	**–**	–	**9**	–	**–**	–	**9**	–	**1%**	–
Mortgage Backed	**–**	–	**30**	22	**–**	–	**30**	22	**2%**	1%
Other Investments:										
Private Equity Funds	**–**	–	**–**	–	**20**	21	**20**	21	**1%**	1%
	675	669	**990**	975	**20**	21	**1,685**	1,665	**100%**	100%

The following table presents the net change in the Level III fair value category:

(millions of dollars, pre-tax)	Private Equity Funds
Balance at December 31, 2009	25
Realized and unrealized losses	(6)
Purchases and sales	2
Balance at December 31, 2010	21
Realized and unrealized losses	**(2)**
Purchases and sales	**1**
Balance at December 31, 2011	**20**

Employee Future Benefits of Joint Ventures

Certain of the Company's joint ventures sponsor DB Plans as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The following amounts in this note, including those in the accompanying tables, represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $59 million in 2011 (2010 – $58 million; 2009 – $54 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2012, and the next required valuations will be as at January 1, 2013.

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Change in Benefit Obligation				
Benefit obligation – beginning of year	**864**	695	**208**	170
Current service cost	**27**	19	**11**	8
Interest cost	**46**	42	**11**	10
Employee contributions	**8**	7	**–**	–
Benefits paid	**(33)**	(31)	**(4)**	(5)
Actuarial loss	**73**	132	**25**	25
Benefit obligation – end of year	**985**	864	**251**	208
Change in Plan Assets				
Plan assets at fair value – beginning of year	**727**	641	**–**	–
Actual return on plan assets	**13**	57	**–**	–
Employer contributions	**53**	53	**6**	5
Employee contributions	**8**	7	**–**	–
Benefits paid	**(33)**	(31)	**(4)**	(5)
Plan assets at fair value – end of year	**768**	727	**2**	–
Funded status – plan deficit	**(217)**	(137)	**(249)**	(208)
Unamortized net actuarial loss	**317**	230	**71**	49
Unamortized past service costs	**–**	–	**2**	2
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**100**	93	**(176)**	(157)

The accrued benefit asset/(liability), net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Intangibles and Other Assets	**100**	93	**–**	–
Deferred Amounts	**–**	–	**(176)**	(157)
	100	93	**(176)**	(157)

The following amounts were included in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Benefit obligation	**(979)**	(864)	**(251)**	(208)
Plan assets at fair value	**761**	727	**2**	–
Funded Status – Plan Deficit	**(218)**	(137)	**(249)**	(208)

The expected total funding contributions of the Company's joint ventures in 2012 are approximately $73 million for the pension benefit plans and approximately $7 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2012	37	7
2013	38	8
2014	40	8
2015	42	9
2016	44	10
2017 to 2021	310	60

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures were as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31	**2011**	2010	**2011**	2010
Discount rate	**4.75%**	5.25%	**4.60%**	5.10%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures were as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.25%**	6.00%	6.75%	**5.10%**	5.80%	6.40%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.00%			
Rate of compensation increase	**3.50%**	3.50%	3.50%			

An 8.50 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2019 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	4	(3)
Effect on post-employment benefit obligation	35	(28)

The Company's proportionate share of net benefit cost of joint ventures is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2011**	2010	2009	**2011**	2010	2009
Current service cost	**27**	19	16	**11**	8	5
Interest cost	**46**	42	40	**11**	10	9
Actual return on plan assets	**(13)**	(57)	(63)	**–**	–	–
Actuarial loss/(gain)	**73**	132	68	**25**	25	27
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**133**	136	61	**47**	43	41
Difference between expected and actual return on plan assets	**(38)**	12	25	**–**	–	–
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(62)**	(128)	(67)	**(22)**	(24)	(28)
	33	20	19	**25**	19	13

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2011**	2010	**2011**
Debt securities	**45%**	41%	**40%**
Equity securities	**55%**	59%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.2 per cent of total plan assets) and $1 million (0.2 per cent of total plan assets) at December 31, 2011 and 2010, respectively. Equity securities included the Company's common shares of $4 million (0.6 per cent of total plan assets) and $4 million (0.5 per cent of total plan assets) at December 31, 2011 and 2010, respectively.

The assets of the joint ventures' pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

NOTE 21 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with financial risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk
The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity and natural gas. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate operational and price risks in its asset portfolio.
- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk
TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and on these forward contracts are not representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk
Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's net income. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated interest expense.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the foreign exchange rate exposures of the Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations
The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10 billion (US$9.8 billion) (2010 – $9.8 billion (US$9.8 billion)) and a fair value of $12.7 billion (US$12.5 billion) (2010 – $11.3 billion (US$11.4 billion)). At December 31, 2011, $79 million (December 31, 2010 – nil) was included in Other Current Assets, $66 million (December 31, 2010 – $181 million) was included in Intangibles and Other Assets, $15 million (December 31, 2010 – nil) was included in Accounts Payable, and $41 million (December 31, 2010 – nil) was included in Deferred Amounts for the fair value of the forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

	2011		2010	
Asset/(Liability)		**Notional or Principal**		Notional or Principal
December 31 (millions of dollars)	**Fair Value[1]**	**Amount**	Fair Value[1]	Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2018)	**93**	**US 3,850**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2012)	**(4)**	**US 725**	2	US 100
	89	**US 4,575**	181	US 2,900

[1] Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open positions will not exceed the reported VaR. The VaR methodology is a statistically calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the regulated natural gas pipelines, as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2011 (2010 – $12 million).

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using contract netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts receivable and other, and Available for sale assets in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2011, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2011, the Company had a credit risk concentration of $274 million (2010 – $317 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it

was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

In August 2011, the Company received final distributions of 2.1 million common shares as a result of previous claims in the 2005 Calpine Corporation bankruptcy. These shares were sold into the open market resulting in total pre-tax gains of $30 million, of which the Company had accrued pre-tax gains of $15 million in 2010. In 2008, the Company had received 15.5 million common shares which were sold into the open market for $279 million. Claims by NGTL and Foothills PipeLines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in 2008 and 2009 and were passed onto the shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section of this note.

At December 31, 2011, the Company had unutilized committed revolving bank lines of US$1.0 billion, US$1.0 billion, US$300 million and $2.0 billion maturing in October 2012, November 2012, February 2013 and October 2016, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms and recently initiated a commercial paper program in the U.S.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2011, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Equity. Net debt comprises Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 (millions of dollars)	**2011**	2010
Notes payable	**1,863**	2,081
Long-term debt	**18,567**	17,922
Junior subordinated notes	**1,009**	985
Cash and cash equivalents	**(654)**	(660)
Net Debt	**20,785**	20,328
Equity attributable to non-controlling interests	**1,465**	1,157
Equity attributable to controlling interests	**17,324**	16,727
Total Equity	**18,789**	17,884
	39,574	38,212

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates and applying a discounted cash flow valuation model. The fair value of power and natural gas derivatives, and of available for sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary
The carrying and fair values of non-derivative financial instruments were as follows:

	2011		2010	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**765**	**765**	764	764
Accounts receivable and other[2][3]	**1,576**	**1,620**	1,555	1,595
Available for sale assets[2]	**23**	**23**	20	20
	2,364	**2,408**	2,339	2,379
Financial Liabilities[1][3]				
Notes payable	**1,880**	**1,880**	2,092	2,092
Accounts payable and deferred amounts[4]	**1,536**	**1,536**	1,436	1,436
Accrued interest	**373**	**373**	367	367
Long-term debt	**18,567**	**23,757**	17,922	21,523
Junior subordinated notes	**1,009**	**1,027**	985	992
Long-term debt of joint ventures	**822**	**940**	866	971
	24,187	**29,513**	23,668	27,381

(1) Consolidated Net Income in 2011 included losses of $13 million (2010 – losses of $8 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At December 31, 2011, the Consolidated Balance Sheet included financial assets of $1,265 million (2010 – $1,271 million) in Accounts Receivable, $41 million (2010 – $40 million) in Other Current Assets and $293 million (2010 – $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for $350 million (2010 – $250 million) of Long-Term Debt that is adjusted to fair value.

(4) At December 31, 2011, the Consolidated Balance Sheet included financial liabilities of $1,494 million (2010 – $1,406 million) in Accounts Payable and $42 million (2010 – $30 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2011:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Notes payable	1,880	1,880	–	–	–
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009	–	–	–	1,009
Long-term debt of joint ventures	822	33	94	213	482
	22,278	2,848	1,968	2,524	14,938

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2011, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2011			
December 31 *(all amounts in millions unless otherwise indicated)*	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$213**	**$176**	**$3**	**$22**
Liabilities	**$(212)**	**$(212)**	**$(14)**	**$(22)**
Notional Values				
Volumes[3]				
Purchases	**23,500**	**103**	**–**	**–**
Sales	**23,158**	**82**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**684**
U.S. dollars	**–**	**–**	**US 1,269**	**US 250**
Cross-currency	**–**	**–**	**47/US 37**	**–**
Net unrealized (losses)/gains in the year[4]	**$(3)**	**$(50)**	**$(4)**	**$1**
Net realized gains/(losses) in the year[4]	**$58**	**$(74)**	**$10**	**$10**
Maturity dates	**2012-2018**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$42**	**$3**	**$–**	**$13**
Liabilities	**$(277)**	**$(22)**	**$(38)**	**$(1)**
Notional Values				
Volumes[3]				
Purchases	**17,188**	**8**	**–**	**–**
Sales	**9,217**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**US 91**	**US 600**
Cross-currency	**–**	**–**	**136/US 100**	**–**
Net realized losses in the year[4]	**$(150)**	**$(17)**	**$–**	**$(16)**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2012-2015**

(1) All derivative financial instruments in the held for trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on held for trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million. In 2011, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2011, Net Income included losses of $3 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2011, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2011. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Derivative financial instruments held for trading					
Assets	414	282	123	9	–
Liabilities	(460)	(292)	(151)	(17)	–
Derivative financial instruments in hedging relationships					
Assets	217	121	91	5	–
Liabilities	(408)	(208)	(135)	(50)	(15)
	(237)	(97)	(72)	(53)	(15)

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2010			
December 31 *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading(1)				
Fair Values(2)				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values				
Volumes(3)				
Purchases	15,610	158	–	–
Sales	18,114	96	–	–
Canadian dollars	–	–	–	736
U.S. dollars	–	–	US 1,479	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year(4)	$(32)	$27	$4	$43
Net realized gains/(losses) in the year(4)	$77	$(42)	$36	$(74)
Maturity dates	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(2)				
Assets	$112	$5	$ –	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values				
Volumes(3)				
Purchases	16,071	17	–	–
Sales	10,498	–	–	–
U.S. dollars	–	–	US 120	US 1,125
Cross-currency	–	–	136/US 100	–
Net realized losses in the year(4)	$(9)	$(35)	$–	$(33)
Maturity dates	2011-2015	2011-2013	2011-2014	2011-2015

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2010, Net Income included a gain of $1 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2010, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2011**	2010
Current		
Other current assets	**404**	273
Accounts payable	**(502)**	(337)
Long Term		
Intangibles and other assets (Note 9)	**213**	374
Deferred amounts (Note 11)	**(352)**	(282)

Derivative Financial Instruments of Joint Ventures

Included in the Derivative Financial Instruments Summary tables are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power derivatives was $35 million at December 31, 2011 (2010 – $48 million). These contracts mature from 2012 to 2018. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 2,979 gigawatt hours (GWh) at December 31, 2011 (2010 – 3,772 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 1,595 GWh at December 31, 2011 (2010 – 2,322 GWh).

Derivatives in Cash Flow Hedging Relationships

Information about how derivatives and hedging activities affect the Company's financial position, financial performance and cash flows is as follows:

	Cash Flow Hedges							
	Power		Natural Gas		Foreign Exchange		Interest	
Year ended December 31 (millions of Canadian dollars, pre-tax)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Change in fair value of derivative instruments recognized in OCI (effective portion)	**(252)**	(79)	**(59)**	(26)	**5**	10	**(1)**	(137)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**61**	(7)	**100**	(21)	**–**	–	**43**	32

Credit Risk Related Contingent Features

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2011, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2010 – $92 million), for which the Company has provided collateral of $28 million (2010 – $4 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2011, the Company would have been required to provide additional collateral of $82 million (2010 – $88 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative financial instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets are included in this category. Long-dated commodity prices are derived with a third-party modelling tool that uses market fundamentals to derive long-term prices.

There were no transfers between Level I and Level II in 2011 or 2010. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 (millions of dollars, pre-tax)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Natural Gas Inventory	**–**	–	**29**	49	**–**	–	**29**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**–**	–	**35**	28	**–**	–	**35**	28
Foreign exchange contracts	**11**	10	**131**	179	**–**	–	**142**	189
Power commodity contracts	**–**	–	**244**	269	**2**	5	**246**	274
Gas commodity contracts	**124**	93	**55**	56	**–**	–	**179**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**–**	–	**(23)**	(47)	**–**	–	**(23)**	(47)
Foreign exchange contracts	**(13)**	(11)	**(89)**	(54)	**–**	–	**(102)**	(65)
Power commodity contracts	**–**	–	**(465)**	(299)	**(15)**	(8)	**(480)**	(307)
Gas commodity contracts	**(208)**	(178)	**(26)**	(15)	**–**	–	**(234)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**23**	20	**–**	–	**–**	–	**23**	20
	(63)	(66)	**(109)**	166	**(13)**	(3)	**(185)**	97

The following table presents the net change in the Level III fair value category:

(millions of dollars, pre-tax)	Derivatives[1]
Balance at December 31, 2009	(2)
New contracts[2]	(16)
Settlements	(3)
Transfers into Level III[3]	3
Transfers out of Level III[3][4]	(38)
Change in unrealized gains recorded in Net Income	14
Change in fair value of derivative instruments recorded in OCI	39
Balance at December 31, 2010	(3)
New contracts[2]	**1**
Settlements	**1**
Transfers out of Level III[3][4]	**(1)**
Change in unrealized gains recorded in Net Income	**1**
Change in fair value of derivative instruments recorded in OCI	**(12)**
Balance at December 31, 2011	**(13)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) At December 31, 2011, the total amount of net gains included in Net Income attributable to derivatives that were entered into during the year and still held at the reporting date was nil (2010 – $1 million).

(3) Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable.

(4) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2011.

NOTE 22 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2011**	2010	2009
(Increase)/decrease in accounts receivable	**(6)**	(305)	314
Decrease/(increase) in inventories	**27**	70	(19)
Increase in other current assets	**(20)**	(89)	(249)
Increase/(decrease) in accounts payable	**300**	84	(154)
Increase/(decrease) in accrued interest	**9**	(9)	18
Decrease/(Increase) in Operating Working Capital	**310**	(249)	(90)

NOTE 23 ACQUISITIONS AND DISPOSITIONS

Natural Gas Pipelines

TC PipeLines, LP

On May 3, 2011, TransCanada completed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$605 million which included US$81 million of long-term debt, or 25 per cent of GTN LLC's outstanding debt. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, TC PipeLines, LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Net proceeds of approximately US$331 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on TC PipeLines, LP's bridge loan facility and US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TransCanada made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in TC PipeLines, LP and did not purchase any other units. As a result of the common units offering, TransCanada's

ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Contributed Surplus.

In November 2009, TC PipeLines, LP completed an offering of five million common units at a price of US$38.00 per unit, resulting in net proceeds to TC PipeLines, LP of US$182 million. TransCanada contributed an additional US$3.8 million to maintain its general partnership interest but did not purchase any other units. Upon completion of this offering, the Company's ownership interest in TC PipeLines, LP decreased to 38.2 per cent and the Company recognized an after-tax dilution gain of $18 million ($29 million pre-tax) in income.

In July 2009, TransCanada sold North Baja to TC PipeLines, LP. As part of the transaction, the Company agreed to amend its general partner incentive distribution rights arrangement with TC PipeLines, LP. TransCanada received aggregate consideration totalling approximately US$395 million from TC PipeLines, LP, including US$200 million in cash and 6,371,680 common units of TC PipeLines, LP. As a result of this transaction, TransCanada recorded no gain or loss and its ownership in TC PipeLines, LP increased to 42.6 per cent. The Company's increased ownership in TC PipeLines, LP also resulted in a decrease in Non-Controlling Interests and an increase in Contributed Surplus.

Oil Pipelines

Keystone

In August 2009, TransCanada purchased the remaining ownership interest in Keystone of approximately 20 per cent for US$553 million plus the assumption of US$197 million of short-term debt. The acquisition increased the Company's ownership interest in Keystone to 100 per cent and was recorded in Plant, Property and Equipment. TransCanada began fully consolidating Keystone upon this acquisition.

In 2009, prior to August, TransCanada funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an increase in ownership from 62 per cent to 80 per cent for $313 million. The Company proportionately consolidated the Keystone partnerships prior to August 2009.

NOTE 24 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2012	87	(8)	79
2013	85	(7)	78
2014	81	(7)	74
2015	76	(5)	71
2016	75	(3)	72
2017 and thereafter	363	(2)	361
	767	(32)	735

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 10 years. Net rental expense on operating leases in 2011 was $79 million (2010 – $80 million; 2009 – $64 million).

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability and other factors. TransCanada's share of payments under the PPAs in 2011 was $394 million (2010 – $363 million; 2009 – $384 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments
At December 31, 2011, TransCanada was committed to Natural Gas Pipelines capital expenditures totalling approximately $250 million, primarily related to construction costs of the Alberta System and Guadalajara.

At December 31, 2011, the Company was committed to Oil Pipelines capital expenditures totalling approximately $992 million, primarily related to construction costs of Keystone XL.

At December 31, 2011, the Company was committed to Energy capital expenditures totalling approximately $290 million and includes TransCanada's share of capital costs of Bruce Power and Cartier Wind.

On December 15, 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately $470 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the Ontario Power Authority (OPA) under the Feed-in Tariff program in Ontario. TransCanada anticipates the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2011, the Company had accrued approximately $49 million (2010 – $59 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Sundance A PPA
In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by the PPA owner in January 2011. In February 2011, the owner notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated.

TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe the owner's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of pre-tax income for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $863 million at December 31, 2011. The fair value of these Bruce Power guarantees at December 31, 2011 is estimated to be $29 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these assurances was estimated at December 31, 2011 to range from $182 million to a maximum of $498 million. The fair value of these guarantees at December 31, 2011 is estimated to be $7 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

NOTE 25 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

As previously discussed in Note 3, TransCanada will be adopting U.S. GAAP effective January 1, 2012. The consolidated financial statements have been prepared in accordance with CGAAP which in some respects, differ from U.S. GAAP. The effects of significant differences between CGAAP and U.S. GAAP are described in this note.

Reconciliation of Net Income and Comprehensive Income to U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net Income – CGAAP	**1,711**	1,387	1,476
U.S. GAAP adjustments:			
Unrealized loss/(gain) on natural gas inventory held in storage[1]	**4**	15	(3)
Tax impact of unrealized loss/(gain) on natural gas inventory held in storage	**(1)**	(5)	1
Dilution gain[2]	**–**	–	(29)
Tax impact of dilution gain	**–**	–	11
Tax recovery due to a change in tax legislation substantively enacted in Canada[4]	**(4)**	(4)	–
Net Income – U.S. GAAP	**1,710**	1,393	1,456
Less: Net Income Attributable to Non-Controlling Interests	**(129)**	(115)	(96)
Net Income Attributable to Controlling Interests – U.S. GAAP	**1,581**	1,278	1,360
Less: Preferred Share Dividends	**(55)**	(45)	(6)
Net Income Attributable to Common Shareholders – U.S. GAAP	**1,526**	1,233	1,354
Other Comprehensive Loss – CGAAP	**(36)**	(239)	(153)
U.S. GAAP adjustments:			
Change in funded status of post-retirement plan liability[3]	**(106)**	(11)	7
Tax impact of change in funded status of post-retirement plan liability	**27**	4	(2)
Change in funded status of post-retirement plan liability of equity investment	**(80)**	(119)	(48)
Other Comprehensive Loss – U.S. GAAP	**(195)**	(365)	(196)
Less: Other Comprehensive Income Attributable to Non-Controlling Interests	**(11)**	(6)	(7)
Other Comprehensive Loss Attributable to Controlling Interests – U.S. GAAP	**(206)**	(371)	(203)
Comprehensive Income Attributable to Common Shares – U.S. GAAP	**1,320**	862	1,151

Information Prepared in Accordance with U.S. GAAP

The differences between CGAAP and the following information prepared in accordance with U.S. GAAP relates principally to the accounting for joint venture investments. Under CGAAP, the Company accounts for joint venture investments using the proportionate consolidation basis of accounting whereby the Company's proportionate share of assets, liabilities, revenues, expenses and cash flows are included in the Company's financial statements. U.S. GAAP requires that these joint venture investments be recorded on an equity basis of accounting. Information on the balances that have been proportionately consolidated under CGAAP is included in Note 8 to these financial statements. The effects of any additional differences between CGAAP and U.S. GAAP are described in the footnotes below.

Condensed Consolidated Statement of Income – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Revenues[1]	**7,694**	6,634	6,778
Income from Equity Investments	**415**	453	478
Operating and Other Expenses			
Plant operating costs and other[2]	**2,768**	2,434	2,621
Commodity purchases resold	**846**	960	772
Depreciation and amortization	**1,328**	1,160	1,201
Valuation provision for MGP	**–**	146	–
	4,942	4,700	4,594
Financial Charges/(Income)			
Interest expense	**937**	701	954
Interest income and other	**(55)**	(94)	(118)
	882	607	836
Income before Income Taxes	**2,285**	1,780	1,826
Income Taxes Expenses/(Recovery)			
Current[2][4]	**210**	(139)	13
Deferred[1]	**365**	526	357
	575	387	370
Net Income – U.S. GAAP	**1,710**	1,393	1,456
Net Income Attributable to Non-Controlling Interests	**129**	115	96
Net Income Attributable to Controlling Interests – U.S. GAAP	**1,581**	1,278	1,360
Preferred Share Dividends	**55**	45	6
Net Income Attributable to Common Shares – U.S. GAAP	**1,526**	1,233	1,354
Net Income per Common Share – U.S. GAAP			
Basic	**$2.17**	$1.79	$2.08
Diluted	**$2.17**	$1.78	$2.08

Consolidated Statement of Comprehensive Income – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net Income – U.S. GAAP	**1,710**	1,393	1,456
Other Comprehensive Income/(Loss), Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations[8]	**113**	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[9]	**(73)**	89	258
Change in fair value of derivative instruments designated as cash flow hedges[10]	**(212)**	(169)	(29)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[11]	**147**	53	71
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[3][12]	**(89)**	(12)	(1)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[3][13]	**10**	5	6
Other Comprehensive Loss on equity investments[14]	**(91)**	(151)	(30)
Other Comprehensive Loss – U.S. GAAP	**(195)**	(365)	(196)
Comprehensive Income – U.S. GAAP	**1,515**	1,028	1,260
Comprehensive Income Attributable to Non-Controlling Interests	**140**	121	103
Comprehensive Income Attributable to Controlling Interests – U.S. GAAP	**1,375**	907	1,157
Preferred Share Dividends	**55**	45	6
Comprehensive Income Attributable to Common Shares – U.S. GAAP	**1,320**	862	1,151

Condensed Consolidated Balance Sheet – U.S. GAAP

As at December 31 (millions of dollars)	**2011**	2010
Assets		
Current Assets[1]	**3,110**	2,799
Plant, Property and Equipment[7]	**32,467**	30,987
Equity Investments[3][5][6]	**5,077**	4,683
Goodwill	**3,534**	3,457
Regulatory Assets[3]	**1,684**	1,699
Intangibles and Other Assets[3][6]	**1,466**	1,624
	47,338	45,249
Liabilities		
Current Liabilities[4][7]	**5,522**	5,352
Regulatory Liabilities	**297**	308
Deferred Amounts[3][5]	**929**	728
Deferred Income Tax Liabilities[1][3][6]	**3,591**	3,241
Long-Term Debt[6]	**17,724**	17,122
Junior Subordinated Notes[6]	**1,016**	993
	29,079	27,744
Equity		
Common shares, no par value Issued and outstanding: 2011 – 704 million shares Issued and outstanding: 2010 – 696 million shares	**12,011**	11,745
Preferred shares	**1,224**	1,224
Additional paid-in capital[2]	**380**	349
Retained earnings[1][2][4]	**4,628**	4,273
Accumulated other comprehensive (loss)/income[3]	**(1,449)**	(1,243)
Equity Attributable to Controlling Interests	**16,794**	16,348
Equity Attributable to Non-Controlling Interests	**1,465**	1,157
	18,259	17,505
	47,338	45,249

Consolidated Statement of Accumulated Other Comprehensive (Loss)/Income – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Balance at beginning of year	**(1,243)**	(872)	(669)
Change in foreign currency translation gains and losses on investments in foreign operations[8]	**113**	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[9]	**(73)**	89	258
Change in fair value of derivative instruments designated as cash flow hedges[10]	**(213)**	(165)	(27)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[11]	**137**	43	62
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[3][12]	**(89)**	(12)	(1)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[3][13]	**10**	5	6
Other Comprehensive Loss on equity investments[14]	**(91)**	(151)	(30)
Balance at end of year	**(1,449)**	(1,243)	(872)

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net cash provided by operations	**3,759**	2,876	3,008
Net cash used in investing activities	**(3,127)**	(5,296)	(7,347)
Net cash (used in)/provided by financing activities	**(642)**	2,188	4,204
Effect of foreign exchange rate changes on cash and cash equivalents	**4**	(7)	(93)
Decrease in cash and cash equivalents	**(6)**	(239)	(228)
Cash and cash equivalents beginning of year	**660**	899	1,127
Cash and cash equivalents end of year	**654**	660	899

(1) Under U.S. GAAP, inventory is recorded at lower of cost or market. Under CGAAP, natural gas inventory held in storage is recorded at its fair value.

(2) Under U.S. GAAP, the dilution gain resulting from TC PipeLines, LP's 2009 equity issuance was accounted for as an equity transaction. Under CGAAP, the dilution gain was included in Net Income.

(3) Under U.S. GAAP, an employer is required to recognize the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability in its Consolidated Balance Sheet and to recognize changes in that funded status, through OCI, in the year in which the changes occur. The amounts recognized in the Company's U.S. GAAP Consolidated Balance Sheet for its DB Plans and other post-retirement benefits are as follows:

December 31 (millions of dollars)	**2011**	2010
Intangibles and other assets	**–**	40
Deferred amounts	**(321)**	(156)
	(321)	(116)

Pre-tax amounts recognized in U.S. GAAP AOCI are as follows:

	2011		2010		2009	
December 31 (millions of dollars)	**Pension Benefits**	**Other Benefits**	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Net loss	**283**	**29**	179	24	170	21
Prior service cost	**7**	**2**	9	2	10	2
	290	**31**	188	26	180	23

Pre-tax amounts recognized in U.S. GAAP OCI were as follows:

	2011		2010			2009
December 31 (millions of dollars)	**Pension Benefits**	**Other Benefits**	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Amortization of net loss from AOCI to OCI	**(10)**	**(1)**	(5)	(1)	(5)	(1)
Amortization of prior service (credit) from AOCI to OCI	**(2)**	**–**	(2)	–	(2)	–
Funded status adjustment	**113**	**6**	15	4	2	(1)
	101	**5**	8	3	(5)	(2)

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

December 31 (millions of dollars)	**2011**	2010
Accumulated benefit obligation	**1,691**	1,463
Fair value of plan assets	**1,656**	1,636
Funded status – (deficit)/surplus	**(35)**	173

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

December 31 (millions of dollars)	**2011**	2010
Accumulated benefit obligation	**446**	182
Fair value of plan assets	**391**	178
Funded status – (deficit)	**(55)**	(4)

The estimated net loss and prior service cost for the DB Plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $10 million and $1 million, respectively. The estimated net loss and prior service cost for the other post-retirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $1 million and $1 million, respectively.

(4) In accordance with CGAAP, the Company recorded current income tax benefits resulting from substantively enacted Canadian federal income tax legislation. Under U.S. GAAP, the legislation must be fully enacted for income tax adjustments to be recorded.

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

December 31 (millions of dollars)	**2011**	2010
Unrecognized tax benefits at beginning of year	**62**	55
Gross increases – tax positions in prior years	**9**	7
Gross decreases – tax positions in prior years	**(7)**	(1)
Gross increases – current year positions	**11**	9
Settlements	**–**	(7)
Lapses of statute of limitations	**(23)**	(1)
Unrecognized tax benefits at end of year	**52**	62

TransCanada expects the enactment of certain Canadian federal tax legislation in the next 12 months which is expected to result in a favourable income tax adjustment of approximately $20 million. Otherwise, subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

TransCanada and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2006. Substantially all material U.S. federal income tax matters have been concluded for years through 2007 and U.S. state and local income tax matters through 2006.

TransCanada's continuing practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. Net tax expense for the year ended December 31, 2011 reflects a reversal of $12 million of interest expense and nil for penalties (2010 – $3 million for interest expense and nil for penalties; 2009 – $8 million reversal of interest expense and nil for penalties). At December 31, 2011, the Company had $7 million accrued for interest expense and nil accrued for penalties (December 31, 2010 – $19 million accrued for interest expense and nil accrued for penalties).

(5) As a consequence of using equity accounting for certain of these joint ventures under U.S. GAAP, the Company is required to reflect an additional liability of $111 million at December 31, 2011 (December 31, 2010 – $150 million) for certain guarantees related to debt and other performance commitments of the joint venture operations that were not required to be recorded when the underlying liability was reflected on the balance sheet under the proportionate consolidation method of accounting.

U.S. GAAP requires the disclosure of the difference, if any, between the carrying value of the investment and the investor's underlying equity in the net assets of the investee on an ongoing basis, rather than only at the date of purchase as required under CGAAP. At December 31, 2011, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company and Bruce Power is US$120 million (2010 – US$121 million) and $752 million (2010 – $783 million), respectively. This difference is primarily due to goodwill recorded with respect to the acquisition of Northern Border and the fair value assessment of assets at the time of acquisition of Bruce Power.

The distributed earnings from long-term investments for the year ended December 31, 2011 were $494 million (2010 – $250 million; 2009 – $265 million). The undistributed earnings from long-term investments as at December 31, 2011 were $1,283 million (2010 – $1,361 million; 2009 – $1,174 million).

(6) In accordance with U.S. GAAP, debt issue costs are recorded as a deferred asset rather than being included in Long-Term Debt as required under CGAAP.

(7) In 2009, the Company purchased the remaining 20 per cent ownership interest in Keystone, increasing its ownership interest to 100 per cent. Under CGAAP, the transaction was considered to be an asset purchase; however, under U.S. GAAP it is considered to be a business combination. The purchase price was allocated to Plant, Property and Equipment (US$734 million) and Short-term Debt (US$197 million) using fair values of the net assets at the date of acquisition. There is no Income Statement impact under U.S. GAAP as no gain or loss was created.

(8) Net of income tax recovery of $29 million in 2011 (2010 – $65 million expense; 2009 – $92 million expense).

(9) Net of income tax recovery of $28 million in 2011 (2010 – $37 million expense; 2009 – $124 million expense).

(10) Net of income tax recovery of $106 million in 2011 (2010 – $82 million recovery; 2009 – $38 million recovery).

(11) Net of income tax expense of $77 million in 2011 (2010 – $28 million expense; 2009 – $48 million expense).

(12) Net of income tax recovery of $30 million in 2011 (2010 – $7 million recovery; 2009 – nil).

(13) Net of income tax expense of $3 million in 2011 (2010 – $3 million expense; 2009 – $2 million expense).

(14) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges, offset by gains and losses on derivative instruments designated as cash flow hedges. Net of income tax recovery of $3 million in 2011 (2010 – $69 million recovery; 2009 – $17 million recovery).

SUPPLEMENTARY INFORMATION

SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

Toronto Stock Exchange *(Stock trading symbol TRP)*	First	Second	Third	Fourth	Annual
2011 (dollars)					
High	**39.64**	**43.72**	**43.23**	**44.74**	**44.74**
Low	**36.10**	**38.95**	**37.00**	**39.25**	**36.10**
Close	**39.31**	**42.35**	**42.54**	**44.53**	**44.53**
Volume (millions of shares)	**106.9**	**85.9**	**107.4**	**120.6**	**420.8**
2010 (dollars)					
High	37.87	38.16	38.88	39.28	39.28
Low	33.96	30.01	35.50	35.49	30.01
Close	37.22	35.61	38.17	37.99	37.99
Volume (millions of shares)	91.8	93.5	89.2	108.1	382.6
2009 (dollars)					
High	35.00	34.40	34.00	36.49	36.49
Low	28.86	29.34	30.19	31.92	28.86
Close	29.83	31.32	33.37	36.19	36.19
Volume (millions of shares)	113.7	131.8	110.9	97.2	453.6
2008 (dollars)					
High	40.97	40.71	40.65	39.26	40.97
Low	36.21	35.98	35.95	29.42	29.42
Close	39.55	39.50	38.17	33.17	33.17
Volume (millions of shares)	86.1	134.0	114.0	159.7	493.8
2007 (dollars)					
High	41.35	40.29	39.83	40.73	41.35
Low	36.75	35.77	35.43	36.47	35.43
Close	38.35	36.64	36.47	40.54	40.54
Volume (millions of shares)	88.7	78.7	91.4	77.2	336.0
New York Stock Exchange *(Stock trading symbol TRP)*					
2011 (U.S. dollars)					
High	**40.76**	**45.09**	**44.08**	**44.38**	**45.09**
Low	**36.12**	**40.37**	**37.29**	**37.58**	**36.12**
Close	**40.53**	**43.84**	**40.49**	**43.67**	**43.67**
Volume (millions of shares)	**30.3**	**23.8**	**51.6**	**48.5**	**154.2**
2010 (U.S. dollars)					
High	37.11	38.01	37.75	38.59	38.59
Low	31.58	25.80	32.86	34.77	25.80
Close	36.76	33.43	37.12	38.04	38.04
Volume (millions of shares)	17.8	23.8	19.7	23.6	84.9
2009 (U.S. dollars)					
High	29.01	30.93	31.74	34.59	34.59
Low	20.01	23.20	25.88	29.66	20.01
Close	23.65	26.91	31.02	34.37	34.37
Volume (millions of shares)	42.1	27.2	20.9	21.7	111.9
2008 (U.S. dollars)					
High	41.53	40.64	39.29	36.33	41.53
Low	35.60	35.33	34.01	23.52	23.52
Close	38.53	38.77	36.15	27.14	27.14
Volume (millions of shares)	8.7	8.8	9.8	17.2	44.5
2007 (U.S. dollars)					
High	35.30	37.21	38.06	43.94	43.94
Low	31.33	32.91	32.92	36.68	31.33
Close	33.28	34.41	36.61	40.93	40.93
Volume (millions of shares)	8.2	5.7	9.0	7.9	30.8

FIVE YEAR FINANCIAL HIGHLIGHTS

(millions of dollars except where indicated)	**2011**	2010	2009	2008	2007
Income Statement					
Revenues	**9,139**	8,064	8,181	8,547	8,731
EBITDA					
Natural Gas Pipelines	**2,967**	2,769	3,122	3,315	3,077
Oil Pipelines	**587**	–	–	–	–
Energy	**1,281**	1,117	1,132	1,169	970
Corporate	**(86)**	(99)	(117)	(104)	(102)
	4,749	3,787	4,137	4,380	3,945
Depreciation	**(1,528)**	(1,354)	(1,377)	(1,247)	(1,237)
EBIT	**3,221**	2,433	2,760	3,133	2,708
Financial charges and other	**(937)**	(666)	(897)	(961)	(898)
Income taxes	**(573)**	(380)	(387)	(602)	(490)
Net income	**1,711**	1,387	1,476	1,570	1,320
Net income attributable to non-controlling interest	**(129)**	(115)	(96)	(130)	(97)
Net income attributable to controlling interests	**1,582**	1,272	1,380	1,440	1,223
Preferred share dividends	**(55)**	(45)	(6)	–	–
Net income attributable to common shares	**1,527**	1,227	1,374	1,440	1,223
Comparable earnings	**1,565**	1,361	1,325	1,279	1,100
Cash Flow Statement					
Funds generated from operations	**3,663**	3,331	3,080	3,021	2,621
Decrease/(increase) in operating working capital	**310**	(249)	(90)	135	63
Net cash provided by operations	**3,973**	3,082	2,990	3,156	2,684
Capital expenditures and acquisitions	**3,274**	5,036	6,319	6,363	5,874
Disposition of assets, net of current income taxes	**–**	–	–	28	35
Cash dividends paid on common and preferred shares	**1,016**	754	728	577	546
Balance Sheet					
Assets					
Plant, property and equipment:					
Natural Gas Pipelines	**18,385**	18,230	18,333	19,339	18,122
Oil Pipelines	**9,254**	8,184	5,305	1,361	158
Energy	**10,545**	9,745	9,158	8,435	5,127
Corporate	**78**	85	83	54	45
Total assets	**48,995**	46,794	43,841	39,414	30,330
Capitalization					
Long-term debt	**17,632**	17,028	16,186	15,368	12,377
Junior subordinated notes	**1,009**	985	1,036	1,213	975
Non-controlling interests	**1,465**	1,157	1,174	1,194	999
Preferred shares	**1,224**	1,224	539	–	–
Common shareholders' equity	**16,100**	15,503	15,220	12,898	9,785

	2011	2010	2009	2008	2007
Per Common Share Data (dollars)					
Net income – basic	**$2.18**	$1.78	$2.11	$2.53	$2.31
– diluted	**$2.17**	$1.77	$2.11	$2.52	$2.30
Comparable earnings per share	**$2.23**	$1.97	$2.03	$2.25	$2.08
Dividends declared	**$1.68**	$1.60	$1.52	$1.44	$1.36
Book Value[1][7]	**$22.87**	$22.27	$22.24	$20.92	$18.13
Market Price					
Toronto Stock Exchange ($Cdn)					
High	**44.74**	39.28	36.49	40.97	41.35
Low	**36.10**	30.01	28.86	29.42	35.43
Close	**44.53**	37.99	36.19	33.17	40.54
Volume (millions of shares)	**420.80**	382.60	453.6	493.8	336.0
New York Stock Exchange ($US)					
High	**45.09**	38.59	34.59	41.53	43.94
Low	**36.12**	25.80	20.01	23.52	31.33
Close	**43.67**	38.04	34.37	27.14	40.93
Volume (millions of shares)	**154.20**	84.94	111.9	44.5	30.8
Common shares outstanding (millions)					
Average for the year	**701.6**	690.5	651.8	569.6	529.9
End of year	**703.9**	696.2	684.4	616.5	539.8
Registered common shareholders[1]	**32,113**	32,639	33,169	33,681	34,204
Per Preferred Share Data (dollars)					
Dividends declared:					
Series 1, 3 and 5 cumulative first preferred shares[2]	**$3.25**	$2.60	$0.29	$–	$–
Financial Ratios					
Return on average common shareholders' equity[3]	**9.7%**	8.0%	9.8%	12.7%	14.0%
Dividend yield[4][5]	**3.8%**	4.2%	4.2%	4.3%	3.4%
Price/earnings multiple[5][6]	**20.4**	21.3	17.2	13.1	17.5
Price/book multiple[5][7]	**1.9**	1.7	1.6	1.6	2.2
Debt to debt plus shareholders' equity[8]	**54%**	53%	53%	57%	59%
Total shareholder return[9]	**22.2%**	9.7%	14.4%	(15%)	3%
Earnings to fixed charges[10]	**2.5**	1.9	2.1	2.7	2.6

(1) As at December 31.

(2) Preferred shares were issued for Series 1, 3 and 5 in September 2009, March 2010 and June 2010, respectively, with annual dividend rates of $1.15, $1.00 and $1.10 per share, respectively. The first quarterly dividends for each series were paid in December 2009, June 2010 and November 2010, respectively.

(3) The return on average common shareholders' equity is determined by dividing net income applicable to common shares by average common shareholders' equity (i.e. opening plus closing common shareholders' equity divided by two) for each year.

(4) The dividend yield is determined by dividing dividends per common share declared during the year by price per common share as at December 31.

(5) Price per common share refers to market price per share as reported on the Toronto Stock Exchange as at December 31.

(6) The price/earnings multiple is determined by dividing price per common share by the basic net income per share.

(7) The price/book multiple is determined by dividing price per common share by book value per common share as calculated by dividing common shareholders' equity by the number of common shares outstanding as at December 31.

(8) Debt includes junior subordinated notes, total long-term debt, including the current portion of long-term debt, as at December 31 and excludes long-term debt of joint ventures. Common shareholders' equity in this ratio is as at December 31.

(9) Total shareholder return is the sum of the change in price per common share plus the dividends received plus the impact of dividend re-investment in a calendar year, expressed as a percentage of the value of shares at the end of the previous year.

(10) The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of EBIT and interest income and other, less income attributable to non-controlling interests with interest expense and undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of interest expense, interest expense of joint ventures and capitalized interest.

INVESTOR INFORMATION

STOCK EXCHANGES, SECURITIES AND SYMBOLS

TransCanada Corporation

Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

First Preferred Shares, Series 1 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.A

First Preferred Shares, Series 3 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.B

First Preferred Shares, Series 5 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.C

TransCanada PipeLines Limited (TCPL)*

Preferred shares are listed on the Toronto Stock Exchange under the following symbols:

First Preferred Shares, Series U: TCA.PR.X and Series Y: TCA.PR.Y

* TCPL is a wholly owned subsidiary of TransCanada Corporation.

Annual Meeting The annual meeting of shareholders is scheduled for April 27, 2012 at 10:00 a.m. (Mountain Daylight Time) at the BMO Centre, Calgary, Alberta.

Dividend Payment Dates Scheduled common share dividend payment dates in 2012 are January 31, April 30, July 31 and October 31.

For information on dividend payment dates for TransCanada Corporation and TCPL Preferred Shares visit our website at www.transcanada.com.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan (Plan) allows common and preferred shareholders of TransCanada and preferred shareholders of TCPL to purchase common shares of TransCanada by reinvesting their cash dividends without incurring brokerage or administrative fees. Participants in the Plan may also buy additional common shares, up to Cdn$10,000 per quarter. For more information on the Plan please contact our Plan agent, Computershare Trust Company of Canada or visit our website at www.transcanada.com.

TRANSFER AGENTS, REGISTRARS AND TRUSTEE

TransCanada Corporation Common Shares Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver) and Computershare Trust Company, N.A. (Golden)

TransCanada Corporation First Preferred Shares, Series 1 Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver)

TransCanada Corporation First Preferred Shares, Series 3 Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver)

TransCanada Corporation First Preferred Shares, Series 5 Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver)

TCPL First Preferred Shares, Series U and Series Y Computershare Trust Company of Canada (Montréal, Toronto, Calgary and Vancouver)

TCPL Debentures

Canadian Series: BNY Trust Company of Canada (Halifax, Montréal, Toronto, Calgary and Vancouver)

11.10% series N 10.50% series P 11.90% series S 11.80% series U
9.80% series V 9.45% series W

U.S. Series: The Bank of New York (New York) 9.875% and 8.625%

TCPL Canadian Medium-Term Notes CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Calgary and Vancouver)

TCPL U.S. Medium-Term Notes and Senior Notes The Bank of New York Mellon (New York)

TCPL U.S. Junior Subordinated Notes The Bank of Nova Scotia Trust Company of New York

NOVA Gas Transmission Ltd. (NGTL) Debentures

Canadian Series: BNY Trust Company of Canada (Halifax, Montreal, Toronto, Calgary and Vancouver)

11.20% series 18 12.20% series 20 12.20% series 21 9.90% series 23

U.S. Series: U.S. Bank Trust National Association (New York) 8.50% and 7.875%

NGTL Canadian Medium-Term Notes BNY Trust Company of Canada (Halifax, Montreal, Toronto, Calgary and Vancouver)

NGTL U.S. Medium-Term Notes U.S. Bank Trust National Association (New York)

REGULATORY FILINGS

Annual Information Form TransCanada's 2011 Annual Information Form, as filed with Canadian securities commissions and as filed under Form 40-F with the SEC, is available on our website at www.transcanada.com.

A printed copy may be obtained from:

Corporate Secretary, TransCanada Corporation, 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1

SHAREHOLDER ASSISTANCE

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone or e-mail at:

Computershare Trust Company of Canada, 100 University Avenue, 9th Floor, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1.800.340.5024
Telephone: 1.514.982.7959

E-mail: transcanada@computershare.com

www.computershare.com

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

If you would like to receive quarterly reports, please contact Computershare or visit our website at www.transcanada.com.

Electronic Proxy Voting and Delivery of Documents TransCanada is pleased to offer registered and beneficial shareholders the ability to receive their documents (annual report, management information circular, notice of meeting and view-only proxy form) and vote online.

In 2012, registered shareholders who opt to receive their documents electronically will have a tree planted on their behalf through eTree. For more information and to sign up online, registered shareholders can visit www.etree.ca/transcanada.

Shareholders who do not have access to e-mail, or who still prefer to receive their proxy materials by mail also have the ability to choose whether to receive TransCanada's annual report by regular mail. Each year, shareholders are required to renew their option and will receive a notification for doing so. The annual report is available on the TransCanada website at www.transcanada.com at the same time that the report is mailed to shareholders.

Electronic delivery and the ability to opt out of receiving the annual report by mail, provides increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the company.

TransCanada in the Community TransCanada's annual Corporate Responsibility Report is available at www.transcanada.com. If you would like to receive a copy of this report by mail, please contact:

Communications 450 1st Street SW, Calgary, Alberta T2P 5H1, 1.403.920.2000 or 1.800.661.3805 or Communications@transcanada.com

Visit our website at www.transcanada.com to access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call webcasts and investor presentations.

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site web ou vous adresser par écrit à TransCanada Corporation, bureau du secrétaire.

BOARD OF DIRECTORS

(as at December 31, 2011)

S. Barry Jackson[1][2]
Chairman
TransCanada Corporation
Calgary, Alberta

Russell K. Girling
President and CEO
TransCanada Corporation
Calgary, Alberta

Kevin E. Benson[1][3]
Corporate Director
Calgary, Alberta

Derek H. Burney, O.C.[1][4]
Senior Strategic Advisor
Norton Rose Canada LLP
Ottawa, Ontario

Wendy K. Dobson[2][5]
Professor, Rotman School
of Management and Director,
Institute for International Business
University of Toronto
Uxbridge, Ontario

E. Linn Draper[4][6]
Former Chairman, President and CEO
American Electric Power Co., Inc. (AEP)
Lampasas, Texas

The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C.[2][5]
Senior Partner
Stein Monast L.L.P.
Québec, Québec

Paul L. Joskow[1][4]
President
Alfred P. Sloan Foundation
New York, New York

John A. MacNaughton[4][7]
Chairman
Business Development Bank of Canada
Toronto, Ontario

David P. O'Brien, O.C.[1][2]
Chairman
Encana Corporation
Royal Bank of Canada
Calgary, Alberta

Paula Rosput Reynolds[9]
President and CEO
PreferWest LLC
Seattle, Washington

W. Thomas Stephens[5][8]
Former Chairman and
Chief Executive Officer
Boise Cascade, LLC
Greenwood Village, Colorado

D. Michael G. Stewart[4][5]
Corporate Director
Calgary, Alberta

(1) Member, Governance Committee

(2) Member, Human Resources Committee

(3) Chair, Audit Committee

(4) Member, Audit Committee

(5) Member, Health, Safety and Environment Committee

(6) Chair, Health, Safety and Environment Committee

(7) Chair, Governance Committee

(8) Chair, Human Resources Committee

(9) Ms. Reynolds was appointed to the Board of Directors effective November 30, 2011. She had not been appointed to any Committee as at December 31, 2011.

CORPORATE GOVERNANCE

Please refer to TransCanada's Notice of 2012 annual meeting of shareholders and Management information circular for the company's statement of corporate governance.

TransCanada's Corporate Governance Guidelines, Board charter, Committee charters, Chair and Chief Executive Officer terms of reference and codes of business conduct and ethics are available on our website at www.transcanada.com. Also available on our website is a summary of the significant ways in which TransCanada's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Additional information relating to the company is filed with securities regulators in Canada on SEDAR (www.sedar.com) and in the United States on EDGAR (www.sec.gov). The documents referred to in this Annual Report may be obtained free of charge by contacting TransCanada's Corporate Secretary at 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1, or by telephoning 1.800.661.3805.

Ethics Help-Line The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1.888.920.2042.



(From left to right)

Alex Pourbaix
President,
Energy and Oil Pipelines

Wendy Hanrahan
Executive Vice-President,
Corporate Services

Sean McMaster
Executive Vice-President,
Stakeholder Relations and General Counsel

Russ Girling
President
and Chief Executive Officer

Don Wishart
Executive Vice-President,
Operations and Major Projects

Don Marchand
Executive Vice-President
and Chief Financial Officer

Dennis McConaghy
Executive Vice-President,
Corporate Development

Greg Lohnes
President,
Natural Gas Pipelines

CONTACT INFORMATION

Visit www.transcanada.com for more information on:

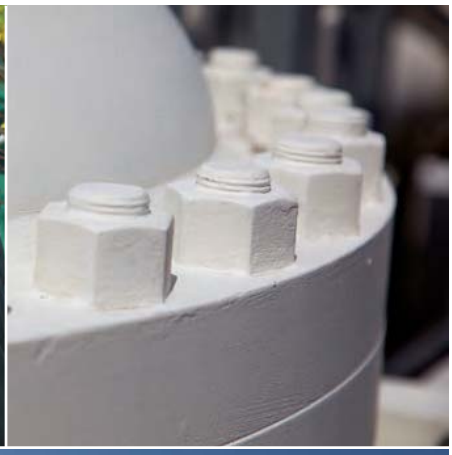
Our pipelines and energy businesses • Projects and initiatives • Corporate responsibility • Corporate governance • Investor services

TransCanada welcomes questions from shareholders and investors.
Please contact: David Moneta, Vice-President, Investor Relations 1.800.361.6522 (Canada and U.S. Mainland)

TransCanada Corporation TransCanada Tower, 450 First Street SW, Calgary, Alberta T2P 5H1
1.403.920.2000 1.800.661.3805









OUR VISION

TransCanada will be the leading energy infrastructure company in North America, with a strong focus on pipelines and power generation opportunities located in regions where we have or can develop significant competitive advantage.

Please recycle Printed in Canada March **2012**

Dow Jones Sustainability Indexes
Member 2011/12

TransCanada
In business to deliver

“Exhibit I”

ISOLUX CORSÁN

Annual 2011 Report



annual report
2011

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CI
Letter from the Chairman



Luis Delso Heras | Chairman

The success of a strategy

In the global context of decline that has characterised 2011, we have seen our Group's ability to compete in an even more adverse environment than in previous years. Isolux Corsán closed the year with record breaking portfolio of €43.11 Bn, 43% higher than in the previous year, and recorded a new all-time high in EBITDA growth -26% - which brought gross operating earnings to €393 Mn. We also increased our total revenues, up to €3.372 Bn and expanded our workforce, now employing more than 8,900 people. This performance would not have been possible without the important role of the international market: 63% of turnover comes from abroad.

For over seven years, Isolux Corsán has had a clear need to think about the business globally. And this idea is the key to our past, present and future results.

Our global business vision has allowed us to have a presence in over 30 countries, with significant activity in what today are the world's leading economies, such as Brazil, USA and India, and we have expanded our international presence with new contracts in Africa and the Middle East.

We have consolidated our presence in Brazil with new contracts, and are executing one of the most complex projects in the company's history: construction of 1,191 km of transmission lines in the Amazon jungle while safeguarding the natural resources of the area. In the past year have begun to build 295-metre high tension towers that will cross the 2.5 km between the banks of the Amazon River. This project includes many of the 3,328 km of transmission lines we hold under concession in this country. In the field of infrastructure, we build and manage 680 km of motorways.

USA is one of the key countries in our international expansion strategy in the coming years. The company, which has begun the construction of 605 km of transmission lines in the State of Texas, achieved the milestone of being the first non-American company to win a concession for the construction, maintenance and management of electric transmission lines in the USA.

India is the main focus of Isolux Corsán in Asia. The strategic alliance signed with Morgan Stanley Infrastructure Fund will enable us to jointly invest US$400 million in long-term road infrastructure concession contracts in this country. The company's activity in this country includes the concession and construction of four motorways totalling 710 km, and the construction of 1,600 km of transmission lines in Uttar Pradesh. The latter project is the largest energy contract in the country. In addition, the Group has expanded its presence in Asia with the construction of two large power plants in Bangladesh.

Despite our strong and growing commitment to internationalisation, the Spanish market continues to hold an important position in our company. In Spain, where the economic crisis has hit businesses the hardest, especially in regard to public works contracts, Isolux Corsán has managed to position itself at the forefront of high speed rails and R&D+i. We have participated in the construction of almost all Spanish high-speed railway lines and collaborate in several innovation programmes and projects, among which we would particularly highlight the agreement with ADIF in the field of railway technology.

Demand in such a large and constantly changing market has led our company to adapt to the idiosyncrasies of each country, facing the difficulties of new challenges with a commitment to overcome them. Our philosophy, based on excellence in business and professional management and respect for the environment in which we operate, has enabled us to grow and become stronger in recent years of economic recession.

I am convinced that our company's achievements have been made possible through the efforts of a strong and committed professional team and I hope that everyone who is now part of Isolux Corsán, and all those who join us in the future, will continue contributing to development of our company to overcome any difficulties and strengthen our presence in all countries where we operate.



Board of Directors

Chairman

Luis Delso Heras

Vice-Chairman

José Gomis Cañete

Directors

Antonio Portela Álvarez
Serafín González Morcillo
Francisco Moure Bourio
Javier Gómez-Navarro Navarrete
Ángel Serrano Martínez-Estéllez
Antonio Hernández Mancha
José Luis Ros Maorad
Vicente Sánchez Álvarez
Eduardo López Milagro
Antonio Pulido Gutiérrez
José María de Torres Zabala

Secretary

Juan Francisco Falcón Ravelo

(as of 31st December 2011)



International Presence

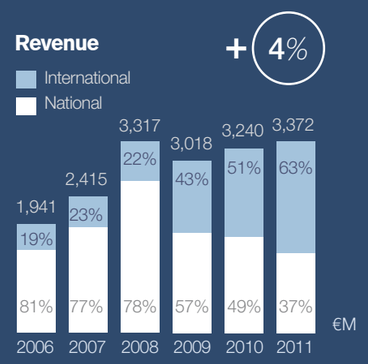
Europe	America	Asia	Africa
Spain	Argentina	Saudi Arabia	Angola
Italy	Bolivia	Bangladesh	Algeria
Portugal	Brazil	India	Gabón
United Kingdom	Chile	Jordan	Equatorial Guinea
	Colombia	Kuwait	Kenya
	Ecuador	Oman	Morocco
	USA	Qatar	Mauritania
	Guatemala	Siria	Mozambique
	México		
	Nicaragua		
	Panama		
	Peru		

Employees

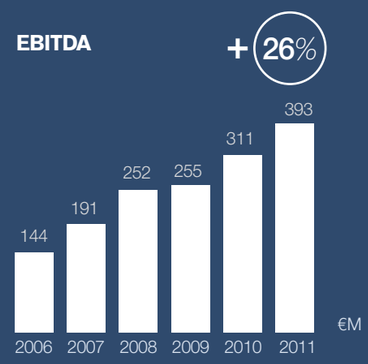
8,922

2011 in figures

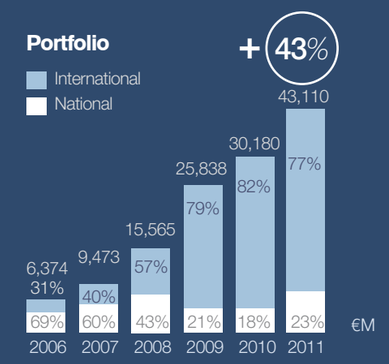
Revenue + 4%



EBITDA + 26%



Portfolio + 43%



Revenues

3,372
Million euros

EBITDA

393
Million euros



Portfolio

43,110
Million euros

Revenue by geographical area

America **45%**



Europe **40%**



Asia **9%**



Africa **6%**



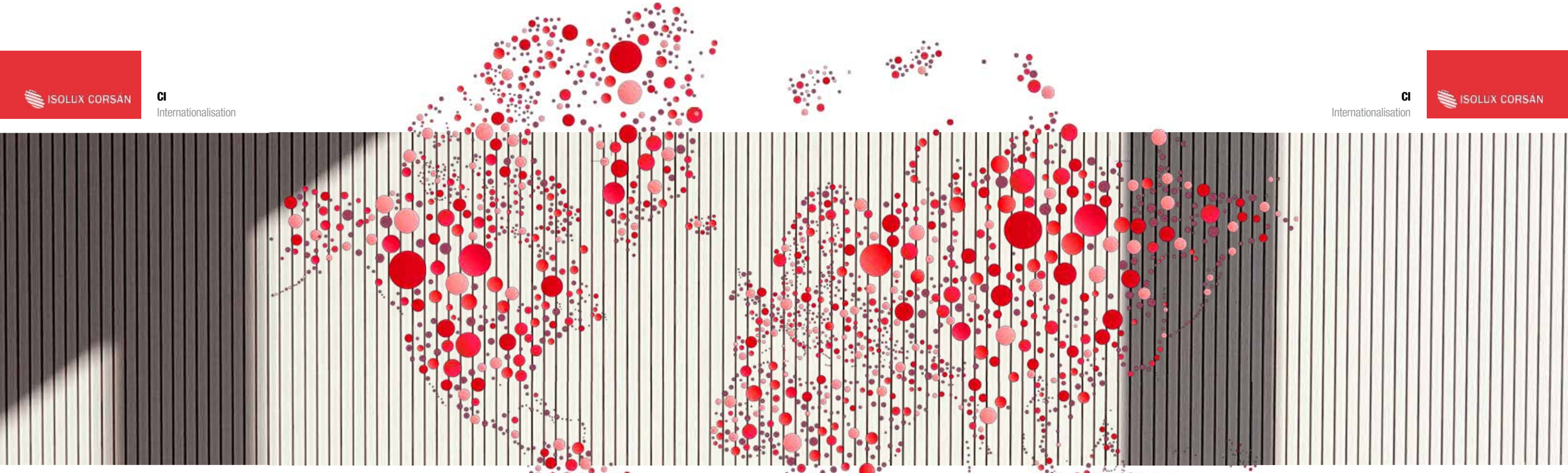
Key figures

5,533 Km of transmission lines in Brazil, India and the USA

1,610 Km of motorways in India, Brazil, Mexico and Spain

230 MWp of solar power developed and managed by the Group

22,779 Parking spaces in Spain



Expanding globalisation

Isolux Corsán has consolidated its internationalisation strategy and strengthened its position in the global market. For the second consecutive year, revenues from abroad in 2011 exceeded those generated in Spain (63% vs 37%). The business portfolio outside of Spain is also much higher than within our home country, representing 77% of the total and more than €33 Bn.

The distribution of income according to geographical area places the American continent as Isolux Corsán's main market, accounting for 45% of turnover. It is followed by Europe with 40%.

In the international concessions market, Isolux Corsán has important concession assets: 1,610 km of motorways in India, Brazil, Mexico and Spain, of which 1,400 km are in operation-, 5,533 km of transmission lines in Brazil, USA and India, and solar photovoltaic power plants in Italy, India, Peru and Spain.

India
In 2011, Isolux Corsán has fully entered the energy concessions market in India with the largest transmission lines contract in this country: 1,600 km of high tension lines in Uttar Pradesh with an approximate investment of €815 million. In this country, where, in 2011, the company operated more than 700 km of motorways, Isolux Corsán signed an agreement with the global infrastructure fund Morgan Stanley Infrastructure Partners for the investment of US$400 million in highway projects under India's National Highways Authority's programme for the coming years.

Brazil
The Brazilian market is also one of the most important for Isolux Corsán's activity in 2011. In this country, one of the most dynamic in the world, the company has 3,328 km of transmission lines (we won a new contract in Taubaté) and is executing one of the largest and most complex transmission line construction projects: 1,191 km of lines in the Amazon. This activity has resulted in the recruitment of about 3,000 people in Brazil, expanding the number of employees in the North and South America by 46%.

United States
Isolux Corsán remains active in the USA and is advancing in the construction of the 605 km of transmission lines managed through WETT (Wind Energy Transmission Texas), a project awarded in 2009, which will bring clean power produced by wind turbines to the population of southeast Texas.

Africa
Isolux Corsán has been awarded the contract to build the largest high voltage transmission line in Kenya, and one of the largest in Africa, with a voltage of 400 kV and a length of 428 km. The price of this EPC contract, which the company signed with Kenya Electricity Transmission Company (Ketraco), an agency of the Ministry of Energy of Kenya, is €142 million.

This contract represents the consolidation of the Group in East Africa and its presence throughout the continent, where it already has table operations in eight countries: Angola, Algeria, Gabon, Equatorial Guinea, Kenya, Mauritania, Morocco and Mozambique. Activity in Africa accounts for 6% of the company's income. Ongoing projects in Africa, mostly belonging to the energy sector, represent turnover in excess of €1 billion for Isolux Corsán.

Middle East and Asia
The Group is active in Saudi Arabia, Jordan, Kuwait, Oman, Qatar, Syria and India. This part of the world will clearly be one of the areas of international consolidation of the company in the future.

In the Energy field, Isolux Corsán operates in 23 countries with projects of all its business lines, particularly in generation, T&D and renewable energy. In generation, the company has won major projects for power plants in Bangladesh. Regarding renewable energy, the Group has expanded its international business with the entry into the photovoltaic market in the UK. Regarding Oil & Gas, Isolux Corsán, through its subsidiary Tecna, has major projects in Africa, Europe, Latin America and the Middle East.

In the Construction business, the company has international projects in over 9 countries. The opening of new markets with significant awards in Peru and Chile and more than €180 million of new work awarded in the last year in Argentina, Brazil and Chile, are a clear example of the success of our internationalisation strategy and our advance towards the globalisation of the company.

01

Concessions

Concessions

Consolidation of a strategy

Morgan Stanley, KKR and MEAG are the new partners of Isolux Corsán

The keys to our success lies in the increased activity in strategic countries like USA, India and Brazil, the financing and operation of concessions

The Isolux Corsán concessions business ratified the consolidation of the business strategy developed in recent years. Thanks to this commitment, the growth in turnover from concessions reached €323.7 Mn, up 98% over 2010.

Isolux Corsán has successfully interpreted the changes implied by the crisis by combining public interest and private development. This awareness has opened the doors to the international concessions market, and, above all, has earned the recognition of major players in the world economy, such as Morgan Stanley, KKR and MEAG, which have become strategic partners in various operations of the Concessions division. In addition, Isolux Corsán has managed to penetrate the energy concessions market in India with the largest transmission lines contract in this country (1,600 km of high tension lines in Uttar Pradesh) and has consolidated its presence in the USA (605 km of lines managed through WETT) and Brazil, with the award of new contracts (Taubaté-Nova Iguaçu).

There is one more element to this strategy that completed this review of the keys to success: the entry into operation of much of our concession business (83% of the length of Isolux Corsán's toll road concessions are already in operation) and high financing capacity demonstrated in 2011, which is based on very solid numbers.

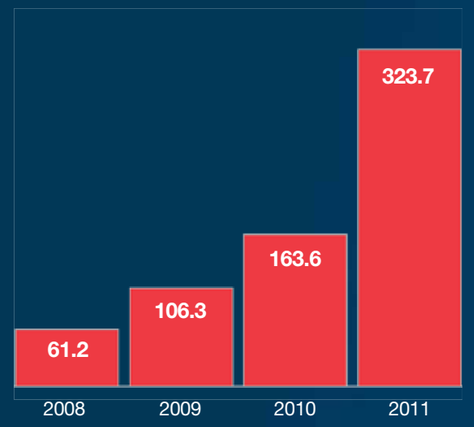
The Concessions business focuses on the management of road and energy infrastructure with an investment of more than €7.5 billion and backlog of €35.805 billion.

In the past year, the Group has added photovoltaic power to its Concessions activity



Isolux Corsán has consolidated its presence in the Brazilian energy market

Concession revenues. In €Mn



The Concessions business area grew 98% in 2011 and achieved turnover of €323.7 million

The specific weight of this business area has led to the reorganization of the business in 2011 around Isolux Infrastructure, the concessions subsidiary of Isolux Corsán, engaged in the management and operation of the concession assets of the Group, most notably motorway concessions in India, Brazil, Mexico and Spain, the transmission lines concessions in Brazil, USA and India and photovoltaic power generation in Italy, India and Peru.

Operation and financing

The Group increased its entry into operation of infrastructures concessions and consolidated its financing

Morgan Stanley associated with Isolux Corsán for the development of existing and future projects in India, committing to a combined capital investment of US$400 million.

In a global financial environment as complex as that in 2011, the entry of Morgan Stanley Infrastructure as Isolux Corsán partner is one of the greatest milestones of the Infrastructures Concessions business.

In 2011, Morgan Stanley Infrastructure associated with Isolux Corsán for the development of existing and future projects in India, committing to a combined capital investment of US$400 million.

This transaction reinforces the Group in two ways. On the one hand, represents the recognition of the growth strategy undertaken in one of the economies distinguished as one the new international powerhouses. On the other, it shows the confidence in Isolux Corsán by world-class investors in infrastructures. In addition, this confirms the role of Isolux Corsán in India, where it has become the leading European developer of infrastructures operating in the country.

For Isolux Corsán, India is the Group's main focus in Asia and one of the most important, along with Brazil, in its growth strategy abroad.

The Group currently has 1,400 km of motorways in operation in India, Brazil, Mexico and Spain, an increase of 15.6% over the previous year.



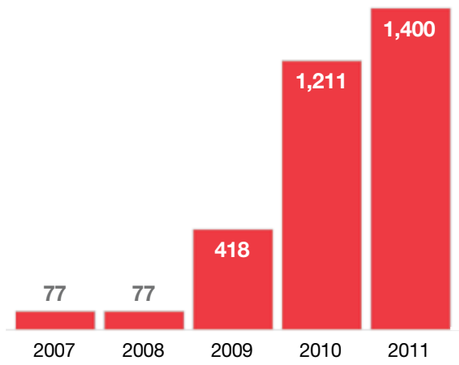
Toll area on BR 116 ■ **Salvador de Bahia | Brazil**



The company has 1,610 km of motorways in India, Brazil, Mexico and Spain, 83% of which is in operation

Stretch of NH-1 Panipat - Jalandhar, with an average rate of 23,147 vehicles per day ■ **Panipat** | India

■ **Km of motorways in operation**



An investment of more than €3 billion

In total, the company builds and manages 1,610 km of motorways (710 km of toll roads in India, 680 km in Brazil, 155 km in Mexico and 64 km in Spain), with an investment in excess of €3.8 billion.

The Group has 83% of the total km under concession in operation. In 2011 100% of the Saltillo-Monterrey motorway in Mexico came into operation. The performance of this business area in general and the results achieved in 2011 in particular, have garnered the confidence of the great international traders when assessing the capabilities of the Group in the development of large infrastructure projects in markets with high strategic value.

Power for strategic economies

Isolux Corsán has 5,533 km of transmission lines in Brazil, USA and India

In 2011, the Isolux Corsán's Energy Concessions business continued to grow in key countries in the new global economy. The Group has 5,533 km of transmission lines in Brazil (3,328 km), United States (605 km) and India (1,600 km). An especially strategic geographical presence due to the need that these economic powers have for this type of infrastructure.

The Group's expertise has enabled it to grow in those countries where it was already settled and penetrate new markets. The entry in 2011 in the Asian market with the largest power transmission concession is one of the milestones in this business area. The best example of growth is provided by Brazil, where the Group achieved 247 new km of transmission lines between Taubaté-Nova Iguaçu.

This new concession, located between Rio de Janeiro and Sao Paulo, call for a total investment of €133 million and will bring in estimated annual income of €13 million. The concession is for 30 years.

The Energy Concessions business includes project management for both transmission lines and associated substations and for generation projects.

Transmission lines concessions

Country	Km
Brazil	3,328
India	1,600
USA	605
Total	**5,533**

In 2011, the Group confirmed its presence in the Brazilian energy market with the award of new lines and substations



Transmission tower ■ Brazil

Transmission lines under concession

Lines	Country	Km
South East Uttar Pradesh Power Transmission Company Limited	India	1,600
IENNE Interligaçao Eletrica Norte e Nordeste	Brazil	720
Linhas de Macapá	Brazil	713
WETT - Wind Energy Transmission Texas	USA	605
Jauru Transmissora de Energia Tramo Norte	Brazil	595
Linhas de Xingu	Brazil	527
Jauru Transmissora de Energia Tramo Sur	Brazil	345
Linhas de Taubaté	Brazil	247
Cachoeira Paulista Transmissora de Energia	Brazil	181

Entry into India with the largest high tension line contract in the country

Isolux Corsán was awarded in India the largest high tension transmission lines concession in the country and one of the largest in the world market. This contract includes the construction and operation of 1,600 kilometres of high voltage transmission lines (765 kV and 400 kV), 2 GIS substations and 3 AIS substations with 5,730 MVAs of different transformation combinations of 765/400/220/132 kV, with an estimated investment of €815 million. The concession, awarded by Uttar Pradesh Power Transmission Corporation Limited in a public tender process, is for 37.5 years.

The new network, located in Uttar Pradesh, will carry 4,600 MW to be generated by new power plants being built in this State, which, with over 150 million inhabitants, is the most populous in India.

This project ensures Isolux Corsán's presence in the concessions market in India and makes the Group the leading European infrastructure developer operating in this country.

Isolux Corsán will build and operate 1,600 km of transmission lines in India with an investment of €815 Mn.

Local partners

For the execution of the 1,600 kilometres of power lines awarded in Uttar Pradesh, Isolux Corsán has partnered with a local partner: C&C Constructions.

Such partnerships, together with the ambitious infrastructure investment plan of the Indian government, strengthens the role of Isolux Corsán in coming years, both in this country and in other neighbouring areas like the Middle East.

The largest solar photovoltaic power generator in Europe

Isolux Corsán takes control of T-Solar

Through T-Solar, the Group develops and manages more than 230 MWp in Spain, Italy, India and Peru

Among the most important milestones of the Concessions business in 2011, we would highlight the integration of T-Solar as the Solar PV business division with a particular international outlook.

With the expansion of Isolux Corsán's stake in T-Solar (up to 58.8%), the Group assumed control of the company, integrating it into a new solar photovoltaic power division.

T-Solar, which was founded in 2006, has in less than five years become a leading solar photovoltaic Independent Power Producer (IPP). The company currently has an installed capacity of 173 MWp in operation and more than 55 MW under construction.

The 43 solar PV power plants that the company has in operation generated in 2011 a total of 245 GWh of clean electricity, which is equivalent to average annual electricity consumption of a population of over 55,000 homes.

In 2011, T-Solar placed an additional 8 MW in operation in Italy and 5 MW in India. In addition, T-Solar has a cutting-edge factory with a production capacity of 60 MW, which manufactures photovoltaic solar modules, using thin-film hydrogenated amorphous silicon modules, of up to 5.7 m^2.

Photovoltaic Division | T-Solar

173 MW in operation
More than 55 MW under construction
245 GW/h of electricity generated in 2011
43 plants in operation
Thin-film hydrogenated amorphous silicon modules of up to 5.7 m^2

Osiyan Solar Farm ■ **Rajasthan** | India

Investment partnerships with MEAG and KKR

The company has an alliance agreement with Munich Re, one of the leading insurance groups in the world, through its asset management company MEAG, and with the global investment firm Kohlberg Kravis Roberts & Co. L.P. (KKR), to acquire 49% of operating assets that T-Solar has in operation.
This alliance with highly qualified investors enables Isolux Corsán to expand its presence in the solar energy field and develop an ambitious business plan in 2014 to reach over 500 MW of generating capacity.



Isolux Corsán operates internationally

Energy Management Centre

At its Madrid headquarters, T-Solar has a Energy Management Centre (EMC) which can monitor continuously and in real time (24 hours a day, 365 days a year) the performance of all solar photovoltaic power plants connected to the centre located anywhere in the world.

This is a pioneer control centre, approved in 2011 by Red Eléctrica Española, equipped with state-of-the-art technology and telecommunications infrastructure that allows real-time monitoring of all parameters and indicators that help to optimise the operation, performance and maintenance each plant.

In 2011, T-Solar signed a commercial agreement with GDF Suez Energía España to offer power producers a special control centre service and send them remote measurements in real time.

A benchmark in R&D+i

T-Solar leads the European research project HELATHIS, included under the Seventh Framework Programme of the European Commission which aims to reduce costs and improve the performance of thin-film silicon photovoltaic modules.



Energy Management Centre of T-Solar ■ **Madrid** | Spain

Consolidation and growth

Isolux Corsán maintains stable growth in the car park business line despite the economic environment

Isolux Corsán is entrenched as the third car park operator in Spain

The car park sector in Spain encompasses 1.2 million parking spaces and generates around €864 million and about 12,000 jobs. Isolux Corsán's car parks division is one of the top companies in this sector in Spain, currently managing 22,779 spaces in 46 parks in 23 cities. The investment in this division amounted to €250 million.

With the maturation of the car parks that were commissioned in recent years, the development of the hospital car park business line and the management of third party car parks, have led Isolux Corsán's car parks division to once again rank as the third parking management company in Spain, with average weighted growth since 2006 of 26.27%.

During 2011 the division was awarded the concessions for the parking facilities of the new courts of Las Palmas de Gran Canaria (460 spaces), three car parks in Vigo (1,251 spaces), another belonging to the Mutualidad de la Abogacía of Alicante (374 spaces) and the new Hospital de Burgos (1,378 spaces).

Currently, 81.59% of the spaces in operation, while 3.20% and under construction and 15.21% are in the design phase.

The Isolux Corsán car parks division comprises several business lines: the development and operation of car parks in rotation, which satisfies the short and medium term demand for parking in places like hospitals, business centres and shopping malls, municipal on-street parking (known as ORA in Spain), aimed at the integrated management and regulation of parking on public roads, and also includes services such as towing and the handling of complaints, and the management of parking contracts for third parties. Lastly, the company is engaged in the promotion and sale of parking spaces for residents, including their design, construction and management.

Parking spaces in operation, 18,586 at the close of the year, increased by 15.63% in 2011



Acueducto Oriental Car Park ■ **Segovia** | Spain

Car Park Concessions

Total number of spaces	22,779
Facilities	46
Cities	23
Spaces in operation	18,586
Spaces under construction	728
Spaces being designed	3,465

Wind power

Isolux Corsán has strengthened its wind power concessions business and now has 271 MW

Isolux Corsán has extensive experience in the field of wind power starting in 2002. The Wind Energy Concessions division specializes in the design, financing, construction and operation of wind farms, both in Spain and internationally. In total, the company manages, under concession, 271 MW in different wind farms.

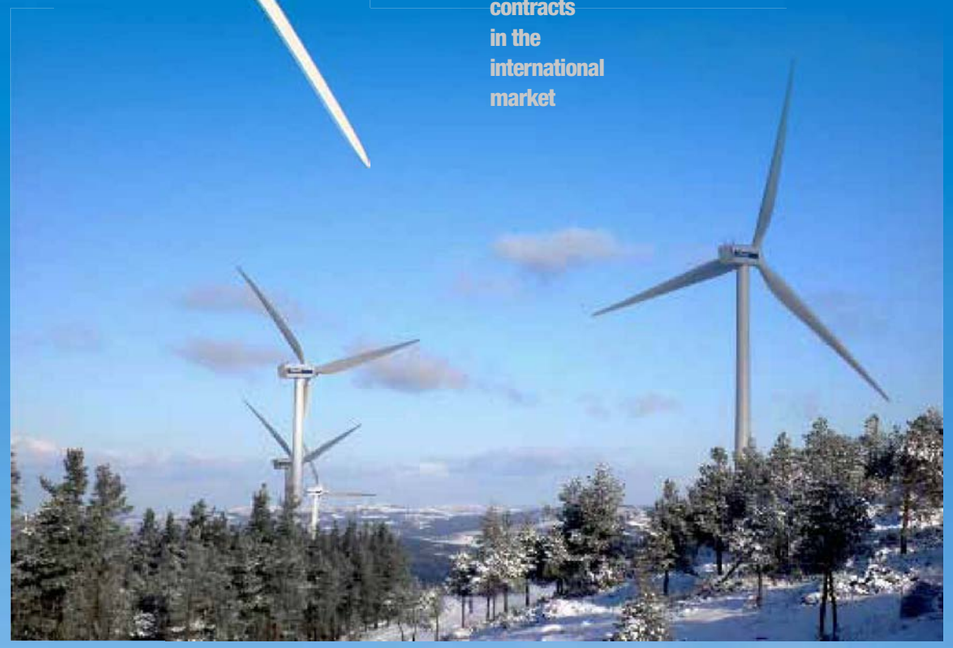
In 2002 Isolux Corsán was awarded a 50 MW wind farm plan to take place in two phases. In 2008 the company was awarded the first phase for the construction and commissioning of 24 MW. The second phase, 26 MW, is currently under construction and expected to be completed and put into operation in 2012.

Isolux Corsán is undertaking the construction of Loma Blanca Wind Farm in the province of Chubut, Argentina. The Argentine state agency ENARSA (Energía de Argentina, S.A.) awarded this project to the Group in 2010 for a total installed capacity of 200 MW.

Wind Farm Concessions

Wind Farm	Capacity
Sierra Cabrera | Spain	21 MW
Cova da Serpe | Spain	50 MW
Loma Blanca | Argentina	200 MW

The Group achieved new contracts in the international market



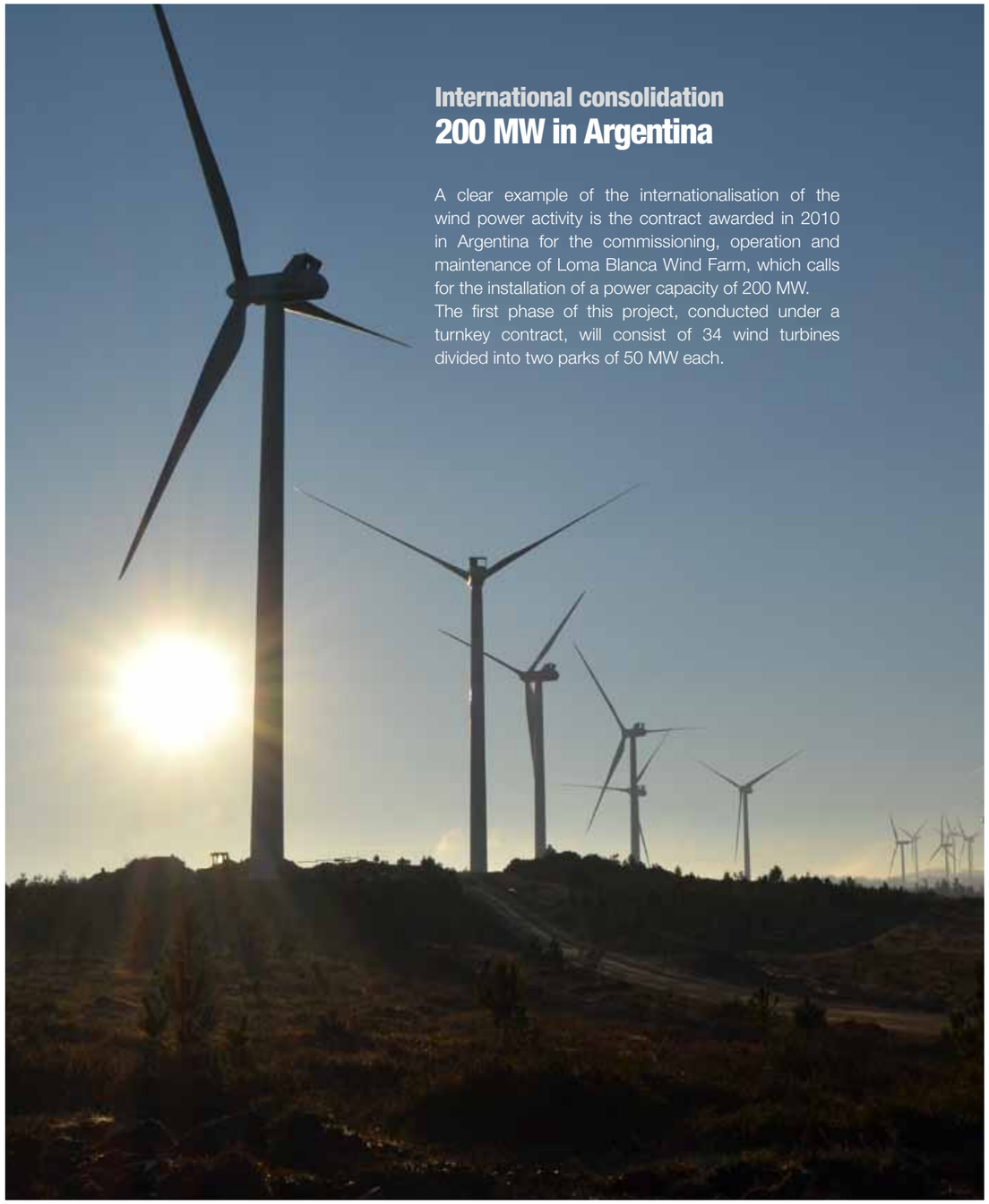
Cova da Serpe Wind Farm ■ **Lugo** | Spain

Loma Blanca Wind Farm | Argentina

Developer: **ENARSA** | Power: **200 MW** | Commissioning: **2013 (first phase 100 MW)**
Execution period: **16 months**

International consolidation
200 MW in Argentina

A clear example of the internationalisation of the wind power activity is the contract awarded in 2010 in Argentina for the commissioning, operation and maintenance of Loma Blanca Wind Farm, which calls for the installation of a power capacity of 200 MW.
The first phase of this project, conducted under a turnkey contract, will consist of 34 wind turbines divided into two parks of 50 MW each.



México: two key motorways

Saltillo-Monterrey Highway | Length: **95 km** | Concession: **45 years**
Perote-Banderilla Highway | Length: **60 km** | Concession: **45 years**



Saltillo-Monterrey contributes to the modernisation of a very large network ■ **Monterrey** | México

Saltillo - Monterrey and Perote - Banderilla

Essential roadways for the organisation and cohesion of the country

Isolux Corsán currently operates 100% of the Saltillo-Monterrey motorway and is building the Perote-Banderilla, measuring 95 km and 60 km respectively and both have a concession period of 45 years.
In 2011, the Group opened up the last sections of the Saltillo-Monterrey motorway.

The Saltillo-Monterrey Motorway has become a hub of competitiveness for the more than 5 million people living in the metropolitan areas of both cities, while Perote-Banderilla, which connects Mexico City with the Port of Veracruz, Mexico's most important sea port, represents the fastest and safest alternative between these cities.

Saltillo-Monterrey and Perote-Banderilla were awarded in 2006 and 2008 respectively

These two toll roads total 155 km under concession


Isolux Corsán operates 100% of the motorway


Panoramic view of the motorway


Toll area of the motorway Saltillo-Monterrey


Section of the motorway Saltillo-Monterrey


Morones Prieto viaduct



Section of the motorway

Brazil: Taubaté Transmission Lines

Project name: **Linhas de Taubaté Transmissora de Energia** | Transmission lines: **Taubaté-Nova Iguaçu**
Client: **Agencia Nacional de Energía Eléctrica (ANNEL)** | Km length: **247** | Voltage: **500 kV** | Investment: **€133 Mn**
Duration of the concession: **30 years**



The Group has been active for more than a decade in the Brazilian market

New energy awards
Consolidated growth in Brazil

Isolux Corsán reinforces its presence in Brazil with the award, in 2011, of 247 km of 500 kV transmission lines between Rio de Janeiro and Sao Paulo by the National Electric Energy Agency (ANNEL) of this country.
The project also includes associated substations in Nova Iguaçu (530/345 kV and 500/138 kV, 1,800 MVA of transformation).

With an investment of 133 million euros and a concession period of 30 years, this project is part of the existing Cachoeira Paulista project, currently managed by Isolux Corsán and leading to the creation of 900 jobs. The new line will provide an annual income of €13 million.
With this award, Isolux Corsán has 3,328 km of transmission lines in Brazil.

The new line has a maximum term of 26 months to start operations





High Tension Towers ■ Brazil

Photovoltaics: increasing international expansion

Italy. 8 plants in operation: **8 MW** | **India.** 1 plant in operation: **5 MW**
Peru. 2 plants in operation: **44 MW** | **India.** 1 plant under construction: **12 MW**



Russo Solar Farm
in Lessina
Puglia | Italy

T-Solar is the first Spanish company to connect a solar plant in India

Operations launched in India and Peru
The company already has 69.3 MW outside of Spain

T-Solar has consolidated its international expansion plan in 2011 with the start of its activity in India and Italy. The company is currently present in Spain, Italy, India and Peru with a total capacity of 230 MW in operation and under construction.
In 2011, the company connected its first photovoltaic power plant in India with a capacity of 5 MW, with the thin-film hydrogenated amorphous silicon modules produced by the company at its plant in Galicia, Spain. In Peru, T-Solar is building two 44 MW plants located in the region of Arequipa in the south. In Italy, the first destination of the international activity of the company, T-Solar had 8 MW in operation in 2011.



Osiyan Solar Farm ■ **Rajasthan** | India



Laronga Solar Farm ■ **Puglia** | Italy

The success of a strategy: parking at hospitals

Car Parks: **7,253 spaces** at hospitals



Isolux Corsán was awarded the operation of the hospital parking at the future Burgos Hospital

32% of the parking spaces managed by the Group are owned by hospitals

In 2011, Isolux Corsán reinforced the Parking business area by extending its business to the hospital sector. The promotion and management of car parks in rotation has become a key success factor for this business area, in which the company currently manages a total of 7,253 spaces located in major hospitals in Spanish territory.

Recently, Isolux Corsán Aparcamientos was awarded a contract for the operation of the parking facilities are what will become the largest hospital in Castilla y Leon, the new Burgos Hospital, with a capacity of 1,378 parking spaces.

The management of the hospital parking at Miguel Servet Hospital in Zaragoza (199 spaces), Cartagena Hospital (1,780 spaces) and Mar Menor Hospital (633 spaces) has contributed to the growth in the hospital parking business line.

The Group has 7,253 parking spaces at hospitals across Spain



Parking at the Hospital Los Arcos del Mar Menor

Murcia | Spain



Parking at the Hospital of Cartagena

Murcia | Spain

02

Energy

Activity Report
02. Energy

Unstoppable growth and projection abroad

The Energy department contributes a third of the total turnover of the Group and maintains its growth trend for another year

With revenues of €1.293 billion, this department reinforces its presence in key countries and entered into new foreign markets

Isolux Corsán's Energy Department consolidates its growth for another year (an 18% increase in sales) and its important role in the four main areas in which it operates: T&D, generation, renewable energy and Oil & Gas. In all of its business lines, the company has managed to project itself in terms of growth, international expansion and business diversification.

With annual revenues of €1.293 billion, the Energy Department represents a third of the turnover of the company, becoming one of the most strategic areas for the Group. Isolux Corsán has diversified its business and strengthened its international presence in key countries, such as the USA, India and Brazil, and has entered into new markets.

Today, Isolux Corsán operates in 23 countries in Energy-related projects.

Among the intense activities in 2011, the Amazon project remains one of the most representative, both for the great complexity of the work involved and for the very size of the project, already in full swing. The company is building 1,191 km of transmission lines in the Amazon jungle that will allow the use of renewable energy for electricity consumption in the region. For the development of this work, Isolux Corsán has hired more than 3,000 people.

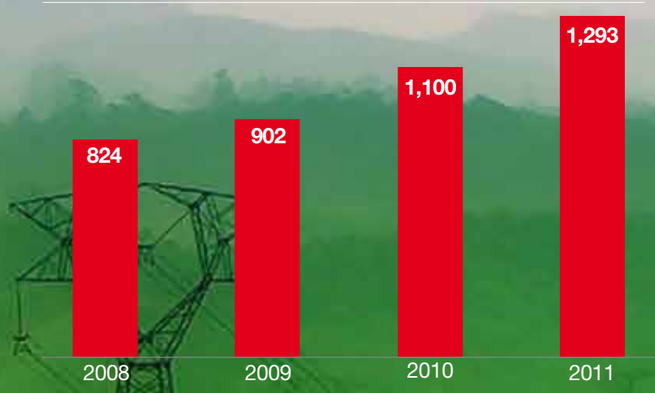
Another major milestones of the year was the award of two power plants in Bangladesh and a contract in India for the construction of 1,600 km of transmission lines and 800 kV substations in Uttar Pradesh.

The company consolidated its role as a benchmark for both T&D and construction of power plants through EPC contracts

Also, regarding renewable energy, the Group has expanded its international business with the entry into the photovoltaic market in the UK.

Lastly, in Oil & Gas, Isolux Corsán, through its subsidiary Tecna, has major projects in Africa, Europe, Latin America and the Middle East.

Energy revenues. In €Mn



Strong momentum in Asia, Africa and Latin America

The Group consolidates its activities in Argentina, Bangladesh and Angola

In 2011, Isolux Corsán was awarded two major contracts for electricity generation in Bangladesh

Isolux Corsán is strongly active in the field of electricity generation by thermal power plants. In 2011, the company increased the MW under construction thanks to the award of major contracts in Bangladesh and Argentina.

The most important milestones of the area in 2011 include two large power generation projects in Bangladesh. The first, current in execution, involves the construction of a 180 MW open cycle power plant in Khulna, the third largest industrial city of Bangladesh. The second project, located in Siddhirganj (one of the first industrial hubs in the country, is a 330 MW combined cycle plant. These contracts have been awarded by the national electricity company of Bangladesh North-West Power Generation Company and Electricity Generation Company of Bangladesh, respectively.

In order to explore new market opportunities in Asia, Isolux Corsán has performed studies in India and Bangladesh on the improvement of electricity transmission networks and the installation of new power plants. The goal is to support the continuity and capacity of the expansion plans of these countries and strengthen the stability of their systems. In Argentina, Isolux Corsán was awarded two contracts from the National Electricity Company of Argentina (ENARSA) for conversion to combined cycle of the two power plants that the company is building in the country: Ensenada Barragán and Brigadier López. This combined cycle technology will allow the plants to raise their output by close to 58%.

The Ensenada Barragán plant, in 2x1 configuration, will reach a combined cycle power of 830 MW, up from 560 MW in single cycle, while the Brigadier López plant, in 1x1 configuration, will generate 410 MW combined cycle. Also in Argentina, in 2011 Isolux Corsán has advanced in the construction of the Río Turbio coal power plant, the southernmost in the world.

In Argentina, the company was awarded two contracts for conversion to combined cycle

In Angola, Isolux Corsán has made the final adjustments and testing for entry into operation of the 90 MW Fútila Plant (Cabinda). This plant is configured with two simple cycle turbines that can operate with both liquid fuel (diesel) and natural gas.

Also in Africa, the company is conducting studies on the installation of new power plants, where the increased production of natural gas allows the installation of new thermal power plants.

Generation Milestones | 2011

Projects	MW	Country
Conversion to combined cycle of the Ensenada Barragán power plant	830 MW	Argentina
Conversion to combined cycle of the Brigadier López plant	410 MW	Argentina
Construction of the open cycle plant in Khulna	180 MW	Bangladesh
Tests for the entry into operation of the Fútila Plant (Cabinda)	90 MW	Angola
Studies for the upgrade of the electrical system		India
Studies for the upgrade of the electrical system		Bangladesh
Advanced studies for the installation of new power plants		Africa



Power Plant in Río Turbio, the southernmost in the world ■ **Santa Cruz** | Argentina

Record growth in awards

Isolux Corsán has new projects in India, USA, Brazil and Gabon

Isolux Corsán enters the market of direct current lines and became one of the main suppliers in the world

Isolux Corsán is one of the world's leading operators in the installation and maintenance of high voltage electricity transmission and distribution lines (T&D). In 2011, this division registered record growth in awards, over 1 billion euros, and recorded sales of more than €750 million. Among the major contracts won this year, we would highlight those in India, USA, Brazil and Gabon.

In India, Isolux Corsán was awarded a project to build 1,600 km of T&D lines and five substations in Uttar Pradesh, the fifth largest and most populous state in the country, with an investment of €660 million. This project will carry most of the 4,600 MW generated by the new thermal plants being built in the eastern territory to a population of over 200 million people. Also in this country, the company has successfully completed the design and testing of the first 800 kV tower.

USA is one of the key markets for the Group in T&D. Isolux Corsán won a contract of more than €390 million with the company Wind Energy Transmission Texas (WETT) for the construction of over 600 km of transmission and distribution lines. These lines will transport the electricity produced by wind farms in north-west Texas to the south east of the state, which accounts for most of industry and population.

Isolux Corsán has become one of the few contractors in the world doing the construction of high voltage DC converter stations with the first project in 2011.This contract in Brazil was awarded by IE Madeira (Interligaçao Eletrica do Madeira) for the construction of the converter stations and substations in Araraquara, Sao Paulo, which are used for the electricity produced by a huge hydraulic power plant located 3,000 km from Sao Paulo.

In Gabon, the company was awarded a contract from the Ministry of Mines, Energy, Oil and Water Resources, to provide power to the villages between Kango-Bifoun, Ebel-Abanga and Tchibanga-Mayumba.



Cabinda-Landana Substation project ■ **Landana** | Angola

Milestones in T&D awards

Lines	Country	Km
Uttar Pradesh	India	1,600
IENE - Interligaçao Eletrica Norte e Nordeste	Brazil	720
Linhas de Macapá	Brazil	713
WETT - Wind Energy Transmission Texas	USA	605
Jauru Transmissora de Energia Tramo Norte	Brazil	595
Linhas de Xingu	Brazil	527
Jauru Transmissora de Energia Tramo Sur	Brazil	345
Linhas de Taubaté	Brazil	247
Cachoeira Paulista Transmissora de Energia	Brazil	181

In 2011, Isolux Corsán advanced in the projects the company has under development. We would highlight the activity in Mexico, where the company has completed the construction of a transmission line and transformation substation to provide electrical service to Azul de Cortes Tourism Development in Baja California and the construction of three 220 kV transmission lines to evacuate the power generated by three wind farms in the State of Oaxaca, on the Isthmus of Tehuantepec. In Argentina, the company opened in 2011 a 500 kV transmission line in the province of Calingasta, connecting the provincial and national networks that will supply power throughout the area west of the province of San Juan.

In Africa, we would highlight the completion of the Cabinda project in Angola, where Isolux Corsán has built transmission lines, an electrical substation, transformer stations and networks to connect more than 3,000 users for the first time, leading to the development of thousands of families in the cities of Cabinda and Landana.

The Amazon

Without doubt, the Isolux Corsán's project par excellence in T&D is Amazon Project in Brazil, where the company is building 1,191 km of high voltage transmission lines over the Amazon River.

The Amazon project requires an investment in excess of €900 Mn.

Isolux Corsán consolidated its position in the solar PV market

The plants built by the company have a combined installed capacity of 300 MWp

The Group has built and launched the three largest existing PV stations in the UK

In the past year, Isolux Corsán has reaffirmed its leadership position in the construction of solar PV power plants EPC contracts, which have allowed the company to accumulate an installed capacity of about 300 MWp.

The company's activity in the development of solar PV projects range from administrative processing, engineering, and construction, to the commissioning and maintenance of the facility during its useful life.

The experience gained has enabled the company to optimise the construction process, shortening construction times.

In 2011, Isolux Corsán built nine plants in the UK and Italy. Specifically, the Group has built and launched the three largest existing PV stations in the UK for Santander-Low Carbon.

In Italy, Isolux Corsán has built four solar farms for Banco Santander: Pezzullo I and II (Melicucco), Paglialonga I (Bisignano) and Angrone (Meliccucco) and two for Sun Edison-Banco Santander, Ardea (Ardea) and Noce Laccu (Filandari). The installed capacity of these plants is over 11 MWp.

In 2012, Isolux Corsán will begin construction of two new plants in Peru with 44 MWp. The management and implementation of all these works is supported by the leading official certifications of R&D+i (UNE 166.002), quality (ISO 9001), environmental management (ISO 14001) and prevention of occupational risks (OHSAS 18001).

Main Solar PV Plants

Plant	MW	Country
East Langford	5 MWp	United Kingdom
Churchtown	5 MWp	United Kingdom
Manor Farm	5 MWp	United Kingdom
Ardea	2.9 MWp	Italy
Noce Laccu	2 MWp	Italy
Angrone	2 MWp	Italy
Pezzullo 2	1.5 MWp	Italy
Paglialonga 1	1.5 MWp	Italy
Pezzullo 1	1 MWp	Italy

Arnedo Solar PV Power Plant ■ **La Rioja** | Spain

Advances in wind energy

Using the experience gained in the Concessions and engineering and construction capabilities, Isolux Corsán has also strengthened its activities in the field of wind energy.

Since 2004, Isolux has built nine wind farms in Spain with a total installed capacity of 471 MW.

In 2011, the company's main project was building the wind farm in Cova da Serpe. With more than 50 MW of capacity, it is considered one of the most efficient wind farms in Spain.

The goal for 2012 is to build a 100 MW capacity wind farm in Loma Blanca (Argentina), which is the first phase of the project.

Since 2004, the company has built nine wind farms in Spain (471 MW)

Wind farms built

Farm	MW	Country
Pehimo	90 MW	Spain
Pena Ventosa	89 MW	Spain
Fonsagrada	76 MW	Spain
Suldo II	75 MW	Spain
Cova da Serpe	50 MW	Spain
Gamolde	33 MW	Spain
Serra do Páramo	20 MW	Spain
Gralade	20 MW	Spain
Grallas	18 MW	Spain



Integral development of Oil & Gas

The Group, through Tecna, is active in Latin America, Europe and the Middle East



Isolux Corsán operates in Oil & Gas through its subsidiary Tecna, a global engineering and construction company with up-mid and downstream technological capacity. Founded in 1974, and since 2006 integrated in Isolux Corsán, Tecna is specialised in the design, engineering, construction and commissioning of facilities for energy markets, oil and gas, refining, petrochemical, biofuels, electricity generation integrated in oil and gas plants, alternative energies, renewable energies and nuclear energy.

Tecna has a team of 800 people, composed mostly of engineers, technicians and specialists in the development of project engineering and management, with a presence in Latin America, Europe, the Middle East and Africa.

Strategic Projects

Colombia. TGI. Compressor stations
Isolux Corsán is finalising the EPC turnkey delivery of four natural gas compressor stations: Jagua del Pilar, Curumaní and San Alberto, with a capacity of 330 MMSCFD (Million standard cubic feet per day) and the Puente Guillermo compressor station with a capacity of 450 MMSCFD.

Peru. Pluspetrol. Camisea, Malvinas EPC 21
Since 2004, Isolux Corsán has developed, through Tecna, the Malvinas plant expansion project in the Peruvian Amazon jungle.

Peru. Repsol. Campo Kinteroni Facilities
The project prepared for Repsol Peru involves the engineering, procurement and construction (EPC) of surface facilities for a three well production platform with a daily production of 180 MMSCFD of gas in the Peruvian jungle.



Brazil. Transportadora Urucú-Manaus (TUM). Coarí and Juaruna compressor stations
Through its subsidiary Tecna, Isolux Corsán was contracted by Transportadora Urucu-Manaus (TUM), a subsidiary of Petrobras and operator of the Urucu-Manaus gas pipeline, for the provision of two compressor plants located in the Amazon jungle. These new plants will provide increased transport capacity of the pipeline, 660 km long, which supplies the city of Manaus.

Brazil. Petrobras – Caraguatatuba
The new Isolux Corsán project in Brazil involves the installation of a dew point adjustment unit (UAPO-3) of 6 MMSCFD and two natural gas condensate processing units (UPGN 2 and 3) of 2,400 m^3/d each.

Angola
The consortium comprised of Pluspetrol, Sonangol, Force Petroleum and Cupet awarded Tecna the EPC contract for the Castanha onshore field production facilities in Angola.

The plant comprises the crude oil receiving units, primary separation and complementary production facilities.

Mexico
The Isolux-Tecna consortium has completed the construction phase of the sulfur recovery plant (SRU) at the Antonio Amor refinery, in Salamanca and have started work on roll out of the unit.



BPZ Energy Peru offshore Platform Albacora ■ Peru

Tecna is active in Europe, the Middle East, Africa and Latin America

Generation: Ensenada Barragán | Argentina

Client: **Empresa Eléctrica Nacional de Argentina (ENARSA)** | Year of Award: **2011**
Execution period: **30 months starting with commercial operations**
Ensenada Barragán Capacity: **830 MW** | Brigadier López Capacity: **410 MW**



Ensenada Barragán thermoelectric power plant
■ **La Plata, Buenos Aires** | Argentina

This project will increase the plant's output by up to 58%

Ensenada Barragán and Brigadier López Power Plants
Conversion to combined cycle for power generation

In 2011, Isolux Corsán was awarded two contracts from the National Electricity Company of Argentina (ENARSA) for conversion to combined cycle of the Brigadier López and Ensenada Barragán plants to boost plant output by close to 58%. Combined cycle allows the heat energy, which in simple cycle power is dissipated into the atmosphere, to be utilized to generate steam which, in turn, will become additional electricity using a generator, all without increasing the consumption of fuel. In the Ensenada Barragán plant, which has two gas turbines, the project will add two heat recovery boilers and one steam turbine, which will boost the power output from 560 MW to 830 MW.
In the case of Brigadier López with a single gas turbine, we will add a heat recovery boiler and a steam turbine set, reaching about 410 MW.

In 2011, Isolux Corsán was awarded two contracts by ENARSA



Ensenada Barragán substation
■ **La Plata, Buenos Aires** | Argentina



With the conversion to combined cycle the plant will reach 830 MW ■ **La Plata, Buenos Aires** | Argentina

T&D: Amazon Project | Brazil

Developer: **Agencia Nacional de Energía Eléctrica (ANNEL)** | Km of T&D lines: **1,191 km**
Power transmitted: **2,400 MW** | Start of the work: **2009**



The new lines will connect Manaus, the largest city in the Amazon, with the Brazilian interconnected grid

295 foot Towers in the Amazon jungle
Over 1,191 km of T&D lines on the Amazon River

This is one of the most complex works developed by Isolux Corsán both for its size and the difficulties of the terrain, which employs more than 3,000 people in the Amazon jungle. To overcome the difficulties of the terrain the company has developed complex engineering solutions and is building 295 m towers in order to cross the Amazon River.

These new 500 and 230 kV transmission lines will enable the use of renewable energy and allow the capitals of Manaus and Macapa have a fibre optic network to support growing demand for voice and data communications. In 2011, Isolux Corsán developed 100% of the infrastructure needed to carry out the works. It has also executed 30% of civil works, 70% of the accesses, 50% of the foundations and 25% of the tower assemblies.

The project will provide a fibre optic network for the cities of Manaus and Macapa to support the growing demand for voice and data communication



Works of the project requiring over 3,000 workers
Amazon | Brazil



High tension towers crossing the Amazon River
Amazon | Brazil

Renewable energies: Solar farms in the UK

Developer: **Banco Santander and Low Carbon** | PV modules: **66,000 uds**
Power transmitted: **15 MWp** | Date of work: **2011 (completed in 10 weeks)**



Churchtown
Solar Farm
Cornwall | UK

This is the first solar photovoltaic work in this country performed by Isolux Corsán

The three plants are Churchtown, East Langford and Manor Cornwall
The company has built the largest solar farms in the UK

Isolux Corsán completed in 2011 the construction and operation of three solar power plants, the largest in the United Kingdom. With a total of 15 MWp of installed power and a budget of around €40 million, the solar parks, located in the towns of Kilkhampton, St. Austell and Hayle, have 22,000 (total installed photovoltaic modules is 66,000 units) crystalline silicon photovoltaic modules on fixed arrays with 5 MWp of installed capacity each. This project, promoted by Banco Santander and a local partner, is the first photovoltaic work that Isolux Corsán has developed in the UK and has been executed in record time of less than ten weeks. With the construction of these three solar farms, the company reaffirms its leadership position among the top solar PV construction companies in the world.



Manor Solar Farm
ST. Austell | United Kingdom



Churchtown Solar Farm
Churchtown | United Kingdom

Malvinas Gas production plant | Peru

Developer: **Pluspetrol-Peru Corporation** | Cryogenic train capacity**: 520 MMSCFD**
Power transmitted: **15 MW** | Start of the work: **2011**



The Group has participated since 2004 in all stages of the Camisea project
Isolux Corsán expands the Malvinas gas production plant

In 2011, Tecna, a subsidiary of Isolux Corsán, was contracted by Pluspetrol-Peru to expand the Malvinas gas production plant, located in the Amazon jungle of Peru.
The work, which is part of the expansion of the Camisea facilities, involved the installation of a new cryogenic train with a 520 MMSCFD (Million standard cubic feet per day) capacity, a new condensate stabilisation unit, two turbogenerators and twin turbocompressors, as well as the expansion work of all the facilities of the plant and the camp. The goal of this extension is to achieve the new requirements processes to adapt to the increased levels of gas production planned for 2012.
With the award of this work, Pluspetrol-Peru again relied on the ability of Isolux Corsán to develop and implement projects. The company has been participating since 2004 in all previous stages of the Camisea project.

With this expansion, the plant is adapted to the increase in gas production levels for 2012



The Malvinas plant is located in the Amazon jungle
Cusco | Peru



The work is part of the expansion of the Camisea facilities
Cusco | Peru

03

Construction

Construction

Stability and solvency

In the complex context of the sector, our construction activity strengthened its international presence by increasing its portfolio in foreign markets by 24.8%

The construction sector is arguably one of the hardest hit by the global economic crisis.

Spanish Market data reveal a dramatic drop in public tenders. Although during the early years of the recession the decline was moderate, the spending cuts in the last two years by the administration have sparked a collapse of government tenders. In 2006, the total value of the awards by the Spanish government was just over €47 billion. In 2011, this figure fell to €13.755 billion, representing a reduction of 70.9%.

The analysis of cement consumption in Spain also offers a photograph of a total collapse in the activity of this sector, down 63.4% since the start of the crisis. In 2007, Spain consumed about 56 million tonnes of cement, while in 2011 the figure was 20.5 million.

In this scenario, Isolux Corsán demonstrates its solvency as one of the leading companies in construction of major infrastructure in the country with a successful international growth strategy.

The portfolio of the construction activity of the company in foreign markets now accounts for 47.3% of the total, an increase of 24.8% over the previous year.

The opening of new markets, such as Peru and Chile, with the award of significant tenders are a clear example of the success of this globalisation strategy. The company develops construction projects in more than nine countries.

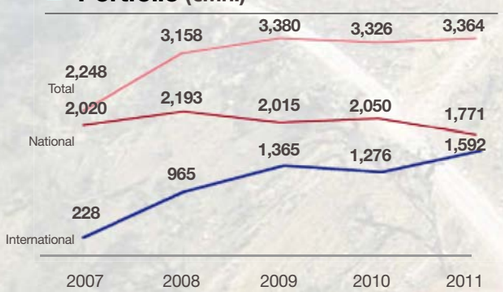
Maintaining the level of construction activity in 2011, the Group has guaranteed work for 37 months

The total portfolio of the construction business line is €3.364 billion, having improved the projection of the activity over time. Thus, maintaining the pace of business in 2011, Isolux Corsán guarantees its construction activities during the next 37 months

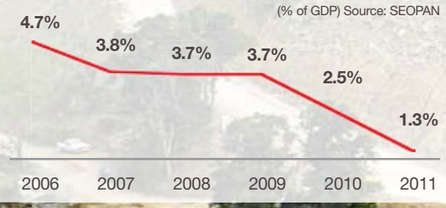
The impact of the crisis has been felt in revenue/turnover, which amounted to €1.085 billion, with the company overcoming other difficulties associated with this situation, such as defaults and financing. Despite the widespread increase in delinquencies in the sector, the Group has significantly improved its collection period.

The company strengthened its expansion strategy with the signing of new contracts in Peru and Chile

Portfolio (€Mn.)



Public tenders | Spain



K-61 overpass of Perote-Banderilla Motorway ■ Mexico

Builders of large infrastructure

75% of the construction portfolio corresponds to civil works

The amount of the most important works completed during 2011 amounted to €1.215 billion of which €986 million corresponded to civil works

The construction of major road and rail infrastructure continues to represent the lion's share of the company's construction activities. In total, civil works represents 75% of the Construction portfolio (€2.522 Bn.), with the remaining 25% corresponding to buildings.

Within civil works, road construction accounts for 47.7% of the portfolio. In 2011, Isolux Corsán completed major road infrastructure, including the Saltillo-Monterrey motorway in Mexico, with a total contract price of €276 Mn, the A7 Concentaina-Muro de Alcoy in Spain, a contract exceeding €58 million and water supply for Mostaganem in Algeria for a total amount that exceeded the €181 million.

International strategy

The international expansion of our business has been the highlight of 2011. With over €180 million of new work awarded in the last year in Brazil, Peru and Chile, the company has reinforced its consolidation strategy in foreign markets. In these countries, Isolux Corsán has received major awards, such as Metro Line 4 of São Paulo, for the construction of 5 stations and a bus terminal completed in early 2012 and the award of the second batch of works that complement the second phase of this project, as well as the works replacing the Bicentennial Bridge over the Biobío River in Chile.

The company won new contracts in Brazil, Peru and Chile totalling more than €180 Mn.



A7 Concentaina - Muro de Alcoy Highway ■ **Alicante** | Spain

Construction activity remained stable in the Spanish market

The decrease of total tenders in Spain, especially those by the Ministries of Development and the Environment, has led to a decline from €5.443 billion in 2010 to €3.210 billion in 2011, a decrease of 43%.

Like other companies in the sector, Isolux has been affected by the decline in public works contracts in the domestic market, with a reduction of 13.57% in the portfolio.

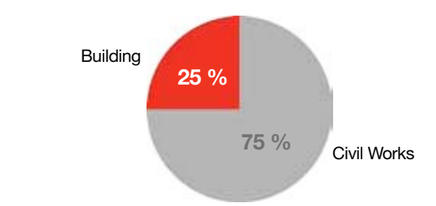
Portfolio 2011

Portfolio by type of works

Major projects completed in 2011

Project	Type	Price	Location
Saltillo-Monterrey Motorway	Roads	€276.5 Mn	Mexico
AVE Ourense - Amoeiro	High-Speed Rail	€226 Mn	Spain
AVE Trinidad - Montcada	High-Speed Rail	€203.9 Mn	Spain
Mostaganem supply works	Hydraulic	€182.3 Mn	Algeria
A7 Cocentaina-Muro de Alcoy Highway	Roads	€58.2 Mn	Spain
Lerida supply works	Hydraulic	€39.7 Mn	Spain

Portfolio by activity



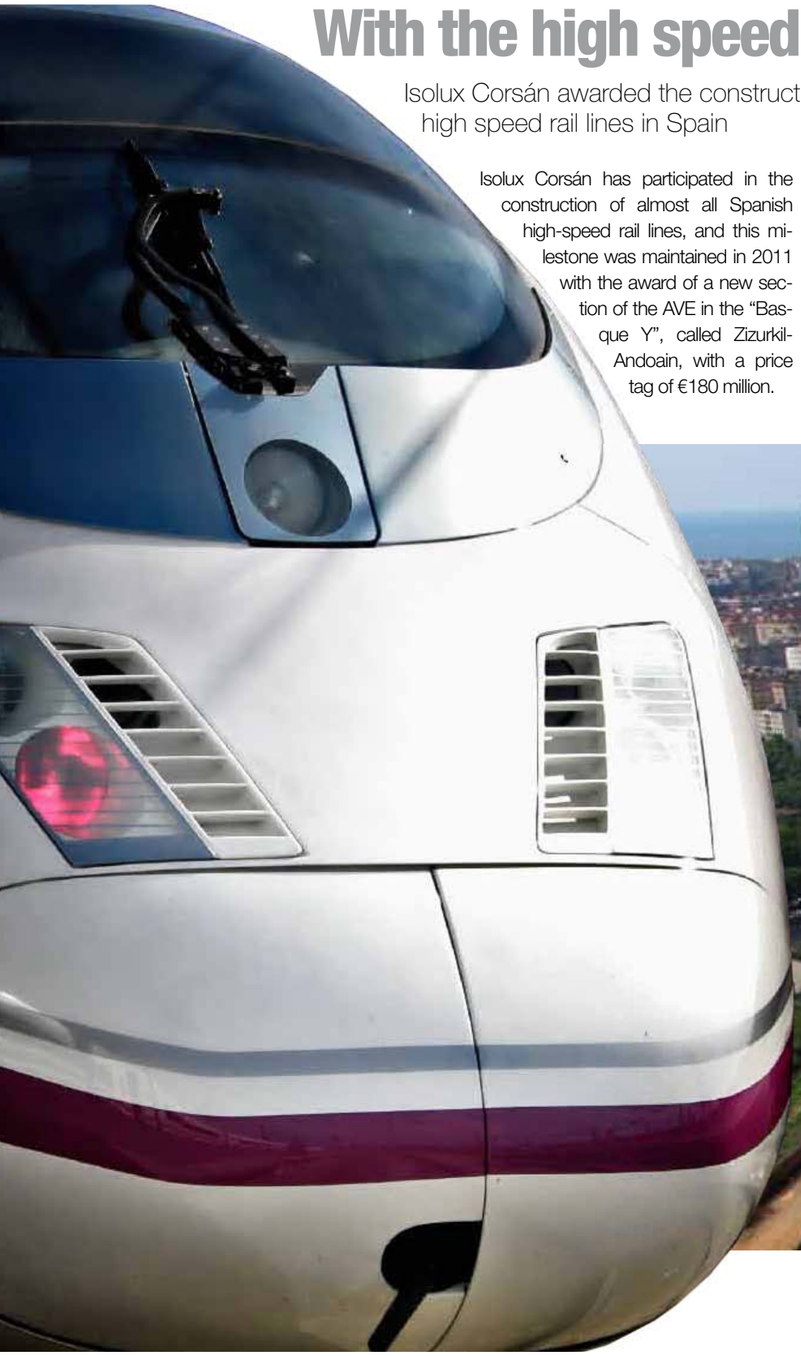
With the high speed rail

Isolux Corsán awarded the construction of new high speed rail lines in Spain

Isolux Corsán has participated in the construction of almost all Spanish high-speed rail lines, and this milestone was maintained in 2011 with the award of a new section of the AVE in the "Basque Y", called Zizurkil-Andoain, with a price tag of €180 million.

The railway works, focusing on high speed rail in Spain, account for 15.4% of the construction portfolio.

In the last year, the company has completed works on Orense-Amoeiro section in Galicia, and the works for the Trinidad-Montcada section of the Madrid-Barcelona corridor, with a contract price in excess of €429 million.



Activity Report
03. Construction | Civil Works
ISOLUX CORSÁN

New contracts for civil works

Project	Budget	Type of work	Location
Basque Y high speed line. Zizurkil-Andoain section	€180 Mn	Railways	Spain
Lagares WWTP - Vigo	€136.7 Mn	Hydraulic	Spain
Metro Sao Paulo. Line 4, stations and terminal	€72.9 Mn	Railways	Brazil
Raw water aqueduct Puerto Lavalle-Juan José Castelli	€58.7 Mn	Hydraulic	Argentina
Replacement of Bicentennial Bridge on the Biobío River	€51.9 Mn	Roads	Chile

Railway works account for 15.4% of the construction portfolio



High speed line La Sagrera ■ **Barcelona** | Spain

Singular buildings

In 2011 the new Santiago de Compostela airport was inaugurated with an expected annual volume of four million passengers

Isolux Corsán was awarded the construction of the City of Justice of Córdoba with a budget of over €243 million

The completion and opening of the new Lavacolla Airport terminal in Santiago de Compostela (Galicia) is probably one of the great milestones of the Building division, which has an overall portfolio of €802 Mn.

Works on the airport of Santiago de Compostela began in 2009 and is a clear example of the high qualifications of Isolux Corsán for the construction of large and complex buildings.

In 2011, the company also completed several residential construction projects: a total of 630 dwellings were built in La Ventilla (Madrid), Alcorcón (Madrid), Zabalgana (Vitoria) and Burgos, all in Spain. Also the company concluded the construction of the High Performance Centre of Sant Cugat, Barcelona and the Prison of Ceuta.

Despite the difficult economic situation of the country, and the sharp drop in construction in general, Isolux Corsán has won major contracts in 2011, such as the building of the City of Justice of Córdoba (€243.9 Mn.), the offices of the new headquarters of news agency EFE in Madrid (€33.2 Mn.) and Hospital del Bicentenario in Argentina (€32.3 Mn).

Most significant works contracted in 2011

Project	Budget	Type of work	Location
City of Justice of Córdoba (surface rights)	€243.9 Mn	Administrative Bldg	Spain
Headquarters of Agencia EFE in Madrid	€33.2 Mn	Administrative Bldg	Spain
Hospital del Bicentenario	€32.3 Mn	Healthcare	Argentina

Projects completed in 2011

Project	Type	Budget	Location
Santiago de Compostela Airport	Airport	€166.2 Mn	Spain
226 houses Burgos	Housing	€20.8 Mn	Spain
161 houses Zabalgana	Housing	€13.7 Mn	Spain
138 houses Alcorcón	Housing	€11.1 Mn	Spain
IES FP Alcoy	School	€8.4 Mn	Spain
105 houses La Ventilla	Housing	€8.1 Mn	Spain

The company will build the new headquarters of the EFE news agency in Madrid

High Performance Centre of Sant Cugat
Barcelona | Spain

NH-8 Motorway: Kishangarh Beawar Section | India

Client: **NHAI (National Highways Authority Of India)** | Execution Period: **30 months**
Budget: **€185.4 Mn** | Length: **44.1 km**



Construction of NH-8 ■ **Rajasthan** | India

Since 2009 the Group has increased its construction activity in India, which already covers 700 km

Consolidation of the Group presence in India
Isolux Corsán builds 4 motorways under concession

The NH-8 Motorway is part of a proposed construction of four motorways in India, where Isolux has increased its activity since 2009. The project, which runs between the towns of Kishangarh and Beawar in the state of Rajasthan, has a total length of 44.1 km. The works, with a budget of €185.4 million and an execution period of 30 months, involve the expansion of the existing road 2/4 lane highway to a new six lane divided highway, with three lanes in each direction measuring of 3.5 and 12.25 meters wide each. This motorway runs along a flat terrain occupying mostly the corridor of the old NH-8, so there are neither large embankments or clearing needed. The main elements of the project are 3 railroad overpasses, 5 viaducts, 1 overpass, 17 underpasses and 78 cross drainage works.



The total investment in the project is €185.4 Mn.
■ **Rajasthan** | India

The NH-8 Motorway will have two three-lane roadways



The motorway is built on the route of the old NH-8
■ **Rajasthan** | India

Trinidad-Montcada High Speed Rail Line | Spain

Client: **Ministry of Public Works ADIF**
Execution period: **24 months** | Budget: **€203.9 Mn**



Overview of the access shaft



Lowering of the shield



Lowering of the cutting head



Cutting head



Assembling the machine



TBM



Views inside the Trinidad-Montcada high-speed train tunnel ■ **Barcelona** | Spain

Most of its almost five kilometres are underground

New high-speed rail section in Barcelona

The construction of the Trinidad-Montcada section (Barcelona) is part of the high speed line between Madrid, Zaragoza and Barcelona to the French border. With a price tag of €203.9 million and an execution period of 24 months, extendible, the project aims to complete construction of 4,754 m of railway platform, including the execution of a tunnel measuring 3,017 meters long and a false tunnel between the concrete screens of 692 m. The project also includes the implementation of major detours on conventional rail lines, along with other affected services. The complexity and heterogeneity of the land, together with the abundant presence of abrasive minerals, have been among the biggest challenges during the execution, forcing us to make many stops to review and change the cutting tools of the TBM.



Work routes in the tunnel



Command post



Repair and reinforcement of the cutting head



Ventilation and emergency shaft



Breakthrough of the TBM



Breakthrough of the TBM

Airport of Santiago de Compostela | Spain

Client: **AENA** | Execution period: **24 months** | Budget: **€166.2 Mn**



The terminal building has a surface area of 74,000 m² ■ **Santiago de Compostela** | Spain

The terminal will handle 27 operations per hour

The new terminal is already in operation
With capacity to serve 2,500 passengers at peak times

In 2011, Isolux Corsán completed the construction of the new passenger terminal for the Lavacolla Airport in Santiago de Compostela. The project includes a terminal building of 74,000 m², with capacity to serve more than 3.5 million passengers a year and manage 45,000 annual operations, a five-storey car park with 3,500 parking spaces, the external infrastructure, including road access structures needed for general operation and supply networks, and central plant and utility tunnel.

The new terminal, with a price tag of €166.2 million and an execution period of 24 months, is designed to serve 2,500 passengers at peak times and manage 27 aircraft operations per hour.

The terminal has 3,500 parking spaces on 5 floors



The terminal building has a capacity to serve 3.5 million passengers a year ■ **Santiago** | Spain



The new terminal has had a budget of €166.2 Mn.
■ **Santiago** | Spain

04

Environment

Environment

Isolux Corsán doubles the volume of foreign activity

Revenue in the Environment Department has increased nearly 70% since 2008

In 2011, revenues from the international market have almost doubled that of the domestic market

For over 30 years, Isolux Corsán, through the Environment Department, designs, builds and operates all types of infrastructure related to water cycle. This extensive experience places the company amongst the leading companies in the sector, both nationally and internationally.

Strategies for participation in increasingly ambitious tenders have led the Group to undertake larger projects. Examples include the Lagares Waste Water Treatment in Vigo, awarded in 2011, and the Campo Limpo Plant in Brazil, currently in execution.

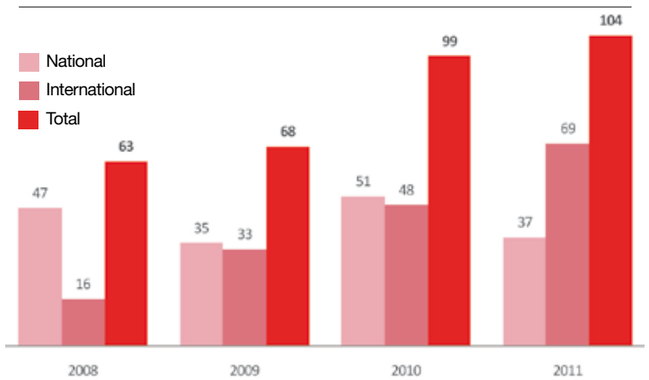
Recently, Isolux Corsán has become part of the Technology Partnership for Water Treatment (ATTA).

Environmental activities, despite the difficult situation in the sector, have grown steadily in recent years with revenues increasing nearly 70% since 2008, surpassing €100 Mn in 2011.

This strong revenue growth comes from expanding the scope of our activities. Isolux Corsán's presence in over 30 countries has helped the Environment Department in the award of new projects in countries like Brazil, Argentina, Mexico and Algeria.

In 2011, revenues from the international market have almost doubled that of the domestic market.

Revenues from environmental activities. In €Mn





Quality and innovation for the environment

As part of its commitment to the environment, Isolux Corsán considers research and innovation in the field of the integral water cycle as a fundamental commitment, with the goal of making treatment systems more energy efficient and therefore environmentally friendly. In this regard, we continue increasing investment in R&D+i, leading projects such as ANAGUA, co-financed by CDTI, and ADECAR, funded by the MICIIN. The total investment in both projects exceeds 4.5 million. All activities of the environmental business line are included in the scope of the certificates of ISOLUX INGENIERÍA, S.A. issued by AENOR, for both the Quality Management System (UNE-EN ISO 9001:2008) with registration number ER-0215/1994 and for the Environmental Management System (UNE-EN ISO 14001/2004) with registration number GA-2001/0048.

Featured Projects

Project	Budget In €Mn	Country
Expansion and modernization of the Lagares WWTP. Vigo	115.9	Spain
Waste water purification and Campo Limpo collectors. Sao Paulo	65.0	Brazil
WWTP for area 8A of region of Aragón. Teruel	45.9	Spain
Desalination plant in Moncofa. Castellón	43.8	Spain
San Felipe WWTP. Tucumán	36.3	Argentina
Waste water purification and collectors for Tomelloso and Argamasilla de Alba. Ciudad Real	23.1	Spain
Operation and maintenance of the WWTP of La China (4 years). Madrid	15.2	Spain
Torres de la Alameda WWTP. Madrid	14.6	Spain
Comarca Agraria de Cáceres WWTP	12.5	Spain
Management, conservation, maintenance of sewage service of Tremp, La Pobla de Segur, Sort, Ignatius Press, Espot, Ribera de Cardós, La Guingueta D'Áneu and Esterri D'Áneu. Lleida	12.4	Spain
Operation of the Val d'Aran treatment plants. Lleida	10.5	Spain
El Bayadh WWTP	9.6	Algeria
Expansion of the North II WWTP in Puerto Vallarta. Jalisco	7.2	Mexico

Wastewater treatment plant in Puerto Vallarta | Mexico

Total equivalent population: **486,000 people**
Total treatment capacity: **1,125 litres per second**



The infrastructure will serve 486,000 residents ■ **Puerto Vallarta** | Mexico



With this extension the operating capacity jumps from 750 to 1,125 litres per second ■ **Puerto Vallarta** | Mexico

Entry into the hydraulic works market in Mexico

Isolux Corsán completed in 2011 the wastewater treatment plant of Puerto Vallarta, an infrastructure with which the company enters the hydraulic works market of Mexico. This facility is a breakthrough in our commitment to the environment in this important tourist resort in the Pacific. The work involved the construction of the extension of the operating capacity of the WWTP Norte II, from 750 to 1,125 litres per second.

The work, completed in 2011, had a budget of over €7 million

Desalination plant in Moncofa | Spain

Production capacity: **30,000 m³/day** | Length of land outfall: **2,756 m**
Total length of submarine pipelines: **4,320 m** | Water tank capacity: **43,244 m³**



The project includes the distribution network for Chilches and Moncofa ■ **Castellón** | Spain



Implementation of intake ■ **Castellón** | Spain



Interior view of the desalination plant ■ **Castellón** | Spain

The project included the design, execution and operation and maintenance for 3 years

Production capacity of 30,000 m³ of water a day

Isolux Corsán developed the seawater desalination plant in Moncofa, Castellón, including the design, construction, operation and maintenance of the plant for 3 years. The total budget was €43,853,911. This infrastructure has a production capacity of 30,000 m³/day of desalinated water using reverse osmosis.



The total contract budget amounts to about 44 million euros ■ **Castellón** | Spain

06

Facilities, Maintenance and Services

Facilities, Maintenance and Services

Leaders in high-speed rail

Isolux Corsán awarded the first public-private partnership with Adif

The Facilities, Maintenance and Services business line is noted for their expertise in the field of electrification and railway communications systems, electromechanical installations in singular buildings, turnkey projects in utilities substations, large deployments of fibre optics and security systems.

The company was awarded new high speed rail works in the Albacete-Alicante section worth €280 Mn.

Transport

High speed rail, key to the business

In 2011, the company closed a contract for a public-private partnership with ADIF, the first of its kind in our country, for the implementation of telecommunications and signaling systems on the Albacete-Alicante section of the Madrid-Levante line with a price tag of €280 Mn. Isolux Corsán, which participated in a joint venture with 3 companies, will be responsible for carrying out the construction projects and the execution of the works in less than a year and for maintaining them for 20 years.

Internationally, we would highlight the implementation of the Facilities Management, Maintenance and Services Department in Algeria, Argentina, Brazil, India and Portugal. This business line has grown especially in India with the award of contracts with Metro Mumbai and Metro Calcutta. These contracts were awarded in public tenders that have enabled the Group to establish an advantageous position in such a strategic sector in Asia as railways. In addition, Isolux Corsán is siallting the catenary installations for power supply of the Oran tram in Algeria and for the Compañía Paulista de Transporte Metropolitano of Brazil.



Energy

Firm commitment to "turnkey" projects

Within this business line, the energy sector has committed to comprehensive turnkey construction contracts for Red Eléctrica Española, with power transformer substations such as Mezquita and Carril, and substations for private clients such as Reigosa, San Juan and Rugui.

In parallel, work and our commitment has continued on major maintenance and facilities contracts for electric utilities and power plants and infrastructure for large clients: Endesa in Aragón and the Canary Islands, Iberdrola in Castilla and Levante, Unión Fenosa in Galicia and Madrid, Hidrocantábrico in Asturias and Repsol and Alcoa in Galicia.

The Group continues its activity in India with a project for the central station of the Mumbai Metro

Facilities

Efficiency in the rehabilitation and provision of installations

For AENA, Isolux Corsán has performed the renovation and upgrading of installations and air conditioning in the terminal building of the Tenerife Airport, one of the main Spanish airports with an annual average of 54 million passengers.

The company has made the electrical installations of the ship North Sea Giant for Metal Ships. This is a multipurpose offshore vessel, built in 2011, designed to work in support of oil and gas platforms in the Gulf of Mexico, North Sea and Angola. The ship has a LOA of 161 metres, a beam of 30 meters and gross tonnange of 17,200 tonnes, capable of reaching a top speed of around 15 knots, the North Sea Giant is one of the largest ships in the world. Performed under a turnkey contract, the company was responsible for the supply of all electrical panels of the vessel, pump starters and frequency converters, battery chargers and transformers (690/440V 1500 kVA). In addition, Isolux Corsán assumed the installation of all lighting equipment such as projectors and navigation lights as well as heaters, electric radiators and Ethernet equipment, using more 350,000 metres of cable.

Isolux Corsán has executed the electromechanical installations, special and security systems for numerous singular buildings. We would highlight the recent awards: the comprehensive rehabilitation of the facade and the basement of Edison 4 (future headquarters of the National Securities Market Commission) with the challenge of a tight deadline for implementation, and the refurbishment of heating and air conditioning systems in the central production plant of insurer Mutua Madrileña at Plaza Colón in Madrid. In the latter project the company had to maintain the operation of the building during the execution of the work, despite the complexity of the elevation to the rooftop of the new equipment and removal of existing equipment, overcoming the difficulty of manoeuvring at high altitude.

Internationally, we would emphasise the implementation of electromechanical equipment and development of the building that houses Sidi Maarouf Tram depot in Oran, Algeria.



Telecommunications

Isolux Corsán has executed works at various Spanish airports with the latest technologies, networks and data centres for telephone operators. We would highlight the multiservice network for AENA at the Santiago de Compostela Airport, with a very tight execution time and the completion and commissioning of the facilities of the Vodafone Data Processing Centre at Barajas.

Internationally, the company has been awarded a contract for laying fibre optic cables for ARSAT (Empresa Argentina de Soluciones Satelitales) under the Argentina Connected plan, which aims to strengthen strategic inclusion of the country, optimise the use of the radio spectrum, generate employment through telecommunications and increase competitiveness through improved infrastructure and connectivity.

Safety

The company operates through its subsidiary Watsegur, with all certifications and approvals necessary to provide security services, fire protection and special facilities in different areas.

The major projects include perimeter security facilities at T-Solar PV farms and active security installations in prisons and social integration facilities in the Ceuta penitentiary and various access control facilities, management and guidance of parking places in public parking facilities and ticketing services.

Systems

The Control and Systems Division is responsible for the implementation of control and automation systems in the railway, airport and hydroelectric plants in the international area.

Among the most recent projects we would highlight the remote control and remote installations in the Bielsa tunnel (Huesca) and remote control system of the WWTP for the water authority Canal de Isabel II in Madrid.

Maintenance

Isolux Corsán develops important projects with highly qualified teams equipped with the latest technological innovations. One of the major milestones of the company in this area has been the maintenance of solar PV farm in Rovigo, Italy, for SunEdison, and the network of solar parks for the company T-Solar.

The company has also extended the contract to operate the gangways of T4 terminal at Barajas Airport (Madrid) and the maintenance of the general facilities of Barajas Airport's T4 terminal and at the Airport of Bilbao.

06

Factories



The Coirós factory has a total surface area of 109,000 m² ■ **A Coruña** | Spain

Emesa

An industry benchmark in the manufacture of metal structures and wind turbines

The company is implementing projects worth €36 Mn

Founded over fifty years ago, the company is currently a leader in the manufacture of wind towers and metal structures for singular works. The company is located in Coirós (A Coruña) where it has a factory over an area of 109,000 m² and a production capacity of 45,000 tonnes per year.

After a period of adaptation to the current situation in the sector, the company faces 2012 with major ongoing projects worth €36 million.

The Paris Philharmonic and the Utrecht railway station are examples of the large works to be carried out in 2012.

Corvisa

The latest technology for business

With over 30 years of activity, Corvisa is engaged in the manufacture and sale of products for roads, streets and airports. The company has seven factories in Spain whose main activity is the manufacture of bituminous emulsions and execution of works of bituminous slurry. In addition, two of its factories are also involved in the manufacture of modified bitumen. Among its products, we would highlight the cold-rolled microagglomerate surfacing for application in works, an especially valued product for use on roads for its environmental sustainability and non-slip nature.

With turnover of between 10 and 12 million euros, Corvisa has been able to maintain stable performance in recent years.

Corvisa recently added a new business line, the validation of waste, especially designed for the application of R&D in waste recovery.

Typsa

Professionalism at all levels

Founded in 1962, Typsa is one of the main national manufacturers of concrete beams. The company provides sleepers for all State infrastructure projects and high-speed rail lines.

The Luceni factory (Zaragoza) is equipped with the latest technologies and recorded a production volume of 140,000 units in 2011.



Luceni factory reached production of 140,000 sleepers in 2011
■ **Zaragoza** | Spain

CSR

Corporate
Social
Responsibility



Renewal of Commitment to United Nations Global Compact

Isolux Corsán presents its first Progress Report on its sustainable development strategy

During 2011, Isolux Corsán renewed its commitment to the United Nations Global Compact and we have presented the first progress report since joining the sustainable development strategy promoted by the United Nations in 2010.

Through the Renewal of Commitment Letter, the Management of Isolux Corsán, highlights the need to translate ethical values and principles of corporate social responsibility to all countries where we undertake activities and develop a corporate policy of engagement with the country and the environment and sets its goal to ensure that our suppliers, both local and large worldwide suppliers, undertake and commit to the principles of corporate responsibility that Isolux Corsán wants to adopt in all countries.

Principles

- Support and respect the protection of the fundamental, internationally recognized Human Rights within its sphere of influence
- Ensure that its companies are not complicit in Human Rights violations
- Support the freedom of association and the effective recognition of the right to collective bargaining
- The elimination of all forms of forced or compulsory labour
- The effective abolition of child labour
- The elimination of discrimination in respect of employment and occupation
- Maintain a precautionary approach that benefits the environment
- Support initiatives to promote greater environmental responsibility
- Encourage the development and diffusion of environmentally friendly technologies
- Work against corruption in all its forms, including extortion and bribery

Commitment to employees

Under the economic context and globalisation that we are current exposed to, with increasingly competitive markets, the efforts and commitment of every member of our company is essential. Knowing where we are going allows for motivated and committed human capital. This combination is the cornerstone of our work.

Workforce	
Corporate Structure	**3.2%**
Business structure and worksite personnel	
Construction	35.15%
Energy	36.90%
Concessions	1.56%
Infinita Renovables	1.01%

Workforce by area	2011
Europe	3,528
America	4,168
Africa	599
Asia	627

* Information reported by the Board of Directors

Our human resources

The growth and increasingly consolidated international activity of the Group is reflected in our workforce data, which this year totalled 8,922 people, an increase of 38% over the previous year. Most of the growth occurred in Brazil, which has increased by 78% compared to 2010 as a result of the project for the construction and concession of 1,191 kilometres of high tension power lines that the Group is installing in the Amazonas. Projects in India and Angola have also contributed to this increase in the workforce.

In Spain, of the total workforce, 83.61% are the men and 16.39% are women, the average age is 42 and the average seniority is 9 years. Of all employees, 82% hold permanent contracts and 18% are temporary.

In full development

We are convinced that the company's growth can only be achieved through the growth of our employees. For this reason so firmly develop the skills of the people who form the Group and believe that the company is responsible for offering professional alternatives, and to seek, train and develop talent.

During 2011, more than 300 people have experienced career growth and a total of 230 people have experienced international development. Angola, Algeria, Argentina, Bangladesh, Brazil, Colombia, China, Spain, USA, Gabon, India, Italy, Kenya, Mexico, Morocco, Oman and Peru have been the recipients of our talents.

ITACA establishes criteria for measuring and enhancing talent

Implementing core competencies

ITACA: Isolux Corsán Talent Calibration

ITACA was realesed in 2011, a Human Resources project with the aim of establishing a continuous improvement model in the development of our people. Itaca, which is also the Spanish name of the island that the mythical hero Odysseus struggled to reach (Ithaca), represents our struggle for professional development.

The project has been created in order to establish objective criteria to measure and develop talent. To this end, we conducted an intensive analysis of the successful behaviours within the Group through workshops with representatives from all hierarchical and functional levels. With the information obtained and, adapting it to the current situation, we redefined our corporate competencies that will serve to identify individuals with high potential and to design specific training programmes. These competencies have been divided into two groups, management competencies and generic competencies, in order to customise the individual development processes as much as possible.

Management competencies

- Communication
- Leadership
- Negotiation
- Business Vision

Generic competencies

- Work capacity
- Flexibility / adaptation
- Organisation and planning
- Customer orientation
- Results orientation
- Proactivity / initiative
- Decision Making
- Teamwork

This work has helped to strengthen our performance evaluation as the basis for the development of talent. This year, more than 2,000 people have participated in the evaluation process and we would highlight three new facts: the high rate of participation, direct access to individualised report on the results and the addition of a feedback interview as an evaluator-employee communication tool.

The results obtained through our performance appraisal process are important for professional development as they enable us to estimate the potential of our people and receive an objective reference for career planning and promotions, improve communication and integrate the various businesses, thereby increasing the efficiency of industrial relations, contributing to the detection of training needs and measuring the effectiveness of training programmes.

In short, this year has been crucial for consolidating the effectiveness of our processes to promote people through the identification and development of talent.
During 2011, we implemented a Professional Skills Development Programme that allowed us to measure, develop and establish specific plans for retaining each of the 50 participants identified as potential talent from the different countries where the Group is present.

This programme, consisting of classroom training workshops, has achieved four major milestones:

- **Develop a process to organise critical negotiation information** and enhance **profitability and the implementation** of agreements reached with their main representatives.
- Enhance **communication effectiveness,** through a **performance model** that allows them to successfully resolve situations of influence to **ensure the desired communication impact.**
- Strengthen the **managerial skills** of the group so that they **can successfully address all situations** with their own management team.
- Provide and train in **skills and processes** aimed at **increasing effectiveness in teamwork situations** (awareness of the importance of each individual in the team outcome, compromise on a common vision, recognise patterns that promote cohesion).



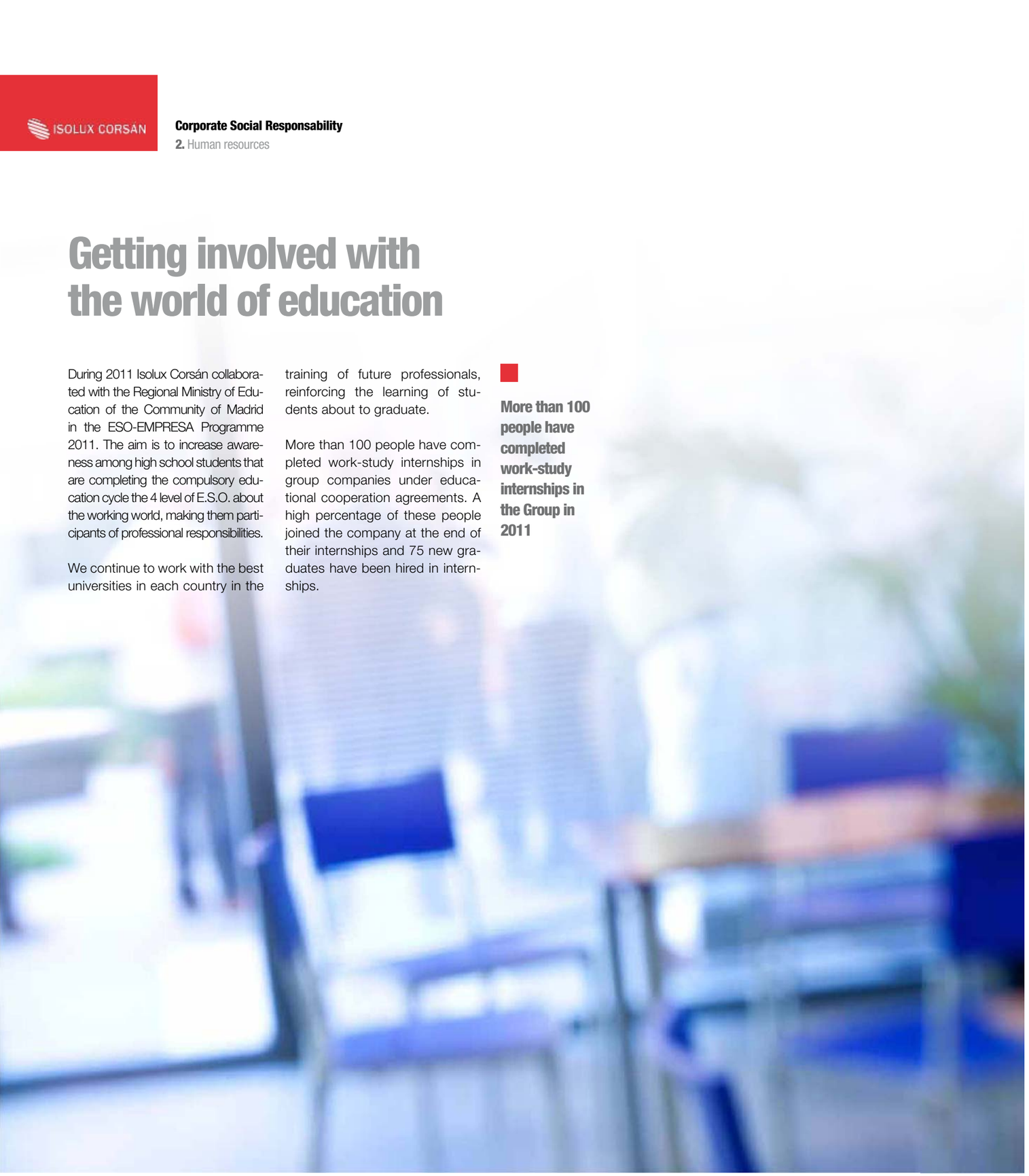
Getting involved with the world of education

During 2011 Isolux Corsán collaborated with the Regional Ministry of Education of the Community of Madrid in the ESO-EMPRESA Programme 2011. The aim is to increase awareness among high school students that are completing the compulsory education cycle the 4 level of E.S.O. about the working world, making them participants of professional responsibilities.

We continue to work with the best universities in each country in the training of future professionals, reinforcing the learning of students about to graduate.

More than 100 people have completed work-study internships in group companies under educational cooperation agreements. A high percentage of these people joined the company at the end of their internships and 75 new graduates have been hired in internships.

More than 100 people have completed work-study internships in the Group in 2011



Diversity of human resource

A major human resource challenge is the people working in different countries with divergent cultures into a single corporate culture that respects diversity. The annual international human resource meeting brings the Group's diversity closer to a single management culture. This diversity is embodied in our workers from 40 different nationalities.

We develop human resource strategies from a global point of view in line with the Group's global nature and integrate the local practices of the countries where we work.

International Professional Exchange Programme

Because of this diversity, in 2011 we launched the first International Professional Exchange Programme, whose aim is to integrate professionals from different countries in the corporate systems and policies for subsequent implementation in the country of origin. On this occasion, the programme enabled 10 professionals from India to be integrated into the corporate philosophy and culture through a training methodology. These people, who have had a tutor, were incorporated into different departments of the company with each having specific and progressive functions according to their development.

While in Spain, these professionals were evaluated in:

- Technical competencies
- Knowledge of the position
- Technical knowledge
- Technical Autonomy
- Contribution to results
- Work quality
- Personal skills
- Initiative and dedication
- Interdisciplinary integration
- Adaptation to the country
- Identification of corporate culture
- Integration with the team
- Management competencies
- Expertise with management tools
- Expertise in administrative processes
- Compliance with corporate policies

A rewarding experience which has allowed us to strengthen international teamwork.

Training of human resources

In an increasingly competitive market, training is a strategic tool in the management of human potential. Accordingly, the training plan prepared annually by the International Human Resource Development Department is the result of the training demands collected, in general, across business lines of the company and, in particular, through the performance evaluations.

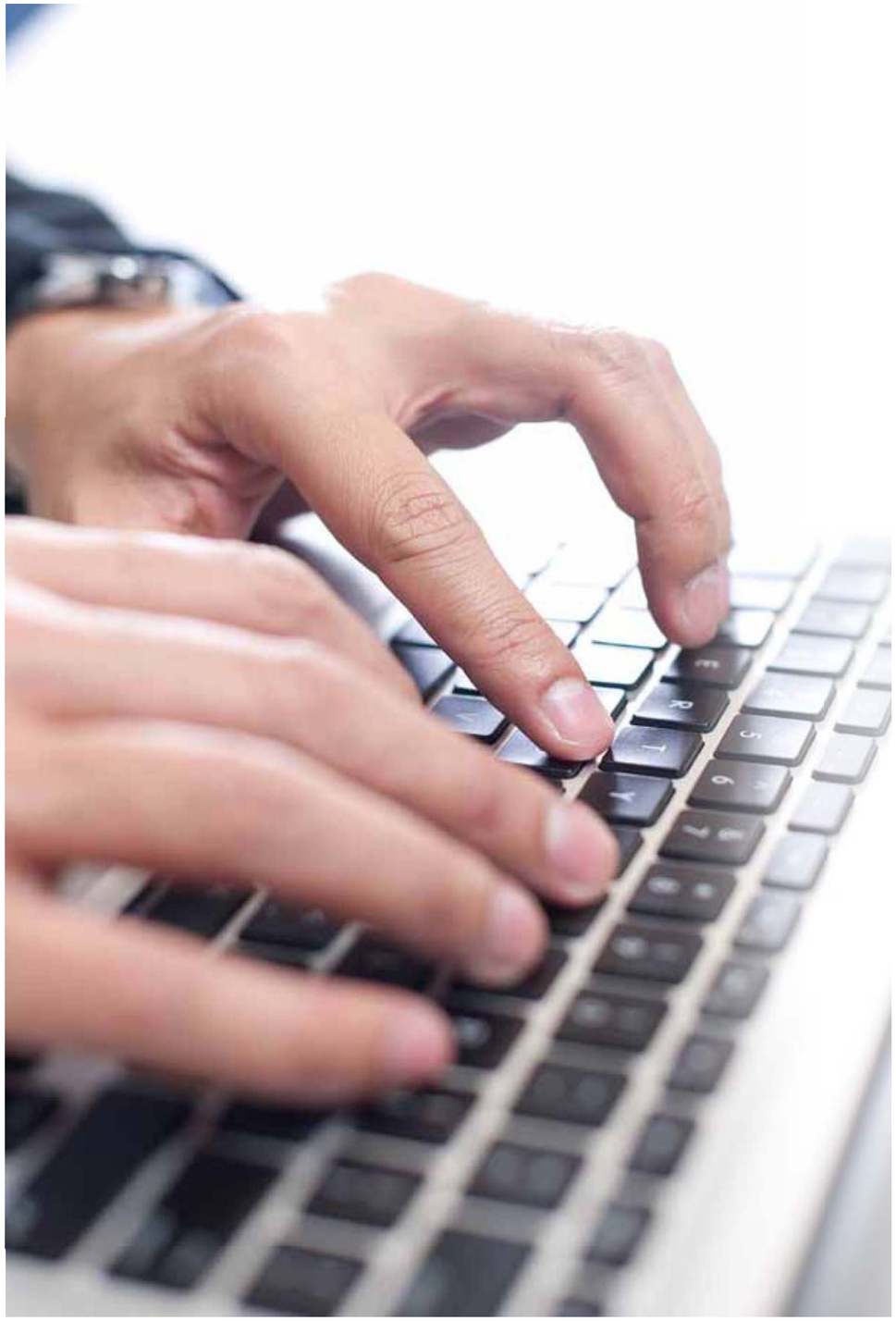
The opening of new markets has increased the need for language training, hence the effort to strengthen this competency among our employees.

During 2011, Isolux Corsán provided over 70,000 hours of training to 3,500 employees, which equals, over the previous year, an increase of 9% in the number of participants and 8% in number of training activities.

The geographical diversity of the business has forced us to work in different areas of training, enhancing adaptation to new training methods. In Mexico and Angola training was mainly in occupational risk prevention, in Argentina it was in management systems and in Brazil it covered quality, accounting and taxation. 62% of the training throughout the year has been carried out using “blended learning” method, remote, mixed or e-learning, while classroom training accounted for 34%.

Training hours by subject

Subject	Percentage
Prevention of Occupational Risks	39%
Technical skills	37%
Language skills	11%
Quality and the Environment	5%
Development of new technologies	4%
Management skills	4%



We are connected

2011 resulted in the birth of the new Group intranet. Under 2.0 technology, the new intranet, which is in three languages, provides service to 3,800 users in over 16 countries. This new platform is fed by a high degree of participation through new collaborative tools like wikis, blogs and forums.

Informative, participative and management elements are combined on this new intranet for knowledge to circulate quickly and accessibly. With an average of three news items published weekly, the new employee intranet provides continuous information of the most significant events of the Group. Week after week, Human Resource experts publish new entries in the Development blog on the human capital management, leadership and professional development, so that everyone can know our competency management tool.

In addition, each division and country has its own space in which they can post information and knowledge adapted to their particular needs.

This new information channel allows for the of online management of documentation, provides an efficient search engine and a new communication model based on the multi-directionality of information.

During 2011, we have also undertaken a series of improvements in the data communications infrastructure. Mainly, we have analysed the communication lines between the new data processing centres in Madrid to different locations of the Group -offices, branches and subsidiaries in other countries and work sites- to strengthen backup systems and increase the capacities and speeds wherever necessary. In addition, we have incorporated new technological elements that increase the security of the data network of the Group, diversifying suppliers to ensure service provision in case of contingencies.

We have also launched new lines of communication in countries where we have started operations in 2011, including Colombia, Bangladesh, the USA and Italy.

On the other hand, following the outsourcing of IT services, the monitoring of the data communications infrastructure has been strengthened, solving any problem in less time and more efficiently.

The new intranet provides service to 3,800 users in over 16 countries

Respect, equal opportunity and non-discrimination

The diversity of the workforce is a key factor and enriches the human resource policy of Isolux Corsán. Therefore, we ensure the absence of any discrimination, because of age, sex, disability, religion and ethnicity, politics or otherwise. Maintaining a safe working environment is one of the Group's main objectives.

Isolux Corsán maintains and promotes a policy of equality and non-discrimination based on respect for workers regardless of their religious, sexual preference, gender, race or age.

Salaries are linked to professional category and are identical for all people, regardless of gender, nationality or any other personal characteristic.

Isolux Corsán continues to develop, together with the legal representation of workers, the Equality Plan through committees appointed for that purpose. With the new appointments of women to executive positions in the past year, female representation on the management level has increased by 28% over the previous year.

The subjects to be discussed and developed in the plan are: access to employment, job classification and promotion, training, pay, working time arrangements, sexual harassment, pregnancy or maternity discrimination, sexist language, guarantees for victims of domestic violence and those who can be identified based on the characteristics of the job.

The percentage of women managers has increased by 28% in 2011

Equal opportunities

In Isolux Corsán we work to integrate people with disabilities in the workforce as part of our corporate culture.

Our main lines of action are:

- Standardisation to reduce fears and myths that sometimes give rise to discrimination.
- Awareness and empathy for such workers.
- Information, advice and support in the integration and social development and employment of people with disabilities.

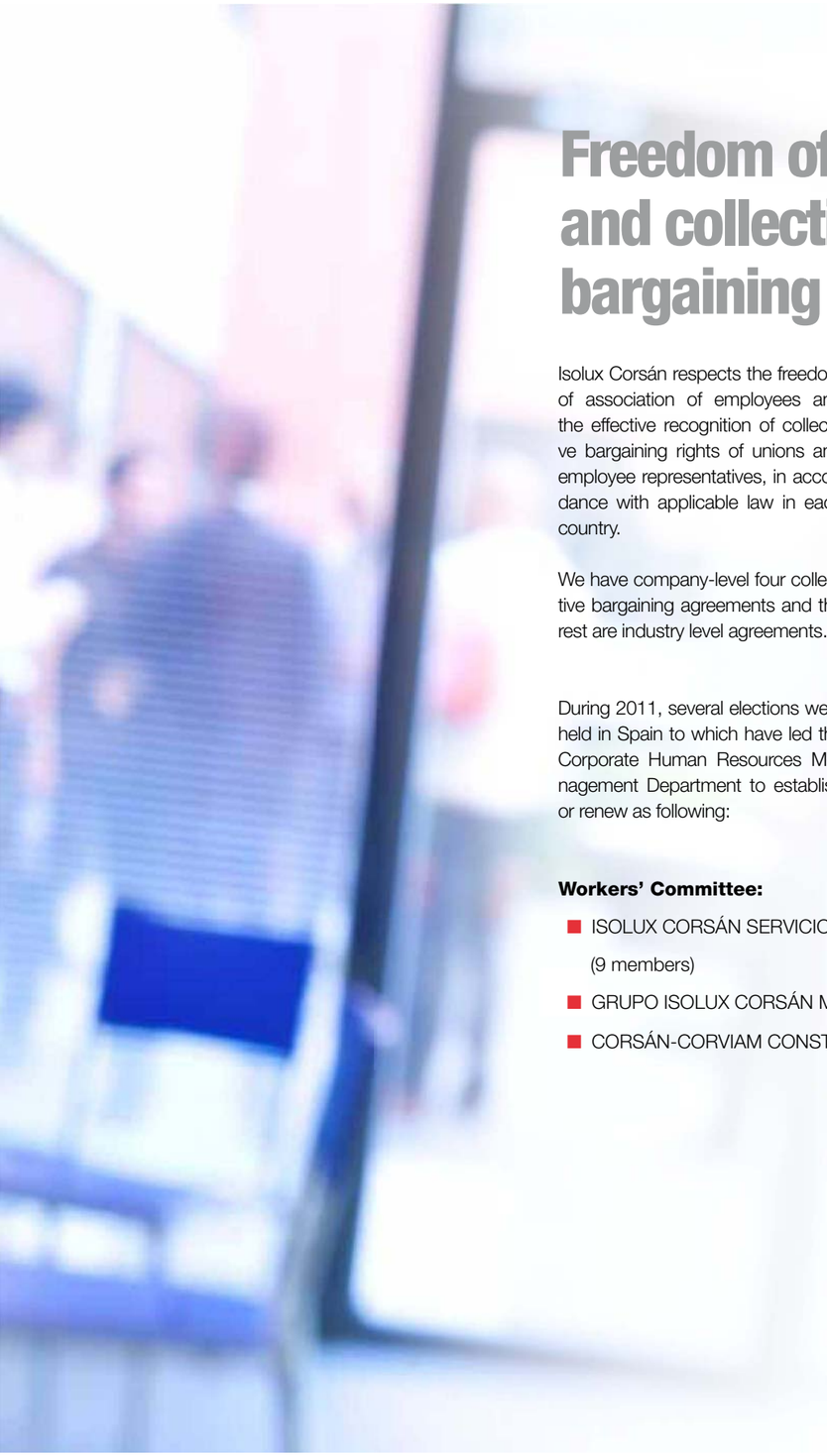
In Spain, the number of employees with disabilities rose to 56 workers in 2011.



Family Plan

The Group's commitment to people with disabilities is embodied not only in actions target at employees but also their families. Accordingly, in 2010, we launched the Family Plan together with Fundación Adecco, a programme aimed at promoting social integration and employment of relatives of employees with disabilities through the assessment of skills and needs by a multidisciplinary team of professionals and the design a personalised support plan. This year, nine relatives of employees have benefited from this plan.

Nine relatives of employees have benefited from the Family Plan



Freedom of association and collective bargaining

Isolux Corsán respects the freedom of association of employees and the effective recognition of collective bargaining rights of unions and employee representatives, in accordance with applicable law in each country.

We have company-level four collective bargaining agreements and the rest are industry level agreements.

Union representation	
Workplace	**Number**
Isolux Ingeniería	49
Corsán-Corviam Construcción	64
Gif Fábricas	5
Emesa	13
Isolux Corsán Servicios	25

During 2011, several elections were held in Spain to which have led the Corporate Human Resources Management Department to establish or renew as following:

Workers' Committee:

- ISOLUX CORSÁN SERVICIOS Madrid – Pasarela de Barajas (9 members)
- GRUPO ISOLUX CORSÁN Madrid (9 members)
- CORSÁN-CORVIAM CONSTRUCCIÓN (13 members)

Health and Safety: strategic commitment

Isolux Corsán considers a priority objective to ensure that its activities are carried out while maintaining the highest standards of health and safety. To achieve this, we are committed to providing our employees with a secure and stable environment, pledging to permanently update the prevention of occupational hazards, and enforcing compliance with applicable regulations in this area, both among our employees, and our suppliers, contractors and business partners. Accordingly, through our Health and Safety Policy, which applies to all countries where the Group is present, we assume the commitments of developing all the Group's activities considering safety as an essential value and continuous improvement in the Occupational Risk Prevention management system.

The Group provides employees a secure and stable work environment

Group management believes that, to achieve the highest levels of safety at work, it is essential that workers integrate the guidelines of the Health and Safety Policy of the company in their daily activities. To do this, the Group is committed to disseminating the content and documentation generated by appropriate training programs to all areas and hierarchical levels of the company. In this endeavour, Isolux Corsán, through the corporate intranet, makes the Management Manual, the general and specific procedures that comprise the Prevention Management System available to all employees in three languages: Spanish, Portuguese and English.

Thanks to the involvement and commitment of all employees, suppliers, contractors and business partners, Isolux Corsán is advancing towards the creation of the desired prevention culture. Proof of this is the downward trend in accident rates in recent years.





An international culture of prevention

In 2011, Isolux Corsán consolidated its commitment to health and safety in all countries where it provides activity. The target set was to strengthen the prevention culture, promoting the values, attitudes and safe behaviours in all projects. To achieve this goal in 2011, the Prevention Service of the Isolux Corsán Group implemented an action plan to promote safety, respect for compliance with legal requirements, specialised training and information, and awareness of responsibilities.

The basic points of the plan are:

- Presentation of the Occupational Risk Prevention Management System among the corporate personnel in each country responsible for this function.
- Adaptation of the Occupational Risk Prevention Management System to the applicable legislation in each country.
- Implementation of the Occupational Risk Prevention Management System in each country through training programmes in line with the production in each.
- Audits by the corporate officers of both country and headquarters to check the level of compliance with the Occupational Risk Prevention Management System in the different projects.

In this regard, we have expended substantial efforts to provide all countries with the human and material resources necessary to conduct this work in terms of the turnover in each country. Those responsible for health and safety in each country directly and continuously communicate with the Corporate Prevention Service Manager. The Occupational Risk Prevention Management System Occupational is implanted across the Group based on the International Occupational Health and Safety Assessment Series (OHSAS) 18001:2007, adapting to the applicable legislation in each country.

Management tools

Throughout 2011 we have implemented the specific computer risk prevention management tool, People Net, in all countries where we are active. This tool allows for the objective tracking of prevention activities, given that it enables the analysis and assessment of results and facilitates the detection of areas for improvement both globally and in the different countries where the Group operates.

Based on data provided by this tool, the Corporate Prevention Service issues a monthly report to Management on the different activities of the service, as well as on the evolution of the Group's overall accident rate.

People net **allows for the monitoring of prevention activities**

Management results

Monitoring and assessment of the results of management represent an essential tool for the detection of possible areas for improvement, thus facilitating the continued development of the Management System.

The results of the most relevant indicators for 2011 are as follows.

Audits

Departments	Number
Corporate	1
Energy	41
Environment	33
Fclts, Maint., Serv.	429
Concessions	12
Factories	3
Construction	81
Total	**600**

Audits

All Isolux Corsán companies are subject to a series of internal audits, both by the technicians of the prevention service and external entities, which contrast and verify not only the degree of compliance but also the level of implementation of the Occupational Risk Prevention Management System and the depth of the prevention culture in the organisation. The attached table shows the number of audits performed during 2011, distributed by business line.

All Group companies are subject to legal and regulatory audit and a large proportion of them are certified under OHSAS 18001:2007.

We would highlight the award of OHSAS certification to our subsidiary Isolux Corsán of Mexico. This certification process has also begun in Argentina, and is scheduled to be completed in early 2012. We will continue through the rest of the year with certificates in India and Brazil.

A total of 600 audits were performed in 2011



Health and safety training

Training and information are fundamental pillars for the development of the prevention policy of Isolux Corsán and they are the most effective means to increase awareness of health and safety among company personnel.

The Occupational Risk Prevention Training Plan is integrated into the Annual Training Plan of the Group.

In general, all employees receive training in health and safety when they join the Group. Then receive additional training, based on the characteristics of their jobs, depending on the tasks performed. The latter is provided on site and the scope affects both their employees and subcontractors.

Of the 1,508 training actions performed in 2011, 1,262 were on-site training, given to 8,433 workers, both Group employees and subcontractors, and 246 correspond to specific training activities provided by specialized institutions for the activities developed, as specified in the applicable collective bargaining agreements. This training has been provided to 2,415 students.

Management indices

Indicators	2009	2010	2011
Training Actions	1,498	1,509	1,508
Hours of training	8,109	7,735	12,054
Workers trained	7,296	7,838	10,858

* Data for Spain

Management indices

Indicators	2009	2010	2011
Safety plans developed or revised	2,033	1,825	1,518
Coordination meetings on business activities	721	554	604
Accident investigation reports	387	188	268
Internal Audits	1,024	711	600
Visit to work sites and workplaces	4,584	3,586	2,917
Ergonomic studies / hygienic evaluations	10	15	6
Emergency plans	18	25	23
Health and Safety Committee Meetings	39	42	42
Awareness actions	3,572	2,469	5,370

* Data for Spain

Other management indexes

The following table highlights the increasing number of awareness raising activities during 2011, especially targeting the activities in the international area. These actions include on the spot explanations, targeted to personnel detected doing their job incorrectly, whether belonging to the Group or or to any subcontractor. The increase of these actions is intended to strengthen the depth of the prevention culture among Group personnel and those of the companies that collaborate with us.

Accident rates in the Group declined significantly in 2011

Accident rates

All the efforts made by Isolux Corsán in health and safety has reflected in a significant decrease in accident rates of the Group; accident rate (-17.52%), frequency rate (-33.97%) and severity index (-33.74%), reflecting the commitment, performance and cultural level of health and safety among all Group employees.

One of the core activities in this area is the investigation of accidents and incidents and identifying their causes, developing specific action plans for activities with higher accident rates.

Number of accidents 2009-2011

Accidents	2009	2010	2011	Change 2009-2010
Minor	384	236	253	7.20%
Major	2	3	12	300.00%
Deadly	1	0	3	100.00%
Total	387	239	268	12.13%
Commuting	32	22	40	81.82%
Average personnel	5,427	4,945	6,336	28.13%
Days lost	7,620	4,833	4,838	0.10%
Days lost ratio	1.4	0.98	0.76	-22.45%
Accident ratio	0.071	0.048	0.040	-16.67%

Accident rates 2009-2011

Indicators	2009	2010	2011	Change 2009-2010
Incidents	65.76	44.81	36.96	-17.52%
Frequency	35.96	23.90	15.78	-33.97%
Severity	0.77	0.53	0.33	-37.74%

Occupational health

In the area of Occupational Health has continued to develop a management major in health protection. Among the various activities of the Group in this area we would highlight the following:

Medical examinations of workers

In total, 5,982 medical examinations were performed (915 at the central offices). Of the medical examinations, 2,824 corresponded to new hires and 3,158 to annual check-ups. All of them applied the specific medical protocols based on the risk assessment of the particular job.

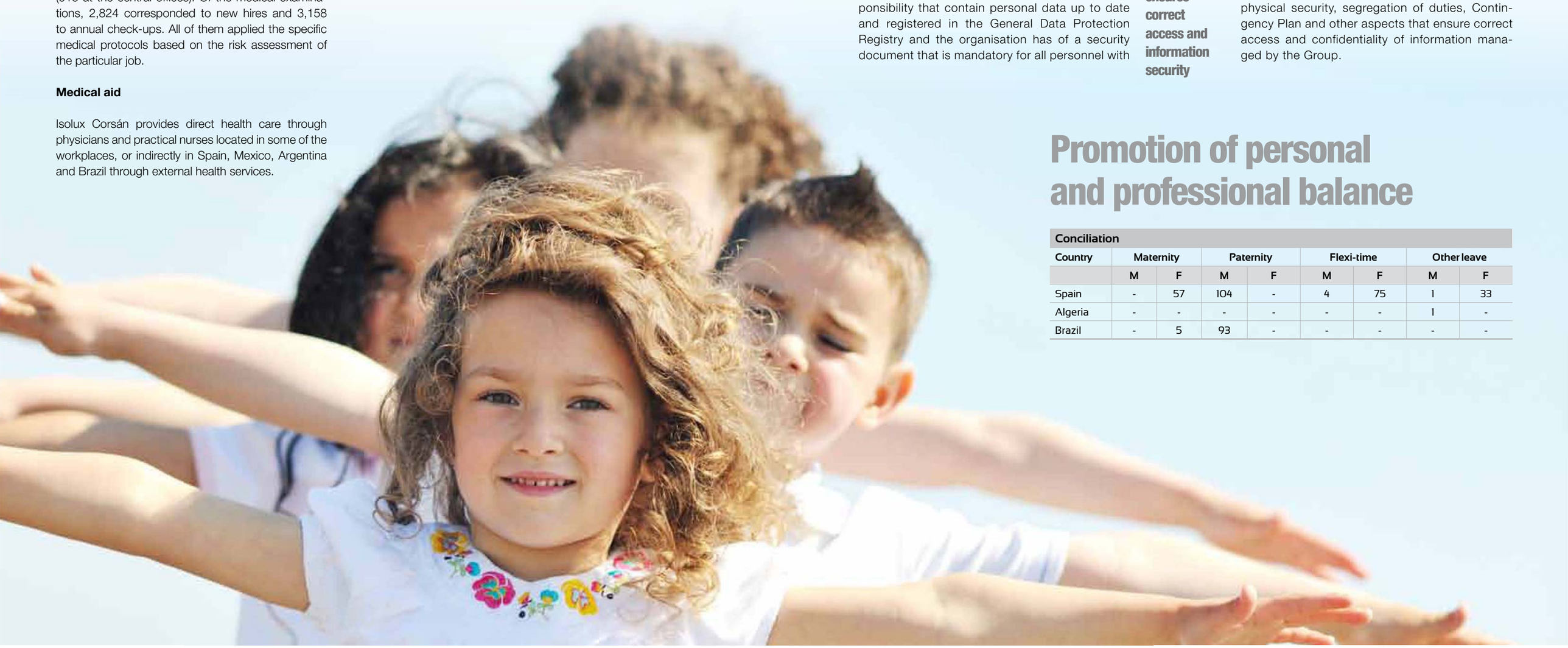
Medical aid

Isolux Corsán provides direct health care through physicians and practical nurses located in some of the workplaces, or indirectly in Spain, Mexico, Argentina and Brazil through external health services.

All employees are covered by Group medical insurance

International activity

All activities carried out by Isolux Corsán meet with applicable legislation in each country, especially with regard to the health and safety of workers, with the collaboration of local clinics and, if necessary, specialised institutions. All staff, whether local or expatriate are covered by medical insurance.



Respect for privacy and confidentiality of data

In accordance with Organic Law 15/1999 of 13 December on the Protection of Personal Data and Security Measures Regulations (Royal Decree 994/1999 of 11 June), we have maintained all files of our responsibility that contain personal data up to date and registered in the General Data Protection Registry and the organisation has of a security document that is mandatory for all personnel with access to computerised personal data. Similarly, an annual review of IT controls in the organisation has been conducted by the external auditor, verifying all aspects concerning logical security, physical security, segregation of duties, Contingency Plan and other aspects that ensure correct access and confidentiality of information managed by the Group.

Isolux Corsán ensures correct access and information security

Promotion of personal and professional balance

Conciliation

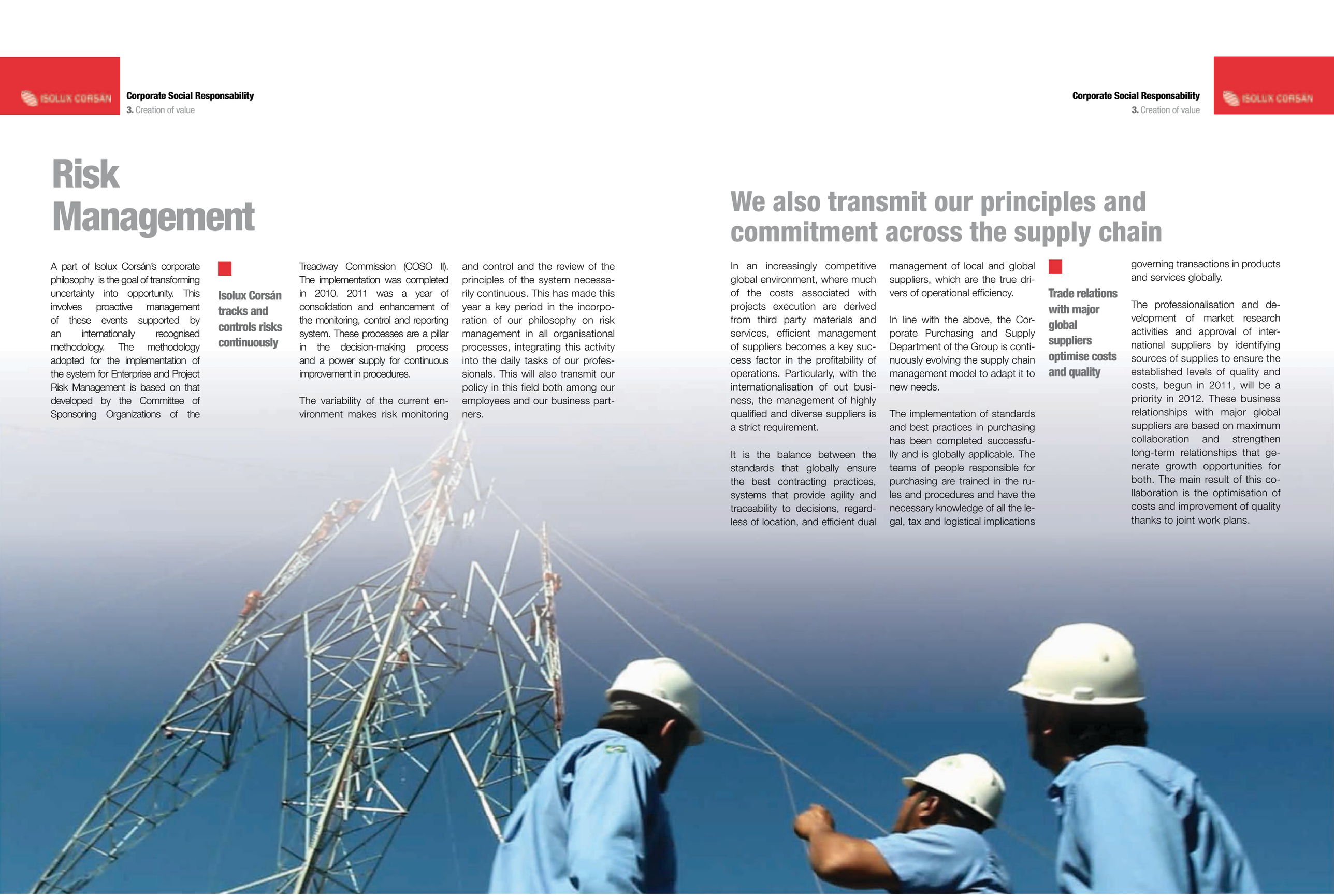
Country	Maternity		Paternity		Flexi-time		Other leave	
	M	F	M	F	M	F	M	F
Spain	-	57	104	-	4	75	1	33
Algeria	-	-	-	-	-	-	1	-
Brazil	-	5	93	-	-	-	-	-

Risk Management

A part of Isolux Corsán's corporate philosophy is the goal of transforming uncertainty into opportunity. This involves proactive management of these events supported by an internationally recognised methodology. The methodology adopted for the implementation of the system for Enterprise and Project Risk Management is based on that developed by the Committee of Sponsoring Organizations of the Treadway Commission (COSO II). The implementation was completed in 2010. 2011 was a year of consolidation and enhancement of the monitoring, control and reporting system. These processes are a pillar in the decision-making process and a power supply for continuous improvement in procedures.

Isolux Corsán tracks and controls risks continuously

The variability of the current environment makes risk monitoring and control and the review of the principles of the system necessarily continuous. This has made this year a key period in the incorporation of our philosophy on risk management in all organisational processes, integrating this activity into the daily tasks of our professionals. This will also transmit our policy in this field both among our employees and our business partners.



We also transmit our principles and commitment across the supply chain

In an increasingly competitive global environment, where much of the costs associated with projects execution are derived from third party materials and services, efficient management of suppliers becomes a key success factor in the profitability of operations. Particularly, with the internationalisation of out business, the management of highly qualified and diverse suppliers is a strict requirement.

It is the balance between the standards that globally ensure the best contracting practices, systems that provide agility and traceability to decisions, regardless of location, and efficient dual management of local and global suppliers, which are the true drivers of operational efficiency.

In line with the above, the Corporate Purchasing and Supply Department of the Group is continuously evolving the supply chain management model to adapt it to new needs.

The implementation of standards and best practices in purchasing has been completed successfully and is globally applicable. The teams of people responsible for purchasing are trained in the rules and procedures and have the necessary knowledge of all the legal, tax and logistical implications governing transactions in products and services globally.

Trade relations with major global suppliers optimise costs and quality

The professionalisation and development of market research activities and approval of international suppliers by identifying sources of supplies to ensure the established levels of quality and costs, begun in 2011, will be a priority in 2012. These business relationships with major global suppliers are based on maximum collaboration and strengthen long-term relationships that generate growth opportunities for both. The main result of this collaboration is the optimisation of costs and improvement of quality thanks to joint work plans.

As a complement to our global agreements, partnerships with local providers in both supplies and services are of utmost importance. This collaboration allows us to participate in the knowledge of the local market and are vital to create value in the community where we execute our projects and works.

In 2011 the focus has been to ensure that the panel of all international suppliers is available to everyone involved in procurement, so that the knowledge of who we can work with in a particular country and how to contract local sources is readily available and useful.

The final implementation of systems and processes and the creation of local and central teams and, above all, the capitalisation of existing experience to make management repetitive, have been key in order to efficiently handle the amalgamation of projects and geographically and technically disperse works in the future.

With the fulfilment of this objective, the company has obtained visibility and traceability in all procurement processes and greater control and consistency in decision making and approvals for any work or project, which has allowed us to increase the efficiency of purchasing.

Improvements or new features of the Purchasing Department

As part of the purchasing and supplier management organisational model, Isolux Corsán has launched the "Purchasing Function Community", consisting of all employees responsible for managing purchases, regardless of the business line, country or project which they support.

The community is a virtual forum in which the users can shared standards, procedures, training, career development opportunities, etc., as well as strategies, objectives and results. The dispersion of resources and the global nature of our business, make it essential to develop innovative solutions for communication between our team members.

It is important to note the creation of the Central Logistics function, which will support all projects and works globally, establishing the company's logistics strategy while coordinating local operations on the project level.

Similarly, we also continue to evolve and equip the purchasing function with the management tools needed to facilitate their work and allow us to optimise existing resources. Along these lines, at the close of 2011 we had begun developing a portal for the publication of international tenders.

Suppliers 2007-2010 | Key figures

Indicator / year	2008	2009	2010	2011
Total volume of purchases from suppliers (€Mn)	2,732	2,408	2,550	2,590
Total volume of purchases from local suppliers (€Mn)	1,675	1,862	2,002	1,945
Total number of suppliers	19,127	19,572	20,015	20,314
% local sourcing	75.30%	77.24%	79.43%	78.82%



Commitment to quality in all our activities

The quality management systems are implemented in all countries

Quality is one of the fundamental pillars of Isolux Corsán's activity and is an effective tool to ensure the successful outcome of our products and services and therefore the satisfaction of our customers.

To this end, the Quality Management Systems of Isolux Corsán are implanted in all activities and all countries where the Group operates to ensure that the culture of the company is transferred to all projects.

Quality Policy

Isolux Corsán is fully aware that the growth and competitiveness of all its business areas, Engineering, Construction, Concessions and Services, closely depend on the level of customer satisfaction with our products and services. The Corporate Quality Policy is established as the model for the performance of all our activities and is a reference for Management Systems. Through this policy we commit to the following:

- To develop and implement quality management systems adapted to our organisation and consistent with the principles established in UNE EN ISO 9001 and in this policy and to adopt measures to continually improve the effectiveness of these systems.
- To meet the requirements for products and services provided, as required by the legal standards in place and the specifications of our clients.
- To optimise the management of processes and methodologies for works, information, supplies, resources, skills and the internal and external relations that are brought into play in the development of our activities.
- To establish and monitor compliance with objectives consistent with this policy and with the capabilities of our organisation. To ensure that these objectives contribute to improving the quality of our products and services and the effectiveness of quality management.
- To periodically review this policy to maintain its alignment with the vision and strategic objectives and address the needs identified at each moment in the market, social and natural environment in which we operate.
- The management of the company ensures the implementation of the measures necessary to achieve knowledge of the Quality Policy and its implementation by all members of the organisation.

Internal Audits

Isolux Corsán has extensive experience in implementing Management Systems. We have gradually increased the internal audits of all our activities. The analysis of results and corrective actions resulting from them are one of our fundamental tools to achieve the continuous improvement of our operations.

To this end, every year we qualify new auditors in the different countries, all with extensive technical experience and knowledge of quality management.

In 2011 we increased the number of internal environmental and quality audits by 32% over the previous year:

Number of audits

	2009	2010	2011
Corporate	2	6	9
Construction	22	72	119
Engineering and Services	50	70	67
Total	**74**	**148**	**195**

In 2011 we increased internal quality audits by 32%

Number NCs/AI

	2009	2010	2011
Group	2.00	1.00	1.00
Construction	3.36	2.81	1.61
Engineering and Services	3.34	3.30	1.48
Total	**3.31**	**2.96**	**1.54**

The deviations detected during this year are mostly minor and temporary.

Internal audits, as effective monitoring and control tools, help reinforce a good perception of our quality management systems among our clients.

External audits

Isolux Corsán seeks certification of its Quality Management Systems under ISO 9001 in those countries where it has created a permanent corporate structure.

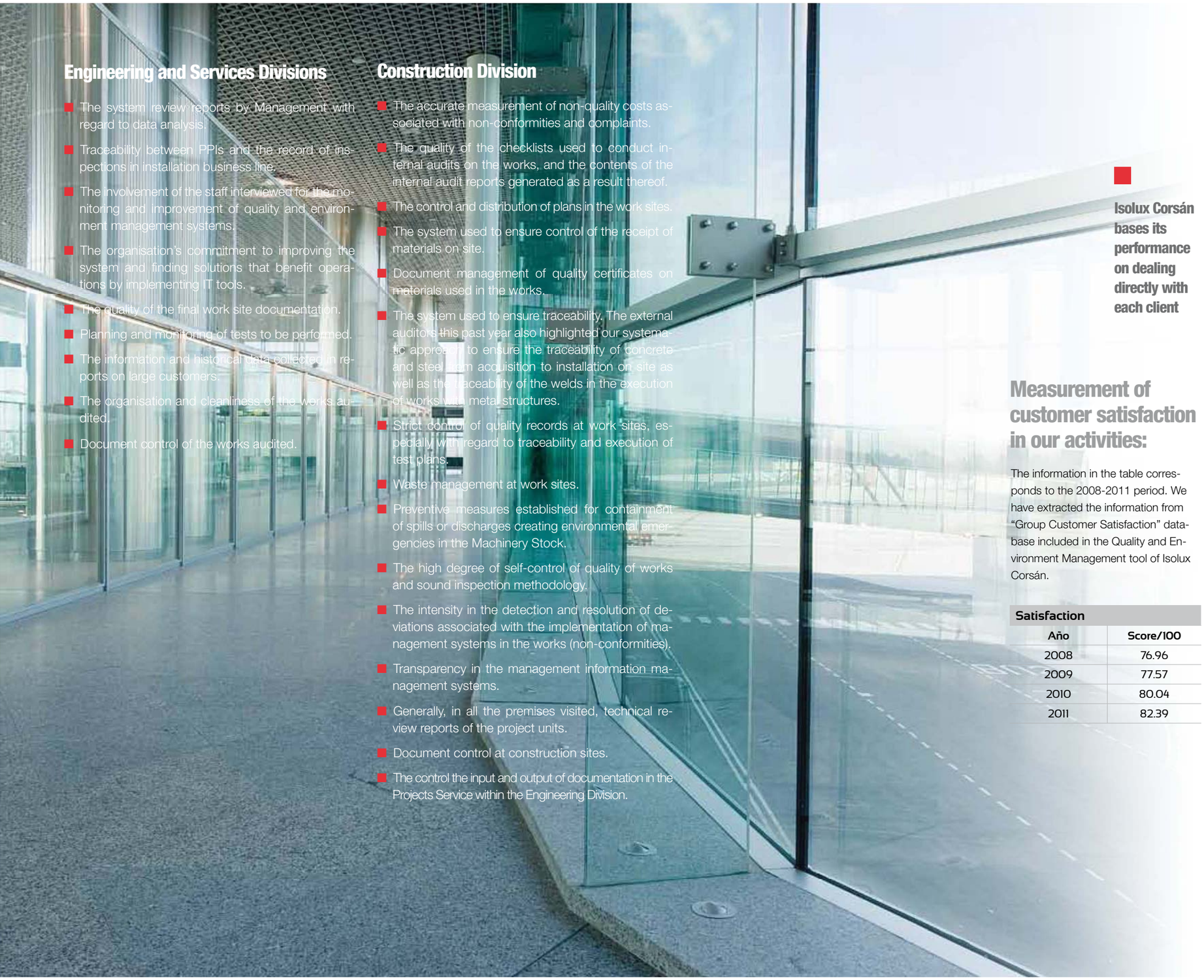
In 2011 our construction activities in Mexico were awarded ISO 9001 and we have started the certification process on the engineering activities in Argentina. In 2012 we will continue this process, increasing the scope of the certification obtained in Mexico, culminating and extending the certification in Argentina and starting the certification process in India and Brazil.

In Spain, following the established cycles for maintenance and renewal of ISO 9001, our activities are evaluated annually by independent entities with international prestige, such as AENOR and DNV.

In recent years, external auditors have highlighted several strengths in Isolux Corsán companies, which include:

Corporate Area

- The support and involvement of management in the implementation and effectiveness of management systems.
- The implementation of the new tool “ITACA project” for performance evaluations that allows us to target the training needs in all Group companies.
- The creation of new indicators to measure the process and analysis systems monthly through committees.
- The integration of purchasing management tools, automatic evaluations and assessments, and the action taken on negative evaluations of suppliers.
- The quality and environment requirements included in model contracts.
- The effort made in the management of R&D+i, Quality and Environment of the Group for the maintenance and improvement of systems.
- The graphical and historical analysis of the data collected in the process monitoring reports on the computer systems.
- The integration of the R&D+i Management System in the Quality Management System and Environmental Management of the Group.
- Performance management in the organisation.
- The quality of Corporate Social Responsibility Report.



Engineering and Services Divisions

- The system review reports by Management with regard to data analysis.
- Traceability between PPIs and the record of inspections in installation business line.
- The involvement of the staff interviewed for the monitoring and improvement of quality and environment management systems.
- The organisation's commitment to improving the system and finding solutions that benefit operations by implementing IT tools.
- The quality of the final work site documentation.
- Planning and monitoring of tests to be performed.
- The information and historical data collected in reports on large customers.
- The organisation and cleanliness of the works audited.
- Document control of the works audited.

Construction Division

- The accurate measurement of non-quality costs associated with non-conformities and complaints.
- The quality of the checklists used to conduct internal audits on the works, and the contents of the internal audit reports generated as a result thereof.
- The control and distribution of plans in the work sites.
- The system used to ensure control of the receipt of materials on site.
- Document management of quality certificates on materials used in the works.
- The system used to ensure traceability. The external auditors this past year also highlighted our systematic approach to ensure the traceability of concrete and steel from acquisition to installation on site as well as the traceability of the welds in the execution of works with metal structures.
- Strict control of quality records at work sites, especially with regard to traceability and execution of test plans.
- Waste management at work sites.
- Preventive measures established for containment of spills or discharges creating environmental emergencies in the Machinery Stock.
- The high degree of self-control of quality of works and sound inspection methodology.
- The intensity in the detection and resolution of deviations associated with the implementation of management systems in the works (non-conformities).
- Transparency in the management information management systems.
- Generally, in all the premises visited, technical review reports of the project units.
- Document control at construction sites.
- The control the input and output of documentation in the Projects Service within the Engineering Division.

Optimisation with our clients

Isolux Corsán bases its performance on dealing directly with each client

Since its inception, Isolux Corsán has oriented its activities to achieve continuous improvement and customer satisfaction.

To this end, the company bases its performance on dealing directly with each client, involving the production and commercial areas, so as to ensure the identification of requirements, needs and expectations of our clients.

Thus, resources are aligned with the priorities of our customers and enhance improvements in the lowest scoring areas. In addition to these actions, Isolux Corsán analyses, using comparable surveys, the level of customer satisfaction with various aspects, ranging from the development of tenders to the processing of complaints, to the quality of the documents exchanged during project execution and the quality of the work finally delivered.

Each of the responses is given a numerical value, so that the end result of each survey is translated into a scale of 0 to 100.

Additionally, our customers have the ability to add comments to their responses, as well as to make any suggestions.

Measurement of customer satisfaction in our activities:

The information in the table corresponds to the 2008-2011 period. We have extracted the information from "Group Customer Satisfaction" database included in the Quality and Environment Management tool of Isolux Corsán.

Satisfaction	
Año	Score/100
2008	76.96
2009	77.57
2010	80.04
2011	82.39

The concessions business particularly emphasises the end customer, the user of the infrastructure. In this business area, meeting the needs of these users affects every one of our activities. Building loyalty in such a competitive environment has become the primary goal of all the personnel of our concessions and is always present in the work performed in each area of operation.

To properly serve users of the infrastructure we manage, each contract has appropriate communication channels to address their complaints and suggestions. Additionally, a team has been assigned to analyse and respond to such complaints and suggestions from users.

Also, the toll roads that operate have a permanent driver assistance service to ensure the resolution of any problems that can arise as they travel across the infrastructure. In all these contracts, mobile breakdown warnings are provided in different languages to make it easier for drivers.

In addition, all car parks we manage have a permanent user support service to ensure the resolution of minor problems with their vehicles.

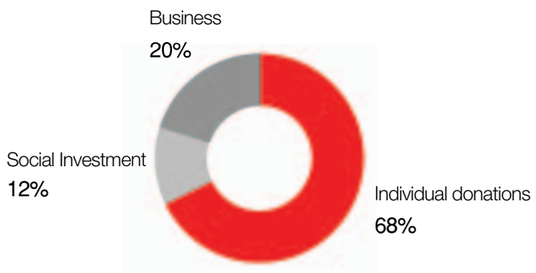
Commitment to community and the environment

Social Investment

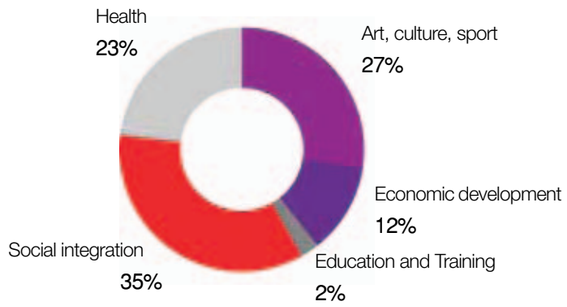
The main objective of Isolux Corsán with regard to social issues is to harmonise our social investment with our responsibility as a company. To do so, as a company expert in engineering, building and managing infrastructures for transport, the environment, energy and services, we play an important role in the structure and economic evolution of the countries where we undertake our business. Our intention is to improve the quality of life and the opportunities for those who are in these communities.

That is why we opt for implementing our projects in line with the responsibility which is derived from our business and the areas in which we undertake our activity.

Project-based contributions



Contributions by area of activity



Investment Policy

During 2011, Isolux Corsán assigned more than €1.2 million to the development of over 35 social initiative projects.

In **Spain**, the main beneficiaries of our social action have been the foundations Adecco, Apai and Prodis, all dedicated to the promotion of social integration and employment of people with disabilities.

Art, culture and sport have been the target of 27% of the Group's social investment. The contributions made to the Prado Museum, the Crucible of Cultures Foundation of Ceuta, the Mining Academy Music Palace in Mexico, the Numancia Sports Club for the training of young athletes, the Mar Alicante Handball Club, the Móstoles Football City, and Arrate S.A.D. are just some examples. In the field of education, we would higlight the collaboration with the Universidad Pontificia de Comillas (ICADE) to commemorate the fiftieth anniversary of the beginning of university studies. Isolux was one of 16 winning companies for their support and collaboration with the institution.

In 2011 we collaborated with United Firefighters Without Borders and we donated three ambulances that to date were used by SUMMA 112 in the Community of Madrid. These ambulances will begin operating in the city of Arequipa, southern Peru, in an attempt to strengthen the pre-hospital services in the city. In parallel, were arranged the symbolic sale and financing of another twenty-five ambulances, which also served SUMMA 112 of the Community of Madrid, which are slated for pre-hospital care in different places in Peru, Haiti, Nicaragua and Guatemala.

At the international level, the contributions go far beyond mere economic contributions. The Group's presence in some countries is a source of employment for the hiring of both workers and local suppliers, which often involves improving professional training and working conditions and boosting the economic and infrastructure development of the area. On many other occasions, we introduce new construction processes, new technologies and promote respect for the environment and preservation in rural areas.

In **Brazil**, where the Group is undertaking major transmission and power generation projects, we have renewed agreements with local authorities to develop social responsibility policies and practices in both social and environmental projects to promote sustainability in the region.

To do this, we have been carried out during 2011 several actions in the communities affected by these new projects:

The Group has dedicated over €1.3 million to 35 social initiative projects

- With the health services. Through actions to combat malaria and health education campaigns for the prevention of sexually transmitted diseases (STDs), health tips and moderation in alcohol consumption.
- Campaign for Sustainable Agriculture. This is an educational process aimed at enabling rural citizens to acquire knowledge, skills and abilities for the exercise of a profession, working in accordance with labour market realities and sustainable use of natural resources.
- In order to maintain cultural values in areas where construction is done, Isolux Corsán supports various events related to culture, art and sport.
- Environmental education activities. With the aim of promoting social and environmental activities among communities affected by projects to improve their quality of life.

In the vicinity of the work on the NH8 motorway in India, we provided a nursery for the children of the workers, not only hiring teachers but also providing school supplies and toys, food and drinking water. In 2011, once again, the Group's presence in Angola has allowed the local population to benefit from the anti-venom that Isolux Corsán provides workers at the work sites.

We also carried out corporate volunteering initiatives in Spain and Argentina during the year, working with the Food Bank of Madrid and the Open Hands Foundation in Argentina.



Corporate Volunteering

In Spain, through the Cesta Solidaria campaign, nearly 2,000 kg of food from the Christmas baskets that employees receive annually in Spain were donated to the Food Bank of Madrid. The donation was completed with a financial contribution with the company doubling the economic value of each basket donated.

In Argentina, employees donated and collected toys, food and clothing and Isolux Corsán Argentina made a contribution of food to needy families.

Commitment to the environment in the development of our business

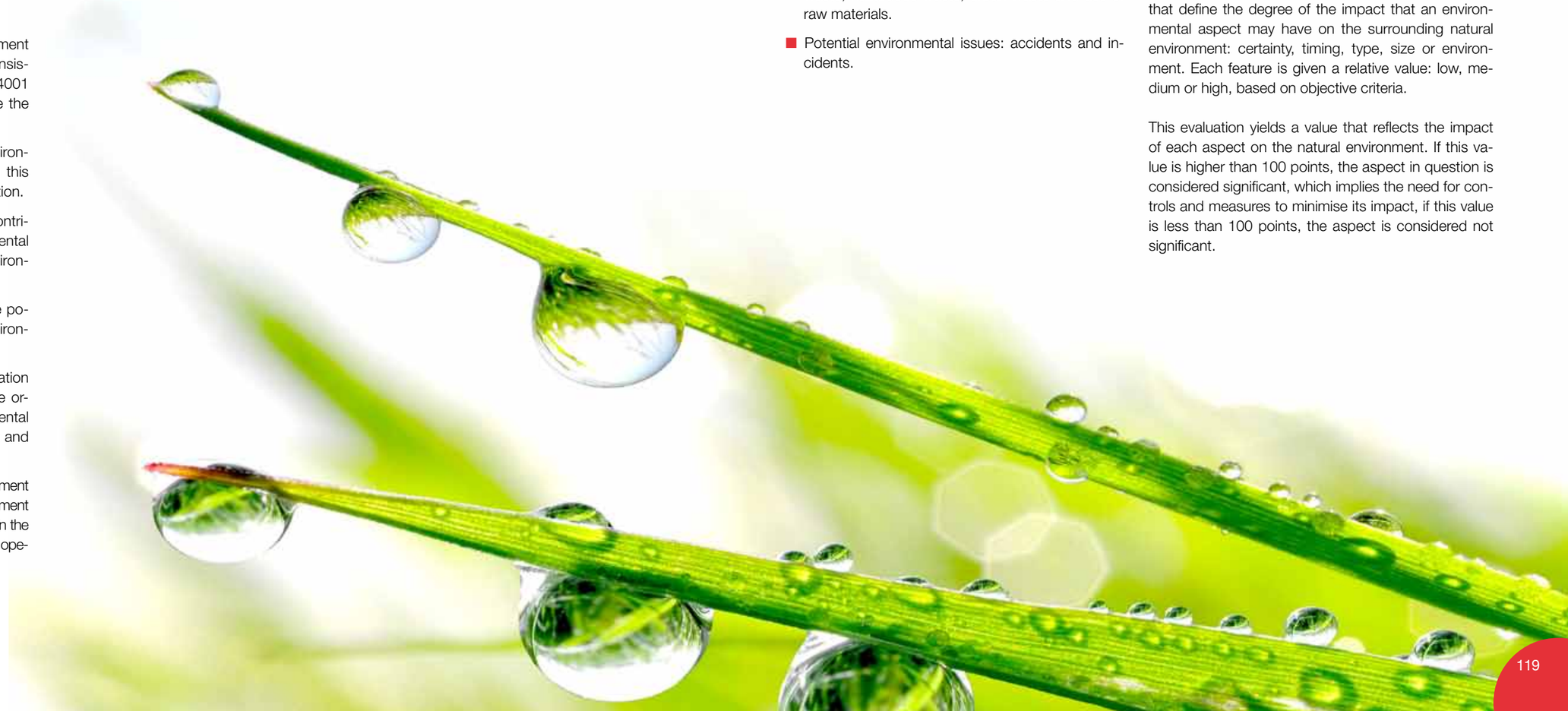
Environmental management policy

Isolux transmits its commitments to pollution prevention, environmental and legal compliance and continuous improvement in environmental management through its environmental management policy, which is disseminated on all levels of the organisation and integrated into all activities, regardless of the country where they are developed.

Management ensures the implementation of the measures necessary to achieve the knowledge and commitment of all members of the Organisation and external collaborators to this environmental policy. Similarly, to ensure that it is available to any interested party and the general public.

Through this policy, Isolux Corsán commits itself:

- To develop and implement quality management systems adapted to our organisation and consistent with the principles established in ISO 14001 and to adopt measures to continually improve the effectiveness of these systems.
- To establish and monitor compliance with environmental objectives and targets consistent with this policy and with the capabilities of our organisation.
- To ensure that these objectives and targets contribute to progressively increase good environmental performance and the effectiveness of our environmental management system.
- To implement practices to prevent and reduce pollution, attempting to minimise significant environmental impacts.
- To comply with applicable environmental legislation and other environmental requirements that the organisation subscribes to in relation to environmental aspects. To maintain all information up to date and conveniently available.
- To periodically review this policy to maintain its alignment with the vision and strategic objectives of Management and address the needs identified at each moment in the market, social and natural environment in which we operate.



Identification of the environmental aspects of projects

In accordance with the commitment to pollution prevention and compliance with environmental and legal requirements, all projects shall include the identification of environmental aspects associated with its activities and applicable environmental and legal requirements in the planning process. To do this, Isolux Corsán has tools to assess and prioritise the issues identified and to establish operational controls that minimise the impact of the activities to be developed.

Environmental aspects are classified into one of the following categories and subcategories:

- Real environmental issues: water condition, consumption of natural resources/products, damage to soil, acoustic emissions, air emissions, inert waste, hazardous waste, urban waste and use of raw materials.
- Potential environmental issues: accidents and incidents.

In 2011, among the “real” environmental aspects identified, the highest percentage corresponds to the generation of inert waste (29%), followed by the generation of urban waste (17%) and hazardous waste (16%), together with the consumption of natural resources/products (14%).

Furthermore, within the category of ‘potential’ aspects, we have mainly identified the possible occurrence of environmental accidents (65%) compared to the likelihood of an incident (35%).

Evaluation of environmental aspects

For the evaluation of environmental aspects we use a tool that is based on the analysis of various features that define the degree of the impact that an environmental aspect may have on the surrounding natural environment: certainty, timing, type, size or environment. Each feature is given a relative value: low, medium or high, based on objective criteria.

This evaluation yields a value that reflects the impact of each aspect on the natural environment. If this value is higher than 100 points, the aspect in question is considered significant, which implies the need for controls and measures to minimise its impact, if this value is less than 100 points, the aspect is considered not significant.

Waste management

Special attention is paid to the management of the waste we generate in all projects we execute, so that all personnel assigned to the project collaborate in waste management.

There have been numerous talks and awareness training aimed at all staff and subcontractors involved in the works so that they participate in the proper segregation and storage of waste and know the legal obligations arising from waste management.

Isolux Corsán enables containers for the collection of all waste generated in the projects and hires operators authorised to withdraw and apply the most appropriate treatment.

During 2011, as a result of our project activities in Algeria, Argentina, Brazil, India and Mexico, we have managed the following amounts of waste:

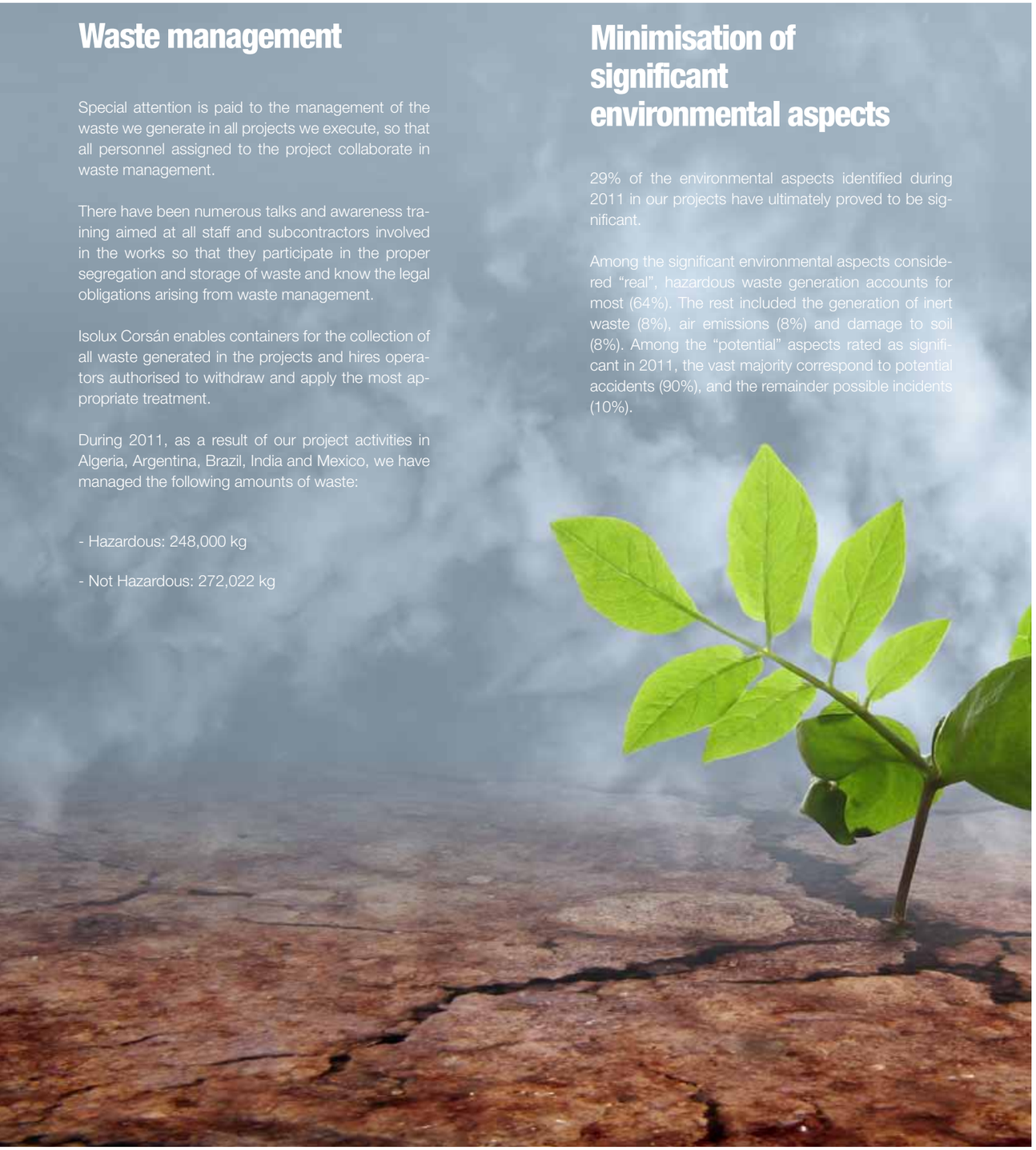
- Hazardous: 248,000 kg

- Not Hazardous: 272,022 kg

Minimisation of significant environmental aspects

29% of the environmental aspects identified during 2011 in our projects have ultimately proved to be significant.

Among the significant environmental aspects considered "real", hazardous waste generation accounts for most (64%). The rest included the generation of inert waste (8%), air emissions (8%) and damage to soil (8%). Among the "potential" aspects rated as significant in 2011, the vast majority correspond to potential accidents (90%), and the remainder possible incidents (10%).



The protection of the environment, everyone's job

The internationalisation process that the Group is undertaking and the entry into new businesses have made the Environmental Management System a key tool to understand, control and minimise the environmental risks of our activities.

For this reason, it has become especially relevant for all efforts to achieve the values and environmental requirements of Isolux Corsán to permeate all levels of the organisation.

The environmental management system is key to managing environmental risks

These initiatives were:

- Creation of a corporate structure in each country with the capacity to implement and monitor the environmental management of all projects.
- Staffing and reinforcement of qualified resources needed for environmental prevention in all projects.
- Identification of legal requirements in each of the countries where the Group operates, and evaluation of compliance therewith.
- Development of good environmental management practices, regardless of the country where the activity takes place.
- Standardisation in the identification and evaluation of environmental aspects.
- Establishment of measures to minimise environmental risks.
- Training of project teams in environmental issues in all countries where the Group operates.
- Establishment of guidelines for reporting and monitoring of indicators to consolidate information from different countries where the Group operates.
- Performance checks and internal audits on projects in all countries where the Group operates.
- Establishment of targets, monitoring and review of systems.

This has laid the groundwork to begin the process of certification under ISO 14001 in countries in which we are fully implemented, such as Mexico and Argentina, and will continue in India and Brazil.

Commitment to pollution prevention

Isolux Corsán is committed to renewable energy as a way to combat climate change and an opportunity to reduce energy dependence.

In this sense, the company T-Solar combines the economic profitability of its activities with a clear commitment to environmental stewardship and development. T-Solar applies the principles of sustainable development to each of its activities.

Specifically, the clean electricity produced by T-Solar in 2011 (244.96 GWh) has avoided the emission of some 270,800 tons of CO_2, approximately.

Commitment to energy efficiency

Isolux Corsán's commitment to sustainability and the Group's alignment with the international policies and standards that seek the energy efficiency of our activities have resulted in a number of 2011-2013 initiatives that began with actions aimed at reducing energy and water consumption at the headquarters of the Group.

These actions, which will be translated to the rest of the delegations is each country have the following objectives:

The Group has undertaken initiatives to optimise the energy efficiency of its activities

- Improving the energy efficiency ratio.
- Improving the efficiency ratio of water consumption.
- Minimising waste generation and improving waste management.
- Integrating environmental considerations into all activities.

To this end, the Plan starts off with actions such as:

- Installation of taps with timers and aerators in toilet.
- Installation of timers and motion detectors in determined areas of the building.
- Automatic switching off lights and air conditioning.
- Renovation of printer and photocopying equipment for lower consumption.
- Creation of pool of printing and photocopying equipment in reducing the number of units.
- Internal regulations limiting the request for office equipment seeking to reduce the consumption of such material.
- Posters and signage communicating environmental good practices.

In order to establish a starting point for environmental improvement and inform our stakeholders of our performance in this area, we have performed the first Inventory of Greenhouse Gas Emissions generated in the head office in Madrid and associated activities following the guidelines of UNE-ISO 14064-1: 2006 Greenhouse gases Part 1: "Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals."

GHG Emissions Inventory prepared included scopes 1 and 2, which define the standard reference on the 2011 data, being year 0 or as the first year that we estimate GHG emissions.



Scope 1: Direct emissions

GHG emissions from GHG sources owned or controlled by the organisation. These emissions were estimated by identifying the equipment, machinery, fuels and confined gases encompassed within the various facilities of the building, which are: thermal comfort (boilers and air conditioning), provision of emergency power (generator), food preparation (kitchen equipment), maintenance of fire extinguishers and potential emissions of HFC gas.

t CO_2 direct emissions

83.84

Scope 2: Indirect emissions from energy

GHG emissions coming from electricity generation, heat or steam from external sources consumed by the organisation. Energy consumption (electric) to power the various facilities and equipment of the building have been identified in this scope, calculating it by using an emission factor provided by the utility company.

With these initial data, Isolux Corsán set reduction targets and implemented measures aimed at greater efficiency and energy management in the headquarters building.

t CO_2 indirect emissions from energy

897.66

QUALITY MANAGEMENT, ENVIRONMENTAL MANAGEMENT, AND HEALTH AND SAFETY MANAGEMENT

Commitment to the promotion of quality, environmental management and occupational risk prevention

International implementation of our work culture

In line with the reality of internationalisation of the company, in 2011 Isolux Corsán expended a huge effort to apply the Safety, Health, Quality and Environment Management Systems, and the commitments of its policies, to all countries where we do business, adapting to the requirements of the particular countries and enabling these corporate structures to ensure effective implementation of these systems.

Our goal for future years to ensure that our local and major global suppliers adopt and commit to the principles of corporate responsibility Isolux Corsán wants to adopt in all countries, which are:

- Legal compliance
- Integrity and transparency
- Efficiency and efficacy
- Safe working environments
- Commitment to quality
- Commitment to pollution prevention

To achieve these objectives, The Group has established a Quality, Environment and Health and Safety structure in each country, with responsibility for the implementation and monitoring of management systems and reporting to the Corporate Quality, ORP and Environment Department on the progress, needs and preventive and corrective actions to be implemented for the continuous improvement of the System.

We have also strengthened the monitoring of the implementation of Management Systems in countries through:

- Regular visits and audits by the Corporate Quality, Safety and Environment supervisors of the different projects under implementation in their countries, reinforcing training and communicating values and system requirements for all business units.
- Implementation of a reporting system that allows for the efficient reporting to Management of reliable consolidated data on the indicators of accidents, non-compliance, audits and resources.
- Implementation of IT tools that allow online access to management data and indicators.
- Monthly videoconference with the quality, health and safety and environment teams of the countries to track the needs and actions to apply in each project.
- Training and exchange of experiences through meetings of the quality, health and safety and environment teams.

This routine has laid the foundation to have verifiable management systems under ISO 9001, ISO 14001 and OHSAS 18001 by prestigious companies in each country where we have a corporate structure. Isolux Corsán Mexico has obtained the certification of the three standards indicated. This process has begun in Isolux Corsán Argentina and will be completed in early 2012, at which time we are scheduled to begin the certification process in India and Brazil.

International certifications

ISO 9001 (Quality) and ISO 14001 (Environment)

All management systems that Isolux Corsán has implemented according to international standards ISO 9001 and ISO 14001 are certified by independent, globally-renowned certification bodies.

Annually, these independent bodies review our Management Systems through the development of on-site audits, ensuring that their application in our offices and projects is consistent with both international standards, offering our customers everywhere, and society in general, an additional guarantee.

Currently, Isolux Corsán has the following ISO certifications, spread among several of its companies, and limited to Spain:

EMAS registration

The Elaborados Metálicos Emesa factory and the Photovoltaic Module Factory of T-Solar hold environmental certification according to the EMAS Regulation, a voluntary regulation of the EU recognising companies that have implemented an Environmental Management System and have acquired a commitment to improvement.

Under this commitment, T-Solar and EMESA produce an environmental statement which includes regular and systematically documents the solid performance of their factories plants in environmental sustainability, by controlling the impact of all activities and processes related to their production lines.

OHSAS 18001 (Health and Safety)

The external audit processes allow us to promote the continuous improvement of our management system. For this reason we promote the certification of the different companies within the Group under OHSAS 18001:2007.

The Group companies that hold this certification are: Isolux Ingeniería, Corsán-Corviam Construcción, Isolux Corsán Servicios and Grupo Isolux Corsán.

Throughout 2011, all these companies are subjected to periodic audits for control or recertification.

Certificates in Spain

Company	Certification - *Certifier*
Corsán-Corviam Construccción, S.A.	ISO 9001 + ISO 14001 - AENOR
Isolux Ingeniería, S.A.	ISO 9001 + ISO 14001 - AENOR
Isolux Corsán Servicios, S.A.	ISO 9001 + ISO 14001 - AENOR
Global Vambrú, S.L.	ISO 9001 + ISO 14001 - AENOR
Watsegur, S.A.	ISO 9001 + ISO 14001 - AENOR
Elaborados Metálicos, S.A.	ISO 9001 + ISO 14001 + EMAS - DNV
Corvisa Prod. Asfálticos y Anlic. S.L.	ISO 9001 - DNV
Grupo Isolux Corsán, S.A.	ISO 9001 + ISO14001 -AENOR

RESEARCH, DEVELOPMENT AND INNOVATION

Commitment to innovation and R&D

Isolux Corsán has a strong background in R&D dating from its inception. This experience has allowed it to develop a Management System under the UNE 166.002:2006 that promotes the development of R&D and Technological Innovation within the Group's business units and thereby offering high value added to our customers.

The Group's management system encourages the development of R&D

The Management of Isolux Corsán expressses its commitment to innovation through the Corporate R&D+i Policy, which includes the following principles:

- To develop and implement an R&D&i management system adapted to our organisation and consistent with the principles established in UNE 166,002:2006, adopting measures to continually improve its effectiveness.
- To provide, through the R&D&i Management System, a framework for the organisation to set R&D&i targets, to seek their achievement and perform periodic reviews.
- To ensure the availability of resources for achieving the R&D&i objectives and to know and analyse the latest technological developments in our industry.
- To identify new ideas that allow the development of new products and services.
- To promote, among all our business units, cooperation in R&D&i with external entities that provide expertise, methodologies and resources.

Construction Division

Recognition through certification of the technical innovations that are implanted into the works is a strategic priority for the Construction business area. The justification for each of these innovations is formally collected in a Project R&D+i Report.

Similarly, any research and development being done by project technical departments is reflected in the Project R&D+i Report. These reports are prepared according to the requirements set in the R&D+i Management System, implemented in the organisation according to UNE 166002:2006.

In 2011, 6 new R&D+i projects have been presented for certification

Subsequently, the R&D+i Reports developed in accordance with the above are evaluated by independent experts to ensure that the projects are finally certified under the UNE 166001:2006.

During 2011 we have presented six new R&D+i projects for certification. These projects were in the technological areas of hydraulics, concrete structures, geotechnics and foundations, and bridges.

Health and Safety Strategic Line - PTEC

Corsán-Corviam Construcción is a member of the governing bodies of the Spanish Construction Technology Platform (PTEC for the Spanish initials). The platform consists of the largest institutions, public research organisations, universities and companies in the construction sector. Within this platform, Corsán-Corviam Construcción leads the Health and Safety Strategic Line (LESS for the Spanish initials), focused on research and development of new technologies and solutions that enhance safety and reduce adverse health effects for workers.

In 2011, Corsán-Corviam Construcción has led, within the LESS, the launch of two new projects in the area of health and safety:

- New Intelligent Collective Safety Systems in Dynamic Environments of Linear Infrastructure (PRECOIL). This project aims to develop new intelligent collective preventive safety systems based on the use of sensors and low-cost technologies in personnel, machinery and the working environment.
- A 3D simulator for the Prevention of Occupational Risks in the construction sector (SIPREL 3D). This project aims to create a tool that, based on a review of project documentation, creates a three-dimensional model thereof and of the conditions at any time, to determine the risks at each stage and present them through the relevant risk map.

Both projects were submitted to the aid program INNPACTO 2011, of the Ministry of Science and Innovation (MICINN). The first (PRECOIL) received the requested assistance.

Also in 2011 Corsán-Corviam Construcción continued to actively participate in other strategic lines of PTEC. Within the Sustainable Construction Strategic Line (LECS), Corsán-Corviam Construcción has been part of the consortia which have submitted the following projects to national R&D+i support programmes:

- Methodology for the Integral Evaluation and Minimisation of the Environmental Impact of Linear Infrastructure (INFRAMB). This project is the continuation of several research lines of the CLEAM project, completed in 2010. The project consists of the development of a tool that supports decision making throughout the project from design to commissioning, with a dual focus: the overall environmental impact of the infrastructure and the impacts associated with different environmental factors affected by each and every one of the activities of the project.
- Innovative Solutions for the Generation of Sustainable Performance Models (SIGMAS): It aims to discover significant and high value added differential solutions to promote and undertake repeatable sustainable rehabilitation initiatives in clearly defined specific scenarios publicly in government-owned buildings and linear infrastructure.



PTEC Foundation

Corsán-Corviam Construcción is a founding member of the PTEC Foundation and one of their current sponsors. The main mission of this foundation is to contribute to the sustainable progress of the construction sector, paying particular attention to fostering innovation in order to obtain and ensure greater efficiency in the use of R&D+i investment in the sector, promoting improved efficiency, productivity, quality and safety, and a significant reduction in the environmental impact of construction activities and increased well-being of society in general.

In 2011 the Foundation has worked to develop the internal procedures of the Board. These procedures will allow the Foundation to organize and perform its functions properly, effectively coordinating with the governing bodies and strategic research lines of the Spanish Construction Technology Platform, to which it is linked.

By 2012 the Foundation has planned, in coordination with the Permanent Commission of the Platform, various activities aimed at promoting R&D in our industry, which include:

- Promote the organisation of online training courses on R&D+i.
- Promote the submission of new projects to R&D+i support programmes in 2012.
- Participate in R&D+i forums.
- Collaborate with public bodies in R&D+i.
- Participate in trade fairs, conferences and seminars related to the construction industry.
- Disseminate the activities of PTEC and implement activities that enhance the innovative image of the sector.
- Participate in workshops and events of other technology platforms.
- Monitor other technological innovations that could be useful to members of PTEC.

The indispensable R&D+i in the Engineering area

Isolux Corsán considers R&D+i necessary to strengthen its industry position, accompanying the adaptation to new regulatory frameworks and developing new business in the field of integral water cycle, renewable energy and the environment in general. This need is reinforced by the commitment to provide the best possible quality in all activities.

R&D+i has played a key role in the water sector, where the Group's main objectives are energy optimisation in the water treatment processes, water reclamation and desalination in all its stages, and in the waste recovery segment of treatment plants and brine rejection, which focuses on improving the efficiency of production processes and developing new technologies for waste treatment, sludge in particular. Our aim is to maintain our leadership position in the business areas in which we currently operate, maintaining our competitive position and allowing for long-term growth.

Isolux Corsán, through its Environment Department, is very actively working as a member of the Water Technology Platform (PTA), which has resulted in the development of numerous projects whose primary focus is sewage and very

Isolux Corsán is actively involved in the Water Technology Platform

especially in the drafting of the Country Project presented by the PTA for submission to the European Commission.

The result of this leadership vocation in innovation in the water sector, the company in 2011 successfully completed the project started in 2009:

- Development of a biocatalytic electrolysis process for wastewater. The 2-year R&D project, subsidised by the CDTI and executed in collaboration with the University of León, has amply achieved the treatment objectives defined in the project, for which the parties are considering its extension.

In 2011 Isolux Corsán has received further support from government agencies that have promoted the continuity of research plans set out in the Group and has launched the following projects:

ADECAR. Application of Capacitive Deionisation of wastewater, a three-year R&D+i project funded by the Ministry of Science and Innovation through the Subprogramme INNPACTO and aimed at developing capacitive deionisation technology, applicable to the re-

generation of urban and industrial wastewater, fresh and brackish water to efficiently remove nutrients, which can be considered microcontaminants, in particular nitrogen and phosphorus ions, as well as sulfates, boron, lithium and arsenic.

ADIF. Within the railway sector, in which Isolux Corsán has extensive experience in R&D+i, the company in December 2011 signed a collaboration agreement with the Spanish Administrator of Railway Infrastructure (ADIF) for collaboration in research, technological development and innovation at the Centre for Railway Technologies that ADIF operates in Malaga.

The aim of the agreement is to cooperate in the implementation of R&D+i projects that contribute to increasing the competitiveness of Spanish companies in the railway industry and position Spanish railway transportation in forefront of European and global technological leadership.

The collaboration includes the execution of projects and research programmes, reciprocal advice, and technical training of research staff and the creation of public-private

In 2011 the control system project for solar power plants started in 2008 was completed

partnerships for the presentation of R&D+i projects to grant applications and joint tenders in national and international auctions.

A joint committee will be responsible for monitoring progress in each work area and to identify new projects. The main lines of research will focus on energy recovery systems, distributed control systems for electrical substations, multi-voltage electrical substations to supply direct and alternating current and specific software applications integrated in the Davinci platform.

Taking advantage of Isolux Corsán's leadership in the promotion and implementation of solar photovoltaic facilities and the Group's extensive experience in control systems and automation, the project "Control system for solar PV power plants", was concluded in 2011. Launched in 2008, this project was funded by the Ministry of Industry, Tourism and Trade and allowed the company to design and implement an industry-leading solar PV control system, with over one hundred and eighty thousand signals managed in over thirty locations.



External Communication

In the past year, Isolux Corsán's external communication department has focused its efforts on corporate positioning according to the expansion of company business. Communication activity have grown significantly beyond our borders (59% are international news), which translates into a greater presence in online media, both generalist and trade.

In 2011 the Group led most of the published information, with a proactive approach that far exceeded previous years figures (79% of the articles were generated by the company).

Consistent with the communications strategy of recent years, Isolux Corsán advocates a transparent and accountable management of the relationship to the media, which has been extended this year to both national and international media.

We believe in transparent management of media relations

Media presence

- Over 2011 there have been a total* of 3,440 articles on Isolux Corsán in the media, representing growth of 157% over the previous year.
  *This estimate is based on the information received through the GBA clipping service.
- The company was mentioned in 14,299 cases, multiplying the number of mentions in 2010 by five.

Greater international presence

- In 2011 the Group received a strong presence in international media. 59% of the information (2,029 news articles) were published in foreign media. In addition to the volume of international impacts, we would highlight the presence of Isolux Corsán in industry and strategic media for the company in key countries like the USA, India or Brazil.

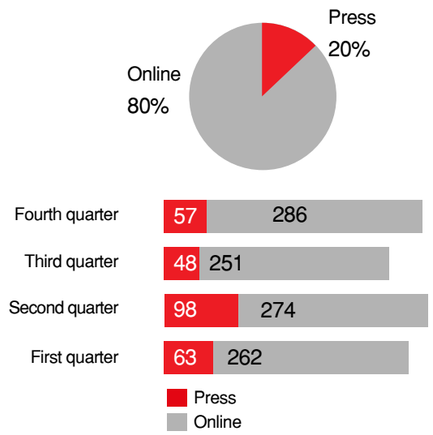
Breakdown by type of media

- In a context of global communication, Isolux Corsán appearances detected in the network have grown in line with the internationalisation strategy. Of the total of identified information about the company, 92% (3,179 articles) correspond to online media* and 8% (261 articles) to print.

Institutional Communication

- Isolux Corsán has strengthened its institutional presence in 2011 participating and collaborating in organising over 30 events around the world: Spain, Argentina, Algeria and Mexico are the most prominent in this area.
- Institutional communication has revolved not only around the actual activity of Isolux Corsán through inaugurations, laying of the first stones or visits by authorities to work sites, but also through the management of our company's participation in international forums and conferences such as the World Road Conference in Mexico or the International Renewable Energy Exhibition in Oran.

Breakdown by type of media



- *International news is monitored through online media.



Awards and Distinctions

- Isolux Corsán received the award for Project Finance Deal of the Year 2011 for WETT.
- Isolux Corsán awarded the Power Award for best works or projects 2011
- Isolux Corsán received an award in the 50th Anniversary of ICADE.
- Isolux Corsán is installing electric system for the ship North Sea Giant, named best off-shore in the world.
- Isolux Corsán received the Infrastructure Investor Award 2011 as the Asia Pacific Infrastructure developer of the year.
- T-Solar receives the award for best "Project Finance" in Latin America for the financing of its photovoltaic plants in Peru.

Corporate Social Responsability
4. Community and environment

Institutional Relations

January

- Inauguration of the reform of Puerto del Carmen, Lanzarote - Spain
- Inauguration of the Police Station in Castellón - Spain
- First stone of the Toulouse-Hernialde section of the País Vasco, Vizcaya - Spain
- Inauguration of the extension and reform of the Archaeological Museum of Cordoba - Spain

February

- Opening of the Vallehermoso-Arure Highway in Las Palmas - Spain
- First stone of the Court Building in Plasencia - Spain
- Visit of the Minister of Public Works to High-Speed Rail works in Granada - Spain

March

- Opening of Santa Barbara Car Park, Cádiz - Spain
- Signing of the contract for the burying of Commuter Rail Line 3 in Getafe - Spain
- Inauguration of the WWTP in Zamora - Spain
- Inauguration of the WWTP in Tomelloso - Spain
- First stone of the Municipal Market in Tarragona - Spain
- Inauguration of the Santa Teresa Bridge, Valladolid - Spain
- Visit to Moncófar Desalination Plant, Castellón - Spain
- Visit of the Secretary of State for Transport to the Lavacolla Airport works, Santiago de Compostela - Spain
- Inauguration of the Borox treatment plant in Toledo - Spain

April

- Futurcivil Job Fair, Barcelona - Spain
- Induforum Job Fair, Madrid - Spain

May

- Inauguration of the Restoration of the Taylor Customs Building and conversion to a Museum. Buenos Aires - Argentina
- Electronics Fair 2011 in Gabon



Isolux Corsán received an award in the 50th Anniversary of ICADE. | MADRID

June

- Inauguration of the Salto Andersen Hydroelectric Power Plant - Argentina
- 5th Annual International Conference on High Speed Railway Engineering in Córdoba - Spain

July

- Delivery of 138 of subsidised housing under the Official Protection Housing Plan for Youth of Alcorcón - Spain

August

- First stone of the Car Park and the new judicial seat in Las Palmas - Spain

September

- Opening of the new terminal of the Lavacolla Airport, Santiago de Compostela - Spain
- Tunnel breakthrough in the Basque Y, Ganzelai - Spain
- Visit of the Regional Minister of Health of Andalucía to the works of car park at the Virgen de las Nieves University Hospital in Granada - Spain
- World Road Congress - Mexico

October

- International Exhibition of Renewable Energies in Orán - Algeria
- Employment Forum Universidad Pontificia de Comillas in Madrid - Spain
- Inauguration of the bridge, Puente Vaguada de las Llamas, in Santander - Spain

November

- Inauguration of the extra 500 kV high voltage line Calingasta - Rodeo/Iglesia - Argentina

December

- Inauguration of the Third Ring Road, A Coruña - Spain

02

Economic Report

Economic

GRUPO ISOLUX CORSÁN, S.A. AND SUBSIDIARIES

Consolidated Annual Accounts at 31 December 2011
and 2011 Management Report

pwc

This version of our report is a free translation of the original, which was prepared in Spanish. All possible care has been taken to ensure that the translation is an accurate representation of the original. However, in all matters of interpretation of information, views or opinions, the original language version of our report takes precedence over this translation

AUDIT REPORT ON THE CONSOLIDATED ANNUAL ACCOUNTS

To the shareholders of Grupo Isolux Corsán, S.A.:

1. We have audited the consolidated annual accounts of Grupo Isolux Corsán, S.A. (Parent Company) and its subsidiaries (the Group), consisting of the consolidated balance sheet at 31 December 2011, the consolidated income statement, the consolidated statement of other comprehensive income, the consolidated statement of changes in equity, the consolidated cash flow statement and related notes to the consolidated annual accounts for the year then ended. As explained in Note 2.1 to the accompanying related notes, the Directors of the Parent Company are responsible for the preparation of these consolidated annual accounts in accordance with the International Financial Reporting Standards as endorsed by the European Union, and other provisions of the financial reporting framework applicable to the Group. Our responsibility is to express an opinion on the consolidated annual accounts taken as a whole, based on the work performed in accordance with the legislation governing the audit practice in Spain, which requires the examination, on a test basis, of evidence supporting the annual accounts and an evaluation of whether their overall presentation, the accounting principles and criteria applied and the estimates made are in accordance with the applicable financial reporting framework.

2. In our opinion, the accompanying consolidated annual accounts for 2011 present fairly, in all material respects, the consolidated financial position of Grupo Isolux Corsán, S.A. and its subsidiaries at 31 December 2011 and the consolidated results of its operations and the consolidated cash flows for the year then ended in accordance with the International Financial Reporting Standards as endorsed by the European Union, and other provisions of the applicable financial reporting framework.

3. The accompanying consolidated Directors' Report for 2011 contains the explanations which the Parent Company's Directors consider appropriate regarding the consolidated Group's situation, the development of its business and other matters and does not form an integral part of the consolidated annual accounts. We have verified that the accounting information contained in the consolidated Directors' Report is in agreement with that of the consolidated annual accounts for 2011. Our work as auditors is limited to checking the consolidated Directors' Report in accordance with the scope mentioned in this paragraph and does not include a review of information other than that obtained from the accounting records of Grupo Isolux Corsán, S.A. and its subsidiaries.

PricewaterhouseCoopers Auditores, S.L.

Original in Spanish signed by
Fernando Chamosa
Partner

10 April 2012

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Consolidated balance sheet
(Thousand euro)

	Note	31 December 2011	31 December 2010
ASSETS			
Non-current assets			
Property, plant and equipment	**6**	190,359	203,834
Goodwill	**7.1**	577,436	487,114
Intangible assets	**7.2**	24,889	66,509
Investment property		14,574	-
Concessionary assets assigned to projects	**8.1**	2,451,377	1,400,922
Other non-current assets assigned to projects	**8.2**	1,488,601	252,201
Investments in associates	**9**	34,634	178,996
Financial investments	**10**	10,956	11,512
Trade and Other receivables	**12**	124,759	69,093
Deferred income tax assets	**20**	232,618	115,886
Derivative financial instruments	**11**	1,155	4,287
		5,151,358	**2,790,354**
Current assets			
Inventories	**13**	357,725	427,860
Trade and other receivables	**12**	1,886,931	1,941,875
Derivative financial instruments	**11**	6,201	4,710
Financial assets at fair value through profit or loss	**14.2**	14,447	2,300
Cash and cash equivalents	**14.1**	674,366	937,555
		2,939,670	**3,314,300**
Total assets		**8,091,028**	**6,104,654**

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Consolidated balance sheet
(Thousand euro)

	Note	31 December 2011	31 December 2010
EQUITY			
Equity attributable to owners of the parent company			
Share capital	**15**	17,463	17,463
Share premium	**15**	468,413	469,163
Legal reserve	**15**	10,564	8,207
Hedging reserve	**11**	(60,741)	(36,316)
Cumulative translation differences	**16**	(30,262)	38,119
Retained earnings	**17**	197,558	199,710
		602,995	**696,346**
Non-controlling interest	**17**	**293,318**	**74,728**
Total equity		**896,313**	**771,074**
LIABILITIES			
Non-current liabilities			
Borrowings	**19**	929,930	877,564
Project finance	**8.3**	2.257,823	1,012,530
Derivative financial instruments	**11**	174,359	47,647
Deferred income tax liabilities	**20**	142,879	66,752
Provisions for other liabilities and charges	**21.1**	47,060	47,167
Other payables	**18**	418,897	41,028
		3,970,948	**2,092,688**
Current liabilities			
Borrowings	**19**	449,058	372,804
Project finance	**8.3**	358,342	222,480
Trade and other payables	**18**	2.303,064	2,559,171
Current tax liabilities		28,224	21,779
Derivative financial instruments	**11**	24,400	12,559
Provisions for other liabilities and expenses	**21.2**	60,679	52,099
		3,223,767	**3,240,892**
Total liabilities		**7,194,715**	**5,333,580**
Total equity and liabilities		**8,091,028**	**6,104,654**

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Consolidated income statement
(Thousand euro)

	Note	Year ended 31 December	
		2011	2010
Total operating revenue		**3,371,940**	**3,239,786**
Revenue / Sales	22	3,200,700	3,188,740
Other operating income	24	55,166	44,995
Change in inventories		(2,331)	5,034
Own work capitalized		118,405	1,017
Total operating expenditure		**(3,106,047)**	**(3,032,084)**
Materials consumed and other external costs	23	(2,251,624)	(1,864,095)
Employee benefit expenses	25	(378,925)	(379,270)
Depreciation, amortization and impairment losses	6,7,8 & 2.5	(119,169)	(86,692)
Change in trade provisions		(7,672)	(16,804)
Other operating expenses	24	(348,657)	(685,223)
Operating results		**265,893**	**207,702**
Financial costs	27	(300,810)	(171,743)
Financial income	27	83,530	56,022
Net financial results	27	**(217,280)**	**(115,721)**
Share of profits/ (losses) of investments accounted for the equity method	9	(15,787)	(7,072)
Profit before income tax		**32,826**	**84,909**
Income tax	28	(27,350)	(20,949)
Profit for the year		**5,476**	**63,960**
Attributable to:			
Non-controlling interest		24,069	63,155
Owners of the parent	17	(18,593)	805
		5,476	**63,960**
Earnings per share attributable to the equity holders during the year – Basic and diluted (euro per share)	29	0.27	0.72

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Consolidated statement of comprehensive income for the year endend at 31 december 2011 and 2010
(Thousand euro)

	Note	Year ended at 31 December	
		2011	2010
Profit/(loss) for the year		**5,476**	**63,960**
Other comprehensive income:			
Changes due to financial statement translation	16	**(76,489)**	**34,819**
Fair value changes in cash flow hedges	11	(109,179)	(54,609)
- Tax effect	20	33,987	15,245
Cash flow hedge transferred to profit and loss	11	20,897	21,952
- Tax effect	20	(6,269)	(6,545)
Net cash flow hedges		**(60,564)**	**(23,957)**
Comprehensive income for year attributable to:		**(131,577)**	**74,822**
Owners of the parent		(101,459)	68,129
Non-controlling interest		(30,118)	6,693

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Consolidated statement of changes in equity – year 2011

(Thousand euro)

	Attributable to equity holders of the Parent Company							
	Share Capital (Note 15)	Share Premium (Note 15)	Legal Reserve (Note 15)	Hedging reserve (Note 11)	Cumulative translation difference (Note 16)	Retained earnings (Note 17)	Non-controlling interests (Note 17)	Total Equity
Balance at 31 December 2010	**17,463**	**469,163**	**8,207**	**(36,316)**	**38,119**	**199,710**	**74,728**	**771,074**
Profit/(loss) for the year	**-**	**-**	**-**	**-**	**-**	**24,069**	**(18,593)**	**5,476**
Net cash flow hedges	-	-	-	(57,147)	-	-	(3,417)	(60,564)
Foreign currency translation differences	-	-	-	-	(68,381)	-	(8,108)	(76,489)
Total other comprehensive income	**-**	**-**	**-**	**(57,147)**	**(68,381)**	**-**	**(11,525)**	**(137,053)**
Total comprehensive income	**-**	**-**	**-**	**(57,147)**	**(68,381)**	**24,069**	**(30,118)**	**(131,577)**
Other movements and additions to consolidation scope	-	-	-	32,722	-	5,386	248,708	286,816
Dividends to equity holders of the company (Note 17)	-	(750)	2,357	-	-	(31,607)	-	(30,000)
Balance at 31 December 2011	**17,463**	**468,413**	**10,564**	**(60,741)**	**(30,262)**	**197,558**	**293,318**	**896,313**

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Consolidated statement of changes in equity – year 2010

(Thousand euro)

	Attributable to equity holders of the Parent Company							
	Share Capital (Note 15)	Share Premium (Note 15)	Legal Reserve (Note 15)	Hedging reserve (Note 11)	Cumulative translation difference (Note 16)	Retained earnings (Note 17)	Non-controlling interests (Note 17)	Total Equity
Balance at 31 December 2009	**17,463**	**469,763**	**5,850**	**(13,663)**	**10,492**	**183,088**	**52,457**	**725,450**
Profit/(loss) for the year	**-**	**-**	**-**	**-**	**-**	**63,155**	**805**	**63,960**
Net cash flow hedges	-	-	-	(22,653)	-	-	(1,304)	(23,957)
Foreign currency translation differences	-	-	-	-	27,627	-	7,192	34,819
Total other comprehensive income	**-**	**-**	**-**	**(22,653)**	**27,627**	**-**	**5,888**	**10,862**
Total comprehensive income	**-**	**-**	**-**	**(22,653)**	**27,627**	**63,155**	**6,693**	**74,822**
Other movements (Incentives; net from tax effect) (Note 34)	-	-	-	-	-	(19,266)	-	(19,266)
Other movements	-	-	-	-	-	(1,510)	15,578	14,068
2009 dividends to equity holders of the company (Note 17)	-	(600)	2,357	-	-	(25,757)	-	(24,000)
Balance at 31 December 2010	**17,463**	**469,163**	**8,207**	**(36,316)**	**38,119**	**199,710**	**74,728**	**771,074**

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Consolidated statement of cash flows

(Thousand euro)

	Notes	Year ended 31 December 2011	2010
Cash flows from operating activities			
Profit for the year before taxes		**32,826**	**84,909**
Adjustments for:			
- Depreciation, amortization and impairment losses	**6,7,8 & 2.5**	119,169	86,692
- Change in trade provisions		7,672	16,804
- Profit on non-current assets assigned to projects disposal	**24**	-	(26,562)
- Profit on property, plant and equipment disposal		687	-
- Share of results on investments accounted for the Equity Method	**9**	15,787	7,072
- Net financial results	**27**	217,280	115,721
- Financial remuneration on concessionary assets assigned to projects	**8.1**	(71,044)	-
- Other adjustments to profit for the year	**24**	(4,533)	-
Subtotal		**285,018**	**199,727**
Changes in working capital:			
- Inventories		64,226	(79,893)
- Trade and other receivables		61,124	(306,058)
- Financial assets at fair value through profit or loss		(14,119)	(1,796)
- Trade and other payables		(257,505)	318,774
- Provisions for other liabilities and charges		911	14,139
- Other changes		-	(4,303)
Cash generated from operations		**172,481**	**225,499**
- Taxes paid		(28,922)	(16,997)
Net cash generated from operating activities		**143,559**	**208,502**
Cash flows from investing activities			
- Acquisition of subsidiary, net of cash acquired	**32**	(60,869)	-
- Purchases of property, plant and equipment and intangible assets		(21,599)	(46,615)
- Income from property, plant and equipment and intangible assets disposal		3,789	1,415
- Acquisition of concessionary assets and non-current assets assigned to projects		(1,019,949)	(506,019)
- Net change in long-term payables		16,930	-
- Revenue due to non-current assets assigned to projects disposal		-	256,535
- Acquisitions of investments in associates and financial investments		(3,035)	(1,374)
- Net change in other receivables		(7,440)	(6,061)
- Interest received and other financial income		47,027	2,002
Net cash used in investing activities		**(1,045,146)**	**(300,117)**

	Notes	Year ended 31 December 2011	2010
Cash flows from Financing activities			
- Net income from borrowings		275,421	467,030
- Net reimbursement of borrowings		(77,943)	(124,616)
- Income from project finance		652,730	505,863
- Reimbursement of project finance		(104,843)	(58,037)
- Other debt instruments		43,135	-
- Interest paid		(246,638)	(161,718)
- Non-controlling interests contributions		128,711	-
- Dividends paid		(30,000)	(24,000)
Net cash generated from/(used in) financing activities		**640,573**	**604,522**
Net change in cash and cash equivalents		**(261,014)**	**512,907**
Cash and cash equivalents at beginning of the year		937,555	420,778
Exchange differences included in net change for the year		(2,175)	3,870
Cash and cash equivalents at the end of the year	**14.1**	**674,366**	**937,555**

Notes 1 to 39 and Appendices I to IV form an integral part of these consolidated annual accounts.

Notes to the consolidated annual accounts

(Thousand euro)

1 General information

At the 2011 year end GRUPO ISOLUX CORSÁN, S.A. (hereinafter, the Company) forms a group (hereinafter, the Group) comprising the parent company Grupo Isolux Corsán, S.A. and its subsidiaries and associates. Additionally, the Group participates with other entities or members in joint ventures and temporary joint ventures (hereinafter, Joint Ventures). Appendices I, II, III and IV to these notes contain additional information on the entities included in the consolidation scope. The Group companies hold interests of less than 20% in other entities over which they have no significant influence. The Group's main activities and sales are carried on and made in Spain and Latin America, and it is in expansion in Asia, Africa and North America.

For the purposes of preparing the consolidated annual accounts, a group is understood to exist when the parent company has one or more subsidiaries, which are those entities that the parent company controls directly or indirectly. The principles applied during the preparation of the Group's consolidated annual accounts, together with the consolidation scope, are described in Note 2.2.

Appendix I to these notes set outs the identification details of the subsidiaries included in the consolidation scope under the full consolidation method.

Appendix II provides the identification details of the associates included in the consolidation under the equity consolidation method.

Appendix III contains the identification details of the joint ventures included in the consolidation scope under the proportionate consolidation method.

The parent company and certain subsidiaries are members of temporary joint ventures, whose assets, liabilities, income and expenses are recognized using the proportionate method. Appendix IV contains a detail of the temporary joint ventures of which Group companies are members.

Changes in the consolidation scope during 2011 are as follows:

- The following companies were incorporated: I.C. Plaza de Benalmádena Canarias, Líneas de Tabuate Transmisora de Energía LTDA, Isolux Projectos, Investimentos e Participaçoes LTDA, Residuos Ambientales de Galicia S.L., Societat Superficiaria Preventius Zona Franca S.A., Isolux Infrastructure, S.A. and Ciudad de la Justicia de Córdoba S.A.

- Shareholding increase in Cachoeira Paulista T. Energia, S.A., from 33.33% to 100% and in Grupo T-Solar Global, S.A., from 19.80% to 58.84%. (Note 32).

- Sale of 33.33% shareholding in Porto Primavera Transmisora Energía, S.A. and Vila do Conde Transmisora Energía, S.A. (See note 8).

Changes in the consolidation scope during 2010 were as follows:

- The following companies were incorporated: Isolux Corsán Concesiones de México, S.A. de C.V., Isolux Corsan Energy Cyprus Limited, Isolux Corsan Power Concessions India Private Limited, Mainpuri Power Transmission Private Limited, Isolux Corsán Concessions India Privated Limited, Soma Isolux Varanasi Aurangabad Tollway Private Limited, Isolux Soma and Unitech JV, Isolux Corsán Brasileña de Infraestructuras, S.L., ICI Soma JV, Carreteras Centrales de Argentina, S.A., Wett Holdings LLC., Eclesur, S.A., Empresa Concesionaria Líneas Eléctricas del Sur, S.A., Isolux Corsán Renovables, S.A , Isolux Corsán Panamá, S.A., Hixam Gestión de Aparcamientos III, S.L., Isolux Corsán Arabia Saudí, LLC and Isolux Corsán Gulf, LLC.

- The following companies were acquired: AB Alternative Investment, B.V., ICC Sandpiper, B.V., Isolux Corsán Participaciones de Infraestructura Ltda. Isolux Corsán Participaciones en Viabahía Ltda.

- Shareholding increase in Infinita Renovables, S.A. from 70% to 80.7%.

- Shareholding decrease in Luxeol, S.L. from 100% to 70% and in Viabahia Concessionaria de Rodovias, S.A. from 75% to 55%.

- Joint ventures sale in Brazil (see note 8.1), sale of Infinita Renovables Patagonia, S.A. and Aparcamientos IC Gómez Ulla, S.L.

- During the year, Isolux de México, S.A. de C.V. absorbed Isolux Corsán Construcción S.A. de C.V. (both came within the consolidation scope in 2009).

On 17 December 2004, the Company was incorporated which, following several name changes, is now named Grupo Isolux Corsán, S.A. The Company is the parent of a group that is continuing the activities of Grupo Isolux Wat. The latter group gained broad experience in the Spanish market and was engaged mainly in engineering. At the beginning of 2005 it merged with the Corsán Corviam Group, which was also reputable and engaged mainly in construction. Grupo Isolux Corsán is the result of the 2005 merger.

Grupo Isolux Corsán, S.A.'s registered office is at Caballero Andante 8 Street, 28021 Madrid, Spain. The Company is registered in the Madrid Mercantile Register, volume 20,745, book 0, section 8, sheet 194; page M-367466, entry 11. The latest adaptation and rewording of its bylaws is entered in volume 20,745, book 0, section 8, sheet 189, and page M-367466, entry 7.

Grupo Isolux Corsán, S.A. does business in Spain and abroad, mainly consisting of the following activities (carried on by the Company itself or its subsidiaries):

- Engineering studies, industrial assembly and manufacture of the necessary components, integrated facilities and construction.
- Manufacture, sale and representation of electrical, electronic, electromechanical, computer and industrial products, machinery and equipment.
- Rendering of all types of consultancy, audit, inspection, metering, analysis, report, research and development services; project design, planning, supply, execution and assembly; project and site management and supervision; tests, trials, commissioning, control and evaluation; repair and maintenance services in integrated facilities; electrical and electronic facilities, air conditioning and aeration systems; sanitary fluid and gas systems; elevators and freight elevators; fire protection and detection systems; hydraulic systems, information systems, mechanical and industrial systems; communications, energy, environment; and energy lines, substations and power plants.
- Integrated construction, repair, conservation and maintenance of all kinds of construction and all kinds of installation and fitting work.
- Purchase, sale, lease and operation by any means of real property or real property rights.
- Holding, management and administration of securities and equity interests in any entity.

The Group mainly operates through the following business lines:

- Construction: all kinds of civil engineering and construction projects, both residential and non-residential.
- Engineering and industrial services: engineering, energy, telecommunications, installations and environment.
- Concessions: the Group holds land infrastructure concessions including motorways and car parks, and electricity infrastructure concessions such as high-voltage power cables and power plants and transformation energy plants.
- Renewable energy: activity in bio-fuel and solar-photovoltaic energy.

During 2011, the Group initiated an initial public offering, which affects the concession and solar-photovoltaic energy division, in the Sao Paulo (Brazil) Stock Exchange, where it was registered as a "publicly-held company" in December. At the date of preparation of these consolidated annual accounts, the Group had not yet issued securities.

These consolidated annual accounts were prepared by the Board of Directors on 26 March 2012. The Directors will submit these consolidated annual accounts to the General Shareholders` Meeting for approval. The accounts are expected to be approved without changes.

2 Summary of significant accounting policies

The principal accounting policies applied in the preparation these consolidated annual accounts are set out below. These policies have been consistently applied to all the financial years presented in these consolidated annual accounts.

2.1. **Basis of presentation**

The Group's consolidated annual accounts at 31 December 2011 have been prepared in accordance with International Financial Reporting Standards (IFRS) adopted for its use by the European Union, approved by the European Commission Regulations (IFRS-EU) and effective at 31 December 2011. The group started working under IFRS-EU on 1 January 2006.

The policies described below have been consistently applied to all the financial years presented in these consolidated annual accounts.

The amounts are expressed in thousands of euro in this document, unless otherwise stated.

The consolidated annual accounts have been prepared on a historical cost basis, except for certain cases stipulated by IFRS-EU in which assets and liabilities are carried at fair value. The Company has made the following choices in cases in which IFRS-EU allow for alternative criteria:

- Measurement of property, plant, equipment and intangible assets at historical cost, capitalizing financial expenses over the construction period.
- Joint ventures and temporary joint ventures are proportionately consolidated.

The preparation of consolidated annual accounts under IFRS-EU requires the use of certain critical accounting estimates. It also requires that management exercise judgment in the process of applying the Company's accounting policies. Note 4 discloses the areas that require a higher level of judgment or entail greater complexity, and the areas where assumptions and estimates are significant for the consolidated annual accounts.

Standards, amendments and interpretations that came into effect in 2011

New and amended standards adopted by the Group:

- **IAS 24 "Related-party disclosures".** Revised in 2009, this clarifies and simplifies the related-party definition. In addition, it abolishes certain related-party disclosure requirements such as the disclosing of all transactions carried out with government-related entities and other related-parties. These requirements in the revised standard can be fully or partially adopted in advance.
- **IFRIC 19 "Extinguishing financial liabilities with equity instruments".** IFRIC 19 clarifies the IFRS requirements when an entity renegotiates the terms of a financial liability and issues shares to its creditors to fully or partially extinguish the financial liability (debt-for-equity swap). This interpretation requires booking a profit or loss when the liability is settled through the issue of equity instruments. The profit or loss is calculated as the difference between financial liability carrying amount and the fair value of the equity instruments issued. If the fair value of the equity instruments cannot be determined in a reliable way, the fair value of the financial liability will be used to determine the profit or loss and to book the equity instruments issued. The Group applies this interpretation from 1 January 2010, on a retrospective basis.
- **The 2010 improvements project** was published by IASB in May 2010 and adapted by the EU in February 2011. It modifies IFRS 1 "First-time adoption of IFRS", IFRS 3 "Business combinations", IFRS 7 "Financial instruments: information disclosure", IAS 1 "Presentation of financial statements", IAS 27 "Consolidated and separate financial statements", IAS 34 "Interim financial reporting" and IFRIC 13 "Customer loyalty programmes". Amendments introduced by this improvement project must be applied from 1 January 2011, except for the amendments with respect to IFRS 3 and IAS 27; these must be applied to those periods beginning from 1 July 2010.

The new standards, amendments and interpretations adopted by the Group have no significant impact on these consolidated financial statements.

New standards, amendments and interpretations issued but not effective for the financial year beginning 1 January 2011 and not adopted in advance:

- **IFRS 7 (amended) "Financial instruments: information disclosure – financial assets transfer".** The amendment to IFRS 7 requires additional disclosures concerning risk exposures arising from financial assets transferred to third parties. This amendment will affect, among others, financial assets for sale, factoring agreements, financial assets securitization and securities loan arrangements. Although they may be adopted in advance, amendments to IFRS 7 are of compulsory application for those periods beginning from 1 July 2011.

No significant impact on the Group's consolidated financial statements is expected from these amendments.

Standards, amendments and interpretations not adopted by the European Union:

- **IAS 19 "Employee benefits",** modified in June 2011. The effect of this amendment is described

below: removal of the broker approach and registration in the overall income statement of all actuarial profit or loss at the timet they occur; immediate recognition of all past services costs; and substitute interest cost and the expected return on subject-to-plan assets by an amount (net of interest) calculated by applying the discount rate to the defined benefit plan net liability (asset). In this respect, the Group has yet to assess the full impact of these amendments.

- **IFRS 9 "Financial instruments",** addresses the classification, valuation and recognition of financial assets and financial liabilities. IFRS 9 was issued in November 2009 and October 2010. It replaces those parts of IAS 39 that relate to the classification and valuation of financial instruments. IFRS 9 requires financial assets to be classified into two valuation categories: those valued at fair value and those valued at amortised cost. The determination is made at the initial recognition. The classification depends on the entity's business model for managing its financial instruments and the contractual cash flow characteristics of the instrument. For financial liabilities, the standard retains most of the IAS 39 requirements. The main change is that, in those cases in which the fair value option is adopted for financial liabilities, the part of a change in fair value due to an entity's own credit risk is booked in other overall income rather than the income statement, unless this creates an accounting mismatch. The group has yet to fully or partially assess IFRS 9's full impact and intends to adopt IFRS 9 no later than the accounting period beginning on or after 1 January 2013.

- **IFRS 10 "Consolidated financial statements"** builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company. The standard provides additional guidance to assist in the determination of control where this is difficult to assess. This standard has not been adopted by the European Union, and so the Group has yet to assess IFRS 10's full impact and intends to adopt IFRS 10 no later than the accounting period beginning on or after 1 January 2013.

- **IFRS 11 "Joint arrangements".** Although this standard has not yet been adopted by the European Union, its application is compulsory no later than the accounting period beginning on or after 1 January 2013.

- **IFRS 12 "Disclosures of interests in other entities"** includes the disclosure requirements for all forms of interests in other entities, including joint arrangements, associates, special purpose vehicles and other off-balance-sheet vehicles. This standard has not been adopted by the European Union, and so the group has yet to assess IFRS 12's full impact and intends to adopt IFRS 12 no later than the accounting period beginning on or after 1 January 2013.

- **IFRS 13 "Fair value measurement",** aims to improve consistency and reduce complexity by providing a precise definition of fair value and a single source of fair value measurement and disclosure requirements for use across IFRSs. These requirements, which are in general aligned between IFRSs and US GAAP, do not extend the use of fair value accounting but provide guidance on how it should be applied where its use is already required or permitted by other standards within IFRSs or US GAAP. This standard has not been adopted by the European Union, so the group has yet to assess IFRS13's full impact and intends to adopt IFRS 13 no later than the accounting period beginning on or after 1 January 2012.

- **IAS 28 (Revised) "Associates and joint ventures".** Includes the requirements for joint ventures, as well as associates, to be equity accounted for after the issue of IFRS 11. This standard has not been adopted by the European Union and will be mandatory no later than the accounting period beginning on or after 1 January 2013.

- **IAS 32 (Revised) and IFRS 7 (Revised) "Financial assets and liabilities compensation"**. The IAS 32 amendment will be of compulsory application, on a retrospective basis, for those periods beginning from 1 January 2014. The IFRS 7 amendment has not been adopted by the European Union and will be of compulsory application, on a retrospective basis, no later than the accounting period beginning on or after 1 January 2013.

The Group is assessing the impact that these new standards, amendments and interpretations would have on Consolidated Annual Accounts, if they they were adopted.

There are no other non-effective IFRS or IFRIC interpretations that are expected to significantly impact Group's financial statements.

2.2. **Consolidation**

Subsidiaries

Subsidiaries are all entities (including special-purpose companies) over which the Group has the power to govern the financial and operating policies generally accompanying a shareholding of more than one half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Group controls another entity. The Group also assesses the existence of control when it does not hold more than 50% of voting rights but has the ability to manage financial and operating policies through "de facto" control. Such de facto control may arise when the number of Group's voting rights compared with the number and dispersion of other equity-holders' shares provide the Group the ability to manage financial and operating policies, etc.

Subsidiaries are consolidated from the date on which control is transferred to the Group. They are de-consolidated from the date that control ceases.

When through the acquisition of a subsidiary, the Group acquires a group of assets or net assets that are not a business, the group cost is allocated between the identifiable assets and liabilities within the group based on their fair values at the acquisition date. When the Group incurs in costs related to the acquisition of a participation in an entity that is not a business and the transaction has not been finalized at year end, the aforementioned costs are recognized in the balance sheet if it is likely that the transaction will be carried out successfully after year end. In the event that the transaction cannot be estimated as likely, the incurred costs are recognized as expenses in the income statement.

The Group applies the acquisition method to register business combinations. The consideration transferred for the acquisition of a subsidiary corresponds to the fair value of the assets transferred and the liabilities incurred with the previous owners and the equity interests issued by the Group. The above-mentioned consideration includes the fair value of any asset or liability arising from a contingent consideration agreement. Identifiable assets acquired and liabilities and contingent liabilities undertaken in a business combination are measured at fair value on the acquisition date. For each business combination, the Group may recognize any non-controlling interest in the acquired company at either its fair value or the percentage of such non-controlling interest in the acquired company's identifiable net assets.

Acquisition-related costs are expensed as incurred.

If the business combination is achieved in stages, the acquisition date fair value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date through profit or loss.

Any contingent consideration to be transferred by the group is recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration that is deemed to be an asset or liability is recognised in accordance with IAS 39 either in profit or loss or as a change to other comprehensive income. Contingent consideration that is classified as equity is not remeasured, and its subsequent settlement is accounted for within equity.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred and the fair value of non-controlling interests over the net identifiable assets acquired and liabilities assumed. If the consideration is lower than the fair value of the net assets of the subsidiary acquired the difference is recognized in profit or loss.

Intercompany transactions, balances, income and expenses on transactions between Group companies are eliminated. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

Appendix I to these notes set outs the identification details of the subsidiaries included in the consolidation scope under the full consolidation method.

Aparcamiento Los Bandos Salamanca S.L. and Aparcamientos IC Sarrión where the group holds a 70% and a 51% of the shares, respectively, are not considered subsidiaries as the control is not held by the Group. Agreements established between shareholders result in the investment being considered as a joint venture (See Appendix III).

At 31 December 2011, the Group holds 100% of ICC Sandpiper ordinary shares. In addition, it holds most of the voting rights in the Board of Directors of the company; however, MSIP approval is required for the Group to take certain strategic and financial decisions. As a result, the Group classifies its shareholding in ICC Sandpiper as a joint venture (See Appendix III).

Agua Limpia Paulista, S.A., Concesionaria Autovía A-4 Madrid, S.A., ARRL (Mauritius) Limited and Parque Solar Saelices, S.L., where the Group holds 40%, 48.75%, 50% and 5%, respectively, are considered subsidiaries since control is held by the Group, as a result of shareholder agreements (See Appendix I).

Disposal of subsidiaries

When the group ceases to have control any retained interest in the entity is re-measured to its fair value at the date when control is lost, with the change in carrying amount recognised in profit or loss. The fair value is the initial carrying amount for the purposes of subsequently accounting for the retained interest as an associate, joint venture or financial asset. In addition, any amounts previously recognised in other comprehensive income in respect of that entity are accounted for as if the group had directly disposed of the related assets or liabilities. This may mean that amounts previously recognised in other comprehensive income are reclassified to profit or loss.

Changes in the shareholding in subsidiaries without changes in control

Transactions with non-controlling interests that do not result in loss of control are accounted for as equity transactions – that is, as transactions with the owners in their capacity as owners. The difference between fair value of any consideration paid and the relevant share acquired of the carrying value of net assets of the subsidiary is recorded in equity. Gains or losses on disposals to non-controlling interests are also recorded in equity.

Joint ventures

The Group treats incorporated or unincorporated entities in which two or more members have joint control under contractual agreements as joint ventures. Joint control is understood to be the situation established in an agreement between the parties in which financial and operating decisions require the consensus of all members.

Interests in joint ventures are consolidated using the proportionate consolidation method, with the exception of Landscape Corsán, S.L., Pinares del Sur, S.L., Las Cabezadas de Aranjuez, S.L. and Alqlunia 5, S.L. The Group's shareholding in these companies amounts to 50%, 50%, 40% and 50% respectively. They are consolidated through the equity method. The Group combines its share of the assets, liabilities, income, expenses and cash flows of the jointly controlled entity, line by line, with similar items in its own accounts. The Group recognizes, in its consolidated annual accounts, the portion pertaining to the other members of the jointly controlled entity of any profits or losses obtained from the sale of the Group's assets to the entity. The Group does not recognize its own share of the profits or losses of the jointly-controlled entity derived from the purchase by the Group of the entity's assets, until those assets are sold to an independent third party. A loss is immediately recognized on the transaction if it causes a reduction in the net realizable value of current assets or an impairment loss.

Appendix III to these notes set outs the identification details of the joint ventures included in the consolidation scope under the proportionate consolidation method, except those companies mentioned above, which are consolidated through the equity method.

Associates

Associates are all entities over which the Group has significant influence but not control, generally accompanying a shareholding between 20% and 50% of the voting rights. Investments in associates are accounted for by the equity method and are initially recognized at cost. The Group's investment in associates includes goodwill (net of any accumulated impairment loss) identified on acquisition.

If ownership in an associate is reduced, but significant influence is retained, only a proportionate share of those amounts previously recognized through the overall income statement are reclassified to the income statement, as appropriate.

The Group's share on its associates' post-acquisition profits or losses is recognized in the income statement and its share of post-acquisition movements in other comprehensive income statement is recognized in the comprehensive income statement. The cumulative post-acquisition movements are adjusted against the carrying amount of the investment. When the Group's share of losses in an associate equals or exceeds its interest in the associate, including any other unsecured receivables, the Group does not recognize further losses, unless it has incurred obligations or made payments on behalf of the associate.

At each financial information reporting date, the Group assesses if there is any objective evidence of impairment of the investment value in the associate. In such case, the Group caculates the amount of impairment as the difference between the associated recoverable amount and its carrying amount, and recognizes the amount adjacent to "share of profit/ (loss) of an associate" in the income statement.

Gains and losses on transactions between the Group and its associates are recognized in its financial statements to the extent they correspond to other investors' share in associates not related to the investor. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Accounting policies of associates have been changed where necessary to ensure consistency with the policies adopted by the Group.

Dilution gains or losses in associates are recognized in the income statement.

Appendix II to these notes set outs the identification details of the associates included in the consolidation scope under the equity consolidation method.

Temporary joint ventures (UTEs)

A temporary joint venture (UTE), as defined by Spanish legislation and similar legislations, is a system in which entrepreneurs collaborate for a specified, fixed or undetermined period to carry out or to execute a construction work, service or supply.

The UTE's balance sheet and income statement items are included in the shareholder's balance sheet and income statement on a proportionate basis. Transactions between the UTE and other Group subsidiaries are eliminated.

Appendix IV contains details of each UTE consolidated using the proportionate method.

2.3. Foreign currency transactions

Functional and presentation currency

The items included in the annual accounts of each of the Group companies are measured using the currency of the principal economic environment in which the company operates ("functional currency"). The consolidated annual accounts are presented in euro, the Company's functional and presentation currency, although figures are expressed in thousands of euro for presentation purposes.

Transactions and balances

Transactions in foreign currency are translated to the functional currency using the exchange rates effective at the transaction dates; at the year-end they are measured at the exchange rate in force at that moment. Foreign exchange gains and losses resulting from the settlement of transactions and translation at year-end exchange rates of monetary assets and liabilities denominated in foreign currency are recognized in the income statement, except when deferred in equity as qualifying cash flow hedges or qualifying net investment hedges.

Changes in the fair value of monetary instruments denominated in foreign currency and classified as held for sale are separated into translation differences resulting from changes in the instrument's amortized cost and other changes in the instrument's carrying amount. The translation differences are recognized in results for the year and other changes in the carrying amount are recognized in other comprehensive income.

Translation differences on non-monetary financial assets and liabilities such as equity instruments at fair value through profit or loss are recognized in profit and loss as part of the fair value gain or loss. Translation differences on non-monetary financial assets such as equity instruments classified as available-for-sale financial assets are included in other comprehensive income.

Group companies

Results and the financial position of all Group companies (none of which has the currency of a hyperinflationary economy) whose functional currency differs from the presentation currency are translated into the presentation currency as follows:

- The assets and liabilities on each balance sheet presented are translated at the closing exchange rate at the balance sheet date;
- The income and expenses in each income statement are translated at the average exchange rates (unless this average is not a reasonable approximation of the cumulative effect of the rates existing at the transaction dates, in which case income and expenses are translated at the rates on the transaction dates); and
- All resulting exchange differences are recognized as a separate component of equity (other comprehensive income).

On consolidation, any exchange differences resulting from the translation of a net investment in foreign companies and loans and other instruments in foreign currency designated as hedges of those investments are recognized in equity. When sold, such exchange differences are recognized in the income statement as part of the profit or loss on the sale.

Adjustments to goodwill and fair value arising on the acquisition of a foreign entity are treated as assets and liabilities of the foreign entity and translated at the year-end exchange rate, except goodwill arising prior to 1 January 2006.

2.4. **Property, plant and equipment**

Property, plant and equipment mainly comprise lands, buildings, plants, offices, technical installations, machinery and tooling. Property, plant and equipment are recognized at cost less depreciation and cumulative impairment losses, except for land, which is presented net of impairment losses. Historical cost includes expenses directly attributable to purchases of property, plant and equipment.

Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is likely that the future economic benefits associated with the asset will flow to the Group and the cost of the asset can be measured reliably. The carrying amount of a replaced component is written off the accounts. All other repair and maintenance expenses are charged to the income statement in the year in which they are incurred.

Land is not depreciated. Depreciation of other assets is calculated on a straight-line basis in order to allocate costs to their residual values over their estimated useful lives, using the following rates:

	Coeficiente
Buildings	1 % - 3 %
Plant	6 % - 14 %
Machinery	10 % - 17 %
Tooling	12.5 % - 33 %
Furnishings	5 % - 16 %
Data-processing equipment	12.5 % - 25 %
Vehicles	8 % - 14 %

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each balance sheet date.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount (Note 2.9).

Gains and losses on the sale of property, plant and equipment are calculated by comparing the proceeds with the carrying amount and are included in the income statement on the line "Other operating revenue". Own work capitalized is carried at production cost and reflected as income in the income statement.

Assets received through debt collection procedures are measured at the lower of the price related to the receivable for the corresponding asset, and market price.

2.5. **Investment property**

The heading "Investment Property" on the consolidated balance sheet includes the net carrying amount of such land and buildings that are held to be rented under a lease-to-purchase modality.

Based on applicable legislation, investment property are valued at acquisition cost, applying the same criteria as those established for property, plant and equipment elements, regarding capitalization and depreciation, as stated in note 2.4.

In line with the presentation and disclosure requirements contained in IAS 40, and unless the Group applies the cost method to value its investment property, it also determines their fair value periodically, measured as their value in use. The value in use amount is determined based upon market assumptions made by the Group.

Depreciation of real-estate investments is recognized annually through the income statement on a useful life basis; profit / (loss) for the year includes 94 thousand euro, corresponding to depreciation expenses.

2.6. **Intangible assets**

Goodwill

Goodwill arises from the acquisition of subsidiaries, associates and joint ventures and represents the excess of the consideration transferred over the Group's interest in the net fair value of the identifiable net assets acquired, liabilities and contigent and the fair value of the non-controlling interest in the acquired company.

For the purposes of impairment testing, goodwill acquiring in a business combination is allocated to each cash generating unit, or group of cash generating units, which are expected to benefit from the combination synergies. Each unit or group of units to which the goodwill is allocated, represents the lowest level in the entity at which the goodwill is monitored for internal management purposes. Goodwill is monitored at the operating segment level.

Impairment losses on goodwill are reviewed at least once a year or more frequently if events or changes in circumstances indicate a potential impairment loss. Goodwill's carrying amount is compared with the recoverable amount, which is the higher of the value in use or the asset's fair value less sale costs. Any impairment loss is immediately registered as an expense and cannot be reversed.

Administrative concessions

Administrative concessions are recognized in the amount paid by the Company with respect to assignment or operating royalties. In certain cases, concessions relate to the administrative authorization granted by municipal authorities or other public bodies for the construction and subsequent operation of car parks, highways, electric transmission lines and other assets during the periods specified in the relevant contracts; assets related to those concessions are classified under the heading "concessionary assets assigned to projects" (Note 2.7).

Computer software

Software licenses acquired from third parties are capitalized on the basis of the costs incurred to acquire and prepare the licenses for the use of a specific program. These costs are amortized over the useful life of the software for a maximum of 5 years.

Costs associated with developing or maintaining computer software programs are recognized as an expense when incurred. Costs that are directly associated with the production of identifiable and unique software products controlled by the Group, and that will probably generate economic benefits exceeding costs beyond one year, are recognized as intangible assets.

Computer program development costs recognized as assets are amortized over the program's estimated useful lives (no more than 5 years) on a straight-line basis.

Research and development expenses

Research expenditure is recognized as an expense as incurred. Costs incurred in development projects (related to the design and testing of new or improved products) are recognized as intangible assets when the following requirements are met:

- Completion of production of the intangible asset so that it becomes available for use or sale is technically possible;
- Management intends to complete the intangible asset in question, for use or sale;
- There is capacity to use or sell the intangible asset;
- The manner in which the intangible asset will generate probable future economic benefits is demonstrable;
- Adequate technical, financial or other resources are available to complete development in order to use or sell the intangible asset; and
- The outlay attributable to the intangible asset during development can be reliably measured.

Other development expenditure is recognized as an expense when incurred. Development expenses previously recognized as an expense are not recorded as an asset in a subsequent period. No development costs are capitalized at 31 December 2011 and 2010.

Contracts portfolio

Contractual relations with clients acquired through Business combinations are recognized at its fair value at the acquisition date. Contractual customers relationships have a definite life and are measured at cost less accumulated depreciation. Depreciation is calculated on a straight-line basis during the expected duration of the contract (5 years).

Permits, licenses and authorizations (PLA's)

These intangible assets consist of permits, licenses and authorizations required for solar-photovoltaic plant construction. On the date those requirements are met, the costs are capitalized as an intangible asset – this means that, when it is probable that future economic benefits associated with the asset flow to the Group and when the asset cost can be valued on a reliable way. The rest of costs related to PLA's are registered in the income statement during the period in which they are incurred.

PLA's are recognized as intangible assets until the construction of the related solar plants is initiated. At that timet, permits, licenses and authorizations are reclassified as property, plant and equipment, since solar plants cannot be operated without the corresponding permits, licenses and authorizations.

Depreciation of permits, licenses and authorizations is calculated on a lineal basis over the estimated useful life (25 years) and starts once the plants come into operation.

2.7. **Concessionary assets and other non-current assets assigned to projects**

When concessions refer to administrative authorization granted by several public bodies for the construction and later operation, during the period stated in the corresponding agreements, of car park, highways, electric transmission lines and other assets, they are treated as established in IFRIC 12 from an accounting perspective. This applies only when, according to the contractual terms, the Group has authorization to operate the infrastructure but does not control because:

- The concession assets are owned by the granting authority in the majority of cases.
- The granting authority controls or regulates the concession holder's services and the conditions under which they must be rendered.
- Operated by the concession holder in accordance with the criteria set out in the concession documents during the stipulated concession term.
- At the end of that period, the assets revert to the granting authority and the concession holder no longer holds any rights in this respect.

In the cases in which concessions are under the IFRIC 12 scope, related assets may be classified as:

- Financial assets: When the granting authority establishes an unconditional right to receive cash or other financial assets, regardless of public service demand made by users.
- Intangible assets: Only in such cases in which contractual arrangements do not set an unconditional right to receive cash or other financial assets from the granting authority, regardless of public service demand made by users.

These concessions are mainly funded under the heading of "Project Finance".

Although additional guarantees may exist during the construction and operational phases, these funding structures are usually applied to projects that in themselves provide enough support to financial entities related to the debts incurred. Each of these projects is performed through specific companies by which the project's assets are funded on the one hand by promoters contributions, limited to a certain amount, and on the other hand through long-term debt from third parties. Debt servicing of these loans is mainly supported by future cash flows generated by the project and by real guarantees on the project's assets.

Revenue is recognized at the fair value of the service rendered.

Construction services:

The Group recognizes construction services revenue as stated in note 2.23.

The amounts received or outstanding related to construction services are recognized at their fair value.

Assets are valued based upon the costs directly attributable to the construction, such as studies and projects, expropriations, service replacement, work execution, work managment and administration, plants and buildings, until they are in operation, as well as the corresponding part of other indirect attributable costs. This type of costs can be capitalized to the extent that they correspond to the construction period. Likewise, those financial expenses accrued during the construction period are also capitalized (under the intangible asset model).

The Group recognizes contractual obligations to the extent related services are incurred. Nonetheless, when the granting authority has complied with its contractual obligations to a greater extent than those commitments corresponding to the Group's concessionary entity, a liability and an increase in the intangible assets will be recognized for the amount that equalises the obligation rendered by the group to the obligation committed by the granting authority. This situation mainly occurs when the Group's concessionary entity has the right to charge users from the beginning of the concession period and the infrastructure previously existed and will be improved and/or extended later.

Under the intangible asset model, dismantling, retirement or replacement accruals as well as work relating to improvements or increases in capacity the associated incomeof which is included in the concession contract, are recognized from the beginning of the concession period as part of the fair value of the asset. Financial discounts of such accruals and the corresponding amortization are recorded in the income statement for the period.

In addition, provisions related to major repairs are registered in the income statement in a systematic and accrual basis.

Under the financial asset model, the construction service counterpart is a receivable which also includes a financial remuneration. It is calculated based upon the project's expected rate of return in line with its estimated flows, which includes inflation forecasts and tariff reviews in those cases in which they are included in the contract. Once the operational phase begins, the receivable is valued at amortized cost and any difference between actual and expected flows will be recognized in the income statement. Unless the circumstances affecting concession asset flows significantly change (economical re-balances approved by the granting authority, contract enhancement, etc.), the rate of return will not be modified.

Financial remuneration in concession financial assets is classified by the Group as operating revenue, since it is part of the Group's general activity, which is exercised on a regular basis and generates income periodically.

Maintenance and operational services:

Safeguarding and maintenance costs not representing an increase in an assets useful life or productive capacity are registered as an expense in the period in which they occur. At the end of the concession period, the whole investment, net from any amount to be reimbursed by the granting authority, will be covered through recognition of depreciation. The concessionary entity receives income based on services rendered, either directly through the users or through the granting authority.

Once the operational phase begins, collections and operational costs are recognized as operating income and expenses, respectively, in the year. Under the intangible asset model, assets are depreciated on a straight-line basis over the concession period, except for highways and car parks, which are depreciated based upon the demand (traffic volume and expected occupation) during the concession life. At each balance sheet date the project performance is reviewed to assess if assets will be recovered through operating income generated over the concession period; otherwise, there would be an impairment.

2.8. **Interest costs**

Interest costs incurred in the construction of any qualifying assets are capitalized over the period needed to complete and prepare the asset for the intended use. Other interest costs are expensed.

2.9. **Impairment of non-financial asset**

Assets with an indefinite useful life and goodwill are not amortized/ depreciated and are tested annually for impairment. Assets subject to amortization/depreciation are tested for impairment provided that an event or change in circumstances indicates that their carrying amount might not be recoverable. An impairment loss is recognized in the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher between an asset's fair value less sale costs and value in use. For the purposes of assessing impairment, assets are grouped together at the lowest level for which there are separately identifiable cash flows (cash-generating units). Non-financial assets other than goodwill for which impairment losses have been recognized are tested at each balance sheet date in the event that the loss has reversed.

2.10. **Financial assets**

The Group classifies its financial assets in the following categories: at fair value through profit or loss, loans and receivables, held to maturity and held for sale. The classification depends on the purpose for which the financial assets were acquired. Management establishes the classification of financial assets when they are initially recognized and reviews the classification at each reporting date.

In accordance with IFRS 7 amendment, the Group classifies market-valued financial instruments based on the lowest of used data that were significant with respect to the instrument whole fair value. In compliance with this standard, financial instruments must be classified as follows:

1. Quoted prices in active markets for identical instruments.
2. Directly (prices) or indirectly (based on prices), observable data for the instrument.
3. Data not based on market observations.

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss are financial assets held for trading. A financial asset is classified in this category if acquired mainly for short-term sale. Derivatives are also categorized as held for trading unless they are designated as hedges. The assets in this category are included in current assets.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are included in trade and other receivables in the balance sheet (Note 2.13), as well as in concessionary assets assigned to projects in the case of receivables related to the financial assets model (Note 2.7).

They are also included under the consolidated balance sheet heading "cash and cash equivalents" (Note 2.14).

Held-to-maturity financial assets

Held-to-maturity financial assets are non-derivative financial assets with fixed or determinable payments and fixed maturities that Group management has the positive intention and ability to hold to maturity. If the Group sells a non-insignificant amount of its held-to-maturity financial assets, the entire category will be reclassified as held for sale. Such available-for-sale financial assets are included in non-current assets, except those that mature within 12 months as from the balance sheet date, which are classified as current assets.

Financial assets held for sale

Financial assets held for sale are non-derivatives assets that are either designated in this category or not classified in any of the other categories. They are inclu-

ded in non-current assets unless management intends to dispose of the investment within 12 months of the balance sheet date.

Recognition of financial assets

Acquisitions and disposals of investments are recognized at the trading date, i.e. the date the Group undertakes to acquire or sell the asset. Investments are initially recognized at fair value plus transaction costs for all financial assets not carried at fair value through profit or loss. Financial assets at fair value through profit or loss are initially carried at fair value and transaction costs are taken to the income statement. Investments are written off when the rights to receive cash flows from them have expired or have been transferred and the Group has transferred substantially all the risks and rewards of ownership. Available-for-sale financial assets and financial assets at fair value through profit or loss are subsequently carried at fair value. Loans and receivables are carried at amortized cost using the effective interest rate method.

Gains and losses resulting from changes in the fair value of financial assets at fair value through profit or loss are included in the income statement in the year in which they arise. Dividend income from financial assets at fair value through profit or loss is recognized in the income statement when the Group's right to receive payment is established.

Changes in the fair value of monetary instruments denominated in foreign currency and classified as held for sale are analyzed by separating the differences in the instrument's amortized cost and other changes in the instrument's carrying amount. Translation differences on monetary instruments are recognized in the income statement, while translation differences on non-monetary instruments are recognized in equity (other comprehensive income). Changes in the fair value of monetary and non-monetary instruments classified as held for sale are recognized in equity (other comprehensive income).

When available-for-sale instruments are sold or impaired, the cumulative fair value adjustments recognized in equity are taken to the consolidated income statement.

Interest on available-for-sale instruments calculated using the effective interest rate method is recognized in the income statement item "Net financial results". Dividends from available-for-sale equity instruments are recognized in the income statement in "Net financial results" when the Group's right to receive payment is established.

The fair values of quoted investments are based on current bid prices. If the market for a financial asset is not active (and for unlisted securities), the Group establishes fair value using measurement techniques which include recent uncontrolled transactions between willing and knowledgeable parties relating to other instruments that are substantially identical and the analysis of discounted cash flows and option pricing models, maximizing market input and relying as little as possible on the entity's specific inputs.

At the balance sheet date, the Group assesses whether there is objective evidence of impairment losses with respect to a financial asset or group of financial assets. For equity instruments classified as held for sale, in order to determine whether there is impairment losses it will be necessary to examine whether there is a significant or protracted below cost decline in the fair value of the securities. If there is any evidence of this type for available-for-sale financial assets, the cumulative loss determined as the difference between the acquisition cost and current fair value, less any impairment loss in that financial asset previously recognized in the income statement, is removed from equity and recognized in the income statement. Impairment losses recognized in the income statement on equity instruments are not reversed through the income statement.

Impairment testing of receivables is described in Note 2.13.

A financial assets are derecognized when all risks and benefits associatedwith the asset's ownership are substantially transferred. In the case of receivables, this transference takes place when credit and default risks are transferred.

Financial assets and liabilities are offset and presented by its net value in the balance sheet when there is a legally enforceable right to offset the recorded amounts, and the Group has the intention to settle or to realize the asset and settle the liability simultaneously.

2.11. Derivative financial instruments and hedging activities

Derivatives are initially recognized at fair value at the contract date and are subsequently re-measured at fair value. The method to recognize the resulting gain or loss depends on whether the derivative is designated as a hedging instrument and, if so, on the nature of the item being hedged. The Group may designate certain derivatives as:

- fair value hedges of recognized assets and liabilities (fair value hedge);
- hedges of a specific risk associated with a recognized liability or a highly probable forecast transaction (cash flow hedge); or
- hedge of a net investment in a foreign operation (net investment hedge).

The Group documents at the inception of the transaction the relationship between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking hedging transactions. The Group also documents its assessment, both at hedge inception and on an ongoing basis, of whether or not the derivatives used in hedge transactions are highly effective in offsetting changes in the fair value or cash flows of the hedged items.

The fair value of some derivative instruments used for hedging purposes is shown in Note 11. Movements on the hedging reserve are shown in the consolidated statement of changes in equity and Consolidated Statement of Comprehensive Income. The total fair value of hedging derivatives is classified as a non-current asset or liability if the period to maturity of the hedged item is more than 12 months and as a current asset or liability if the period to maturity of the hedged item is less than 12 months. Derivatives not classified as hedges for accounting purposes are classified as current assets or liabilities.

Regarding the amendment in IFRS 7, the Group proceeds to classify financial instruments market valuations as stated in Note 2.10.

Fair value hedge

Changes in the fair value of derivatives that are designated and qualified as fair value hedges are recognized in the income statement together with any change in the fair value of the hedged asset or liability that may be attributable to the risk hedged.

If the hedge no longer meets the criteria for hedge accounting, the adjustment to the carrying amount of the hedged item for which effective interest rate method has been used, is recorded as profit or loss up to its maturity.

Cash flow hedge

The effective portion of changes in the fair value of derivatives that are designated and qualified as cash flow hedges is recognized in equity. The gain or loss relating to the ineffective portion is immediately taken to the income statement item "Net financial results".

Amounts accumulated in equity are reclassified to in the income statement in the periods when the hedged item affects results (for instance, when the forecast sale that is hedged takes place). The gain or loss relating to the effective portion of interest rate swaps hedging variable-rate borrowings is recognized in the income statement item "Net financial results". The gain or loss relating to the effective portion of forward foreign currency contracts hedging sales is recognized in the income statement item "Sales" and the ones hedging purchases is recognized in "Materials consumed and other external costs".

When a hedging instrument expires or is sold, or when a hedge no longer meets the criteria for hedge accounting, any cumulative gain or loss existing in equity at that time remains in equity and it is recognized when the forecast transaction is ultimately recognized in the income statement. When a forecast transaction is no longer expected to occur, the cumulative gain or loss that was reported in equity is immediately transferred to the income statement item "Net financial results".

Net investment hedge

Hedges of net investments in foreign operations are accounted for in a similar way to cash flow hedges. Any gain or loss on the hedging instrument relating to the effective portion of the hedge is recognized in equity. The gain or loss relating to the ineffective portion is immediately recognized in the income statement. Gains and losses accumulated in equity are included in the income statement when the foreign operation is disposed of.

At 31 December 2011 and 2010 the Group does not hold net foreign investment hedge derivatives.

Derivative financial instruments at fair value through profit or loss

Certain derivatives do not qualify for hedge accounting and are recognized at fair value through profit or loss. Changes in the fair value of any derivative instruments that do not qualify for hedge accounting are immediately recognized in the income statement item "Net financial results".

2.12. **Inventories**

Raw materials and finished products are carried at the lower between the acquisition or production cost, using the weighted average cost method, or the net realizable value (the lowest).

Finished products and work in progress items costs include design costs, raw materials, direct work force, other direct costs and general manufacturing costs (based on a normal capacity of production facilities). Changes in prices of such inventories referred to variable indexes are recorded against inventories value.

Buildings under construction and other structures are measured based on direct execution costs, also including financing costs incurred during the development phase and structural costs attributable to the projects. These items are classified as short- or long-term cycle depending on whether the period to completion is less or more than twelve months.

Obsolete, defective or slow-moving products are written down to their net realizable value.

Inventories comprise biological assets (see Note 2.29).

Net realizable value is the selling price estimated during ordinary business course, less applicable sale variable costs.

2.13. **Trade and other receivables**

Trade receivables are amounts due from customers related to goods sold or services rendered in the ordinary course of business. If the receivables are expected to be collected in a year or less (or in the operation cycle if longer), they are classified as current assets. Otherwise, they are recorded as non-current assets.

Trade receivables are initially recognized at fair value and are subsequently measured at amortized cost using the effective interest rate method, less provision for impairment. A provision for impairment of trade receivables is established when there is objective evidence that the Group will not be able to collect all amounts due in accordance with the original terms of the receivables. The existence of significant financial difficulties on the part of the debtor, the probability that the debtor will become bankrupt or undertake a financial restructuring, and late payment or default are considered to be indicators of the impairment of a receivable. The amount of the provision is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the effective interest rate. The asset's carrying amount is written down as the provision is applied and the loss is recognized in the income statement. When a receivable is uncollectable, the provision for receivables is adjusted accordingly. Subsequent recoveries of receivables written off are recognized in the income statement for the year in which the recovery takes place.

2.14. **Cash and cash equivalents**

Cash and cash equivalents include cash in hand, demand deposits in banks and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts are shown within borrowings in current liabilities on the balance sheet.

2.15. **Share capital**

Share capital consists entirely of ordinary shares classified as equity.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

Where any Group company purchases the Company's equity share capital (treasury shares), the consideration paid, including any directly attributable incremental costs (net of income taxes), is deducted from equity attributable to the Company's equity holders until the shares are redeemed, reissued or sold. When these shares are sold or subsequently reissued, any amount received, net of any incremental cost on the transaction which is directly attributable and the corresponding income tax effects, and is included in equity attributable to the Company's equity holders.

2.16. **Deferred income**

a) Official grants

According to IFRS-EU, official grants are booked when there is a reasonable assurance of compliance with all the conditions related to their enjoyment and that they will be received. Grants and aids given to the Group are subject to several conditions. Expectations on compliance with requirements to get the above-mentioned grants are continually assessed, considering that they will be fulfilled without the Group having to restore them. Thus, grants are recognized at 31 December 2011 and 2010 (Note 18).

The Group has several grants to fund its investments. Due to the varied characteristics of each grant received, judgement is used to determine their amount in those cases in which the aids refer to non-interest-bearing loans. In these situations, implicit interests are computed by using the effective market rate to calculate a loan's fair value. The difference between the nominal amount and the fair value of loans is considered as deferred income and is registered in the income statement in line with what is being financed. If the non-interest-bearing loan is allocated to an asset acquisition, the deferred income is registered as profit / (loss) for the year, during the useful life of that asset. Otherwise, if the non-interest-bearing loan is related to an operating cost, the deferred income is recognized in the income statement at the time that the expense is incurred.

b) Non-interest-bearing loans granted by official entities

Non-interest-bearing loans recieved by the Group are registered at present value (calculated applying the effective market interest rate). The difference at the initial date between the nominal value of the loan and its present value is booked as follows:

When the funding is allocated to an asset acquisition, the above-mentioned difference is considered as deferred income and is registered on the income statement during the period in which such financial assets are amortized.

c) Deductions

Tax revenue corresponding to deductions or allowances in the income tax amount pending of application, from investments in non-current assets, is registered in the consolidated income statement in the same period in which the non-current asset that gave rise to them is depreciated, because they are specific aids subject to certain conditions and aimed at encouraging investment in renewable energies.

2.17. **Trade and other payables**

Trade payables are initially recognized at fair value and are subsequently measured at amortized cost using the effective interest rate method.

Payables are classified as current liabilities if payments mature is less than a year. Otherwise, they are classified as non-current liabilities.

2.18. **Compound financial instruments**

Compound financial instruments issued by the group comprise convertible notes that can be converted to share capital at the option of the holder, and the number of shares to be issued does not vary with changes in their fair value.

The liability component of a compound financial instrument is recognised initially at the fair value of a similar liability that does not have an equity conversion option. The equity component is recognised initially at the difference between the fair value of the compound financial instrument as a whole and the fair value of the liability component. Any directly attributable transaction costs are allocated to the liability and equity components in proportion to their initial carrying amounts.

Subsequent to initial recognition, the liability component of a compound financial instrument is measured at amortised cost using the effective interest method. The equity component of a compound financial instrument is not re-measured subsequent to initial recognition except on conversion or expiry.

Borrowings are classified as current liabilities unless the group has an unconditional right to defer settlement of the liability for at least 12 months after the end of the reporting period.

2.19. **Borrowings**

Borrowings are initially carried at fair value net of transaction costs. They are subsequently measured at amortized cost. Any differences between the funds obtained (net of necessary costs) and their repayment value are recognized in the income statement over the life of the debt applying the effective interest rate method.

Borrowings are classified as current liabilities unless the Group has an unconditional right to defer settlement for at least 12 months as from the balance sheet date.

Interest and other costs incurred to obtain bank loans are taken to the income statement for the year on an accrual basis.

2.20. **Current and deferred taxes**

Tax expense for the year comprises current and deferred tax. Tax is recognized in the income statement except to the extent it relates to items recognized directly in equity. In this case, tax is also recognized in equity.

The current tax charge is calculated based on the tax laws approved or about to be approved at the balance sheet date in the countries where the Group's companies operate and generate results subject to tax. Management assesses regularly the positions taken in relation to tax returns with respect to situations where tax law is subject to interpretation, and establishes, where appropriate, the necessary provisions on the basis of the amounts that it is expected to pay to the tax authorities.

Deferred income tax is calculated, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated annual accounts. However, if the deferred taxes arise from the initial recognition of a liability or an asset on a transaction other than a business combination that at the time of the transaction has no effect on the tax gain or loss, they are not accounted for. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the balance sheet date and are expected to apply when the related deferred income tax asset is realized or the deferred income tax liability is settled.

Deferred income tax assets are recognized to the extent that it is probable that future taxable profit will be available against which the temporary differences can be offset.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except where the timing of the reversal of the temporary differences is controlled by the Group and it is likely that the temporary difference will not reverse in a foreseeable future.

Deferred tax assets and liabilities are offset if, and only if, there is a legally recognized right to offset current tax assets against current tax liabilities and when the deferred tax assets and deferred tax liabilities derive from income tax levied by the same taxing authority on the same taxable entity or person or different taxable entities or persons which intend to settle current tax assets and liabilities on a net basis.

2.21. **Employee benefits**

Pension and retirement obligations

For the purposes of their accounting treatment, defined contribution plans under which the company's obligation consists solely of contributing an annual amount must be differentiated from defined benefit plans under which employees are entitled to a specific benefit on the accrual of their pensions.

Defined contribution plans

A defined contribution plan is a pension plan under which the Group pays fixed contributions to a fund and has no legal or constructive obligation to make additional contributions if the fund has insufficient assets to pay to all the employees the benefits related to the services rendered in the current year and in prior years. Contributions accrued in respect of defined contribution plans are expensed annually.

Defined benefit plans

A defined benefit plan is a pension plan that is not a defined contribution plan. A defined benefit plan usually defines the amount of the benefit that will be received by an employee at the time of retirement, normally on the basis of one or more factors such as age, years of service and remuneration.

The liability recognized in the balance sheet with respect to defined benefit pension plans is the present value of the defined benefit obligation at the balance sheet date less the fair value of the plan assets and any unrecognized past service costs. The defined benefit obligation is calculated annually by independent actuaries in accordance with the projected unit credit method. The present value of the obligation is determined by discounting the estimated future cash flows at interest rates on government bonds denominated in the currency in which the benefits will be paid and maturities similar to those of the relevant obligations.

At 31 December 2011 and 2010 the Group does not hold such kind of operations.

Termination benefits

Termination benefits are payable as a result of the Group's decision to terminate employment before the normal retirement date, or whenever an employee accepts voluntary redundancy in exchange for these benefits. The Group recognizes these benefits when it has demonstrably undertaken to terminate current employees' employment in accordance with a formal detailed plan that cannot be withdrawn, or to provide severance indemnities as a result of an offer made to encourage voluntary redundancy. Benefits that will not be paid within 12 months of the balance sheet date are discounted to their present value.

Profit-sharing and bonus plans

The Group recognizes a liability and an expense for bonuses and profit-sharing based on a formula that takes into consideration the profit attributable to the Company's equity holders after certain adjustments. The Group recognizes a provision when contractually obliged or when there is a past practice that has created a constructive obligation.

2.22. **Provisions**

The Group recognizes a provision when: it has a present legal or constructive obligation as a result of past events; it is likely that an outflow of resources will be required to settle the obligation; and the amount has been reliably estimated. Provisions are not recognized for future operating losses.

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognized even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are carried at the present value of forecast payments that are expected to be required to settle the obligation, using a rate before taxes that reflects the current market assessment of the time value of money and the specific risks of the obligation. The increase in the provision due to passage of time is recognized as interest expense.

Guarantee accruals

The Group grants guarantees to customers covering its photovoltaic panel sale contracts. Related accruals are compounded based on a theoretical forecast and historical information on default rates and estimated repair costs; they are periodically revised and adjusted. These accruals are registered through operating expenses by the estimated value of future claims related to the above-mentioned arrangements.

Dismantling accruals

Based on technical studies performed, the Group has estimated the present dismantling cost of solar and biodiesel plants recognized under the heading of assets assigned to projects. This estimation has been capitalized as higher asset value and depreciated over its useful life, which in most cases is similar to lease contracts subscribed for the lands in which the plants have been installed.

In addition, the Group has capitalized the present value of the estimated dismantling and retirement costs of the plants at the end of their useful life.

2.23. **Revenue recognition**

Sales include the fair value of payments received or receivable for the sale of goods and services in the ordinary course of the Group's activities. Sales are presented net of value added tax, returns, rebates and discounts, and after eliminating sales within the Group.

The Group recognizes revenue when the amount may be reliably estimated, it is likely that the future economic benefits will flow to the entity and the specific conditions are fulfilled for each of the Group's activities, as described below. A reliable calculation of the amount of revenue is not deemed possible until all sale-related contingencies have been resolved. The Group's estimates are based on historical results, taking into consideration customer type, transaction type and specific terms of each arrangement.

The methods used to recognize revenue in each of the Group's business activities are described below:

Construction business

When the results of a construction contract may be reliably estimated, ordinary revenue and associated costs of the contract are recognized as such in the income statement, based on the percentage of completion of the activity performed under the contract at the balance sheet date. When a project is expected to generate a loss, the necessary provisions are recorded to cover the entire loss during preparation of the updated budget.

Percentage of completion is generally determined by examining work executed. This method may be used since all contracts generally include:

- a definition of each project unit that must be executed to complete the whole project;
- a measurement of each of these project units; and
- the price at which each unit is certified.

In order to put this method into practice, at the end of each month a measurement of completed units is obtained for each project. The resulting total is the amount of construction work executed at the contractual price, which is recognized as project revenue from inception. The difference with respect to the corresponding figure a month earlier is production for the month, which is the amount recognized as revenue.

Construction work costs are recognized for accounting purposes on an accrual basis; costs actually incurred to execute project units completed, plus costs that may be incurred in the future and must be allocated to the project units completed, are recognized as expenses.

The application of this revenue recognition method is combined with the preparation of a budget made for each construction contract by project unit. This budget is used as a key management tool in order to maintain detailed monitoring, project unit by project unit, of fluctuations between actual and budgeted figures.

In such exceptional cases, when it is not possible to estimate the margin for the entire contract, the total costs incurred are recognized and sales that are reaso-

nably assured with respect to the completed work are recognized as contract revenue, subject to the limit of the total contract costs.

During the execution of construction work, unforeseen events not envisaged in the primary contract may occur that increase the volume of work to be executed. These changes to the initial contract require the customer's technical approval and subsequent financial approval. This approval permits, from that moment, the issue and collection of certificates for this additional work. Revenue from the additional work is not recognized until the customer's approval is reasonably assured; costs incurred in this work are, however, recognized when incurred, irrespective of the degree of approval obtained from the customer.

In the event that the amount of work actually executed in a project exceeds the amount certified at the year end, the difference between the two amounts is reflected in the consolidated balance sheet item "Trade and other receivables". When the amount of work actually executed in a project is lower than the amount of the certificates issued, the difference is recognized in the consolidated balance sheet item "Trade and other payables".

Estimated project close-out costs are provisioned and deferred over the execution period. These costs are recognized proportionally on the basis of estimated costs as a proportion of executed work. Costs incurred from project completion to definitive settlement are charged to the provision recorded and the remaining balance is recognized in the item "Provisions for other liabilities and charges" in current liabilities in the consolidated balance sheet.

Late-payment interest arising from delays in the collection of certificates from public administrations is recognized when it is likely that the interest will actually be collected and the amount may be reliably measured.

Costs relating to the tendering of bids for construction contracts are taken to the income statement when incurred, when the success of the bid is not probable or is not known at the date the costs are incurred. Bid tendering costs are included in the cost of the contract when the success of the bid is probable or is known, or when it is certain that the costs will be reimbursed or included in contract revenue.

Engineering business

Engineering project revenue is recognized on a percentage-of-completion basis, based on direct costs incurred in relation to total estimated costs.

The methods described for the construction business, as regards the recognition of revenue for additional work, recognition of estimated future losses by recording provisions, accounting treatment of any timing differences between revenue recognition for accounting purposes and the certificates issued to customers, and the recognition of late-payment interest, are also applied to the engineering business.

Concessions and services business

The Group has concessions to operate electricity infrastructure, car parks, toll roads, and others (note 2.7). The services business consists mainly of environmental services, such as wastewater treatment, and maintenance services for industrial infrastructure and related areas.

Under concession and management contracts for services, revenue and expenditure is recognized on an accrual basis, irrespective of when the related monetary or financial flows take place. The accounting treatment of the main activities is described below.

Multiple element contracts

Concessions for public services are contracts between a private operator and the Government or a different public body, in which the latter party grants to the private operator the right to provide public services such as the supply of water or electricity, or the operation of roads, airports or prisons. Control over the asset is retained by the public sector, but the private operator assumes responsibility for building the asset and for operating and maintaining the infrastructure. Depending on the contract terms, concessions are treated as intangible assets (when the predominant element is that the concession holder has the right to receive fees directly from users or the level of future flows are not assured by the granting authority) or as financial assets (when the granting authority guarantees a level of future cash flows).

The Group offers certain agreements under which it builds an infrastructure in exchange for a concession to operate it for a specified period. When such contracts contain multiple elements, the amount of revenue recognized is defined as the fair value for each phase of the contract. Revenue from infrastructure construction and engineering is recognized as described in the preceding paragraphs. Revenue from an intangible asset operation is recognized on an accrual basis as operating revenue. When a financial asset has been recognized, revenue is treated as a principal repayment with an interest income component. The characteristics of the Group's main activities are described below:

Toll roads/electricity transmission lines

In most cases, the principle of risk and business venture on the part of the concession holder coexists with the principle of assurance of the concession's economic and financial equilibrium on the part of the Government. Revenue is recognized at fair value during the construction phase. When the granting authority directly provides or guarantees a level of revenue for the concession holder, the asset is included in receivables. When the concession holder has the right to receive fees from users or revenues are not guaranteed, an intangible asset is recognized. In such cases, the Group recognizes revenue on an accrual basis and the intangible asset is depreciated over the concession term using a straight-line method, except for some toll roads infrastructures concessions in which the depreciation is recognized based in the traffic forecast for the concession.

Car parks

Car park business may be divided into:

- *Car parks for local residents:* This business involves the construction of car parks whose spaces are sold directly to the end customer. The sale and related costs are not recognized until the parking space has been handed over, which usually coincides with the execution of the public deed of sale. Additionally, in order to recognize the sale and costs, construction of the car park must have been completed and the license for the use of the car park must have been delivered. Commitments formalized in car park sale contracts pending handover are recorded as advanced receivables in the amounts obtained on account of the parking space. Capitalized costs are included in inventories and measured as described in the relevant section.

- On-street car parks:
This is a public service rendered to local authorities, which mainly concerns the management of public parking and the collection of the fees charged by municipalities for these services. The revenues are usually the hourly parking fees paid or the price paid for the public service by the council and is recognized when the relevant amounts fall due for payment. In the case of concessions, the amount paid to obtain the concession is recognized in the income statement over the concession period. Capitalized costs are included as intangible assets or financial assets, depending on the characteristics of the contract. Depreciation is charged on a straight-line basis during the concession term and begins when the asset is available for use.

- Off-street car parks:
In this case, revenues arise from the use of parking spaces owned by the company or held under an administrative concession. Off-street car park revenues are recorded when the hourly parking rate is paid and, in the case of season ticket holders, on an accrual basis.

Revenues from mixed car parks (off-street and for local residents) are recognized as described in the preceding paragraph, in the case of the off-street spaces. As regards spaces for local residents, the amounts received for spaces handed over are recorded in liabilities and taken to the income statement on a straight-line basis over the relevant concession periods, provided the distributable costs may not be reasonably segregated. During the accounting period in which the revenues are recognized, the necessary provisions are posted to cover costs to be incurred following handover. These provisions are calculated using the best estimates of costs to be incurred and may only be reduced as a result of a payment made in relation to the costs provisioned or a reduction in the risk. Once the risk has disappeared or the payments have been made, the surplus provision is reversed. Capitalized costs are recognized as intangible assets.

Real estate business

The Group companies recognize sales and results of real estate development projects when the property is handed over to the buyer, which usually coincides with the execution of the public deed of sale. Amounts received on account are included in "Trade and other payables" on the liabilities side of the consolidated balance sheet.

Solar-photovoltaic panel sales

Sales are measured at the fair value of the consideration received or receivable in the ordinary course of business. They are stated net of value added taxes, returns, rebates and discounts.

The Group recognizes revenue from solar panel sales when:

- The significant risks and benefits associated to panel ownership have been transferred to the buyer;
- The Group has no implication related to the management of panels sold and has no effective control over them;
- The amount of operating revenue can be reliably measured;
- It is probable that future economic benefits will flow to the entity;
- Costs incurred, or pending, can be reliably measured.

Electric energy sales

Electricity sales carried out by solar-photovoltaic plants in accordance with the sector regulations, as described below, are registered based upon the actual production. Sales revenue includes an estimate of the energy supplied which is pending to billing at the year end.

In line with electricity legislation, there are two types of production plants: those operating under "Ordinary System" rules and those considered as "Special System". Grupo T-Solar Global, S.A. subsidiaries operate in the electricity market under the "Special System" rules. The main regulations regarding this activity are as follows:

The Spanish Royal Decree 661/2007 (25 May), which regulates electricity production activities considered under the special system rule and establishes the financial system for those production plants operating under this system. This regulation defines production objectives for each renewable energy plant.

The photovoltaic activity production objective was agreed in August 2007. As a result, on September 27, 2007, the SGE (Secretaría General de Energía) issued a proposal determining the appliance period for regulated tariffs in the photovoltaic energy sector, as defined in Spanish Royal Decree 661/2007, article 22. After the proposal was published on September 29, 2007 in the Boletín Oficial del Estado, this period was of twelve months. Any plant registered before that date is under the scope of Spanish Royal Decree 1578/2008.

The main aspects considered by Spanish Royal Decree 661/2007 in relation to the financial system for electricity generation in the Group's photovoltaic plants, force owners of those plants that become fully operational after 31 December 2007 to apply, at least for one year, one of the following options:

Regulated fee: producers generate electricity and distribute it through the electrical network, receiving an established fee in return.

Market rate: the price of electricity is established through market mechanisms or negotiated by the plant's owner, and includes a premium. In these cases, only lower and higher thresholds are previously defined. In solar-photovoltaic energy, this option is not considered, so the first one is always applied.

Operating plants under Spanish Royal Decree 661/2007 scope have chosen to apply the regulated fee.

Distinction between the types of plant is one of the innovations introduced by Spanish Royal Decree 1578/2008. This difference is relevant to the extent that the Decree establishes, on a quarterly basis, the annual rate allocation and a specific consideration based on plant category and sub-category.

On November 23, 2010, the Spanish Royal Decree 1565/2010 (November, 19) was issued, which regulates and amends certain aspects associated with electricity production under the special system scope. This legislation introduces a premium decrease ranging from 5% to 45%, which will be removed in 26 years, for new tender offers.

On December 24, 2010, the Spanish Royal-Decree-Law 14/2010 (December, 23) was published, which established urgent measures to correct the tariff deficit in the electricity business. This legislation limits the hours photovoltaic plants can operate to get the premium. Likewise, it extends the period during which companies can sell energy under a premium, from 25 to 28 years. Afterwards, a new regulation related to a Sustainable Economy was issued, increasing the compensation period for two additional years, from 28 to 30 years.

2.24. **Leases**

When a Group company is the lessee – Finance lease

The Group leases certain property, plant and equipment. Property, plant and equipment leases where the Group has substantially all the risks and rewards of ownership are classed as finance leases. Finance leases are capitalized at the lease's inception at the lower between the fair value of the leased property and the present value of the minimum lease payments.

Each lease payment is allocated between the liability and finance charges so as to achieve a constant rate on the outstanding debt. The corresponding rental obligations, net of finance charges, are included in other long-term payables. The interest element of the finance cost is charged to the income statement over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The property, plant and equipment acquired under finance lease is depreciated over the shorter of the useful life of the asset or the lease term.

When a Group company is the lessee – Operating lease

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the income statement on a straight-line basis over the period of the lease.

When a Group company is the lessor

When assets are leased under finance lease, the present value of lease payments is recognized as a financial account receivable. The difference between the gross receivable and the present value of that amount is recognized as a financial return on capital.

Lease revenues are recognized during the lease period in accordance with the net investment method, which reflects a constant periodic rate of return.

Assets leased to third parties under operating lease contracts are included in tangible fixed assets on the balance sheet. Income from leases is recognized on a straight-line basis during the lease term.

2.25. **Non-current assets (or disposal groups) held for sale**

Non-current assets (or disposal groups) are classified as held-for-sale assets and are recognized at the lower between carrying value and fair value less selling costs, if the carrying value is mainly recovered through sale instead of continuing use. There are no non-current assets (or disposal groups) held for sale at the balance sheet dates.

2.26. **Dividend distribution**

Dividend distribution to the Parent Company's equity holders is recognized as a liability in the Group's consolidated annual accounts in the year in which the dividends are approved by the parent Company's equity holders.

2.27. **Environment**

The consolidated Group has no environmental liabilities, costs, assets, provisions or contingencies that could be significant in relation to its equity, financial situation and results. No specific breakdowns are therefore included in these notes to the consolidated annual accounts relating to environmental issues.

2.28. **Operating results**

The income statement caption Operating results includes the results of the Group companies' ordinary activities, excluding financial results (see Note 27) and shares on results of companies consolidated under the Equity method.

2.29. **Biological assets**

Agricultural products harvested or collected from biological assets are measured at the point of sale or harvest at fair value less estimated costs at point of sale. Such measurement relates to the cost value at the harvest or collection date for the purposes of measuring inventories. Gains or losses on the variation in fair value less estimated costs at point of sale are recognized in the consolidated income statement. Specifically: agricultural products like grains are recorded at market value, net of marketing costs. Additionally assets used in the production process are recognized at their replacement cost.

2.30. **Segment reporting**

Operative segments are consistently disclosed with internal information, which is presented to the highest decision-making unit. This unit is responsible for operative segments resources allocation and for these segments' performance assessment. Management Committee has been designed as the highest decision-making unit.

3 Financial risk management

3.1. **Financial risk factors**

Group's activities are exposed to a variety of financial risks: market risk (including foreign exchange risk, fair value interest rate risk and price risk), credit risk and liquidity risk. The Group's overall risk management program focuses on financial markets uncertainty and seeks to minimize potential adverse effects on the Group's financial performance. The Group uses derivative financial instruments to hedge certain risks.

Risk management is performed by the Group's Central Treasury Department in accordance with policies approved by the Board of Directors. This department identifies, evaluates and hedges financial risks in close association with the Group's operating units. The Board provides written policies for overall risk management and for specific areas such as foreign exchange risk, interest rate risk, liquidity risk, use of derivatives and non-derivatives, and investment of cash surpluses.

a. Market risk

a.1. Foreign exchange risk

The Group has international operations and is therefore exposed to foreign exchange risk during currency transactions, relating particularly to the US dollar (USD), Brazilian real, Mexican peso, Qatari real and Indian rupee, as well as to other currencies. Foreign exchange risk arises from future commercial transactions, recognized assets and liabilities and net investments in foreign operations.

Management has implemented a policy that requires the Group companies to manage foreign exchange risk with respect to their functional currency. The Group companies are obliged to hedge all foreign exchange risk through the Central Treasury Department. Foreign exchange risks arising from future commercial transactions and recognized assets and liabilities are hedged by means of forward contracts traded through the Group's Treasury Department. Foreign exchange risk arises when future commercial transactions or recognized assets and liabilities are denominated in a currency other than the company's functional currency.

The Group's Treasury Department has a policy of hedging net forecast flows deriving from forecast transactions in currencies other than the functional currency of the Group company that effects the transaction. At 31 December 2011 and 2010 there were foreign current put transactions related to companies located in Spain, Africa, Asia and Latin America (See Note 11).

The Group's transactions are generally completed in each country's functional currency, although transactions are often effected in a different currency (mainly in Spain, India, Africa and Latin America), particularly in US dollars and Euro. At 31 December 2011, had the functional currency of each country with transactions in US dollars depreciated/appreciated by 10% against the US dollar, without any change in the remaining variables, the consolidated result after tax for 2011 would have been 1,562 thousand euro lower/higher (2010: 8,085 thousand euro lower/higher), mainly due to the effects of the increase/decrease in USD liability/asset positions. Equity would have changed by the same amounts (effects calculated excluding the impact of fair value changes in the derivative financial instruments contracted).

The Group has a number of investments in foreign operations whose net assets are exposed to foreign exchange risk. These investments are located basically in Latin America (Brazil and Mexico), USA and India. In general, the Group ensures that operations in each country are financed by borrowings in the functional currency of that country so that foreign exchange risk only affects the capital investment. Where the investment is partially or fully financed by borrowings, the Group ensures that the loans are obtained in the correspondent functional currency. When no financing is used, the Group does not contract hedges, except in certain cases in which short-term forecast flows relating dividends from the subsidiary are hedged.

	2011	2010
Brazilian Real (*)	539,859	392,592
Mexican Peso (*)	264,022	267,976
Indian Rupee	153,789	93,238
US Dollar (*)	63,839	22,806
Other currencies (*)	8,546	4.343
Total	**1,030,055**	**780,955**

(*) Excluding the value of goodwill at each date, as mentioned in Note 7.1.

a.2. Price risk

The Group is not exposed to equity instrument price risk since it has no significant investments. The Group is partially exposed to market price risk in respect of raw materials, relating basically to metals and oil, which affect the price of supplies of equipment and materials manufactured in the projects executed by the Group. Generally, these effects are efficiently passed on in selling prices by all similar contractors operating in the same sector. It is also exposed to risk of change in price of raw materials used in the biodiesel production and in the solar-photovoltaic modules production. The Group reduces and mitigates price risk by means of policies implemented by management, consisting basically of a reduction or increase in the rate of placements and the selection of currencies and countries of origin, as well as by ensuring the production or acquisition of certain raw materials at a closed price.

For oil purchases to use as raw material in biodiesel production, the Group has purchase contracts in which oil price is referred to diesel quotation, which in turn is the reference price for biodiesel. In this way, margins are assured.

See the information in Note 11, covering the price risk sensitivity of the option included in the arrangement signed with Corpfin Capital Asesores, S.A. and other entities.

a.3. Cash flow and fair value interest rate risk

Interest rate risk must be analyzed in relation to the two types of financing obtained by the Group:

- Project finance

As explained in Note 8, the Group participates in a number of investment projects under "Project finance" arrangements in which, among other aspects, repayments are secured only by cash flows from the respective projects; there may be, in some cases and during the construction phase, additional guarantees. In such cases, financing mainly comprises long-term, variable-rate instruments. The interest rates applicable depend on the country in which the project is located and on the currency in which the financing is issued. Financing issued at variable rates exposes the Group to cash flow interest rate risk. The Group uses interest rate swaps to convert long-term financing totally or partially to fixed interest rates. Additionally, under certain project finance contracts the company that obtains the financing undertakes vis-à-vis the granting banks to contract the above-mentioned derivative financial instruments.

Exposure to variable interest rate risk at each year end is analyzed below:

2011	Euribor rates	TJLP/CDI Rate (1)	TIIE Rate (2)	PLR Rate (3)	LIBOR Rate (4)	Other rates	Total
Project Finance	1,187,178	450,189	351,445	394,857	44,306	18,649	2,446,624
Interest-bearing cash and cash equivalents	(129,071)	(94,973)	(45,974)	(48,333)	(3,788)	(17,304)	(339,443)
Net position	**1,058,107**	**355,216**	**305,471**	**346,524**	**40,518**	**1,345**	**2,107,181**
Portion hedged by derivative financial instruments	85%	0%	85%	0%	115%	0%	57%

(1) Brazilian long-term reference interest rate
(2) Mexican long-term reference interest rate
(3) Indian long-term reference interest rate
(4) International long-term reference interest rate

2010	Euribor rates	TJLP/CDI Rate (1)	TIIE Rate (2)	PLR Rate (3)	Other rates	Total
Project Finance	399,528	285,788	296,782	252,912	-	1,235,010
Interest-bearing cash and cash equivalents	(59,397)	(68,072)	(29,274)	(65,815)	(1,403)	(223,961)
Net position	**340,131**	**217,716**	**267,508**	**187,097**	**(1,403)**	**1,011,049**
Portion hedged by derivative financial instruments	100%	0%	96%	0%	0%	59%

(1) Brazilian long-term reference interest rate
(2) Mexican long-term reference interest rate
(3) Indian long-term reference interest rate
(4) International long-term reference interest rate

The Group analyses its exposure to interest rate risk in a dynamic manner. A simulation is performed in which the Group calculates the effect on results of a specific change in the interest rate. In each simulation, the same interest rate fluctuation is used for all currencies and reference rates. Scenarios are only simulated for liabilities representing the most relevant interest-bearing positions. Based on the simulations performed, the impact on results after tax of an increase/decrease of 100 basic points in the interest rate would have been a reduction/increase of 6,593 thousand euro (2010: 2,839 thousand euro), mainly due to a rise/reduction in interest expense on variable-rate loans; equity would have changed by the same amounts (effects calculated without considering the impact of fair value changes in the derivative financial instruments contracted).

- Borrowings

The Group's interest-rate risk arises mainly from long-term borrowings. Borrowings issued at variable rates expose the Group to cash flow interest rate risk. Fixed-interest borrowings expose the Group to fair value interest rate risk. A large part of the Group's borrowings are obtained at variable rates, the main reference rate being the Euribor. The Group uses interest rate swaps to convert long-term financing to fixed interest rates.

Exposure to variable interest rate risk at each year end is analyzed below:

	2011			2010		
	Euribor Rate	Other rates	Total	Euribor Rate	Other rates	Total
Borrowings	1,235,587	143,401	1,378,988	1,119,646	130,722	1,250,368
Interest-bearing cash and cash equivalents	(138,440)	(174,708)	(313,148)	(237,429)	(436,414)	(673,843)
Net position	**1,097,147**	**(31,307)**	**1,065,840**	**882,217**	**(305,692)**	**576,525**
Portion hedge by derivative financial instruments	79%	0%	81%	86%	0%	131%

The Group analyses exposure to interest rate risk in a dynamic manner. A number of scenarios are simulated taking into consideration refinancing, renewal of current positions, alternative financing, existence of variable-rate investments (in this sense, very short-term interest-bearing placements are treated as being exposed to variable interest rates) and existing hedges. Through these scenarios, the Group calculates the effect on results of a specific change in the interest rate. In each simulation, the same interest rate fluctuation is used for all currencies. Scenarios are only simulated for liabilities that represent the most relevant interest-bearing positions. Based on the simulations conducted, the impact on after-tax results of an increase/decrease of 100 basis points interest rate would decrease/increase in (193) thousand euro (2010: (717) thousand euro), mainly due to higher/lower interest expense on variable rate loans. Equi-

ty would have changed in the same amount (effects calculated not considering the impact of changes in fair value of financial derivatives contracts).

b. Credit risk

The Group manages credit risk in relation to the following groups of financial assets:

- Derivative financial instruments (see Note 11) and balances included under Cash and cash equivalents and financial assets at fair value through profit or loss (see Note 14).
- Balances related to trade and other receivables (see Note 12).

Derivative financial instruments and bank transactions included in cash and cash equivalents and financial assets at fair value through profit or loss are contracted with reputable financial institutions that obtain high credit ratings. Investments in government bonds and treasury bills also relate to governments with high credit ratings.

A high proportion of trade and other receivables (63.61% and 62.37% at 31 December 2011 and 2010, respectively) relate to transactions with national and international public institutions and the Group therefore considers that credit risk is under tight control. A significant part of the receivables from private companies relate to companies with high credit ratings and there is no default history with respect to the Group. A periodic follow-up is performed of the overall position in trade and other receivables and also an individual analysis of the most significant exposures.

c. Liquidity risk

Prudent liquidity risk management implies maintaining sufficient cash and marketable securities, the availability of funding through an adequate amount of committed credit facilities and the ability to close out market positions. Due to the dynamic nature of the underlying businesses, Group Treasury aims to maintain flexibility in funding by keeping committed credit lines available.

Regarding to the Group's project financing arrangements ("Project finance"), as explained in Note 8, repayments are secured only by cash flows from the respective projects. In such cases, the Group hedges liquidity risk by ensuring that financing is long term and structured on the basis of the forecast cash flows for each project. Accordingly, 86% of financing recognized at 31 December 2011 (2010: 82%) falls due after more than 1 year and 71% of the financing recognized at 31 December 2011 (2010: 68%) falls due after more than 4 years.

As regards the Group's liquidity position, management monitors the Group's forecast liquidity based on expected cash flows.

The following table contains a breakdown of the Group's financial liabilities that will be settled in the net amount, grouped together by maturity date based on the period from the balance sheet date to the maturity date stipulated in each contract. The amounts shown in the table relate to undiscounted cash flows stipulated in the contract. Balances payable in less than 12 months reflect the relevant carrying amounts as the effect of discounting is not significant.

	Less than 1 year	Between 1 and 2 years	Between 2 and 5 years	More than 5 years
At 31 December 2011				
Borrowings	449,058	166,097	691,243	72,590
Derivative financial instruments	24,400	11,624	34,872	127,863
Trade and other payables (excluding deferred revenue)	2,303,064	31,554	24,284	78,676
Accrued unmatured interest	51,951	38,110	47,294	1,633
Total	2,828,473	247,385	797,693	280,762
At 31 December 2010				
Borrowings	372,804	62,315	606,621	208,628
Derivative financial instruments	12,559	2,382	7,146	38,118
Trade and other payables (excluding deferred revenue)	2,559,171	3,331	3,405	9,293
Accrued unmatured interest	37,239	31,877	69,515	11,774
Total	2,981,773	99,905	686,687	267,813

Liquidity risk is managed on an overall, centralized basis by the Group Treasury Department. This includes both managing cash from the Group's recurring transactions (analysis and follow-up of debt maturities, collections, renewal and contracting loans, management of available credit lines, and temporary investment of cash surpluses) and managing the funds necessary to undertake planned investments. Although at 31 December 2011 the Group shows negative working capital amounting 284,097 thousand euro, liquidity risk is adequately limited due to the following aspects: cash and cash equivalents cover current borrowings, all drawn credit lines are being renewed as in previous years, there are significant un-drawn credit lines (see Note 19), leverage ratio is adequate (see Note 3.2) and operational cash flows are expected to increase as in previous periods. Thus, operational cash flow net of the tax effect in 2012 is expected to amount 530 million euro.

3.2. **Capital risk management**

The Group's capital management objectives consist of protecting its capacity to do business as a going concern in order to obtain a return for shareholders and profits for other holders of equity instruments, as well as to maintain an optimal capital structure and reduce cost of capital.

In order to maintain or adjust the capital structure, the Group could adjust the amount of dividends payable to shareholders, reimburse capital to shareholders, issue new shares or sell shares to reduce debt.

The Group monitors capital based on the leverage ratio, in line with industry practices. This ratio is calculated as net debt divided by total capital (excluding the position assigned to projects). Net debt is calculated as total borrowings (including current position in trade and other payables, as reflected in the consolidated accounts) less cash and cash equivalents and financial assets at fair value through profit or loss. Capital is calculated as equity, as reflected in the consolidated accounts, plus net debt.

In 2011, the Group's strategy, which has not changed since 2010, consisted of keeping the leverage ratio below 80%, which is deemed reasonable considering that the Group's main businesses (construction and engineering) are characterized by high levels of working capital (both financial assets and financial liabilities). Leverage ratios at 31 December 2011 and 2010 are shown below:

	2011	2010
Borrowings (see Note 19) and Trade and other payables – Current (see Note 18)	3,682,052	3,809,539
Less: financial assets at fair value through profit or loss (see Note 14.2)	(14,447)	(2,300)
Less: cash and cash equivalents (see Note 14.1)	(674,366)	(937,555)
Net debt	2,993,239	2,869,684
Equity (including non-controlling interest)	896,313	771,074
Total capital	3,889,552	3,640,758
Leverage ratio (net debt / total capital)	**77.0%**	**78.8%**

3.3. **Fair value estimation**

The fair value of financial instruments traded in active markets (such as publicly traded derivatives and held-for-trading and available-for-sale investments) is based on quoted market prices at the balance sheet date. The market price used for financial assets is the current bid price.

The fair value of financial instruments that are not traded in an active market is determined by using valuation techniques. The Group uses a variety of methods and makes assumptions that are based on market conditions existing at each balance sheet date. Market prices or brokers' prices are used for long-term payables. Other techniques, such as the estimated discounted cash flow method, are used to determine fair value for the remaining financial instruments. The fair value of interest-rate swaps is calculated as the present value of the estimated future cash flows. The fair value of forward foreign exchange contracts is determined using forward exchange market rates at the balance sheet date.

The fair value of the option under the arrangement with Corpfin Capital and other entities (Note 11) is estimated applying the Montecarlo method (100,000 simulations), considering for that purpose the underlying asset's fair value, market volatility and interest rates and the expected underlying asset dividend yield for spot prices and maturities of such options.

The carrying amount less the provision for the impairment of receivables and payables is assumed to approximate their fair value. The fair value of financial liabilities for disclosure purposes is estimated by discounting the future contractual cash flows at the current market interest rate that is available to the Group for similar financial instruments.

4 Critical accounting estimates and judgments

The preparation of consolidated annual accounts under IFRS-EU requires that management makes estimations and assumptions that could affect the accounting policies adopted and the amounts of assets, liabilities, revenue, expenses and related breakdowns. The estimates and assumptions made are based on past experience or other facts that are deemed to be reasonable under the circumstances, at the balance sheet date, the result of which is the basis from which to judge the carrying amount of the assets and liabilities that cannot be immediately determined in any other manner. Actual results could differ from estimated ones.

Estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Certain accounting estimates are considered to be significant if the amount of the estimates and assumptions is material and if the impact of the estimates and assumptions on the financial position or operating results is material. Group management's main estimates are explained below.

4.1. **Critical accounting estimates and judgments**

The Group makes estimates and judgments concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and judgments that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Business combinations or net-asset group acquisitions

IFRS-EU requires, at the acquisition date of a subsidiary, an analsysis of whether the acquired element can be considered as a business or as a net-asset group not complying with the business definition, as stated in IFRS 3 "Business combinations" (Note 2.2).

When the Group acquires shares in an entity not considered as a business but as a net-asset group, the cost is allocated to identifiable individual assets and liabilities, based on their fair value at the acquisition date. Net-asset group cost may include any element related to share-based payments. In these cases, the difference between the fair value of the acquired assets and the amount payable in cash is directly registered in equity (Note 2.26).

When the Group acquires shares in an entity considered as a business, the business combination cost is allocated to identifiable assets, liabilities and contingent liabilities in the acquired company, at the acquisition date. These assets and liabilities are initially valued at fair value. If a part of the combination cost depends on future events, the amount of such adjustment is included in the combination cost, to the extent it is probable and can be reliably measured.

The excess of business combination cost over the acquirer's shareholding in the acquired net assets at fair value is registered as goodwill.

During 2011, the Group has had business combinations (Note 32). Based on management judgement, the acquisition cost of these businesses has been booked in line with the terms included in the sale-purchase agreements.

Estimated impairment of goodwill

The Group verifies annually whether there is an impairment loss with respect to goodwill, in accordance with the accounting policy in Note 2.9. The recoverable amounts of cash-generating units have been determined based on value-in-use calculations. These calculations require the use of estimates and sensitivity analyses are performed on the most relevant variables included in the estimates, paying particular attention to situations in which potential impairment indicators may be identified (see Note 7.1).

Income tax

The Group is subject to income taxes in numerous jurisdictions. A significant level of judgment is required to determine the worldwide provision for income tax. There are many transactions and calculations with respect to which the ultimate calculation of the tax is uncertain in the ordinary course of business. The Group recognizes liabilities for anticipated tax matters based on estimates as to whether additional taxes will be necessary. When the final tax result differs from the amounts which were initially recognized, such differences will have an effect on income tax and the provisions for deferred taxes in the year in which they are deemed to arise. In this sense, there are no significant aspects subject to estimates that could have a material impact on the Group's position.

Recovery of deferred tax assets

The recovery of deferred tax assets (Note 20) is assesed at the moment they arise, and subsequently each balance sheet date, based upon forecast results included in the Group's business plan. In particular, the Group considers the synergies arising from tax consolidation, as well as future tax benefits based upon the above-mentioned business plan.

Fair value of derivatives or other financial instruments

The fair value of financial instruments that are not traded in an active market is determined by using valuation techniques. The Group exercises judgment to select a variety of methods and to make assumptions based mainly on market conditions at the balance sheet date. The Group has used discount cash flow analyses for a number of available-for-sale financial assets not traded in active markets.

Revenue recognition

The Group recognizes revenue from construction and engineering activities on a percentage-of-completion basis. Percentage of completion is calculated as costs incurred under the contract as a percentage of estimated total contract costs. This revenue recognition method is only used when the result of the contract may be reliably estimated and the contract is likely to generate profits. If the result of the contract cannot be reliably estimated, revenue is recognized as costs are recovered. When a contract's costs are likely to exceed the contract's revenue, the loss is immediately expensed. When applying the percentage-of-completion method, the Group makes significant estimates in relation to total costs necessary to perform the contract. These estimates are reviewed and evaluated periodically to verify whether a loss has been generated and whether the percentage-of-completion method may continue to be applied, or to re-estimate the forecast project profit. During the project, the Group also estimates likely contingencies relating to the increase in the total estimated cost and adjusts revenue recognized accordingly. The Group's historical data indicates that its estimates are adequate and reasonable in relation to the above-mentioned aspects.

Concession contracts

Based upon available information and all relevant terms included in the concession contracts, the Group performs a detailed analysis to determine if such arrangements are within the scope of IFRIC 12. The main aspects to be considered in this analysis are as follows:

a) If the granting authority controls or regulates the use of the infrastructure by the concessionaire, to whom it must render the associated services and at what price.

b) If the granting authority has any residual share of the infrastructure at the end of the concession period.

Based on these terms and on the available information for each contract, the Group determines the accounting model to be applied:

Intangible asset model: the Group applies this model when the concessionaire has the right to receive toll collections (or any other type of payment) from users, as a consideration for infrastructure funding and construction, or when the granting authority remunerates the concessionaire based on the degree of infrastructure utilization.. In both cases, the amounts to be paid to the concessionaire are not guaranteed.

Financial asset model: the Group applies this model when the concessionaire has an unconditional contractual right to receive payments from the granting authority, regardless of the degree of infrastructure utilization.

Mixed model: when the concessionaire is partially paid both by users (depending on the infrastructure use) and by the granting authority (based on an unconditional contractual right to receive payments).

Once the accounting model has been defined, there are key estimations / assumptions used by Management, such as:

- Traffic forecasts to calculate intangible assets depreciation (road concessions).
- Maintenance accrual: estimates of future CAPEX value, based on each business plan used by Management.
- The construction margin expected by Management, used to measure intangible / financial assets at fair value.
- When determining the financial asset value in accordance with electric transmission line contracts and their legal interpretations, the concessionaire Management estimates granting the authority to compensate them for the infrastructure residual value at the end of the concession period.

Useful lives of property, plant and equipment and intangible assets

Group management determines estimated useful lives and related depreciation charges for its property, plant and equipment and its intangible assets. This estimate is based on the period during which the non-current assets will generate economic benefits based on updated business plans. At each closing date, the Group reviews the useful lives of non-current assets. If the estimates differ from previous estimates, the effect of the change is recognized prospectively as from the year in which the change takes place.

For those intangible assets related to motorlway administrative concessions that are depreciated in a systematic way based on the traffic and revenues expected in accordance with updated business plans, Group's management annually updates traffic estimates made for such concessions.

Likewise, in case circumstances imply worse conditions based on business plans, impairment tests will be carried out.

Warranty claims

The Group generally offers 24- or 36-month warranties on its projects and services. Management estimates the related provision for future warranty claims based on historical warranty claim information, as well as recent trends that might suggest that past cost information may differ from future claims. As in the case of revenue recognition, the Group's historical data indicates that its estimates are adequate in this respect.

Receivables and financial assets

The Group makes estimates relating to the collectability of balances owned by customers in projects in which disputes have arisen or litigation is in progress due to disagreement with the work executed or the failure to fulfill contractual clauses linked to the return on the assets handed over to customers. The Group also makes estimates to assess the recoverability of available-for-sale financial assets, based mainly on the financial health and near-term business prospects of the investee company.

Provisions

Provisions are recognized when it is probable that a present obligation arising from past events will result in an outflow of funds and the amount of the obligation may be reliably estimated. Significant estimates are required in order to comply with IFRS-UE. Group management makes estimates of the likelihood of the contingencies and the amount of the liability to be settled in the future, evaluating all relevant information and facts.

5 Segment information

Operative segments have been determined based on the information presented to Management Committee, which is used to strategic decision making.

Regarding operative segments, the Committee considers there are five business units: Construction, Engineering and Industrial Services, Concessions (including solar-photovoltaic energy manufacturing and generation business), Renewable Energies and Real Estate. Moreover, an additional analysis concerning geographical areas in which the Group operates is performed: Spain, Latin America (mainly Mexico, Brazil and Argentina), Asia (basically India), and others (mainly including activities carried out in USA and African countries, such as Angola or Algeria).

Businesses from "Real Estate" and Renewable Energies" segments are included under "Other, Corporate and Consolidation Adjustments", due to its low contribution to Group operations; revenues from these segments are obtained through real estate and fuel (biodiesel) sales.

"Construction" and "Engineering and Industrial Services" segments obtain their revenue mainly by rendering construction services, whereas "Concessions" segment obtain them through the sale of the corresponding service according to the type of concession to which it relates.

Revenues generated between segments mainly come from construction services rendered by "Construction" and "Engineering and Industrial Services" to the rest of segments or to the Group's Corporate. These revenues are carried out under market conditions and analyzed by Management Committee as stated in "Own work capitalized".

Operative segments performance is assessed by Management Committee based on the valuation of each segment operating result. Total impact on "Net financial results" of financial income and expenses are analyzed by each individual segment. A detailed analysis is carried out by Treasury Department, which manages Group's cash position. Likewise, income tax is analyzed at Group level by Management Committee.

Segment-information presented to Management Committee at 31 December 2011 is as follows:

2011	Construction	Engineering and Industrial Services	Concessions	Other, Corporate and Consolidation Adjustments	Total
Revenue from external customers	**1,062,705**	**1,543,664**	**322,325**	**272,006**	**3,200,700**
Segment´s ordinary revenue	1,084,485	1,653,722	323,707	138,786	3,200,700
Own work capitalized	-	-	-	118,405	118,405
Other operating revenue	-	-	203	52,632	52,835
Total operating revenue	**1,084,485**	**1,653,722**	**323,910**	**309,823**	**3,371,940**
Depreciation and charges due to impairment	(4,556)	(17,239)	(71,308)	(26,066)	(119,169)
Operating expenses	(1,005,181)	(1,477,102)	(142,928)	(361,667)	(2,986,878)
Operating result	**74,748**	**159,381**	**109,674**	**(77,910)**	**265,893**
Net financial results	2,040	(10,248)	(124,595)	(84,477)	(217,280)
Share of profit of investments for using the equity method	-	-	(8,761)	(7,026)	(15,787)
Before-tax profit/(loss)	**76,788**	**149,133**	**(23,682)**	**(169,413)**	**32,826**
Income tax	-	-	-	(27,350)	(27,350)
Profit/(loss) for the year	**76,788**	**149,133**	**(23,682)**	**(196,763)**	**5,476**
Total Assets	**1,302,549**	**1,942,586**	**4,414,253**	**431,640**	**8,091,028**
Total assets include:					
Investments in companies consolidated under the Equity method	-	-	-	34,634	34,634
Additions to non-current assets	6,775	11,474	1,384,301	8,362	1,410,912
Total Liabilities	**1,085,017**	**1,382,663**	**3,521,578**	**1,205,457**	**7,194,715**

Segment-information presented to Management Committee at 31 December 2010 is as follows:

2010	Construction	Engineering and Industrial Services	Concessions	Other, Corporate and Consolidation Adjustments	Total
Revenue from external customers	**1,281,931**	**1,422,770**	**163,577**	**320,462**	**3,188,740**
Segment´s ordinary revenue	1,305,269	1,514,871	163,577	205,023	3,188,740
Own work capitalized	-	-	-	1,017	1,017
Other operating revenue	-	45,615	397	4,017	50,029
Total operating revenue	**1,305,269**	**1,560,486**	**163,974**	**210,057**	**3,239,786**
Depreciation and charges due to impairment	(7,725)	(22,904)	(33,598)	(22,465)	(86,692)
Operating expenses	(1,203,640)	(1,433,843)	(51,429)	(256,480)	(2,945,392)
Operating result	**93,904**	**103,739**	**78,947**	**(68,888)**	**207,702**
Net financial results	4,495	(5,274)	(44,410)	(70,532)	(115,721)
Share of profit of investments for using the equity method	-	-	(6,562)	(510)	(7,072)
Before-tax profit/(loss)	**98,399**	**98,465**	**27,975**	**(139,930)**	**84,909**
Income tax	-	-	-	(20,949)	(20,949)
Profit/(loss) for the year	**98,399**	**98,465**	**27,975**	**(160,879)**	**63,960**
Total Assets	**1,558,378**	**1,857,440**	**2,172,660**	**516,176**	**6,104,654**
Total assets include:					
Investments in companies consolidated under the Equity method	-	-	8,761	170,235	178,996
Additions to non-current assets	7,455	11,625	377,102	9,168	405,350
Total Liabilities	**1,309,446**	**1,363,300**	**1,951,108**	**709,726**	**5,333,580**

During 2011 and 2010 no charge due to goodwill impairment has been recognized.

Ordinary revenues from external customers are measured consistently with those applied in the income statement.

Total assets and liabilities amounts presented to Management Committee are measured consistently with those applied in the consolidated annual accounts.

These assets and liabilities are assigned based on segment activities and physical asset location.

The parent company is registered in Spain, but the Group also operates abroad. Information by geographical segment at 31 December 2011 is presented below:

2011	Spain	Latin America	Asia	Other, Corporate and Consolidation Adjustments	Total
Revenue/ sales	**1,214,470**	**1,354,779**	**303,297**	**328,154**	**3,200,700**
Total assets	**4,519,359**	**2,685,784**	**806,755**	**79,130**	**8,091,028**
Total assets include:					
Non-current assets	2,820,017	1,671,088	605,431	54,822	5,151,358
Total Liabilities	**4,394,807**	**2,087,235**	**642,737**	**69,936**	**7,194,715**

Information by geographical segment at 31 December 2010 considering the country of the clients is presented below:

2010	Spain	Latin America	Asia	Other, Corporate and Consolidation Adjustments	Total
Revenue/ sales	**1,588,804**	**865,835**	**201,710**	**532,391**	**3,188,740**
Total assets	**3,353,428**	**2,019,099**	**525,845**	**206,282**	**6,104,654**
Total assets include:					
Non-current assets	1,480,597	1,014,680	296,064	(987)	2,790,354
Total Liabilities	**3,609,985**	**1,254,800**	**388,989**	**79,806**	**5,333,580**

During 2011 and 2010 there is not ordinary revenue from transactions carried out with a single customer representing more than 10% of the Group.

6 Property, plant and equipment

Set out below is a breakdown of property, plant and equipment showing movements:

2011	Land and buildings	Plant machinery and tooling	Furnishings	Vehicles	Data processing equipment	IPPE in progress	Other PPE	Total
Cost								
1 January	122,903	142,756	8,581	20,175	11,239	4,978	4,341	314,973
Additions	3,875	9,689	889	477	1,734	188	1,309	18,161
Disposals	(1,468)	(13,486)	(460)	(3,497)	(1,536)	(116)	(1,151)	(21,714)
Impairment	(3,256)	-	-	-	-	-	-	(3,256)
Transfers	(192)	3,748	(233)	(1,678)	(478)	(4,449)	(175)	(3,457)
31 December	**121,862**	**142,707**	**8,777**	**15,477**	**10,959**	**601**	**4,324**	**304,707**
Accumulated Depreciation								
1 January	(6,533)	(77,279)	(4,226)	(12,771)	(7,058)	-	(3,272)	(111,139)
Depreciation	(953)	(16,171)	(689)	(2,854)	(1,626)	-	(669)	(22,962)
Disposals	384	10,365	359	3,496	1,501	-	1,037	17,142
Transfers	933	1,686	100	955	(208)	-	(855)	2,611
31 December	**(6,169)**	**(81,399)**	**(4,456)**	**(11,174)**	**(7,391)**	**-**	**(3,759)**	**(114,348)**
Net book value	**115,693**	**61,308**	**4,321**	**4,303**	**3,568**	**601**	**565**	**190,359**

2010	Land and buildings	Plant machinery and tooling	Furnishings	Vehicles	Data processing equipment	PPE in progress	Other PPE	Total
Cost								
1 January	121,546	142,625	9,390	21,860	16,949	581	5,172	318,123
Additions	3,247	8,845	833	1,472	1,898	4,397	380	21,072
Disposals	(770)	(9,197)	(1,642)	(3,157)	(7,608)	-	(388)	(22,762)
Impairment	(1,800)	-	-	-	-	-	-	(1,800)
Transfers	680	483	-	-	-	-	(823)	340
31 December	**122,903**	**142,756**	**8,581**	**20,175**	**11,239**	**4,978**	**4,341**	**314,973**
Accumulated Depreciation								
1 January	(5,043)	(64,462)	(4,716)	(10,774)	(11,895)	-	(4,699)	(101,589)
Depreciation	(727)	(20,501)	(673)	(2,466)	(1,585)	-	(504)	(26,456)
Disposals	285	7,724	1,308	1,548	6,422	-	151	17,438
Transfers	(1,048)	(40)	(145)	(1,079)	-	-	1,780	(532)
31 December	**(6,533)**	**(77,279)**	**(4,226)**	**(12,771)**	**(7,058)**	**-**	**(3,272)**	**(111,139)**
Net book value	**116,370**	**65,477**	**4,355**	**7,404**	**4,181**	**4,978**	**1,069**	**203,834**

Property, plant and equipment include at 31 December 2011 vehicles, machinery and other assets totaling 2,095 thousand euro (2010: 3,184 thousand euro) being acquired under finance leases, as analyzed below:

	2011	2010
Capitalized finance lease cost	4,215	8,782
Accumulated depreciation	(2,120)	(5,598)
Carrying amount	**2,095**	**3,184**

Bank borrowings are secured by land and buildings valued at 68,802 thousand euro (2010: 68,765 thousand euro). The balance of secured debt amounts to 38,872 thousand euro (2010: 37,841 thousand euro).

At 31 December 2011, the Group has property, plant and equipment located abroad for a total cost of 54,979 thousand euro (2010: 39,963 thousand euro) and accumulated depreciation of 24,542 thousand euro (2010: 17,637 thousand euro).

At 31 December 2011 property, plant and equipment with an original cost of 40,584 thousand euro (2010: 44,055 thousand euro) and accumulated depreciation of 325 thousand euro (2010: 284 thousand euro) were not used in operations. Mainly corresponding to buildings that were acquired as payment in kind. During 2011 these buildings were impaired in a total amount of 3,256 thousand euro (2010: 1,800 thousand euro).

The income statement includes rental costs of 94,414 thousand euro (2010: 100,241 thousand euro), relating to rented property, plant and equipment.

The consolidated Group has taken out a number of insurance policies to cover risks relating to property, plant and equipment. The coverage provided by these policies is considered to be sufficient.

7 Goodwill and other intangible assets

7.1. Goodwill

Set out below is an analysis of goodwill, the only intangible asset with an indefinite useful life, showing movements:

	2011	2010
Beginning of the year	**487,114**	**486,192**
Additions	89,993	-
Differences on exchange	329	922
Impairment charges	-	-
End of the year	**577,436**	**487,114**

Additions in the current period are due to the incorporation of Grupo T-Solar into the consolidation scope (See note 32).

Goodwill and intangible assets with indefinite useful lives have been assigned to the Group's cash-generating units (CGUs) based on the country concerned and the business segment.

Set out below is a summary by CGU (or CGU group) of goodwill assignment:

CGU	2011	2010
Construction	154,578	154,578
Solar-Photovoltaic Energy (generation)	42,169	-
Solar-Photovoltaic Energy (Manufacturing)	47,824	-
Engineering – México	24,510	24,510
Engineering – Brazil	54,735	54,735
Engineering – Argentina and other	12,613	12,284
Engineering – Spain and other	231,166	231,166
Renewable energies	9,841	9,841
Total	**577,436**	**487,114**

The recoverable amount in CGUs is determined based upon value in use calculations from estimated cash flows net of the tax effect and based on financial budgets approved by Management for a 5-year period (6-year period in case of solar-photovoltaic energy manufacturing). This is not applicable to renewable energies and solar-photovoltaic energy (generation) businesses, in which cash flows are estimated for the full project life. Cash flows after these five years are extrapolated by using the estimated residual growth rates, as stated below. The growth rate does not exceed long-term average growth rates for the businesses in which the CGU operates. For cash flows discounting, a rate based upon the weighted average cost of capital is used for each CGU.

The most relevant key assumptions employed to calculate value-in-use are set out below:

	Operating result (*)		Residual growth rate		Discount rate	
CGU	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Construction	68,628	76,453	1%	1%	11.50%	10.30%
Solar energy (Generation)	42,209	-	(**)	-	7.8%	-
Solar energy (Manufacturing)	3,053	-	(**)	-	7.8%	-
Engineering – México	5,316	5,682	2%	2%	12.18%	13.00%
Engineering – Brazil	26,865	7,669	2%	2%	17.56%	14.00%
Engineering – Argentina and other	10,589	11,564	2%	2%	16.63%	18.00%
Engineering – Spain and other	110,834	122,550	1.7%	1.7%	12.33%	10.50%
Renewable energies	(19,840)	(5,886)	(**)	(**)	11.60%	12.00%

(*) Results included in operating result column refer to the forecast for the following year.
(**) Not applicable.

These assumptions have been used to analyze each CGU in the business segment. Group management considers that changes to assumptions that could cause a CGUs carrying amount to exceed its recoverable amount are not reasonably possible.

Management calculated the budgeted gross margin based on past performance and market expectations. Weighted average growth rates are in line with the forecasts contained in industry reports. Discount rates are before taxes and reflect specific risks related to the relevant business segments.

In 2011 and 2010, no impairment losses were identified.

7.2. **Other intangible assets**

A breakdown of movements for 2011 and 2010 is as follows:

2011	Contract portfolio	Administrative Concessions	Computer software and other	Total
Cost				
1 January	11,116	52,407	22,758	86,281
Additions	-	4	7,274	7,278
Disposals	-	(3,023)	(278)	(3,301)
Transfers	-	(38,205)	(852)	(39,057)
31 December	**11,116**	**11,183**	**28,902**	**51,201**
Accumulated depreciation				
1 January	(4,446)	(3,543)	(11,783)	(19,772)
Amortization	(2,223)	(171)	(4,937)	(7,331)
Disposals	-	31	181	212
Transfers	-	388	191	579
31 December	**(6,669)**	**(3,295)**	**(16,348)**	**(26,312)**
Net book value	**4,447**	**7,888**	**12,554**	**24,889**

2010	Contract portfolio	Administrative Concessions	Computer software and other	Total
Cost				
1 January	11,116	38,039	18,364	67,519
Additions	-	19,607	5,936	25,543
Disposals	-	-	(1,329)	(1,329)
Transfers	-	(5,239)	(213)	(5,452)
31 December	**11,116**	**52,407**	**22,758**	**86,281**
Accumulated depreciation				
1 January	(2,223)	(2,152)	(8,935)	(13,310)
Amortization	(2,223)	(1,166)	(4,031)	(7,420)
Disposals	-	-	1,168	1,168
Transfers	-	(225)	15	(210)
31 December	**(4,446)**	**(3,543)**	**(11,783)**	**(19,772)**
Net book value	**6,670**	**48,864**	**10,975**	**66,509**

At 31 December 2011, projects under this caption mainly correspond to the following concessions:

- Car park concessions located in Spain that at 31 December 2011 had not been assigned-to-projects finance yet.

- Other concessions related to public and environmental services.

The concession awarded in 2009 for the construction and maintenance of seven transmission lines 421-kilometers long and five new substations in Texas (United States) through the joint venture Wind Energy Transmission Texas L.L.C., included in Appendix III, has been transferred to the heading “Other non-current assets assigned to projects” since it has obtained the funding required to undertake the project.

At the year-end these concessions have not yet received of financing assigned to projects; once they obtain such financing, they will be considered as assets assigned to projects.

Administrative concessions include costs related to the construction and/or operation of various assets (car parks, water treatment and waste management plants, and other concessions) for which the Group has obtained the concession to operate the assets for a certain period. At the end of the concession period, the asset will entirely revert to the granting authority. The Group will depreciate capitalized asset over the concession term.

The item Computer software reflects the ownership and right of use of computer software acquired from third parties. The balance of computer software does not include amounts related to software developed in-house.

Bank borrowings are secured by other intangible assets valued at 5,127 thousand euro (2010: 11,577 thousand euro). The balance of secured debt amounts to 751 thousand euro (2010: 5,072 thousand euro).

8 Concessionary assets and other non-current assets assigned to proyects

The consolidation scope includes shareholdings in companies incorporated to engage in a single project. The project companies are usually financed by means of project finance.

The basis of the agreement between the company and the bank is the assignment of cash flows generated by the project to service the debt and interest (including an exclusion or quantified allowance for all other assets), in such a way that investment payback for the bank will take place solely through the project cash flows. Additional guarantees could be settled in some cases during construction phase. Any other borrowings are subordinated to the Project finance until it is fully repaid.

These are financing arrangements which are applied to specific business projects. Companies engaged in some projects, mainly electric transmission lines; solar-photovoltaic energy generation plants, bio-fuel plants and certain toll roads projects are carried out together with other shareholders. In the case of certain toll road and car park concessions, the Group is the only concession holder.

8.1. Concessionary assets assigned to projects

In view of the projects' characteristics a large part of the concessionary assets assigned to projects are related to intangible and financial concessionary assets (see accounting treatment in Notes 2.6, 2.7 and 2.23). This headline includes 707,263 thousand euro (2010: 615,629 thousand euro) relating to non-current assets in progress.

	2011	2010
Cost		
1 January	1,460,039	1,449,248
Additions to the consolidation scope	1,646	1,646
Additions	1,231,348	353,860
Translation differences effects	(142,620)	130,893
Disposals	(10,270)	(480,407)
Transfers	(10,857)	4,799
31 December	**2,529,286**	**1,460,039**
Accumulated depreciation		
1 January	(59,117)	(55,576)
Additions to the consolidation scope	(1,038)	-
Amortization	(35,338)	(39,505)
Translation differences effects	3,006	(2,871)
Disposals	55	37,395
Transfers	14,523	1,440
31 December	**(77,909)**	**(59,117)**
Net book value	**2,451,377**	**1,400,922**

At 31 December 2011, the Group has intangible assets assigned to projects abroad with a total carrying amount of 2,156,115 thousand euro (2010: 1,168,226 thousand euro).

During 2011, 50,040 thousand euro have been capitalized (2010: 52,075 thousand euro), relating to interest accrued during the construction of non-current assets arising on direct financing received to build the assets.

As described in note 2.7, the Group classifies its concession assets as intangible or financial. At 31 December 2011 the net carrying amount of these assets amounts to 1,710,208 thousand euro and 714,169 thousand euro, respectively.

Financial assets mainly include receivables related to transmission line concession arrangements in Brazil. In line with accounting practices and, in compliance with IFRIC 12 regarding this type of contracts, receivables are registered applying the financial asset model. Long-term receivables are recognized at their amortized cost. Interest rates applied (without considering inflation) range from 2% to 11%, depending on each transmission line. The financial remuneration effect in accounts receivable implied revenues amounting to 71,044 thousand euro.

The projects included in this caption relate basically to the following concessions:

- Concessions for electricity transmission lines in Brazil and India for more than 4,982 km and an approximated investment of 2,128 million euro for periods of approximately 30 years and 35 years, through joint ventures at 33.3% and 50% included in Appendix III, as well as through two subsidiaries at 100%, included in Appendix I. At 31 December 2011, the Group has 6 concessions, 3 of which are being operated, and other 3 are under construction or newly awarded. At 31 December 2010, the Group had 7 concessions, 4 of which were in operation, and other 3 were under construction or newly awarded.

  At December 2010, the Group sold the shareholding held over 8 concessions for electricity transmission lines which it operated in previous years (see note 24).

  In June 2011, the subsidiary Energia e Participações, S.A., sold its share in the joint ventures Porto Primavera Transmissora de Energia, S.A., Vila do Conde Transmissora de Energia, S.A. and Cachoeira Paulista Transmissora de Energia, S.A. As the sale consideration, the company acquired all the shares in Cachoeira Paulista Transmissora de Energia, S.A. by a single payment of 9,478 thousand euro, paid in July 2011 (see Notes 24 and 32).

- Car park concessions (mainly off-street car park concessions) in Spain for periods of up to 50 years, through subsidiaries and joint ventures included in Appendix I and III. At 31 December 2011, a part of the concessions are being operated, while the rest of them are under construction. Up to 19,964 places in 41 car parks are under operation, 1,188 places in 2 car parks are in construction and 1,627 places in 3 car parks are in the design phase. Up to 2015, 30,779 places are expected to be managed.

- Two toll road concessions in Mexico, through the subsidiary Concesionaria Autopista Monterrey-Saltillo, S.A. de C.V. and Autopista Perote-Xalapa, S.A. de C.V. At 31 December 2011, these concessions are in the following status:

  - Concesionaria Autopista Monterrey-Saltillo S.A.C.V.: Concession for the construction, operation and maintenance awarded in 2006 and up to 2036 (with an additional 15-year extension) for 95 km, with a total estimated investment of 226 million euro. The concession became partially operative during previous years, expanding those sections in operation. At the 2011 year end, the full concession is fully operative.

  - Concesionaria Autopista Perote-Xapala, S.A.C.V.: Concession for the construction, operation and maintenance achieved in 2008 to 2038 for 59.9 km, with a total estimated investment of 453 million euro approximately. Operating phase is forecasted along 2012.

  - The operation period of these concessions may be extended as described in note 8.3.

- Concession obtained in 2007 for improvement, expansion and maintenance of a 68-kilometer "shadow" toll road (Autovía A-4) through Concesionaria Autovía A-4 Madrid, S.A., included in Appendix I. Period of concession is until 2026. At 31 December 2011 the whole concession is operating. Total investment amounts approximately to 92-million euro.

- Concession for four toll roads in India:

  - Concession obtained in 2008 for 15 years to the extension, improvement, operation and maintenance of a 291-kilometer toll road in India (Panipat-Jalandar) through the subsidiary Soma-Isolux NH One Tollway Private Limited, included in Appendix I. Concession period is up to 2023. Construction works regarding extension and improvement of the existing infrastructure (operation and maintenance activities are carried on since the concession implementation) began in 2009 and the expected investment amounted to 739 million euro, approximately.

  - Concession obtained in 2009 for 19 years to the extension, improvement, operation and maintenance of a 133-kilometer toll road in India (Surat-Hazira) through the joint venture Soma Isolux Surat Hazira Tollway PVT, Ltd., included in Appendix III. Concession period is up to 2028. At 31 December 2011, construction works have begun and expected investment amounts approximately to 404 million euro. Operation is expected by 2012. Concession period may be modified based on traffic levels reached in 2018.

  - Concession obtained in 2009 for 18 years to the extension, improvement, operation and maintenance of a 94-kilometer toll road in India (Kishangarh-Aimer Beawar Highway) through the joint venture Soma Isolux Kishangarh-Ajmer-Beawar Tollway PVT, Ltd., included in Appendix III. Concession period is up to 2027. Construction works are star-

ted at 31 December 2011 and expected total investment amounts approximately to 201 million euro. Operation is expected by 2012. Concession period may be modified based on traffic levels reached in 2021.

- Concession obtained in 2009 for 25 years to the extension, improvement, operation and maintenance of 681-kilometer toll roads in Brazil through the subsidiary Viabahia Concessionaria de Rodovias, S.A., included in Appendix I. Concession period is up to 2035. At 31 December 2011 it is in operation and implementation works concerning toll systems have been performed simultaneously. Expected investment amounts to 710 million euro, approximately. The concession starts generating operating revenue since the beginning (Brownfield Project).

- Concession obtained in 2009 for 25 years to the extension, improvement, operation and maintenance of 681-kilometer toll roads in Brazil through the subsidiary Viabahia Concessionaria de Rodovias, S.A., included in Appendix I. Concession period is up to 2035. At 31 December 2011 it is in operation and implementation works concerning toll systems have been performed simultaneously. Expected investment amounts to 710 million euro, approximately. The concession starts generating operating revenue since the beginning (Brownfield Project).

- During 2011 the Group was awarded the concession contract Uttar Pradesh licensed by the Electricity Regulatory Commission for the construction, operation and maintenance of a 765kV and 1,600-kilometer electricity transmission line in India. The concession term is up to 35 years, tariffs are approved by the granting authority and they can be annually updated based on inflation up to a 5% annual rate. The Group holds a 74% share in this project, maturing in 15 years. The transmission line is expected to start operating on 1 January 2014.

- During the second-half of 2011, the Group was awarded the contract Taubuté-Nova Iguaçu for the construction, operation and maintenance of a 500kV and 247-kilometer electricity transmission line in Brazil. The concession term is up to 30 years.

Control of most concession assets reverts to the granting body at the end of the concession period although there is usually an option to renew concessions at the time they expire.

8.2. **Other non-current assets assigned to projects**

There are other non-current assets assigned to projects, whose detail is presented below:

	2011	2010
Cost		
1 January	273,678	287,787
Additions to the consolidation scope (Note 32)	1,236,308	-
Additions	160,349	3,229
Translation differences effects	(5,751)	2,189
Disposals	(6,909)	(19,840)
Transfers	10,953	313
31 December	**1,668,628**	**273,678**
Accumulated depreciation		
1 January	(21,477)	(9,239)
Additions to the consolidation scope (Note 32)	(110,841)	-
Amortization	(50,188)	(11,511)
Translation differences effects	230	(45)
Disposals	4,000	16
Transfers	(1,751)	(698)
31 December	**(180,027)**	**(21,477)**
Net book value	**1,488,601**	**252,201**

Additions include other non-current elements assigned to projects corresponding to Grupo T-Solar assets (see note 32). The new elements incorporated correspond mainly to:

- Lands, plants and machinery required for photovoltaic module manufacturing in the subsidiary's plant T-Solar Global, S.A. in Orense (Galicia).

- Plant required to generate electric energy under the special system rule through the various solar photovoltaic plants owned by various subsidiaries.

During the year, financial expenses amounting to 540 thousand euro were capitalized (2010: no expense capitalization).

At 31 December 2011, 204,050 thousand euro (2010: 214,929 thousand euro) belonging to two bio-fuel plants (Located in Ferrol and Castellón) and managed through Infinita Renovables are recognized under this caption. Operations in these plants took place during 2009.

Assets relating to construction and maintenance of seven 421-kilometer transmission lines and five new substations in Texas (United States) undertaken through the joint venture Wind Energy Transmission Texas L.L.C. (appendix III) are included under this caption. The concession period is unlimited. At 31 December 2011 work was at the initial development phase and the expected total investment amounts approximately to 464 million euro. For accounting purposes, this contract has been considered as outside the scope of the standards applicable to concession assets (IFRIC 12).

The balance under this headline also includes assets assigned to projects located abroad with a carrying amount of 74,650 thousand euro (2010: 10,453 thousand euro).

At 31 December 2011 this heading registers non-current assets in progress amounting to 34,866 thousand euro (2010: there were no elements in progress).

8.3. **Project finance**

The repayment schedule for project finance is set out below, based on project cash flow forecasts and as stipulated in the relevant contracts:

2011		Non-current					
	Current	**2013**	**2014**	**2015**	**Subsequent**	**Subtotal**	**Total**
Maturities per year	358,342	113,673	139,576	156,530	1,848,044	2,257,823	2,616,165

2010		Non-current					
	Current	**2012**	**2013**	**2014**	**Subsequent**	**Subtotal**	**Total**
Maturities per year	222,480	49,546	51,142	72,247	839,595	1,012,530	1,235,010

The Group's current liabilities include "bridge loans" associated with the infrastructure construction phase, which amount approximately to 235 million euro; they are expected to be converted to long-term financing once the operation period starts.

At 31 December 2011 there are debts totaling 1,415,467 thousand euro (2010: 835,482 thousand euro) denominated in foreign currencies (mainly Brazilian Real, Indian Rupees and Mexican Pesos).

During 2010 the Sociedad Concesionaria Autopista Monterrey-Saltillo, S.A. de C.V. subscribed to a convertible subordinated loan amounting to 1,040,000 thousand Mexican Pesos (57,632 thousand euro at 31 December 2011 exchange rate) with Banco Nacional de Obras y Servicios Públicos, Sociedad Nacional de Crédito. This entity acts as a trust fund in the "National Infrastructure Fund" (FONADIN), whose objectives are the funding of construction activities in Libramiento Norponiente de Saltillo and the restoration of concessionaire's economic balance. The loan is divided into two tranches: the first one maturing at the ending date of the original concession term, expected in 2039; and the second one, expiring 15 years after the first tranch maturity date. This loan will be repaid annually based on a differential income in respect to the base case. After 28 years from the beginning of the concession, balances could be capitalized based on contractual terms. The loan accrues an annual interest rate of 8.5% (in current terms).

On July 13, 2011 Sociedad Concesionaria Autopista Perote Xalapa, S.A. de C.V. subscribed to a convertible subordinated loan amounting to 2,857,000 thousand Mexican pesos (158,322 thousand euro at 31 December 2011 exchange rate) with Banco Nacional de Obras y Servicios Públicos, Sociedad Nacional de Crédito. This entity acts as a trust fund en the "National Infrastructure Fund" (FONADIN), whose objectives are the funding of costs generated in the expansion phase and the coverage of expenses due to the delay in the operational phase. The first credit disposal will be allocated to payment of commissions, while the second and later disposals will fund costs and expenses arising from the expansion phase and due to delays in the operational phase. This loan will be repaid annually through the 80% of the net exceeding cash flows compared to the base case. After 34 years from the beginning of the concession, outstanding balances could be capitalized based on contractual terms. The loan accrues an annual interest rate of 8.5% (in current terms).

On November 11, 2011 Cachoeira Paulista Transmissora de Energia, S.A. issued bonds periodically maturing up to 11 November 2023. The maximum annual rate accrued by such bonds amounts to 8.4%. The instrument is registered in the CVM and ANBIMA, in Brazil.

Project finance can be guaranteed through the promoter company's shares granted by its partners, the transfer of collection rights or limitations on the Project assets disposal. However, mainly during the construction and implementation phases, additional guarantees may exist.

Every funding is referenced to different market rates and these are revised over periods not exceeding 6 months. As a result, fair value of both current and non-current funding amounts approximate to their carrying amounts.

9 Investments in associates

Set out below is an analysis of investments in associates showing movements:

	31/12/2011	**31/12/2010**
Opening balance 1.01.11	**178,996**	**57,059**
Additions	-	-
Disposals	(128,875)	-
Transfers	-	128,875
Profit/(loss) of equity method	(15,787)	(7,072)
Profit/(loss) of equity method – Responsibility provision	300	134
Closing balance 31.12.11	**34,634**	**178,996**

Disposals during 2011 correspond to the acquisition of the investment in Grupo T-Solar Global, S.A. business combination which, due to movements detailed in note 32, resulted in gaining contro, so that it is now considered as a Group company.

Transfers recorded in 2010 related to investment transfer in Grupo T-Solar Global, S.A. (see note 10). Although investment in this company at 31 December 2010 amounted to 19.80%, it was considered as an associate due to the existence of several factors indicating the Group's significant influence (options on receivables capitalization (see note 12), the Group's executives acting as directors in Grupo T-Solar Global, S.A., agreements with other shareholders to company's shares acquisition, and the Group's intention to gain control over the company.

The Group's interests in its joint ventures consolidated through the Equity method, all of which are unlisted, are analyzed below:

2011

Name	**Country of incorporation**	**Assets**	**Liabilities**	**Revenue**	**Results**	**% on Interest**
Alqlunia 5, S.L.	Spain	20,022	22,809	30	(599)	50.00%
Pinares del Sur, S.L.	Spain	44,709	52,290	8,702	(1,463)	50.00%
Las Cabezadas Aranjuez, S.L.	Spain	54,005	57,029	3	(134)	40.00%
Landscape Corsan , S.L.	Spain	275	52	-	-	50.00%

2010

Name	**Country of incorporation**	**Assets**	**Liabilities**	**Revenue**	**Results**	**% on Interest**
Alqlunia 5, S.L.	Spain	20,016	22,204	89	(2,704)	50.00%
Pinares del Sur, S.L.	Spain	39,786	33,993	5,564	(541)	50.00%
Las Cabezadas Aranjuez, S.L.	Spain	54,259	57,110	541	(1,164)	40.00%
Landscape Corsan , S.L.	Spain	275	52	2	(2)	50.00%

The Group's interests in its principal associates, all of which are unlisted, are analyzed below:

2011

Name	Country of incorporation	Assets	Liabilities	Revenue	Results	% on Interest
Autopista Madrid-Toledo, S.A.	Spain	15,368	31,648	7,141	(18,233)	25.50%
Gestión de Participes de Biorreciclajes, S.L.	Spain	283	307	-	-	33.33%
Proyectos Inmobiliarios Residenciales, S.L.	Spain	7,122	9,965	-	-	23.75%

2010

Name	Country of incorporation	Assets	Liabilities	Revenue	Results	% on Interest
Autopista Madrid-Toledo, S.A.	Spain	498,396	420,612	11,821	(5.636)	25.50%
Grupo T-Solar Global, S.A.	Spain	1,281,982	1,120,418	115,285	(116,753)	19.80%
Gestión de Partícipes de Biorreciclajes, S.L.	Spain	283	307	-	-	33.33%
Proyectos Inmobiliarios Residenciales, S.L.	Spain	7,122	9,965	-	-	23.75%

In order to measure its shareholdings, the Group has adjusted the above-mentioned figures in accordance with the accounting policies described in Note 2.

10 Financial Investments

Set out below is an analysis of financial investments assets showing movements:

	2011	2010
Opening balance	**11,512**	**143,006**
Additions	3,035	1,294
Disposals	(1,873)	(55)
Transfers	119	(128,875)
Impairment losses (Note 27)	(1,837)	(3,858)
Closing balance	**10,956**	**11,512**
Less non-current portion	**(10,956)**	**(11,512)**
Current portion	-	-

For measurement purposes, financial investments are classified as available-for-sale financial assets (See Note 2.10).

During 2011 the Group agreed an exchange with Caja Castilla La Mancha Corporación, S.A. whereby the Group gives its share in "Synergy Industry and Technology, S.A." and receives shares representing 4.75% of Grupo T-Solar Global, S.A. share capital as a consideration. This transaction impacted the Group's income statement, generating profits of 17,365 thousand euro (see note 27).

Transfers during 2010 corresponded to the transfer of investment in Grupo T-Solar Global, S.A. (See note 9).

The rest of the financial investments relate entirely to non-controlling interest investments in unlisted companies in which the Group does not have significant influence. As these are residual investments in companies with no significant size within the Group, and given the impossibility of applying measurement methods to the investments, they are presented at acquisition cost, net of impairment disclosed in the financial information of the respective companies. This caption does not include investments in debt instruments.

Financial investments are all denominated in euro. Maximum exposure to credit risk at the reporting date is the carrying amount of the assets classified as financial investments.

Financial instrument balances under this caption are classified in Group 3 for the purpose of information sources used to determine its fair value in compliance with IFRS 7 (See Note 2.10).

11 Derivative financial instruments

Derivative financial instruments are analyzed below at 31 December 2011 and 2010:

	2011		2010	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Interest rate swaps-cash flow Hedges	-	(191,308)	3,789	(47,337)
Interest rate swaps-held for Trading	1,146	-	1	-
Currency forward contracts-cash flow Hedges	6,210	(7,451)	2,803	(12,633)
Currency forward contracts- held for Trading	-	-	2,404	(236)
Total	**7,356**	**(198,759)**	**8,997**	**(60,206)**
Less non-current portion:				
Interest rate swaps –cash flow Hedges	-	(174,304)	3,789	(47,337)
Interest rate swaps –held for Trading	1,146	-	-	-
Currency forward contracts – cash flow hedges	9	(55)	498	(310)
Currency forward contracts – held for Trading	-	-	-	-
	1,155	**(174,359)**	**4,287**	**(47,647)**
Current portion	**6,201**	**(24,400)**	**4,710**	**(12,559)**

Derivatives held for trading are classified as current assets or liabilities. The total fair value of a hedging derivative is classified as a non-current asset or liability if the period to maturity of the hedged item is more than 12 months and as a current asset or liability if the period to maturity of the hedged item is less than 12 months.

The ineffective net portion of cash flow and fair value hedges recognized as revenue in the income statement totals 1,460 thousand euro (2010: 601 thousand euro) (see Note 27).

The maximum credit risk exposure at the reporting date is the fair value of the derivative financial instruments carried in the balance sheet.

Financial instrument balances under this caption are classified in Group 2 for the purpose of information sources used to determine its fair value in compliance with IFRS 7 (See Note 2.10).

Foreign currency forward contracts

The notional principal of currency forward sale contracts, relating mainly to the sale of US dollars and purchase of euro (net of US dollars purchased against euro) outstanding at 31 December 2011 was 36,635 thousand USD (2010: 7,498 thousand USD).

It is expected that high likely future transactions hedged, denominated in foreign currency, take place on different dates, mainly within the next 12 months. Profit and loss recognized in the hedging reserve in equity with respect to foreign currency forwards at 31 December 2011 are recognized in the period or periods during which the hedged transaction affects the income statement. This normally takes place within 12 months of the balance sheet date unless the gain or loss had been included in the initial purchase value of fixed assets, in which case such recognition occurs during asset's life (between five and ten years).

Main currency forward contracts characteristics at 31 December 2011 are shown below:

Project name or associate	Transaction	Currency (**)	Final maturity	Notional value (*)
Forward Isolux Ingeniería	Purchase	CHF	25/01/2012	309
Forward Isolux Ingeniería	Sale	QAR	25/01/2012	(99,597)
Forward Isolux Ingeniería	Purchase	USD	31/05/2013	14,426
Forward Isolux Ingeniería	Sale	USD	31/12/2015	(10,317)
Forward Isolux Ingeniería	Sale	MXN	31/01/2012	(9,837)
Forward Isolux Ingeniería	Purchase	USD	31/08/2012	68,086
Forward Isolux Ingeniería	Sale	USD	31/01/2012	(27,672)
Forward Isolux Ingeniería	Purchase	USD	30/11/2012	118
Forward Isolux Ingeniería	Sale	USD	31/12/2012	(88)
Forward Isolux Ingeniería	Purchase	BRL	25/04/2012	23,581
Forward Isolux Inegniería	Sale	BRL	25/10/2012	(10,461)
Forward Isolux Ingeniería	Sale	BRL	26/02/2013	(40,948)
Forward Isolux Ingeniería/Tecna	Purchase	USD	09/01/2012	5,805
Forward Isolux Ingeniería/Tecna	Sale	USD	31/01/2012	(6,016)
Forward Isolux Ingeniería/Tecna	Purchase	USD	30/08/2012	25,819
Forward Isolux Ingeniería/Tecna	Sale	USD	31/07/2012	(33,526)

(*) Effective at 31 December 2011
(**) USD: US Dollar; QAR: Qatari Real; CHF: Swiss Franc; MXN: Mexican Peso; BRL: Brazilian Real

Main currency forward contracts characteristics at 31 December 2010 are shown below:

Project name or associate	Transaction	Currency (**)	Final maturity	Notional value (*)
Forward Isolux Ingeniería	Purchase	CHF	11/01/2011	309
Forward Isolux Ingeniería	Sale	QAR	17/02/2011	(113,597)
Forward Isolux Ingeniería	Purchase	USD	31/08/2012	71,347
Forward Isolux Ingeniería	Sale	USD	30/09/2011	(72,072)
Forward Isolux Ingeniería	Sale	MXN	19/01/2011	(9,837)
Forward Isolux Ingeniería	Purchase	USD	29/04/2011	41,625
Forward Isolux Ingeniería	Sale	USD	18/01/2011	(12,421)
Forward Isolux Ingeniería/Tecna	Purchase	USD	30/03/2012	12,380
Forward Isolux Ingeniería/Tecna	Sale	USD	30/04/2012	(53,385)
Forward Isolux México	Purchase	USD	12/01/2011	13,235
Forward Isolux México	Sale	USD	14/01/2011	(9,498)
Forward Isolux Ingeniería/Tecna	Purchase	USD	10/01/2011	7,307
Forward Isolux Ingeniería/Tecna	Sale	USD	18/01/2011	(6,016)

(*) Effective at 31 December 2010
(**) USD: US Dollar; QAR: Qatari Real; CHF: Swiss Franc; MXN: Mexican Peso

Although all the contracts in force at 31 December 2011 and 2010 were obtained for hedging purposes, due to the Group's contracting and designation criteria applicable at the contract dates, some of the contracts did not qualify for hedge accounting under IFRS-EU.

Profits and losses recorded in the hedging reserve within the Equity (net of tax effect and external partners) resulting from cash flow hedge at 31 December 2011 amount to (852) thousand euro (2010: (9,645) thousand euro) and will be transferred to the income statement on an ongoing basis until the contract is settled. These derivatives did not generate settlements in the year (2010: 135 thousand euro).

Interest rate swaps

The notional principal of interest rate swaps outstanding at 31 December 2011 amounted to 1,752,546 thousand euro (2010: 1,352,370 thousand euro).

At 31 December 2011, fixed interest rates ranged between 1.80% and 5.05% (2010: 1.80% and 4.82%) for those operations in which interest rate is variable. The variable interest rate is the EURIBOR. In the case of the derivative linked to the TIIE rate (variable rate used for two projects in Mexico), the contracted fixed interest rate range between 5.02% and 8.20% (2010: 8.20%), whereas in operations with LIBOR (variable rate used for Wind Energy Texas companies) as the collected variable interest rate, fixed interest rates range between 1.96% and 3.60% (2010: without transactions).

At 31 December 2011 profit and loss from interest rate swaps registered in equity through a hedging reserve (net of the tax effect and non-controlling interests) amounts to (59,889) thousand euro (2010: (26,671) thousand euro). They will be transferred to the income statement until bank loans are paid off. Settlement of these derivatives generated a loss of 20,897 thousand euro (2010: 21,815 thousand euro).

Although all the contracts in force at 31 December 2011 and 2010 were obtained for hedging purposes, due to the Group's contracting and designation criteria applicable at the contract dates, some of the contracts did not qualify for hedge accounting under IFRS-EU.

Set out below is an analysis of the main interest rate swaps in force at 31 December 2011:

Name	Contract date	Final maturity	Notional value	Fixed interest rate (paid)	Variable interest rate (charged)
Grupo Isolux Corsán	11/09/2009	03/06/2013	50,000 thousand euro	2.66%	Euribor
Grupo Isolux Corsán	23/06/2009	23/06/2012	20,000 thousand euro	2.44%	Euribor
Grupo Isolux Corsán	24/02/2009	24/02/2012	20,000 thousand euro	2.47%	Euribor
Grupo Isolux Corsán	22/06/2009	18/06/2013	85,000 thousand euro	1.80%	Euribor
Grupo Isolux Corsán	10/09/2010	29/06/2015	532,000 thousand euro	2.02%	Euribor
Grupo Isolux Corsán	28/04/2010	03/06/2013	50,000 thousand euro	1.97%	Euribor
Grupo Isolux Corsán	16/05/2011	16/05/2015	45,000 thousand euro	3.05%	Euribor
Grupo Isolux Corsán	28/06/2011	28/06/2014	57,517 thousand euro	2.20%	Euribor
Cova da Serpe II loan	23/01/2012	21/07/2025	13,718 thousand euro	3.60%	Euribor
Infinita Renovables' loan	05/01/2010	30/12/2016	167,368 thousand euro	3.79%	Euribor
Hixam's loan	07/02/2007	29/12/2022	61,395 thousand euro	4.36%	Euribor
Concesionaria Saltillo Monterrey's loan	28/09/2007	30/05/2025	2,314,546 thousand mexican pesos	8.20%	TIIE (*)
Sociedad Concesionaría Autovía A-4's loan	01/08/2008	15/06/2025	57,592 thousand euro	5.05%	Euribor
Concesionaria Perote-Xalapa's loan	18/08/2011	14/12/2012	475,000 thousand mexican pesos	5.02%	TIIE(*)
Concesionaria Perote-Xalapa's loan	13/02/2008	14/01/2022	1,895,320 thousand mexican pesos	8.20%	TIIE(*)
HIXAM II's loan	13/01/2010	23/12/2025	29,735 thousand euro	3.60%	Euribor
Sociedad Concesionaria Zona 8-A's loan	25/02/2008	25/02/2024	7,140 thousand euro	4,79%	Euribor
Wind Energy Trans Texas Hold's loan	29/07/2011	31/03/2016	1,899 thousand dollar	1.96%	Libor
Wind Energy Trans. Texas's loan	29/07/2011	31/03/2016	27,157 thousand dollar	3.60%	Libor
Syndicated loan from NCG (**)	22/12/2008	31/12/2026	40,557 thousand euro	3.96%	Euribor
BBVA's syndicated loan (**)	15/07/2008	31/12/2027	462,724 thousand euro	5.09%	Euribor
La Caixa's loan (**)	18/06/2009	18/06/2021	11,098 thousand euro	4.09%	Euribor
Santander's loan (**)	04/01/2009	04/12/2023	6,572 thousand euro	4.00%	Euribor
Banesto's syndicated loan (**)	31/12/2010	20/12/2023	10,673 thousand euro	3.45%	Euribor
Bankia's loan (**)	18/03/2010	23/04/2026	2,090 thousand euro	3.65%	Euribor
Banesto's syndicated loan (**)	22/12/2010	20/12/2023	22,367 thousand euro	3.54%	Euribor

(*) Mexican long-term reference interest rate
(**) Corresponding to Grupo T- Solar Global

Set out below is an analysis of the main interest rate swaps in force at 31 December 2010:

Name	Contract date	Final maturity	Notional value	Fixed interest rate (paid)	Variable interest rate (charged)
Grupo Isolux Corsán	11/09/2009	03/06/2012	50,000 thousand euro	2.66%	Euribor
Grupo Isolux Corsán	23/06/2009	23/06/2012	20,000 thousand euro	2.44%	Euribor
Grupo Isolux Corsán	24/02/2009	24/02/2012	20,000 thousand euro	2.47%	Euribor
Grupo Isolux Corsán	22/06/2009	18/06/2013	85,000 thousand euro	1.80%	Euribor
Grupo Isolux Corsán	10/09/2010	29/06/2015	532,000 thousand euro	2.03%	Euribor
IC Concesiones' loan	28/04/2010	03/06/2013	50,000 thousand euro	1.97%	Euribor
Infinita Renovables' loan	30/04/2007	30/12/2016	181,800 thousand euro	3.79%	Euribor
Hixam's loan	07/02/2007	29/12/2022	63,273 thousand euro	4.36%	Euribor
Concesionaria Saltillo Monterrey's loan	30/05/2007	30/05/2025	2,330,080 thousand mexican peso	8.20%	TIIE (*)
Sociedad Concesionaría Autovía A-4's loan	01/08/2008	15/06/2025	58,165 thousand euro	4.45%	Euribor
Concesionaria Perote-Xalapa's loan	13/02/2008	14/01/2022	1,900,000 thousand mexican peso	8.20%	TIIE (*)
HIXAM II's loan	13/01/2010	23/12/2025	30,466 thousand euro	3.00%	Euribor
Sociedad Concesionaria Zona 8-A's loan	26/07/2007	25/02/2024	7,607 thousand euro	4.82%	Euribor

(*) Mexican long-term reference interest rate

Cross Currency SWAP

The Brazilian subsidiary company Viabahia Concesionaria de Rodovias S.A. reflects a " Cross Currency Swap" related to debt balances in US dollars (8,216 thousands of Euros), to convert the fixed interest rate to a variable interest rate, and to set the exchange rate between Brazilian reals to US dollars at its maturity date (June, 2013).

Shares call and put.

An agreement was signed during October of 2011 whereby a loan granted by Corpfin Capital Advisors, S.A. and other funds to Grupo T-Solar Global, S.A. (GTSG), which was convertible into GTSG shares, was cancelled. To cancel the loan, 10.8 million euro were paid in cash, along with shares of Grupo T-Solar Global equivalent to 11.66% of the capital of that Company.

Likewise, an agreement was signed between Grupo Isolux Corsán, S.A. and Corpfin Capital Advisors, S.A. and other funds, whereby GTSG shares received by these Companies are subject to a put option and call option by which the Group would have the obligation (under the put option) or on the contrary would have the right (under the call option) to acquire such shares under certain conditions (which defer between both options). The options are exercisable between April 30 and May 31, 2016 for the put option, even though there are situations related to liquidity events that could lead to an early exercise, and between 1 January 2014 and 28 February 2016 in the case of the call option, at an agreed price of 75.6 million euros (which can vary according to the date of exercise and other conditions).

These options have been valued at fair value at December 31, 2011

12 Trade and other receivables

Set out below is an analysis of trade and other receivables:

	31/12/2011	31/12/2010
Non-current		
Loans to companies consolidated under the Equity Method	28,096	24,385
Trade receivables for sales and services	39,586	39,466
Other receivables	57,077	5,242
	124,759	**69,093**
Current		
Trade receivables for sales and services	667,550	826,336
Trade receivables-Work completed pending certification	661,979	592,212
Less: Provision for impairment of receivables	(15,806)	(15,178)
Trade receivables – Net	1,313,723	1,403,370
Trade receivables from companies consolidated under the Equity Method	1,300	21,492
Loans to companies consolidated under the Equity Method	6,472	55,258
Sundry debtors	93,648	102,601
Public entities	210,965	160,777
In advance-payments to suppliers	154,275	144,360
Other receivables	106,548	54,017
	1,886,931	**1,941,875**

In addition to these accounts receivable, note 8.1 includes receivables relating to electricity transmission line concessions classified as financial models and amounting to 741,169 thousand euro.

"Trade receivables for sales and services" includes 26,486 thousand euro corresponding to short-term receivables under the financial asset model concession (see note 8.1).

There is no significant effect on the fair values of trade and other receivables due to its recognition at amortized cost, since nominal values are deemed to approximate fair values.

At 31 December 2011, the sum of 197,412 thousand euro (2010: 45,780 thousand euro) has been deducted, relating to German method contract loans and other invoices assigned to third parties prior to maturity. These assets have been derecognized from the balance sheet since it is considered that they meet the requirements stipulated in IAS 39 regarding de-recognition of financial assets.

At 31 December 2011 "Trade receivables for sales and services" caption includes bills discounted at banks for a total of 79,720 thousand euro (2010: 59,233 thousand euro).

The Group has recognized a loss of 5,599 thousand euro (2010: 15,692 thousand euro) due to the impairment of trade receivables during the fiscal year ended 31 December 2011.

Movements in the provision for impairment of trade receivables are as follows:

	2011	2010
Opening balance	**15,178**	**10,645**
Appropriations	5,599	15,692
Applications	(4,970)	(6,288)
Reversals	-	-
Transfers	(1)	(4,871)
Closing balance	**15,806**	**15,178**

The remaining accounts included in receivables contain no assets that are impaired.

The maximum exposure to credit risk at the reporting date is the fair value of each category of receivables referred to above. It is not Group policy to contract insurance for receivables hedging.

The balance of trade receivables for sales and services includes the following amounts denominated in currencies other than the euro:

	2011	2010
US dollar	60,150	87,691
Qatar riyal	14,750	9,747
Brazilian real	40,698	4,820
Moroccan dirham	1,132	948
Argentinean peso	45,786	72,761
Mexican peso	8,806	877
Algerian dinar	8,615	5,093
Indian Rupee	9,651	-
Other currencies	6,030	1,499
	195,618	**183,436**

Costs incurred and gains recognized (less recognized losses) on all contracts in force at the balance sheet date amounted to 3,977 million euro (2010: 5,293 million euro) and 270 million euro (2010: 403 million euro), respectively.

13 Inventories

A breakdown of inventories is set out in the following table:

	31/12/2011	31/12/2010
Real Estate developments in progress	211,457	229,931
Raw materials and finished products	73,687	113,499
Capitalized project costs	72,581	84,430
	357,725	**427,860**

Set out below is a breakdown of property developments in progress by cycle:

	31/12/2011	31/12/2010
Real Estate developments in progress, short cycle	51,651	65,745
Real Estate developments in progress, long cycle	159,806	164,186
	211,457	**229,931**

At 31 December 2011 and 2010 there are no commitments to sell real estate developments in progress. In this respect, the Group has received advance payments amounting to 16 thousand euro (2010: 33 thousand euro) which are reflected on the liabilities side of the consolidated balance sheet in the item “Advanced receivables”.

During 2011, capitalized interest amounted to 679 thousand euro (2010: 362 thousand euro), relating to interest accrued during the construction of developments and arising on direct financing received to build the properties.

At 31 December 2011 real estate development guarantying funding received amounts to 39,422 thousand euro (2010: 36,798 thousand euro).

During 2011, an impairment amounting 4,785 thousand euro (2010: 3,840 thousand euro) on real estate has been recorded based on the income statement.

14 Cash and cash equivalents and financial assets at fair value through profit or loss

14.1. Cash and cash equivalents

Set out below is a breakdown of cash and cash equivalents:

	31/12/2011	31/12/2010
Cash at bank and in hand	492,156	427,880
Short-term bank deposits and other	182,210	509,675
	674,366	**937,555**

This caption includes cash (cash in hand and demand deposits in banks) and cash equivalents (i.e., short-term highly liquid investments easily convertible into specific cash amounts within a maximum of three months, or with no restriction and no availability penalty if higher, and whose value is not subject to significant change risks).

Of the total figure for cash and cash equivalents, temporary joint ventures contributed 111,026 thousand euro (2010: 179,368 thousand euro) and joint ventures contributed 23,057 thousand euro (2010: 33,395 thousand euro).

Cash and cash equivalents include balances in currencies other than euro totaling 395,805 thousand euro (2010: 612,134 thousand euro).

For the purposes of the cash flow statement, the treasury balance includes the balance in the caption cash and cash equivalents.

At 2011 year end, 7,200 thousand euro (2010: 12,920 thousand euro) are recognized under “Cash in hand and banks”, whose availability is restricted to the requirements of the loan received as funding for Hixam II project.

There are balances which are recorded under the caption cash at bank and in hand that are to hedge the service of the debt, which amounts to 5,727 thousand euro.

During the year 2011, the main transactions that did not generate cash flows are the following:

- Capitalization of part of the concession awarded for the toll road in India (Varanasi), amounting to 106,671 thousand euro (See note 8.1).

- Capitalization of part of the concession awarded for the toll road in Brazil (Viabahia), amounting to 244,652 thousand euro (See note 8.1).

- Synergy Industry and Technology, S.A. shares exchange for shares of Grupo T-Solar Global through an assets disposal of 1,873 thousand euro and an assets addition of 19,238 thousand euro (See note 10).

An amount of 14,836 thousand euro related to the partial capitalization of a toll road in India (Panipat-Jalandar), did not affect cash flows during 2011.

14.2. Financial assets at fair value through profit or loss

Set out below is a breakdown of financial assets at fair value through profit or loss:

	31/12/2011	31/12/2010
Short -term bank deposits and others	14,447	2,300
	14,447	**2,300**

At the year end this caption mainly includes listed financial entities’ shares, which are considered as immediately available since they are listed in a continuous and regulated market.

15 Share capital, share premium and legal reserve

a) Share capital

The parent company’s share capital consists of 87,316,199 ordinary bearer shares (2010: 87,316,199 shares) with a par value of 0.20 euro each (2010: 0.20 euro). The shares are fully paid up in a total amount of 17,463 thousand euro (2010: 17,463 thousand euro). There are no restrictions on the transfer of the shares.

The following companies hold interests in the parent company’s share capital:

	2011		2010	
	No. of shares	% interest	No. of shares	% interest
Construction Investment Sarl	46,864,562	53.67%	46,864,562	53.67%
Caja Castilla La Mancha Corporación, S.A.	10,573,339	12.11%	10,573,339	12.11%
Grupo Corporativo Empresarial de la Caja de Ahorros y Monte de Piedad de Navarra, S.A.U.	5,334,367	6.11%	5,334,367	6.11%
Corporación Empresarial Cajasol, S.A.U.	13,629,406	15.61%	13,629,406	15.61%
Cartera Perseidas, S.L.	8,731,620	10.00%	8,731,620	10.00%
Charanne B.V.	2,182,905	2.50%	2,182,905	2.50%
Total	**87,316,199**	**100.00%**	**87,316,199**	**100.00%**

b) Share premium account

This reserve is unrestricted and stands at 468,413 thousand euro (2010: 469,163 thousand euro).

c) Legal reserve

Appropriations to the legal reserve are made in compliance with Article 274 of the Spanish Capital Companies Act, which stipulates that 10% of the profits for each year must be transferred to this reserve until it represents at least 20% of share capital. At 31 December 2011 and 2010 this reserve amounts to 3,493 thousand euro and is fully incorporated.

The legal reserve is not available for distribution. If it is used to offset losses in the event of no other reserves being available, it must be replenished out of future profits.

In addition, this reserve includes the reserve resulting from the application in the parent company of Article 273.4 of the Spanish Capital Companies Act 2010: “In any event, a restricted reserve equivalent to the goodwill appearing on the asset side of the balance sheet must be allocated and a portion of profits representing at least 5% of that goodwill must be allocated to this reserve. If there were no profits or profits were insufficient, freely available reserves should be used”. This reserve amounts to 7,071 thousand euro (2010: 4,714 thousand euro) at 31 December 2011.

16 Cumulative translation differences

A breakdown by company/subgroup of cumulative translation differences is set out below:

Company or subgroup	2011	2010
Isolux de México S.A. de CV	(2,131)	(545)
Grupo Isolux Energía y Participaciones Ltda.	(13,495)	26,345
Isolux Proyectos, Ltda.	502	1,156
Powertec Proyectos, Ltda.	737	761
Isowat Mozambique, S.A.	1,543	1,452
Isolux Brasil Sociedade Anonima	1,070	(813)
Isolux Corsán Polonia, Sp Zoo	(304)	(214)
Concesionaria Autopista Saltillo-Monterrey, S.A. de C.V.	(2,439)	3,701
Grupo Tecna	(3,043)	(3,676)
Líneas Mesopotámicas Argentinas, S.A.	(30)	(10)
Concesionaria Autopista Perote-Xalapa, S.A.	(6,409)	601
Azul de Cortes, S.A. De C.V.	4,282	6,613
Soma-Isolux NH One Tollway Pvt Ltda.	(3,258)	5,983
Soma-Isolux Surat Hazira Tollway Pvt Ltd.	(637)	1,036
Soma-Isolux Kishangarh - Ajmer - Beawar Tollway Pvt. Ltd.	(747)	1,063
Isolux Corsán Argentina, S.A.	(77)	(57)
Agua Limpia Paulista, S.A.	967	183
Isolux Corsán India PVT	(1,155)	(437)
ICI & Soma Enterprise	(1,423)	(525)
Viabahía Concessionaria de Rodovias, S.A.	(95)	3,099
Corsán Corvián Construcción, S.A. - Sucursales	(1,274)	478
Isolux Ingeniería, S.A.- Sucursales	(8,066)	(6,645)
Iccenlux, Corp.	1,322	-
Isolux Mozambique LDA.	1,543	-
Isolux Corsán Concesiones Chipre	3,747	-
Other	(1,392)	(1,430)
Total	**(30,262)**	**38,119**

17 Retained earnings and non-controlling interest

The proposal for the distribution of the parent company's 2011 results that will be submitted to the Annual General Meeting and the approved (on 30 June 2011) 2010 distribution are set out below:

Available for distribution	2011	2010
Profit for the year	13,669	52,096
Distribution		
Voluntary reserves	1,312	20,489
Reserve for unavailable goodwill (Spanish Capital Companies Act 2010, article 273.4)	2,357	2,357
Freely available reserve (Share premium)	-	(750)
Dividends	10,000	30,000
	13,669	**52,096**

Movements in non-controlling interests during 2011 are set out below:

	Opening balance	Share of profit/ losses	Dividends	Change in shareholding and others	Closing balance
Grupo Tecna	9,825	(2,424)	-	119	7,520
Interisolux Torrejón Viv. Joven, S.L.	12	-	-	-	12
Julitex, S.L.	(97)	(134)	-	(2)	(233)
Interisolux Alcorcón Viv. Joven, S.L.	300	(52)	-	179	427
Agua Limpia Paulista, S.A.	240	961	-	692	1,893
Viabahía Concessionaria de Rodovías, S.A.	20,883	2,029	-	(1,714)	21,198
Grupo Infinita Renovables	527	(5,736)	-	372	(4,837)
Grupo T-Solar Global, S.A.	-	(12,146)	-	245,409	233,263
Mainpuri Power Transmission PL.	-	(2)	-	338	336
Soma-Isolux NH One Tollway Pvt. Ltda.	42,985	(2,041)	-	(5,908)	35,036
Sociedad Concesionaria Auto. A4, S.A.	53	952	-	(2,302)	(1,297)
Total	**74,728**	**(18,593)**	**-**	**237,183**	**293,318**

The main movements recorded during the year were the Grupo T-Solar Global S.A. non-controlling interests' increase which amounts to 245,409 thousand euro. This movement is the result of the shareholding changes and the Group's control takeover which is described in note 32 and to Group operations that took place after the control takeover (including a monetary contribution of 129 million euro due to the entrance of new partners in Grupo T-Solar Global, S.A. business).

Movements in non-controlling interests during 2010 are set out below:

	Opening balance	Share of profit/ losses	Dividends	Change in shareholding and others	Closing balance
Grupo Tecna	7,692	2,023	(617)	727	9,825
Interisolux Torrejón Viv. Joven, S.L.	12	-	-	-	12
Julitex, S.L.	(47)	(50)	-	-	(97)
Interisolux Alcorcón Viv. Joven, S.L.	300	-	-	-	300
Agua Limpia Paulista, S.A.	146	(79)	-	173	240
Viabahía Concessionaria de Rodovías, S.A.	5,208	204	-	15,471	20,883
Grupo Infinita Renovables	2,408	(3,892)	-	2,011	527
Soma-Isolux NH One Tollway Pvt. Ltda.	35,034	3,500	-	4,451	42,985
Sociedad Concesionaria Auto. A4, S.A.	1,704	(901)	-	(750)	53
Total	**52,457**	**805**	**(617)**	**22,080**	**74,728**

18 Trade and other payables

Set out below is a breakdown of trade and other payables at 31 December 2011 and 2010:

	31/12/2011	31/12/2010
Non-current		
Long-term tax payables	59,823	-
Deferred income-Official grants	25,496	10,136
Other payables	333,578	30,892
Total	**418,897**	**41,028**
Current		
Trade payables	1,039,698	1,136,644
Bills payables	571,448	715,197
Interim Billings	176,059	238,929
Advances received on contracted work	151,063	210,272
Social security and other taxes	124,301	160,714
Other payables	240,495	97,415
Total	**2,303,064**	**2,559,171**

Long term tax payables correspond to deferred sales tax on the concessions lines in Brazil.

At 31 December 2011, other non-current payables include costs to be incurred in the amount of 106,671 thousand euro related to the intangible asset of the toll road administrative concession in India (Varanasi).

At 31 December 2011, other non-current payables and other current payables include costs to be incurred in the amount of 113,951 thousand euro and 130,701 thousand euro respectively, related to the intangible asset of the toll road administrative concession of Viabahia Concesionaria de Rodovias S.A. (Brazil).

At 31 December 2010, other non-current payables include costs to be incurred in the amount of 14,836 thousand euro related to the intangible asset recognized in 2009 for the toll road administrative concession in India (Panipat-Jarandar) (There are no remaining balances related to this concession in 2011).

Additionally, on 18 March 2011, the Group has signed an agreement with Morgan Stanley Infrastructure Partner (MSIP), an infrastructure fund, becoming MSIP a strategic partner in the development of the Group in the Indian Infrastructure Concession business area.

The funding provided by MSIP strengthens the financial position of the Group in the Indian Concession infrastructure area, favouring the subgroups to obtain new projects.

Through this partnership MSIP committed to contribute to the holding company (ICC Sandpiper, B.V.) that owns the interests in three toll road concession joint ventures (Kishangarh, Surat and Varanasi) an amount approximately between 106,700 thousand USD (82,447 thousand euro at year ended exchange rate) and 258,500 thousand USD (220,605 thousand euro at year ended exchange rate) over the next five years depending on the number of concession of infrastructure projects obtained by the subgroup in India and will receive in exchange preferred shares which are convertible into ordinary shares of such holding company. The preferred shares are convertible to ordinary shares after an initial period of 5 years (or before in case of other certain specified events such as a breach of contract obligations and exit events as an IPO, a change of control, etc.).

The Group will have the majority in the Board of Directors of ICC Sandpiper although will require authorization from MSIP for certain key strategic and financing decisions. Therefore, the Company consolidated ICC Sandpiper subgroup on a proportional consolidation basis as joint venture.

As of December 31, 2011 MSIP has provided several contributions to ICC Sandpiper for ICC Sandpiper to make capital contributions to the concession joint ventures that amounted to 43,135 thousand euro (classified under "Other non-current payables", which provides MSIP through preferred convertible shares with approximately 23% of the voting rights of ICC Sandpiper and approximately 55% of economic ownership.

Regarding non-current position, deferred income mainly corresponds to grants received for the acquisition of fixed assets assigned to projects.

Nominal values are deemed to approximate fair values.

Information on deferred payments to suppliers. Third additional provision of the "Duty of information disclosure" Spanish Law 15/2010, of 5 July.

In line the resolution of December 29, 2010, of the Spanish Accounting and Account Auditing Institute (ICAC), on the duty of information to be disclosed in the report on the annual accounts in connection with the deferred of payments to suppliers in business operations, companies must publish explicit information on payment terms to their suppliers in the notes on their annual accounts of companies based in Spain that prepare stand-done and consolidated annual accounts.

In accordance with the transitional regime provided for in Law 15/2010, the deferral period allowed is between 120 and 85 days in the case of supplier and subcontractor work contracts and other business-related debts. These terms are applicable to contracts signed after July 7, 2010.

The duty of disclosure refers only to the accounts payable to suppliers and trade payables included under "Current liabilities" in the Consolidated Statement of Financial Position for accounts payable to providers of goods and services. Thus creditors or suppliers that do not meet this condition, such as suppliers of fixed assets or creditors through leasing, are outside the scope of this law.

The Group generally applies the payment management system the confirming through financial entities under the terms of contracts with their suppliers and/or subcontractors. The Group recognizes and pays suppliers financial expenses implicit in these agreements reached with the Group. Bearing the above in mind, at December 31, 2011, the outstanding balances of payment to suppliers to which this law applies does not exceed in significant amounts the stipulated legal period for cumulative deferrals.

In addition, during fiscal year 2011, payments to suppliers of group companies to which this law applies exceeding the prescribed limits has been approximately 61 million euros which is 7% of the total payments, exceeding in 72 days of the legal deadline.

According to the second transitory regulation of the Spanish Accounting and Account Auditing Institute (ICAC) resolution of December 29, 2010, concerning the information to be included in the annual accounts in the first year of implementation requirements, the 2011 information is not presented on a comparative basis with 2010, due to the gradual enforcement regime set for 2010, stated by the mentioned resolution.

	Payments made and pending payments at at year ended	
	2011	
	Thousand euro	%
Payments within the maximum legal limit	829,466	93.2%
Rest	60,754	6.8%
Total year payments	**889,433**	**100%**
Balance pending payment at close of year exceeding the legal limit l	**11,598**	
Average weighted delay in payments (days)	**72**	

19 Borrowings

At 31 December 2011 and 2010, borrowings are as indicated below:

	31/12/2011	31/12/2010
Non-current		
Real Estate development	18,729	16,905
Other mortgage loans	53,992	58,180
Syndicated loans	654,191	532,928
Credit lines	79,015	127,592
Other borrowings	123,280	140,350
Finance lease liabilities	723	1,609
	929,930	**877,564**
Current		
Advanced credit debts	79,964	73,750
Syndicated loans	22,951	3,420
Mortgage loans	8,558	7,786
Credit lines	306,529	268,271
Finance lease liabilities	882	1,246
Other loans	30,174	18,331
	449,058	**372,804**
Total borrowings	**1,378,988**	**1,250,368**

Borrowings relating to Real Estate developments and finance lease liabilities are secured by the financed assets. Other mortgage loans are secured by the non-current assets stated in Note 6.

Virtually all borrowings bear interest at Euribor rates and contracted rates are reviewed after periods which do not generally exceed six months. The fair values of current and non-current borrowings therefore approximate their carrying amounts.

The company has multiple credit lines that are generally classified as short-term since its maturity is used to be on an annual basis. Nevertheless, these lines reflect tacit renewal clauses.

At 31 December 2011 and 2010, non-current borrowings mature as indicated below:

	2011			2010		
Item	**Between 1 and 5 years**	**More than 5 years**	**Total**	**Between 1 and 5 years**	**More than 5 years**	**Total**
Property development	881	17,848	18,729	970	15,935	16,905
Other mortgage loans	18,820	35,172	53,992	16,202	41,978	58,180
Syndicated loan	654,191	-	654,191	532,928	-	532,928
Credit lines	75,253	3,762	79,015	122,160	5,432	127,592
Other borrowings	107,596	15,684	123,280	116,700	23,650	140,350
Finance lease liabilities	599	124	723	1,609	-	1,609
Total	**857,340**	**72,590**	**929,930**	**668,936**	**208,628**	**877,564**

Finance lease liabilities are discounted to their present value. Future financial charges on finance leases total 49 thousand euro (2010: 110 thousand euro).

19.1. **Syndicated loans**

On 14 February 2007, the Group signed an agreement to obtain a credit line of 200,000 thousand euro.

On 26 March 2008, the Group entered into an agreement for a credit line amounting to 305,000 thousand euro, the main aim of which is the funding of the Group's operations.

On 29 June 2010, the Group arranged a long-term syndicated loan under the "Forward Start Facility" mode which cancels the above mentioned agreements, as well as other credit lines and loans amounting to 72,000 thousand euro (arranged on 14 February 2011). The initial amount granted under this operation is 532,000 thousand euro (which may be increased to 700,000 thousand euro by other financial institutions joining in) and is structured in Tranche A (345,800 thousand euro) and Tranche B (revolving credit by 186,200 thousand euro, for the Group´s general treasury financing needs). At 31 December 2010 the syndicated loan has been increased to 552,000 thousand euro (352,300 thousand euro in Tranche A and 189,700 thousand euro in Tranche B), being the book blance of the consolidated loans on 31 December 2011 of 541,361 thousand euro. Disposed balances accrue interest at Euribor plus a variable spread of between 2.25% and 3% depending on certain ratios.

Moreover, the loan must comply with the usual ratios required for this kind of operations. At 31 December 2011 Management understands no covenant under this agreement has been breached.

Maturities per year for such loans are shown below:

Maturity date	**Amount (thousand euro)**
29/12/2012	11,051
29/06/2013	44,168
29/12/2013	55,183
29/06/2014	66,215
29/12/2014	99,368
29/06/2015	276,015
Total	**552,000**

On 17 June 2010, the Group arranged a 85,000 thousand euro credit line with Natixis, ICO and KBC, structured in Tranche A (70,000 thousand euro to infrastructure concession project finance in India) and Tranche B (15,000 thousand euro to Group´s project finance). At 31 December 2011 the outstanding payment amounts to 85,000 thousand euro. The loan accrues interest of Euribor plus a 3% annual spread and cancelation is through a single payment on 17 June 2015 (with potential advanced amortization on 17 June 2013 and 17 June 2015 in the event of agreement between financial entities and the Group). Additionally, as usual for this kind of operations, the loan is subject to certain ratios compliance. At 31 December 2011 Management understands no covenant under this agreement has been breached.

On 28 June 2011, the Group signed a 59,500 thousand euro loan agreement with EBN Banco de Negocios, S.A., Caja de España de Inversiones Salamanca y Soria, CAMP., Montes de Piedad y Caja de Ahorros de Ronda, Cádiz, Almería Málaga, Antequera y Jaén. (Unicaja), Banque Marocaine du Commerce Exterieur Internacional , S.A.U., Banco do Brasil, Suc. España, Bankia, S.A.U., Caja de Ahorros y Monte Piedad de Navarra, Commerzbank Aktiengesellsehft, Suc. España., Caja General de Ahorros de Granada, Banco de la Nación Argentina, Suc. España and Caixa D'Estalvis del Penedes, to finance the Group's Projects. At 31 December 2011 the outstanding payment amounts to 53,500 thousand euro. The loan accrues interest at Euribor plus a 3.5% annual spread.

Maturities per year for such loans are shown below:

Maturity date	**Amount (thousand euro)**
28/12/2011	5,950
29/06/2012	5,950
28/12/2012	5,950
28/06/2013	5,950
28/12/2013	5,950
28/06/2014	29,750
Total	**59,500**

Additionally, as is usual for this kind of operation, the loan is subject to compliance with certain ratios. At 31 December 2011 Management understands no covenant under this agreement has been breached.

19.2 **Other borrowings**

The following debts are included under this caption:

At 2 June 2008, the Company entered into an agreement for a credit line amounting to 100,000 thousand euro with Instituto de Crédito Oficial (ICO), the main aim of which is the funding of the infrastructure concession operations in Mexico carried out by the Group. At the year end, the pending payment balance amounts to 100,000 thousand euro (2010: 100,245 thousand euro). This facility bears interest at Euribor plus 3 % a year, in periods of 1, 3 or 6 months at the borrower's request. The loan must comply with the usual ratios required for this kind of operations. At 31 December 2011 Management understands no covenant under this agreement has been breached.

19.3. **Credit lines**

The Company has several credit lines which are generally classified as short-term as they are usually arranged on an annual basis. Nevertheless, these lines reflect tacit renewal clauses. When the term is longer than a year, they are classified as non-current. The credit lines classified as current liabilities include the following:

On 5 May 2011, the Group signed a 45,000 thousand euro credit agreement with Bank of America, National Association, Spanish branch; the main aim is to finance the Group's operations. At 31 December 2011 the outstanding payment amounts to 45,000 thousand euro. The credit accrued interest at Euribor plus a 2% annual spread, in periods of 1, 3 or 6 months. The credit must comply with the usual ratios required for this kind of operations. At 31 December 2011 Management understands that no covenant under this agreement has been breached. The maturity date of the credit is the 2nd of May of 2012, subjected to annual bank unilateral renewals to a maximum of 4 years.

19.4. **Other information**

The carrying amount of the Group's borrowings is denominated in the following currencies:

	2011	2010
Non-current		
Euro	898,740	845,605
Other currencies	31,190	31,959
	929,930	**877,564**
Current		
Euro	336,846	274,040
Other currencies	112,212	98,764
	449,058	**372,804**
Total borrowings	**1,378,988**	**1,250,368**

The Group has the following unused credit lines:

	2011	2010
Variable interest rate:		
- Maturing in less than one year	115,227	143,825
- Maturing in more than one year	22,589	86,741
	137,816	**230,566**

20 Deferred income tax

The gross movement in deferred income tax is shown below:

	Deferred tax assets		Deferred tax liabilities	
	2011	2010	2011	2010
1 January	**115,886**	**61,744**	**66,752**	**55,035**
Charge to income statement (Note 28)	39,353	43,853	25,008	10,128
Tax charged to equity	27,637	10,289	(81)	1,589
Business combinations (Note 32)	49,742	-	51,200	-
31 December	**232,618**	**115,886**	**142,879**	**66,752**

Deferred tax assets at each year end are as follow:

	2011	2010
Tax losses	98,898	39,037
Tax credits pending application	23,441	35,302
Temporary differences	110,279	41,547
	232,618	**115,886**

Movements during 2011 and 2010 in deferred tax assets and liabilities are as follows:

Deferred tax liabilities	Reversals	Appropriations	Other movements	Total
At 1 January 2010				**55,035**
Charged to income statement	(15,024)	20,084	5,068	10,128
Charged to equity	-	1,589	-	1,589
At 31 December 2010				**66,752**
Charged to income statement	(17,041)	36,967	5,082	25,008
Charged to equity	(81)	-	-	(81)
Business combinations and other operations (Note 32)	-	51,200	-	51,200
At 31 December 2011				**142,879**

Deferred tax assets	Reversals	Appropriations	Other movements	Total
At 1 January 2010				**61,744**
Charged to income statement	(26,213)	57,591	12,475	43,853
Charged to equity	-	10,289	-	10,289
At 31 December 2010				**115,886**
Charged to income statement	(62,230)	97,486	4,097	39,353
Charged to equity	-	27,637	-	27,637
Business combinations (Note 32)	-	49,742	-	49,742
At 31 December 2011				**232,618**

During 2011 some of the Spanish companies left the consolidation scope of the fiscal consolidation Group whose dominant company is Grupo Isolux Corsán S.A. Deferred tax assets have been discharged applying a prudent approach after making a recoverability analysis under these circumstances. In this respect, during 2011, 26,583 thousand euro of deferred tax assets were reversed, which corresponds to fiscal deductions pending application. The disposal has generated expenses of the same amount, which are recorded in the consolidated income statement. (see Note 28).

The Group deferred assets including deductions generated, on the basis of the Consolidated Text of the Corporate Income Tax Act, approved by the Royal Legislative Decree 4/2004, of 5 March, as defined in article 39.3 and as defined in the tenth additional provision on income tax, registering during 2008 a deduction for the percentage set by the existing law in 2008 on investments in new property, plant and equipment intended to benefit renewable energy sources, consisting of solar energy plants and equipment that produce heat or electricity. The deadline for these deductions is 10 years. In the case of new entities, the application of the deductions could be deferred until the first year within the prescription period (four years), if they generate profits. Deductions are subjected to the maintenance of the long term investments (5 years minimum from the addition of the asset that generated it).

Deferred tax assets / (liabilities) charged to equity during the year are as follows:

	2011	2010
Fair value reserves in equity:		
Reserve for hedging transactions	27,718	8,700
	27,718	**8,700**

Deferred tax assets and liabilities arising from temporary differences are analyzed below:

	2011	2010
Deferred tax assets		
Arising from provisions	6,865	10,413
Arising from non-current assets	36,560	13,650
Arising from financial derivatives measurement	59,965	17,484
Arising from other items	6,889	-
Total	**110,279**	**41,547**
Deferred tax liabilities		
Arising from measurement of inventories	(7,665)	(9,465)
Arising from measurement of derivative financial instruments	(1,854)	(2,838)
Arising from non-current assets	(101,513)	(20,180)
Arising from trade and other receivables	(13,251)	(8,175)
Arising from financial investments	-	(19,250)
Arising from other items	(18,596)	(6,844)
Total	**(142,879)**	**(66,752)**

At 31 December 2011 the Group has recognized tax credit with respect to tax losses in the amounts detailed below:

Generation year	Country				
	Spain	Argentina	México	Other	Total
2007	2,767	-	-	-	2,767
2008	2,255	81	54	-	2,390
2009	12,516	-	4,367	-	16,883
2010	13,971	2,486	540	-	16,997
2011	51,481	4,536	3,524	320	59,861
	82,990	**7,103**	**8,485**	**320**	**98,898**

These tax credits must be applied over a 15, 5 and 10-year period since its recognition in Spain, Argentina and Mexico, respectively.

Deferred tax assets with respect to tax credits pending application and tax losses are recognized insofar as the realization of the relevant tax benefit through future taxable profits is likely.

21 Provisions for other liabilities and charges

21.1. Provisions for other liabilities and charges – Non-current

	Provisions for project completion	Provisions for litigation and other	Provisions for major repairs	Decom-missioning provisions	Total
Balance at 1 January 2010	**18,106**	**30,028**	**-**	**1,749**	**49,883**
Appropriations	4,155	6,701	186	-	11,042
Reversals	-	-	-	-	-
Applications	(9,758)	(4,000)	-	-	(13,758)
Balance at 31 December 2010	**12,503**	**32,729**	**186**	**1,749**	**47,167**
Business combinations (Note 32)	-	-	878	3,760	4,638
Appropriations	1,801	11,656	3,075	22	16,554
Reversals	-	-	-	-	-
Applications	(3,942)	(17,357)	-	-	(21,299)
Balance at 31 December 2011	**10,362**	**27,028**	**4,139**	**5,531**	**47,060**

- Provisions for project completion

The balance in this account relates to projects that are completed or substantially completed and consists of the Group's estimate of probable costs to be incurred prior to final acceptance by the customer. Additional customer claims not subject to objective quantification at consolidated anual accounts preparation date could arise, although Management understands no significant loss over provisioned amounts will arise.

- Provisions for litigation and other

This balance relates to provisions set up to cover other liabilities and charges related or not related to litigation, including tax or other contingencies for which the Group considered a provision should be posted. In the opinion of the directors and legal counsel, the lawsuits in question are not likely to generate significant losses above the amounts provisioned.

- Decommissioning provisions

Based upon technical studies, the Group has estimated the current cost of decommissioning central solar installations as well as biodiesel plants that have assets assigned to projects, booking these estimates as a higher asset value and amortizing it over its useful life, which in most cases is similar to the useful life of the lease agreements of the land where the solar center and the biodiesel plants are located.

- Provisions for major repairs

Expected provisions for the replacement and major repairs to be performed in some infrastructure concessions during its concession period, the group calculates that the additions to be made according to the estimated investments schedules of the Business Financial Plan, which is the best estimate.

21.2. Provisions for other liabilities and charges – Current

The balances included in this item, totaling 60.679 thousand euro (2010: 52.099 thousand euro), relate to the Construction Division and the Engineering Division and mainly consist of provisions for project completion costs and other items. "Change in trade provisions" in the income statement registers net allocations made to provisions for other liabilities and current expenses.

22 Revenue / Sales

Sales information by activity and market is included in Note 5.

23 Materials consumed and other external costs

The account Materials consumed and other external costs during 2011 and 2010 is analyzed below:

	2011	2010
Raw materials and other supplies	1,058,067	921,782
Difference between opening and closing inventories, excluding real estate	29,481	(39,811)
Other external costs	1,164,076	982,124
Total	**2,251,624**	**1,864,095**

24 Other income and expense

Other operating income and expense are analyzed below:

	2011	2010
Other operating revenue		
Operating grants	2,333	1,187
Other operating revenue	52,833	43,808
Total	**55,166**	**44,995**
Other operating expense		
Operating leases	94,414	100,241
Other external services	123,473	524,141
Impairment of net receivables	1,423	(1,596)
Taxes	129,347	62,437
Total	**348,657**	**685,223**

On June 2011, the Group exchanged its shareholding in 3 power transmission lines in Brazil (see note 8.1). This resulted in a cash outflow of 9,478 thousand euro. Operating profit on the transaction was 4,533 thousand euro and due to translation differences there was an income amounting to of 11,495 thousand euro. (see note 27).

During 2010 other operating expense included net losses from the sale of non-current assets totaling 812 thousand euro.

On December 2010 the Group carried out joint ventures sale regarding 8 electric line transmission concessions in Brazil (see note 8.1). This transaction has implied a net cash inflow of 256.535 thousand euro, a net operating profit of 26.562 thousand euro and conversion difference revenue amounting to 33.026 thousand euro not generating cash inflows.

25 Employee benefit expenses

	2011	2010
Wages and salaries	302,223	304,022
Social Security contributions	76,702	75,248
	378,925	**379,270**

"Wages and salaries" during 2011 include indemnities amounting 10.758 thousand euro (2010: 11.376 thousand euro).

The Group's average workforce is analyzed below:

	2011	2010
Category		
Graduates	2,872	2,647
Administrative staff	786	794
Workers	5,246	4,199
	8,904	**7,640**

Additionally, the average number of persons employed during 2011 by the proportionately-consolidated companies has been 275 (2010: 1.374).

At 31 December 2011, personnel distribution by gender is as follows:

	Men	Women	Total
Category			
Board Directors	13	-	13
Senior managers	7	1	8
Managers	280	49	329
Graduates	1,721	478	2,199
Administrative staff	504	363	867
Workers	6,103	545	6,648
	8,628	**1,436**	**10,064**

At 31 December 2010, personnel distribution by gender was as follows:

	Men	Women	Total
Category			
Board Directors	13	-	13
Senior managers	7	1	8
Managers	137	17	154
Graduates	1,742	480	2,222
Administrative staff	327	249	576
Administrative staff	3,286	206	3,492
	5,512	**953**	**6,465**

26 Operating leases

Future minimum lease installments under non-cancellable operating leases are analyzed below:

	2011	2010
Less than 1 year	37,699	11,166
Between 1 and 5 years	24,494	18,271
More than 5 years	7,368	10,488
Total	**69,561**	**39,925**

The expense recognized in the income statement during 2011 in relation to operating leases totals 94.414 thousand euro (2010: 100.241 thousand euro).

The Group leases the building in which its headquarters are located from a third party. The lease agreement has a 12-year term as from lease inception (15 March 2007), although the Group may exercise a purchase option as from year five, in which case the parties must previously agree on the terms of the transaction. Since at lease inception and at the preparation date of these consolidated annual accounts, the purchase option is not likely to be exercised the operation has been classified as an operating lease. All payments due throughout the original 12-year term are included in the above table.

27 Net financial results

Net financial results at 31 December 2011 and 2010 are detailed below:

	2011	2010
Interest expense	(246,034)	(139,158)
Impairment of available-for-sale investments (Note 10)	(1,837)	(3,858)
Other financial expense	(52,939)	(28,727)
Financial expenses	**(300,810)**	**(171,743)**
Interest income	33,753	13,398
Results from available-for-sale investment transactions (note 10)	17,365	-
Net gains/(losses) on foreign currency transactions	18,161	28,921
Net gains/(losses) on derivative financial instruments at fair value	1,460	601
Other financial income	12,791	13,102
Financial income	**83,530**	**56,022**
Net financial result – Expense	**(217,280)**	**(115,721)**

Profits from foreign currency transactions in 2011 included 11,495 thousand euro related to the exchange of 3 power transmission lines in Brazil (see note 24).

Results from investments held for sale in 2011 included 17,365 thousand euro related to the exchange of Synergy Industry and Technology, S.A.'s shares (see note 10).

During 2011, there was a capital reduction in the shareholding of Isolux Energia y Participaciones. As a result, a 10,146 thousand euro loss due to foreign currency transactions.was booked.

Profits from foreign currency transactions in 2010 included 33.026 thousand euro relating to a joint ventures sale of 8 power transmission line concessions in Brazil (see note 24).

28 Income tax

Grupo Isolux Corsán, S.A. is the parent company of Fiscal Group 102/01 and is therefore authorized to present consolidated tax declarations in Spain for all companies included in Fiscal Group.

Income tax expense is composed of:

	2011	2010
Current income tax	41,695	54,674
Deferred tax (Note 20)	(14,345)	(33,725)
Total Income Tax Expense	**27,350**	**20,949**

The Group's income tax differs from the theoretical amount that would have been obtained if the tax rate applicable to the consolidated companies' profits had been used as follows:

	2011	2010
Profit before taxes	**32,826**	**84,909**
Tax calculated at the rate applicable to the parent company's profits	9,848	25,472
Effect on tax payable of non-tax deductible expenses	2,517	2,453
Effect of different tax rates abroad and other differences in foreign operations	78	2,440
Deductions generated/reversed during the year	26,583	(3,437)
Other	(11,676)	(5,979)
Tax expense	**27,350**	**20,949**

The caption "Deductions generated during the year", reflects the effect of the fiscal credit disposals pending application by deductions, which amounts to 26,583 thousand euro (see note 20).

Set out below is a breakdown of deductions generated in each year:

	2011	2010
Deductions from export activities	-	3,437
Profits reinvested	-	-
Total	**-**	**3,437**

The effective tax rate in 2011 has been 83.32% (2010: 24.67%). This rate differs from the rate applicable to the parent company (30% in 2011 and 2010) mainly due to the net effect of non-deductible expenses, which increase the effective tax rate, and deductions generated, which reduce the effective tax rate, as well as different tax rates abroad that may be higher or lower than the rate applicable in Spain and therefore increase or reduce the effective tax rate.

On 1 July 2010, inspection activities on Income Tax for the period 2005-2008 were initiated in Grupo Isolux Corsán, S.A., as the parent company of the tax group.

Likewise, several group companies are subject to a general inspection of Value Added Tax (2006-2008), Personal Income Tax (2006-2008), Annual Statement of Operations (2005-2008) and Intra-Community Business Operations Statement (2005-2008).

At the date of preparation of these consolidated annual accounts, these inspections had not yet been completed.

From the actions that the tax authorities could adopt in relation to the inspected years, a tax liability could result which cannot be objectively quantified. However, the management of the parent company estimates that the resulting liability of that potential revision could mean losses higher than the provisioned amounts.

The following taxes and years are open to inspection:

Tax	Fiscal years
Corporate Income Tax	2009 to 2010
Value Added Tax	2009 to 2011
Personal Income Tax	2009 to 2011
Other taxes	Last 4 years

As a result, among other things, of the different interpretations to which Spanish tax legislation lends itself, additional liabilities may be raised in the event of a tax inspection. The directors of the parent company consider, however, that any additional liability that might be raised would not significantly affect these consolidated annual accounts.

29 Earnings per share

Basic and diluted

Basic earnings per share are calculated by dividing the profit attributable to the Company's equity holders by the weighted average number of outstanding ordinary shares for the year.

Diluted earnings per share are calculated by adjusting the weighted average number of outstanding ordinary shares to reflect the conversion of all potentially dilutive ordinary shares. As the Company has no potentially dilutive ordinary shares, diluted earnings per share are the same as basic earnings per share.

	2011	2010
Profit attributable to the Company's equity holders (Thousand euro)	24,069	63,155
Weighted average number of outstanding ordinary shares	87,316,199	87,316,199
Basic earnings per share (euro per share)	0.27	0.72

30 Dividends per share

Dividends paid out (or proposed) in relation to profits for 2011 and 2010 amount to 10.000 thousand euro and 30.000 thousand euro (see Note 17), respectively, entailing a dividend per share of 0.11 euro and 0.34 euro, respectively.

31 Commitments, contingencies and guarantees provided

a) Commitments

Non-current assets purchase commitments

No significant commitments have been made to purchase non-current assets at the balance sheet date, other than those required in the ordinary course of business.

Operating lease commitments

The Group leases a number of premises, offices and other property, plant and equipment under non-cancellable operating leases. These leases contain variable terms, phase-related clauses and renewal rights.

The lease expenditure charged to the income statement during the year and information on future minimum installments is set out in Note 26.

Share purchase undertaking agreement

On 23 January 2011, the three Viabahia Concessionaria de Rodovias, S.A.'s shareholders signed an agreement stating that one of the non-controlling shareholder could sell their shares to the others shareholders. Taking into account the agreement, the Group could increase its stake by a 70%. These transactions could only occur once the restriction period has expired (two years after the signature of the concession agreement), after the signature of the share purchase undertaking agreement and when all the required approvals are obtained.

b) Contingencies and guarantees provided

The Group has contingent liabilities in respect of bank guarantees and other guarantees provided in the ordinary course of business. In accordance with its general terms of engagement, the Group is required to provide technical guarantees in connection with the execution of projects. These guarantees may be provided in cash or in the form of bank guarantees and must remain in effect for a specified period.

In the ordinary course of business, as is common practice in companies engaged in engineering and construction activities, the Group furnished guarantees to third parties totaling 1,611 million euro (2010: 1,136 million euro) for the proper performance of contracts. In relation to concession activities, the Group has furnished guarantees for the proper performance and execution of contracts, totaling 240 million euro (2010: 114 million euro).

Related to sale transaction with investments in Brazilian electric transmission lines carried out in 2010 (see note 8), Isolux Energia e Participações guarantees certain litigations and claims.

No significant liability is expected to arise over such provisioned amounts, as stated in Note 21.

32 Business combinations

a) Grupo T-Solar Global, S.A. acquisition

On May 2011, the Group acquired control of the company Grupo T-Solar Global, S.A. (hereafter GTSG). GTSG is the parent company of a group of companies which main headquarters is in Spain and their activity is the generation of photovoltaic solar power through solar power plants and solar panel manufacturing.

The takeover was performed as follows:

- At 31 December 2010 the group had a 19.80% holding in GTSG, classified as investments in companies by the equity method

- During the first months of 2011, through several corporate transactions related to:

  - Shares purchase from third parties (18,912 thousand euro) and
  - Capital contributions (98,127 thousand euro) diluting the stake of other shareholders, at 31st of May

the Group acquired the control of GTSG, with a 60.74% holding on that date.

The following table summarizes the consideration paid for GTSG and the provisional fair values of the acquired assets, assumed liabilities and the non-controlling shareholding position of GTSG at the acquisition date:

	Thousand euro
Purchase from third parties	18,912
Capital contribution in 2011, in cash	98,127
Total transferred consideration	**117,039**
Shareholding at fair value in the equity of Grupo T-Solar Global before the business combination	128,875
Total consideration	**245,914**
Balances of the identified acquired assets and assumed liabilities	
Cash	65,321
Property, plant and equipment	1,125,467
Goodwill	49,181
Intangible assets	752
Deposits, guarantees and other long term assets	47,730
Deferred tax assets	49,742
Inventory	8,584
Trade and other receivables	95,259
Other current assets	1,311
Borrowings	(785,709)
Other non-current liabilities	(86,994)
Loans	(151,838)
Other current liabilities	(45,367)
Deferred tax liabilities	(35,767)
Total identified net assets	**337,672**
Non-controlling interests	**(132,570)**
Goodwill	**40,812**
Total	**245,914**

The main aspects considered in the preliminary allocation cost were as follows:

- The estimated fair value of the operating and development photovoltaic solar plants included in the existing project portfolio at the acquisition date was calculated by an independent expert using the discounted future cash flow method and it was also based on the value allocated to transactions with independent parties.

- The fair value of the GTSG's non controlling interest has been estimated based on the net assets identified at the acquisition date.

The goodwill generated in the business combination amounts to 40,812 thousand euro. It has been assigned to the photovoltaic solar plants energy generation cash generating unit. Among the assets acquired there is also goodwill amounting to 47,824 thousand euro which is assigned to the manufacturing solar panels' cash generating unit.

Note 7 describes the key assumptions for the value assessment of factory panels and photovoltaic solar plants.

The preliminar estimated assessment is subject to review for a 12 month period after the control takeover.

There is no significant impact on the consolidated income statement related the business combination.

The net turnover added since GTSG's acquisition (June 1, of 2011) amounts to 45,170 thousand euro and it has been recorded in the consolidated income statement. GTSG losses since its incorporation amount to 13,924 thousand euro.

If GTSG had been consolidated from January 1, 2011, the consolidated income statement would show a net turnover of 93,409 thousand euro and a loss of 37,199 thousand euro. The abovementioned impacts include the additional fixed assets' depreciation effect generated in the process by assigning the price. This value amounts to 3,860 thousand euro (net of tax).

b) Cachoeira Paulista Transmissora de Energia, S.A. acquisition

On June 2011, Isolux Energia e Participações, S.A. sold its joint venture shareholdings in Porto Primavera Transmissora de Energía, S.A., Vila do Conde Transmissora de Energía, S.A, and Cachoeira Paulista Transmissora de Energia, S.A. The fair value of the assets and liabilities amounted to 67,311 thousand euro. The Group held 33.33% of each entity. In return for the sale of the shareholding and of a 9,478 thousand euro payment, the Group acquired all the shares of Cachoeira Paulista Transmissora de Energía, S.A.

The estimated fair value of net assets acquired amounts to 81,322 thousand euro. The additional value of 41,334 thousand euro has been assigned to financial concessions assets, considering a deferred tax liabilitites of 14,054 thousand euro. This sale operation has generated profits amounting to 4,533 thousand euro (Note 24) and profits from foreign currency transactions of 11,495 thousand euro (Note 27).

The following table summarizes the consideration paid and the provisional fair values of the acquired assets and assumed liabilities at the acquisition date:

Consideration	Thousand euro
Cash	9,478
Assets and liabilities fair value	71,844
Total consideration	**81,322**
Balances of the indentified acquired assets and assumed liabilities	
Cash	3,887
Other receivables (Financial assets)	129,365
Other assets	7,983
Borrowings	(30,395)
Other liabilities	(15,464)
Deferred tax liabilities	(14,054)
Total identified net assets	**81,322**

During the purchase price allocation, the estimated fair value of the acquisition cost of the transmission lines; based on the discounted future cash flow method.

The preliminary estimated assessment is subject to review for a 12 month period after the control takeover.

Cachoeira Paulista Trasnmisora de Energía's turnover since its acquisition amounts to 17,915 thousand euro. It has been booked in the 2011 consolidated income statement. During the year the results contribute 11,516 thousand euro.

33 Related-party transactions

Transactions with related parties during 2011 and 2010 form part of the Group's ordinary course of business. These transactions are described below:

- **a. Transactions with the Company´s principal Shareholders**

- **a.1. Transactions with Banco CCM (former Caja Castilla La Mancha)**

  Since 2010 CCM Bank is not longer an indirect shareholder of the Group Isolux Corsán, S.A. due to the fact that CCM Bank is not longer a Caja Castilla La Mancha Corporación shareholder. CCM Bank is not longer considered as a related-party of Grupo Isolux Corsánin in 2010 or 2011.

  During 2010, the Group performed transactions with CCM Bank, using its services as an banking entity, signing various bank loans, guarantees, negotiating financial instruments and through the use of several bank accounts to undertake the ordinary transactions of the Group.

  2010 income statement records the impact of the transactions mentioned above, which were performed under market conditions.

- **a.2. Transactions with Corporación Caja Navarra Group**

  The Group effects transactions with Corporación Caja Navarra Group solely in connection with its banking activities. Transactions completed at 31 December 2011 and 2010 are presented below by nature:

	2011		2010	
	Granted	**Disposed**	**Granted**	**Disposed**
Credit lines	26,000	7,337	15,000	14,958
Long-term syndicated loans	28,300	28,300	20,000	20,000
Project finance	13,358	13,358	-	-
Guarantees granted	10,000	9,864	10,000	8,367
Other borrowings	9,000	9,000	2,000	2,000

During 2010 the interest rate swap to hedge future Euribor fluctuations by a notional value of 33.333 thousand euro expired.

On 31 December 2010 the Group had an export letter of credit line with a 5.000 thousand limit. The utilized amount totaled 3.282 thousand euro. At 31 December 2011 the limit is 5.000 thousand euro and there is no amount utilized.

The Group also has several current accounts necessary to carry on its ordinary business and manages a part of its cash resources by contracting financial assets through Corporación Caja Navarra Group.

The income statement for each period includes costs and revenue related to the above-mentioned operations, which reflect market conditions.

a.3. Transactions with Corporación Empresarial Cajasol S.A.U

The Group effects transactions with Corporación Empresarial Cajasol, S.A.U. solely in connection with its banking activities. Transactions completed at 31 December 2011 and 2010 are presented below by nature:

	2011		2010	
	Granted	**Disposed**	**Granted**	**Disposed**
Credit lines	600	600	15,000	14,964
Guarantees	129	129	-	-

During 2010 the interest rate swap to hedge future Euribor fluctuations by a notional value of 33.333 thousand euro expired.

The Group also has several current accounts necessary to carry on its ordinary business and manages a part of its cash resources by contracting financial assets through Corporación Empresarial Cajasol S.A.U.

The income statement for each period includes costs and revenue related to the above-mentioned operations, which reflect market conditions.

a.4. Transactions with Charanne B.V.

The Group has carried out the following transactions with Charanne B.V. shareholder during 2011 and 2010:

- On 7 February 2008, the Company granted a loan to B.V. Vista for a total of 4.700 thousand euro, with a one year maturity and bearing an interest rate of Euribor plus a spread of 1%. During 2009 this loan was transferred to Charanne B.V. During 2011 the loan has been renewed for an additional year.

- On 4 December 2008, the Group acquired the 100% of the shares that Vista B.V had of the Company Azul de Cortes, B.V. During 2009 the Company transferred this debt to Charanne B.V.The balance outstanding debt at 31 December 2011 in connection with this transaction amount to 11.076 thousand euro (11.076 thousand euro at 31 December 2010).

The transactions mentioned above were carried out under market conditions.

a.5. Transactions with Caja Castilla la Mancha Corporación, S.A.

During 2011 the Group exchanged shares with Caja Castilla La Mancha, S.A., as stated in note 10.

b. Transactions with the Company's Board of directors and management

b.1. Information required by articles 229 to 231 of Capital Company Act

Parent company´s directors have nothing to report pursuant to Articles 229 to 231 of Capital Company Act, approved by Royal Decree 1/2010 of 2 July, except for the following offices and functions held and performed, and shareholdings owned with respect to all Group companies at 31 December 2011:

- Mr. Luis Delso Heras is a Board director of Ghesa, Ingeniería y Tecnología, S.A., Cable Submarino de Canarias, S.A., Corsán-Corviam Construcción, S.A. , Isolux Ingeniería, S.A. (Chairman) , Isolux Wat Ingeniería, S.L. (Chairman) , Isolux Corsán Concesiones, S.A. (Chairman), Isolux Corsán Inmobiliaria, S.A. (Chairman), Infinita Renovables, S.A., Grupo Isolux Corsán Concesiones, S.L. (Chairman), Isolux Corsán Concesiones de Infraestructuras, S.L. (Chairman), T-Solar Global, S.A. (Chairman), Grupo T-Solar Global, S.A., Las Cabezadas Aranjuez, S.L. and Isolux Infrastructure S.A.

- Mr. José Gomis Cañete is a Board member of Corsán-Corviam Construcción, S.A. (Vice-President), Isolux Ingeniería, S.A. (Vice-Chairman), Isolux Wat Ingeniería, S.L. (in his capacity as representative of Construction Investments, S.a.r.l.- Vice-Chairman), Isolux Corsán Inmobiliaria, S.A. (in his capacity as representative of Construction Investments, S.a.r.l.- Vice-Chairman), Isolux Corsán Concesiones, S.A. (in his capacity as representative of Construction Investments, S.a.r.l. – Vice-Chairman); Grupo Isolux Corsán Concesiones, S.L. (Vice-Chairman); Isolux Corsán Concesiones de Infraestructuras, S.L. (Vice-Chairman); Infinita Renovables, S.A. (Chairman); T-Solar Global, S.A.; Grupo T-Solar Global S.A. (Chairman) and Isolux Infrastructure S.A.

- Mr. Antonio Portela Alvarez is a Board director of Desarrollo de Concesiones y Servicios, Sercón, S.A.(Chairman) , Infinita Renovables, S.A., T-Solar Global, S.A., Corsán-Corviam Construcción, S.A. (CEO), Isolux Corsán Inmobiliaria, S.A. (CEO), Isolux Corsán Concesiones, S.A. (CEO), Isolux Ingeniería, S.A. (CEO), Grupo Isolux Corsán Concesiones, S.L. (CEO), Isolux Corsán Concesiones de Infraestructuras, S.L. (CEO), Isolux Corsán Aparcamientos, S.L. (Chairman) and Isolux Infrastructure S.A.

  Additionally, Mr Antonio Portela Alvarez holds shares in Infinita Renovables, S.A. (indirect interest of less than 10% through other companies) and Aral, Gestión y Organización S.L. (33%).

- Grupo Corporativo Empresarial de la Caja de Ahorros y Monte de Piedad de Navarra, S.A.U., holds shares in Autovía del Camino, S.A. (10.91%); and in Sociedad Concesionaria de la Zona Regable del Canal de Navarra, S.A. (35%). It is also a member of the Board of Directors of the latter company.

  The companies that form part the Grupo Corporativo Empresarial de la Caja de Ahorros and Monte de Piedad de Navarra, S.A.U. hold shares in Agua y Gestión de Servicios Ambientales, S.A. (24.26%); in Cable Submarino de Canarias, S.A. (5.90%); de Concessia, Cartera y Gestión de Infraestructuras, S.A., (7.29%); de Gestión de Aguas de Alcolea, S.A. (49%); in Ingeniería Río Negro, S.L. (35.01%); in Ingeniería, Diseño y Desarrollo Tecnológico, S.A. (19.98%); and in Metropolitano de Tenerife, S.A. (6%).

  Addtionally, Eduardo Lopez Milagro (as the legal representative of Grupo Empresarial de la Caja de Ahorros y Monte de Piedad de Navarra, S.A.U.), is a member of the Board of Directors of Isolux Corsán Concesiones, S.A.U.; and of Isolux Corsán Inmobiliaria, S.A.

  The Grupo Corporativo Empresarial de la Caja de Ahorros y Monte de Piedad de Navarra, S.A.U. is a Board member of Isolux Corsán Concesiones, S.A. and of Isolux Corsán Inmobiliaria, S.A.

- Mr. Serafín González Morcillo is a Board director of Isolux Wat Ingeniería, S.L., Isolux Corsán Concesiones, S.A.U. and Isolux Corsán Inmobiliaria, S.A.

- Mr. Francisco Moure Bourio is a Board director of Sociedad de Promoción y Participación Empresarial Caja de Madrid, S.A. Aditionally is a Board director of Técnicas y Proyectos, S.A., Isolux Wat Ingeniería, S.L., Isolux Corsán Inmobiliaria, S.A. and Isolux Corsán Concesiones, S.A.U.

- Caja Castilla La Mancha Corporación, S.A. is Board member Las Cabezadas Aranjuez, S.L. (President), and it has a shareholding of 60%, El Reino de Don Quijote de la Mancha, S.A.; Urbanizadora Montearagón, S.L.; CCM Iniciativas Industriales, S.L.; Industrializaciones Estratégicas, S.L; Comtal Estuc, S.L.; Cartera Nueva Santa Teresa, S.L. (President); Global Uninca, S.A. (Joint Administrator) and Obenque, S.A.

  In addition it has shareholding in the following companies: CCM Iniciativas Industriales, S.L. and subsidiaries (99.99%); CCM Inmobiliaria Centrum 2004, S.L. and subsidiaries (99.99%); CCM Inmobiliaria del Sur 2004, S.L. and subsidiaries (99.97%); Comtal Estruct, S.L. (30.51%); Construcciones Sarrión, S.L. (5.00%); DHO Grupo Constructor Corporativo S.L. (16.01%); El Reino de Don Quijote de la Mancha, S.A. (12.80%); Planes e Inversiones CLM, S.A. and subsidiaries (99.99%); Bami Newco, S.A. (1.45%); Midamarta S.L. (0.01%); Diverga Construcciones, S.L. (4.95%), Obenque S.A. (14.33%); Explotaciones Forestales y Cinegeticas Alta-Baja (99.85%); Hormigones y Aridos Aricam, S.L. (25%); and Desarrollo Industrial Aricam, S.L. (4.74%).

- That the companies that form part of the group of Monte de de Piedad, Caja de Ahorros San Fernando de Guadalajara, Huelva, Jerez y Sevilla (Cajasol), in accordance with Article 42 of the Code of Commerce, hold shares in companies with the same, similar or complementary activity to that which constitutes the Company purpose. This companies are: Agua y Gestión de Servicios Ambientales, S.A (24.26%)l; Autovía del Camino, S.A (10. 91%); Cable Submarino de Canarias, S.A, (2.53%); Concessia, Cartera y Gestión de Infraestructuras, S.A. (7.29%); Gestión de Aguas de Alcolea, S.A, (49%), Ingeniería Río Negro, S.L.(35.01%); Ingeniería, diseño y desarrollo tecnológico, S.A, (19.98%); Metropolitano de Tenerife, S.A.(6%) and in the Sociedad Concesionaria de la Zona Regable del Canal de Navarra, S.A, (35%).

  In addition, the companies forming the group of Monte de Piedad and Caja de Ahorros San Fernando de Guadalajara, Huelva, Jerez y Sevilla (Cajasol), in accordance with Article 42 of the Code of Commerce, that holds shares or are in charge in companies with a similar or complementary activity to that which constitutes the Company purpose. This companies are: Agua y Gestión de Servicios Ambientales, S.A. ; Autovía del Camino, S.A.; Cable Submarino de Canarias, S.A.; Concessia, Cartera y Gestión de Infraestructuras, S.A.; Gestión de Aguas de Alcolea, S.A.; Ingeniería, diseño y desarrollo tecnológico, S.A. and Sociedad Concesionaria de la Zona Regable del Canal de Navarra, S.A.

- Mr. Ángel Serrano Martínez-Estéllez is a Board Director member of Corsán-Corviam Construcción, S.A., Isolux Wat Ingeniería, S.L., Isolux Corsán Inmobiliaria, S.A., Isolux Corsán Concesiones, S.A.U.; Alten Energías Renovables S.L; Alten 2010 Energía Renovables, S.A. and Grupo T-Solar, S.A.

- Mr. Javier Gómez-Navarro Navarrete is a Board Director member of Técnicas Reunidas, S.A., Isolux Corsán Inmobiliaria, S.A. and Isolux Corsán Concesiones, S.A.U.

- Mr. José María de Torres Zabala, as representative of Cartera Perseidas, S.L., is a Board Director member of Isolux Corsán Inmobiliaria, S.A. and Isolux Corsán Concesiones, S.A.U. and Grupo T-Solar Global, S.A (1.88%).

  In addition, Cartera Perseidas is member of the Board Director of Aupisa, Autovía de los Pinares, S.A.

  Cartera Perseidas, S.L. is board member of Isolux Corsán Inmobiliaria, S.A. and Isolux Corsán Concesiones, S.A.U. It holds 1.88% shares of Grupo T-Solar Global, S.A.;

Some of the members of the board of directors are in conflict and must disclose this in compliance with article 229.1 of the Capital Companies Act.

The inclusion of the above information in the notes to the consolidated annual accounts of Grupo Isolux Corsán, S.A. is the result of a detailed analysis of the information received from all the members of the Board of Directors of Grupo Isolux Corsán, S.A., based on a teleological interpretation of Articles 229-230 of Capital Companies Act.

b.2. Transactions with companies in which the Board of directors of Grupo Isolux Corsán, S.A. are also directors or administrators:

Transactions and balances with companies in which the Board directors of Grupo Isolux Corsán, S.A. are also directors or administrators are analyzed below:

2011	Debtor balances	Creditor balances	Costs / Purchases	Financial income	Revenue / Sales
Ciudad Real Aeropuerto, S.L.	15,189	-	-	-	-

2010	Debtor balances	Creditor balances	Costs / Purchases	Financial income	Revenue / Sales
Ciudad Real Aeropuerto, S.L.	15,189	-	-	-	-
Synergy Industry and Technology, S.A.	809	-	-	-	-

b.3. Remuneration paid to Board of directors and management of Grupo Isolux Corsán, S.A.

	2011	2010
Wages and salaries (including indemnities)	7,669	4,678
Per diems for attendance at Board meetings	559	630
	8,228	**5,308**

Additionally, certain Board directors and managers are beneficiaries in a multi-annaul incentive plan.

b.4. Loans granted to Board of Directors

	2011	2010
Opening balance	**5,297**	**5,198**
Interest charged	108	99
Closing balance	**5,405**	**5,297**

The loans relate to 2000 and 2002, have no established maturity date and bear interest at the Euribor rate + 0.50%.

b.5. Company's Board of Directors and Management credit

At 31 December 2011 the Group owed to the CEO 7,000 thousand euro (2010: 0 thousand euro).

These credits corresponds to the deferred payment of the acquisition of Grupo T-Solar Global, S.A.'s shares which was transacted with a CEO of the Group during 2011.

b.6. Other transactions with the Company's Board of Directors and Management

On October 7, 2011 the convertible loan of GTSG (see note 11) was cancelled. Members of Grupo Isolux Corsán board of directors also participated in the mentioned loan. In return for the cancellation, the members of the board of directors were given GTSG shares (2.59% of the company). These shares were acquired by Grupo Isolux Corsán, in exchange for 0.7 million euro and assuming the payment obligations of the borrowers with banks to the amount of 7 million euro.

c. Transactions with associates

Transactions and balances with associates at 31 December 2011 and 2010 are analyzed below:

2011	Debtor balances	Creditor balances	Costs / Purchases	Revenue / Sales
Autopista Madrid-Toledo Concesionaria, S.A.	8,328	-	-	168
Proyectos Inmobiliarios Residenciales, S.L.	1,315	-	-	-
Alqlunia5, S.A.	395	-	-	-
Pinares del Sur, S.L.	9,193	-	-	7,569
Las Cabezadas de Aranjuez S.L	13,600	-	-	-

2010	Debtor balances	Creditor balances	Costs / Purchases	Revenue / Sales
Autopista Madrid-Toledo Concesionaria, S.A.	4,450	-	-	-
Proyectos Inmobiliarios Residenciales, S.L.	1,315	-	-	-
Grupo T-Solar Global, S.A.	73,816	151	161	31,799
Alqlunia5, S.A.	395	-	-	-
Pinares del Sur, S.L.	8,874	-	-	1,952
Las Cabezadas de Aranjuez S.L	13,600	-	-	-

Regarding transactions with Grupo T-Solar Global, S.A.:

- During 2010 the main commercial transactions between the Group and Grupo T-Solar Global, S.A. correspond to solar panels purchase to Grupo T-Solar Global and to revenue from services rendering relating construction, operation, maintenance and monitoring in photovoltaic solar plants by virtue of construction, operation and maintenance arrangements between both parts.

- Grupo Isolux Corsán has given technical guarantees amounting 19,277 thousand euro to the company at 31 December 2010.

Transactions mentioned above have been done under market conditions.

34 Share-based payments

In 2006 a three-year incentive plan was created for the Group's managers and Board of directors. In accordance with that plan, incentives would be paid in 2009 by the present shareholders of Grupo Isolux Corsán, S.A. provided certain conditions stipulated in the relevant agreement were fulfilled. In 2006, 2007 and 2008 the Group recorded the corresponding expense against an increase in equity. During 2010, the Company has assumed the payment, recording the impact directly in equity in the amount of 19,266 thousand euro (agreed amount net of tax effect).

35 Joint ventures

The Group has interests in the joint ventures listed in Appendix III. The amounts set out below represented the Group's share, based on its interest in the joint ventures, on assets, liabilities, revenue and results of joint ventures consolidated through the proportional method (see note 2.2). These amounts are included in the consolidated balance sheet and consolidated income statement:

	2011	2010
Asstes:		
Non-current assets	888,614	589,213
Current assets	108,986	209,740
	997,600	**798,953**
Liabilities:		
Non-current liabilities	597,237	303,287
Current liabilities	93,582	183,884
	690,819	**487,171**
Net assets	**306,781**	**311,782**
Revenue	407,041	359,089
Expenses	(389,408)	(334,962)
Profit after taxes	**17,633**	**24,127**

There are no contingent liabilities relating to the Group's interests in joint ventures, or contingent liabilities recognized by the joint ventures themselves.

36 Temporary joint ventures (UTEs) and consortiums

The Group has interests in the UTEs listed in Appendix IV. The amounts set out below represent the Group's share, based on its interests in the UTEs, of assets, liabilities, revenue and results. These amounts are included in the consolidated balance sheet and consolidated income statement:

	2011	2010
Assets:		
Non-current assets	6,719	6,708
Current assets	496,309	493,239
	503,028	**499,947**
Liabilities:		
Non-current liabilities	141	558
Current liabilities	490,847	505,828
	490,988	**506,386**
Net assets	**12,040**	**(6,439)**
Revenue	569,026	919,557
Expenses	(556,986)	(925,996)
Profit after taxes	**12,040**	**(6,439)**

There are no contingent liabilities relating to the Group's interests in UTEs, or contingent liabilities recognized by the UTEs themselves.

At 31 December 2011 the Group was involved in several consortiums (none at 31 December 2010). The following balances have been recorded on the consolidated financial statement and on the consolidated income statement:

	2011
Assets:	
Non-current assets	430
Current assets	52,081
	52,511
Liabilities:	
Non-current liabilities	(18)
Current liabilities	48,941
	48,923
Net assets	**3,588**
Revenue	57,578
Expenses	(53,990)
Profit after taxes	**3,588**

37 Environment

The Group has taken the necessary measures to protect and improve the environment and to minimize environmental impact, if applicable, in compliance with current environmental legislation. Consequently, no provision for environmental liabilities and charges has been deemed necessary and there are no contingencies relating to environmental protection and improvement.

38 Events after the reporting period

There have been no significant post-balance sheet events which may have a significant impact on these consolidated annual accounts.

39 Auditors' fees

The fees accrued by PricewaterhouseCoopers Auditors, S.L. for audit services rendered during 2011 total 1,552 thousand euro (2010: 1,013 thousand euro).

Fees accrued by PricewaterhouseCoopers Auditores, S.L. for other services rendered during 2011 total 1,945 thousand euro (2010: 313 thousand euro).

Fees accrued by other companies operating under the PricewaterhouseCoopers brand for audits and other services rendered abroad during 2011 amount to 1,621 thousand euro (2010: 414 thousand euro).

The fees accrued by other auditors for audit services rendered during 2011 total 680 thousand euro (2010: 369 thousand euro).

Appendix I

Subsidiaries included in the Consolidation Scope

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Isolux Ingeniería, S.A.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	PwC
Watsegur, S.A.	Madrid	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	PwC
Elaborados Metálicos Emesa S.L.	A Coruña	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	Pwc
GIC Fábricas, S.A.	Madrid	100.00%	Isolux Ingeniería, S.A.	FC	Construction	PwC
Eólica Isolcor, S.L.	Madrid	100.00%	Isolux Ingeniería, S.A.	FC	Construction	Unaudited
Luxeol S.L.	Madrid	70.00%	Isolux Ingeniería, S.A.	FC	Concessions	Unaudited
Sociedad Concesionaria Zona 8-A, S.A	Zaragoza	100.00%	Isolux Ingeniería, S.A.	FC	Concessions	PwC
Desarrollos de Ingeniería Iguaran S.A. (1)	Avilés	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	Unaudited
Isolux Eólica, S.A	Madrid	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	Unaudited
Isolux Ingeniería USA LLC	Houston	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	E&Y
Isowat Mozambique, Lda.	Maputo	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	Unaudited
Isolux Maroc, S.A.	Casablanca	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	PwC
Agua Limpa Paulista, S.A	Sao Paulo	40.00%	Isolux Ingeniería, S.A.	FC	Engineering	PwC
Isolux Corsán Polonia Sp Zoo	Varsovia	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	Unaudited
Construcciones e Instalaciones del Noreste S.A. de C.V	México DF	100.00%	Isolux de México, S.A. de C.V.	FC	Engineering	PwC
Tecna Estudios y Proyectos S.A.	Buenos Aires	50.01%	Isolux Ingeniería, S.A.	FC	Engineering	PwC
Tecna Proyectos y Operaciones, S.A.	Madrid	100.00%	Tecna Estudios y Proyectos S.A.	FC	Engineering	PwC
Tecna Engineering LLC	Houston	100.00%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	Other
Latintecna, S.A.	Lima	99.00%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	Other
Tecna Bolivia, S.A.	Sta Cruz de la Sierra	90.00%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	PwC
Tecninct Proyectos e Ingeniería S.A. de C.V.	México DF	100.00%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	Other
Tecna Brasil Ltda.	Rio de Janeiro	98.95%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	PwC
Medianito del Ecuador, S.A.	Quito	76.90%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	PwC
Ven Tecna, S.A.	Caracas	99.00%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	Other
Tecna del Ecuador, S.A.	Quito	76.92%	Tecna Proy. y Operaciones, S.A.	FC	Engineering	PwC
Isolux Wat Ingeniería, S.L.	Madrid	100.00%	Isolux Ingeniería, S.A.	FC	Engineering	Unaudited
Powertec Española, S.A.	Madrid	100.00%	Isolux Wat Ingeniería, S.L.	FC	Engineering	Unaudited
Powertec Proyectos e Obras Ltda.	Rio de Janeiro	100.00%	Powertec Española, S.A.	FC	Engineering	Unaudited
Isolux Corsán Servicios S.A.	Madrid	100.00%	Isolux Wat Ingeniería, S.L.	FC	Services	PwC
Global Vambru, S.L.	Madrid	100.00%	Isolux Corsán Servicios S.A.	FC	Engineering	PwC
Residuos Ambientales de Galicia S.L. (*)	Madrid	100.00%	Global Vambru, S.L	PC	Concessions	Unaudited
Grupo Isolux Corsán Concesiones, S.L.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Concessions	PwC
Isolux Infrastructure, S.A. (*)	Sao Paulo	100.00%	Grupo Isolux Corsán Concesiones, S.L.	FC	Concessions	Unaudited
Isolux Corsán Concesiones, S.A.	Madrid	100.00%	Isolux Infrastructure, S.A.	FC	Concessions	PwC
Grupo T-Solar Global, S.A. (*)	Madrid	58.84%	Isolux Infrastructure, S.A.	FC	Concessions	PwC
Isolux Corsán Concesiones de Infraestructuras, S.L.	Madrid	100.00%	Isolux Infrastructure, S.A.	FC	Concessions	PwC

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Conc. Aut. Monterrey-Saltillo, S.A.C.V.	México DF	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	PwC
Vías Administración y Logística, S.A. de C.V.	México DF	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	PwC
Isolux Corsán Concesiones de México, S.A. de C.V.	México DF	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	Unaudited
Isolux Energia e Participaçoes Ltda.	Rio de Janeiro	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	Deloitte
Cachoeira Paulista T. Energia S.A. (*)	Rio de Janeiro	100.00%	Isolux Energia e Participaçoes Ltda.	FC	Concessions	Deloitte
Linhas de Xingu Transmissora de Energía	Rio de Janeiro	100.00%	Isolux Energia e Participaçoes Ltda.	FC	Concessions	Unaudited
Linhas de Macapa Transmissora de Energía	Rio de Janeiro	100.00%	Isolux Energia e Participaçoes Ltda.	FC	Concessions	Unaudited
Linhas de Taubaté Transmissora de Energía (*)	Rio de Janeiro	100.00%	Isolux Energia e Participaçoes Ltda.	FC	Concessions	Unaudited
Iccenlux Corp.	Delaware	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	E&Y
Isolux Corsan Energy Cyprus Limited	Nicosia	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	Unaudited
Isolux Corsan Power Concessions India Private Limited	Haryana	100.00%	Isolux Corsan Energy Cyprus Limited	FC	Concessions	Unaudited
Mainpuri Power Transmission Private Limited	Haryana	74.00%	Isolux Corsan Power Concessions India Private Ltd	FC	Concessions	Unaudited
Isolux Corsan Concessions Infrast. Holland BV (2)	La Haya	100.00%	Isolux Corsán Concesiones, S.A.	FC	Concessions	Unaudited
Sociedad Concesionaria Autovía A-4 Madrid S.A.	Madrid	48.75%	Isolux Corsán Concesiones de Infraestruct., S.L	FC	Concessions	PwC
Isolux Corsán Mexicana de Infraestructuras, S.L.	Madrid	100.00%	Isolux Corsán Concesiones de Infraestruct., S.L	FC	Concessions	Unaudited
Isolux Corsan NH1 Cyprus Limited	Nicosia	100.00%	Isolux Corsán Concesiones de Infraestruct., S.L	FC	Concessions	Other
Soma-Isolux NH One Tollway Private Limited	Haryana	61.00%	Isolux Corsan NH1 Cyprus Limited	FC	Concessions	Other
Isolux Corsán Brasileña de Infraestructuras, S.L.	Madrid	100.00%	Isolux Corsán Concesiones de Infraestruct., S.L	FC	Concessions	Unaudited
Isolux Corsán Participaciones de Infraestructura Ltda	Sao Paulo	100.00%	Isolux Corsán Brasileña de Infraestructuras, S.L.	FC	Concessions	Unaudited
Isolux Corsán Participaciones en Viabahía Ltda	Sao Paulo	100.00%	Isolux Corsán Participaciones de Infraestruct. Ltda.	FC	Concessions	Unaudited
Viabahia Concessionaria de Rodovias, S.A.	Sao Paulo	55.00%	Isolux Corsán Participaciones en Viabahía Ltda	FC	Concessions	PwC
Desarrollo de Concesiones y Servicios Sercon, S.A.	Madrid	100.00%	Grupo Isolux Corsán Concesiones, S.L.	FC	Services	Unaudited
Parque Eólico Cova da Serpe II, S.L.	Madrid	100.00%	Grupo Isolux Corsán Concesiones, S.L.	FC	Concessions	Unaudited
Intal. y Montajes La Grela, S.A.	A Coruña	100.00%	Grupo Isolux Corsán Concesiones, S.L.	FC	Engineering	Unaudited
Isolux Corsán Aparcamientos, S.L.	Madrid	100.00%	Grupo Isolux Corsán Concesiones, S.L.	FC	Concessions	PwC
Aparcamientos IC Talavera II, S.L.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Aparcamientos IC Segovia II, S.L.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Aparcamientos IC Ruiz de Alda S.A.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Explotaciones Las Madrigueras, S.L.	Tenerife	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Aparcamientos IC Zaragoza Torrero, S.L.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Isolux Corsán Aparcamientos Madrid, S.A.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
I.C. Plaza de Benalmádena Canarias (*)	Las Palmas	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Hixam Gestión de Aparcamientos, S.L.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	PwC
Ceutí de Aparcamientos y Serv., S.A.	Ceuta	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Aparcamientos IC Zaragoza, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Aparcamientos IC Talavera, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Aparcamientos Islas Canarias, S.L.	Las Palmas	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Gestión de Concesiones, S.A.	La Línea	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Aparcamientos IC Toledanos, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Aparcamientos Segovia, S.L.	Segovia	100.00%	Hixam Gestión de Aparcamientos, S.L.	FC	Concessions	Unaudited
Hixam Gestión de Aparcamientos II, S.L.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	PwC
Aparcamientos IC Toledanos II, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos II, S.L.	FC	Concessions	Unaudited

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Aparcamientos IC Ponzano, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos II, S.L.	FC	Concessions	Unaudited
Aparcamientos IC Hospital de Murcia, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos II, S.L.	FC	Concessions	Unaudited
Aparcamientos IC Chiclana, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos II, S.L.	FC	Concessions	Unaudited
Aparcamientos IC Córdoba, S.L.	Madrid	100.00%	Hixam Gestión de Aparcamientos II, S.L.	FC	Concessions	Unaudited
Hixam Gestión de Aparcamientos III, S.L.	Madrid	100.00%	Isolux Corsán Aparcamientos S.L.	FC	Concessions	Unaudited
Corsan-Corviam Construcción, S.A.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Construction	PwC
Constructora Pina do Vale, S.A.	Lisboa	100.00%	Corsán Corviam Construcción S.A.	FC	Construction	PwC
Extremeña de Infraestructura, S.A.	Madrid	100.00%	Corsán Corviam Construcción S.A.	FC	Construction	Unaudited
Isolux Corsán Cyprus Limited	Nicosia	100.00%	Corsán Corviam Construcción S.A.	FC	Engineering	Unaudited
Isolux Corsán Panamá, S.A.	Ciudad de Panamá	100.00%	Corsán Corviam Construcción S.A.	FC	Construction	Unaudited
Isolux de México, S.A. de C.V.	México DF	100.00%	Corsán Corviam Construcción S.A.	FC	Engineering	PwC
Isolux Corsán Argentina S.A.	Buenos Aires	100.00%	Corsán Corviam Construcción S.A.	FC	Engineering	PwC
Isolux Corsán Argelie EURL	Argel	100.00%	Corsán Corviam Construcción S.A.	FC	Construction	Pwc
Isolux Corsán do Brasil S.A.	Rio de Janeiro	100.00%	Corsán Corviam Construcción S.A.	FC	Engineering	Unaudited
Isolux Projectos, Investimentos e Participaçoes LTDA (*)	Sao Paulo	100.00%	Corsán Corviam Construcción S.A.	FC	Construction	Unaudited
Isolux Proyectos e Instalaciones LTDA.	Rio de Janeiro	100.00%	Isolux Projectos, Invest. e Participaçoes LTDA	FC	Construction	Unaudited
Isolux Corsán India Eng. & Constuction Private LTD.	Haryana	100.00%	Corsán Corviam Construcción S.A.	FC	Construction	PwC
Isolux Corsán Inmobiliaria, S.A.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Real-estate	PwC
Valdelrío, S.L.	Madrid	100.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	Unaudited
Electrónica Control de Motores, S.A.	Madrid	100.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	Unaudited
Julitex, S.L.	Las Palmas	80.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	Unaudited
El Sitio de la Herrería, S.L.	Madrid	100.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	Unaudited
Interisolux Torrejón Vivienda Joven, S.L.	Madrid	90.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	PwC
Interisolux Alcorcón Vivienda Joven, S.L.	Madrid	80.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	PwC
Olmosa, S.L.	Madrid	100.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	Unaudited
Cost Wright, S.L.	Madrid	100.00%	Isolux Corsán Inmobiliaria, S.A.	FC	Real-estate	Unaudited
Unidad Mater. Avanz. Ibérica, S.A.	Orense	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
Infinita Renovables, S.A.	Vigo	80.70%	Grupo Isolux Corsán, S.A.	FC	Renewable energies	PwC
Azul de Cortes BV	Amsterdam	100.00%	Grupo Isolux Corsán, S.A.	FC	Real-estate	Unaudited
Azul de Cortes, S. de R.L, de C.V.	La Paz	100.00%	Azul de Cortes BV	FC	Real-estate	PwC
Bendía, S.A.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
EDIFISA, S.A.	Madrid	96.04%	Grupo Isolux Corsán, S.A.	FC	Real-estate	Unaudited
Corvisa, S.L.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	PwC
Powertec Cataluña, S.A.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
Powertec Sistemas, S.A.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
Acta, S.A.	Lisboa	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Other
Isolux Corsan Gulf LLC	Oman	70.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
Isolux Corsan Energías Renovables, S.A.	Buenos Aires	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
Inversiones Blumen, S.L.	Madrid	100.00%	Grupo Isolux Corsán, S.A.	FC	Engineering	Unaudited
T-Solar Global Operating Assets, S.L. (*)	Madrid	51.00%	Grupo T-Solar Global, S.A.	FC	Concessions	PwC
Tuin Zonne Origen, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
T-Solar Global, S.A.U. (*)	Vigo	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	PwC
Global Surya, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
TZ Almodóvar del Río, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Ortosolar Promotor de Energías Renovables, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Global Elefantina, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Tuin Zonne Solar, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
T-Solar Autónoma S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
TZ Albaida 2 S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Tuin Zonne Laguna Dalga S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
TZ Morón Uno, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
TZ Morón 2, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Tuin Zonne Ronda 1, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
TZ Ronda 2, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
TZ Santafe 1, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
TZ Santafe 2, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Tuin Zonne Viana, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Ortosol Energía 1, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Ortosol Energía 2, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Ortosol Energía 3, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Ortosol Energía 4, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Ortosol Energía 5, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Ortosol Energía 6, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Mihuersol Jerez 1, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Mihuersol Jerez 2, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Mihuersol Jerez 3, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 4, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 5, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 6, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 7, S.L.U (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 8, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 9, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 10, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 11, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 12, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Mihuersol Jerez 13, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 14, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 15, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 16, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 17, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 18, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Mihuersol Jerez 19, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A	FC	Concessions	Unaudited
Pentasolar, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Pentasolar Talayuela 1, S.L.U. (*)	Madrid	100.00%	Pentasolar, S.L.U.	FC	Concessions	PwC
Pentasolar Talayuela 2, S.L.U. (*)	Madrid	100.00%	Pentasolar, S.L.U.	FC	Concessions	PwC
Pentasolar Madrigal 1, S.L.U. (*)	Madrid	100.00%	Pentasolar, S.L.U.	FC	Concessions	PwC
Pentasolar Madrigal 2, S.L.U. (*)	Madrid	100.00%	Pentasolar, S.L.U.	FC	Concessions	PwC
TZ Morita, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ Morita 1, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Morita 2, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Morita 3, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Morita 4, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Morita 5, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Morita 6, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Morita 7, S.L.U. (*)	Madrid	100.00%	TZ Morita, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 1, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 2, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 3, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 4, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 5, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 6, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Castillo de Alcolea 7, S.L.U. (*)	Madrid	100.00%	TZ Castillo de Alcolea, S.L.U.	FC	Concessions	PwC
TZ Archidona I , S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Tuin Zonne Archidona 1, S.L.U. (*)	Madrid	100.00%	TZ Archidona I, S.L.U.	FC	Concessions	PwC
TZ Archidona 2, S.L.U. (*)	Madrid	100.00%	TZ Archidona I, S.L.U.	FC	Concessions	PwC
TZ Archidona 3, S.L.U. (*)	Madrid	100.00%	TZ Archidona I, S.L.U.	FC	Concessions	PwC
TZ Archidona 4, S.L.U. (*)	Madrid	100.00%	TZ Archidona I, S.L.U.	FC	Concessions	PwC
TZ Archidona 5, S.L.U. (*)	Madrid	100.00%	TZ Archidona I, S.L.U.	FC	Concessions	PwC
TZ Archidona 6, S.L.U. (*)	Madrid	100.00%	TZ Archidona I, S.L.U.	FC	Concessions	PwC
TZ La Poza, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ La Poza 1, S.L.U. (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ La Poza 2, S.L.U. (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ La Poza 3, SLU (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ La Poza 4, SLU (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ La Poza 5, SLU (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ La Poza 6, SLU (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ La Poza 7, SLU (*)	Madrid	100.00%	TZ La Poza, S.L.U.	FC	Concessions	PwC
TZ Buenavista, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ Buenavista 1, S.L.U. (*)	Madrid	100.00%	TZ Buenavista, S.L.U.	FC	Concessions	PwC
TZ Buenavista 2, S.L.U. (*)	Madrid	100.00%	TZ Buenavista, S.L.U.	FC	Concessions	PwC
TZ Buenavista 3, S.L.U. (*)	Madrid	100.00%	TZ Buenavista, S.L.U.	FC	Concessions	PwC
TZ Buenavista 4, S.L.U. (*)	Madrid	100.00%	TZ Buenavista, S.L.U.	FC	Concessions	PwC
TZ Buenavista 5, S.L.U. (*)	Madrid	100.00%	TZ Buenavista, S.L.U.	FC	Concessions	PwC
TZ Buenavista 6, S.L.U. (*)	Madrid	100.00%	TZ Buenavista, S.L.U.	FC	Concessions	PwC
TZ Buenavista 7, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
TZ Alcolea Lancha, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 1, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 2, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 3, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 4, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 5, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 6, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
TZ Alcolea Lancha 7, S.L.U. (*)	Madrid	100.00%	TZ Alcolea Lancha, S.L.U.	FC	Concessions	PwC
Tuin Zonne Veguilla, S.L. (*)	Madrid	73.53%	Tuin Zonne Orig, S.L.U. y Mihuersol Jerez, S.L.	FC	Concessions	PwC
TZ Veguilla 1, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
TZ Veguilla 2, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
TZ Veguilla 3, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
TZ Veguilla 4, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
TZ Veguilla 5, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
TZ Veguilla 6, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
TZ Veguilla 7, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Veguilla, S.L.	FC	Concessions	PwC
Tuin Zonne Los Mochuelos, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ Los Mochuelos 1, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Los Mochuelos, S.L.U.	FC	Concessions	PwC
TZ Los Mochuelos 2, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Los Mochuelos, S.L.U.	FC	Concessions	PwC
TZ Los Mochuelos 3, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Los Mochuelos, S.L.U.	FC	Concessions	PwC
TZ Los Mochuelos 4, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Los Mochuelos, S.L.U.	FC	Concessions	PwC
TZ Los Mochuelos 5, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Los Mochuelos, S.L.U.	FC	Concessions	PwC
TZ Los Mochuelos 6, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Los Mochuelos, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo 1, S.L.U. (*)	Madrid	100.00%	Pensolar Pozohondo, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo 2, S.L.U. (*)	Madrid	100.00%	Pensolar Pozohondo, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo 3, S.L.U. (*)	Madrid	100.00%	Pensolar Pozohondo, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo 4, S.L.U. (*)	Madrid	100.00%	Pensolar Pozohondo, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo 5, S.L.U. (*)	Madrid	100.00%	Pensolar Pozohondo, S.L.U.	FC	Concessions	PwC
Pensolar Pozohondo 6, S.L.U. (*)	Madrid	100.00%	Pensolar Pozohondo, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada 1, S.L.U. (*)	Madrid	100.00%	Pensolar Pozocañada, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada 2, S.L.U. (*)	Madrid	100.00%	Pensolar Pozocañada, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada 3, S.L.U. (*)	Madrid	100.00%	Pensolar Pozocañada, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada 4, S.L.U. (*)	Madrid	100.00%	Pensolar Pozocañada, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada 5, S.L.U. (*)	Madrid	100.00%	Pensolar Pozocañada, S.L.U.	FC	Concessions	PwC
Pensolar Pozocañada 6, S.L.U. (*)	Madrid	100.00%	Pensolar Pozocañada, S.L.U.	FC	Concessions	PwC
Granadasolar E. Renovables, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Granadasolar Sigüenza 1, S.L.U. (*)	Madrid	100.00%	Granadasolar E. Renovables, S.L.U.	FC	Concessions	PwC
Granadasolar Sigüenza 2, S.L.U. (*)	Madrid	100.00%	Granadasolar E. Renovables, S.L.U.	FC	Concessions	PwC
Aspa Energías Renovables, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
TZ La Seca 1, S.L.U. (*)	Madrid	100.00%	Aspa Energías Renovables, S.L.U.	FC	Concessions	PwC

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
TZ La Seca 2, S.L.U. (*)	Madrid	100.00%	Aspa Energías Renovables, S.L.U.	FC	Concessions	PwC
Tuin Zonne Medina, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Tuin Zonne Medina 1, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Medina, S.L.U	FC	Concessions	PwC
Tuin Zonne Medina 2, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Medina, S.L.U	FC	Concessions	PwC
Tuin Zonne Medina 3, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Medina, S.L.U	FC	Concessions	PwC
TZ El Carpio, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Elduayen Fotovoltaica, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
P.S. Huerto Son Falconer, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Borealis Solar, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
European Sun Park Arnedo, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Windmill Fotovoltaica, S.L.U. (*)	Madrid	100.00%	Tuin Zonne Origen, S.L.U.	FC	Concessions	PwC
Windmill Energie Alicante 1.1, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.2, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Windmill Energie Alicante 1.3, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Windmill Energie Alicante 1.4, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Windmill Energie Alicante 1.5, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.6, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.7, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.8, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.9, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.10, S.L.U.(*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 1.11, S.L.U.(*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.1, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.2, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.3, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.4, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.5, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.6, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.7, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.8, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.9, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.10, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Alicante 2.11, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.3, S.L.U.(*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.4, S.L.U.(*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.5, S.L.U.(*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.6, S.L.U.(*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.7, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.8, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.9, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 3.10, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.1, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited

Appendix I | Subsidiaries included in the Consolidation Scope (Continuation)

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Windmill Energie Valladolid 4.2, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.3, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.4, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.5, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.6, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.7, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.8, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.9, S.L.U. (*)	Madrid	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Windmill Energie Valladolid 4.10, S.L.U. (*)	León	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Unaudited
Yeguas Altas, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Huerto Albercones, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Huerto Las Pesetas, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Huerto Cortillas, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Huerto Paniza, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Huerto Montera, S.L.U. (*)	Madrid	100.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Parque Solar Saelices, S.L (*)	Madrid	5.00%	T-Solar Global Operating Assets, S.L.	FC	Concessions	PwC
Gts Rapartición, S.A.C (*)	Lima	99.99%	Grupo T-Solar Global, S.A.	FC	Concessions	PwC
Gts Majes, S.A.C. (*)	Lima	99.99%	Grupo T-Solar Global, S.A.	FC	Concessions	PwC
Raggio di Puglia 2 S.R.L. (*)	Roma	100.00%	Grupo T-Solar Global, S.A.	FC	Concessions	PwC
ARRL (Mauritius) Limited (*)	Isla Mauricio	50.00%	Grupo T-Solar Global, S.A.	FC	Concessions	Mazars
Astonfield Solar Rajasthan (Private) Limited (*)	Delhi	100.00%	ARRL (Mauritius) Limited	FC	Concessions	Other
Astonfield Solar Gujarat (Private) Limited (*)	Delhi	100.00%	ARRL (Mauritius) Limited	FC	Concessions	Other
T Solar Cyprus Limited (*)	Nicosia	100.00%	Global Elefantina S.L..	FC	Concessions	Unaudited

(*) Companies acquired or incorporated during the year and/or additional investment in companies already included in the consolidation scope in the previous year. The inclusion of these companies in the consolidation scope did not generate additional sales during the year.
(1) Change in social name during the year (before-named Energía de Asturias GIC, S.A.)
(2) Change in social name during the year (before-named AB Alternative Investment, B.V.)
FC: Full Consolidation.

Appendix II

Associates included in the consolidation scope

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Gestión de Partícipes de Bioreciclaje, S.L.	Cádiz	33.33%	Global Vambru, S.L	EC	Concessions	Other
Autopista Madrid Toledo Concesionaria, S.A.	Madrid	25.50%	Grupo Isolux Corsán Concesiones, S.L.	EC	Concessions	Auren
Proyectos Inmobiliarios Residenciales, S.L.	Madrid	25.60%	Isolux Corsán Inmobiliaria, S.A.	EC	Real-estate	Unaudited

(*) Added to the consolidation scope during the year.
EC: Equity method.

Appendix III

Joint ventures included in the consolidation scope

Company name	Address	% of interest	Shareholder	Consolidation method	Activity	Auditor
Lineas de Comahue Cuyo, S.A.	Buenos Aires	33.34%	Grupo Isolux Corsán, S.A.	PC	Engineering	PwC
Indra Isolux de México S.A de C.V.	México DF	50.00%	Isolux de México, S.A. de C.V.	PC	Engineering	Unaudited
Constructora Autopista Perote Xalapa S.A. de C.V.	México DF	50.00%	Isolux de México, S.A. de C.V.	PC	Construction	PwC
Partícipes de Biorreciclaje, S.L.	Madrid	33.33%	Global Vambru, S.L	PC	Concessions	Other
Bioreciclajes de Cádiz S.A.	Cádiz	32.66%	Partícipes de Biorreciclaje, S.L.	PC	Concessions	Other
Isonor Transmission S.A.C. Perú	Lima	50.00%	Grupo Isolux Corsán Concesiones, S.L.	PC	Concessions	PwC
Caravelli Coteruse Transmisora de Energía S.A.C.	Lima	50.00%	Isonor Transmisión S.A.C.	PC	Concessions	PwC
Parking Pio XII, S.L.	Palencia	50.00%	Isolux Corsán Aparcamientos S.L.	PC	Concessions	Unaudited
Aparcamientos IC Sarrión	Madrid	51.00%	Isolux Corsán Aparcamientos S.L.	PC	Concessions	Other
Emiso Cádiz S.A.	Cádiz	50.00%	Isolux Corsán Aparcamientos S.L.	PC	Concessions	Unaudited
Aparcamientos Los Bandos Salamanca, S.L	Madrid	70.00%	Isolux Corsán Aparcamientos S.L.	PC	Concessions	Unaudited
Concesionaria Autopista Perote Xalapa S.A. de C.V.	México DF	50.00%	Isolux Corsán Concesiones, S.A.	PC	Concessions	PwC
Wett Holdings LLC	Delaware	50.00%	Iccenlux Corp.	PC	Concessions	Unaudited
Wett - Wind Energy Transmission Texas, LLC.	Austin	50.00%	Wett Holdings	PC	Concessions	E&Y
ICC Sandpiper, B.V.	Amsterdam	100.00%	Isolux Corsan Concessions Infrast Holland BV	PC	Concessions	Unaudited
Isolux Corsan Concessions Cyprus Limited	Nicosia	100.00%	ICC Sanpiper BV	PC	Concessions	Unaudited
Indus Concessions India Private Limited (3)	Haryana	100.00%	Isolux Corsán Concessions Cyprus Ltd	PC	Concessions	Unaudited
Soma Isolux Surat Hazira Tollway PVT, LTD	Haryana	50.00%	Indus Concessions India Private Limited	PC	Concessions	Other
Soma Isolux Varanasi Aurangabad Tollway Private Ltd	Haryana	50.00%	Indus Concessions India Private Limited	PC	Concessions	Unaudited
Soma Isolux Kishangarh-Ajmer-Beawar Tollway PVT.Ltd	Haryana	50.00%	Indus Concessions India Private Limited	PC	Concessions	Other
Integracao Electrica Norte e Nordeste, S.A.	Sao Paulo	50.00%	Isolux Energia e Participaçoes Ltda.	PC	Concessions	Unaudited
Jauru Transmisora de Energía S.A.	Rio Janeiro	33.33%	Isolux Energia e Participaçoes Ltda.	PC	Concessions	Deloitte
Plena Operaçao e Manutençao de Trans. de Energía Ltda	Rio Janeiro	33.33%	Isolux Energia e Participaçoes Ltda.	PC	Concessions	Unaudited
Carreteras Centrales de Argentina, S.A.	Buenos Aires	49.00%	Corsán Corviam Construcción S.A.	PC	Construction	Unaudited
Societat Superficiaria Preventius Zona Franca S.A. (*)	Barcelona	50.00%	Corsán Corviam Construcción S.A.	PC	Construction	Unaudited
Isolux Corsán India & Soma Enterprises Limited	Haryana	50.00%	Isolux Corsán India Eng. & Const Pvt Ltd	PC	Engineering	Unaudited
Pinares del Sur, S.L.	Cádiz	50.00%	Isolux Corsán Inmobiliaria, S.A.	EC	Real-estate	PwC
Landscape Corsán, S.L.	Madrid	50.00%	Isolux Corsán Inmobiliaria, S.A.	EC	Real-estate	Unaudited
Las Cabezadas de Aranjuez S.L.	Madrid	40.00%	Isolux Corsán Inmobiliaria, S.A.	EC	Real-estate	E&Y
Alqlunia5 S.A.	Toledo	50.00%	Isolux Corsán Inmobiliaria, S.A.	EC	Real-estate	Other
Eclesur, S.A.	Buenos Aires	50.00%	Grupo Isolux Corsán, S.A.	PC	Engineering	Unaudited
Lineas Mesopotanicas S.A.	Buenos Aires	33.33%	Grupo Isolux Corsán, S.A.	PC	Engineering	PwC
Lineas del Norte S.A.	Buenos Aires	33.33%	Grupo Isolux Corsán, S.A.	PC	Engineering	PwC
Ciudad de la Justicia de Córdoba S.A. (*)	Sevilla	50.00%	Corsán Corviam Construcción S.A.	PC	Construction	Unaudited
Empresa Concesionaria Líneas Eléctricas del Sur, S.A.	Buenos Aires	50.00%	Grupo Isolux Corsán, S.A.	PC	Engineering	Unaudited

(*) Companies acquired or incorporated during the year and/or additional investment in companies already included in the consolidation scope in the previous year. The inclusion of these companies in the consolidation scope did not generate additional sales during the year.
(3) Change of social name during the year (before-named Isolux Corsán Concessions India Private Limited)
PC: Proportional consolidation method.
EC: Equity consolidation method.

Appendix IV

Joint Ventures and Consortiums participated by companies included in the Consolidation Scope

Joint ventures' name	% of interest
DEPURADORA MAIMONA UTE	100.00%
UTE. BURGO-MEDIANA	50.00%
UTE EDAR CARBONERO	100.00%
ACCESO PTO. VALENCIA	40.00%
UTE JUCAR VINALOPO	33.33%
CAMINO DE SANTIAGO	50.00%
CORREDOR DEL MORRAZO	50.00%
RONDA LOS OMEYAS UTE	33.34%
FFCC EL PORTAL UTE	70.00%
CONVENTO SAN FRANCISCO	50.00%
UTE PUNTO LIMPIO BENAVENTE	50.00%
UTE ZAMORA VERDE	33.00%
UTE EDAR LA LINEA	50.00%
UTE DESDOBLAMIENTO CARTAMA	60.00%
UTE VARIANTE LINARES	50.00%
UTE MADRID TOLEDO	36.00%
REGADIO BEMBEZAR UTE	50.00%
UTE DESDOBLAMIENTO MARTOS	50.00%
FFCC OSUNA AGUADULCE	50.00%
EJE ATLANTICO ALTA VELOCIDAD	50.00%
UTE LAXE	100.00%
UTE EMERG.QUIEBRAJANO	50.00%
UTE ALMAGRO	100.00%
ABASTECIMIENTO OVIEDO	100.00%
UTE ACCESO CORUÑA	50.00%
M-501 PANTANOS	50.00%
UTE COIN CASAPALMA	50.00%
UTE ALMOHARIN	50.00%
HOSPITAL DE BURGOS	10.00%
UTE ABASTECIMIENTO LERIDA	70.00%
UTE MUELLE BAIONA	65.00%
UTE AITREN.SUPLIDOS	20.00%
UTE HOSPITAL MILITAR	100.00%
UTE MUNICIPO CORDOBA	50.00%
LINEA AVE CAMPOMANES	50.00%
UTE CATENARIA MALAGA	50.00%
UTE L5 HORTA	40.00%
UTE INECAT	39.25%

Joint ventures' name	% of interest
UTE VIA SAGRERA	50.00%
SEDE ADMINISTRATIVA HOSPITAL	100.00%
UTE ENLACE MEIRAS	50.00%
UTE DG POLICIA	100.00%
ACCESOS SOTO RIBERA	60.00%
UTE CAJA DUERO	100.00%
REHABILITACIÓN CUARTEL TENIENTE RUIZ	42.50%
3M APARCAMIENTOS CEUTA	42.50%
BARRIADA PR.ALFONSO	50.00%
LT 220 KV LUCALA-UIGE	33.33%
MANTENIMIENTO ALCALA - MECO	100.00%
GALERIAS BARAJAS	100.00%
UTE VALENCIA V	50.00%
UTE DCS LOMA LA LATA	50.00%
UTE ELECTRIFICACIÓN PARAPLEJICOS	100.00%
SISTEMAS A4T1	50.00%
UTE LEVATEL	50.00%
MUSEO DE AMERICA	100.00%
UTE ENARSA OFF	50.00%
UTE EDAR LA CHINA	50.00%
CSIC EN LA CARTUJA	100.00%
UTE ARQUITECTURA L-5	43.50%
AMPLIACIÓN HOSPITAL GUADALAJARA	50.00%
HOSPITALIZACION	100.00%
MADRES MADRID WATSEGUR	100.00%
UTE PLANTA COMPRESORA	50.00%
PUENTE PISUERGA UTE	50.00%
EUBA-IURRETA UTE	50.00%
RONDA POCOMACO-CORUÑA	80.00%
UTE LOECHES	50.00%
CENTRO PENITENCIARIO CEUTA	100.00%
AZUCARERA PRAVIA UTE	60.00%
MANTENIMIENTO EDIFICIO ADMINISTRATIVO XUNTA	70.00%
TUNEL STA.Mª CABEZA	51.00%
UTE AVE PINAR II	64.29%
BEATRIZ DE BOBADILLA	100.00%
AUTOVIA CONCENTAINA	50.00%
INTERC.ARCO TRIUNFO	100.00%

Appendix IV | Joint Ventures and Consortiums participated by companies included in the Consolidation Scope (Continuation)

Joint ventures' name	% of interest
UTE CLIMATIZACIÓN ALCAZAR	40.00%
UTE GUINOLUX	50.00%
SANEAMIENTO Y ABASTECIMIENTO CHICLANA	50.00%
UTE ACCESOS CIUDAD REAL	70.00%
UTE U 11 SAN LAZARO	70.00%
HOSPITAL PARAPLEJICOS TOLEDO	80.00%
J.M.VILLA VALLECAS	20.00%
J.M.VILLA VALLECAS	80.00%
MANTENIMIENTO J.M.MORATALAZ	100.00%
UTE PRESA SANTOLEA	50.00%
EMISARIO RIO PISUERGA	50.00%
UTE DEPURADORA FERNÁN NUÑEZ	100.00%
UTE AVE TRINIDAD	33.34%
UTE PLAZA SUR DELICIAS	50.00%
UTE MACEIRAS REDONDELA	50.00%
UTE EDIFICIO MEDICINA	50.00%
SANEAMIENTO PUERTO DEL CARMEN	70.00%
TRAVESIA MARTOS II	50.00%
UTE MARBELLA	100.00%
ABASTECIMIENTO OROPESA	100.00%
CARRETERA VALLEHERMOSO-ARURE	70.00%
AUTOVIA IV CENTENARIO	70.00%
VIA PRAT LLOBREGAT	25.00%
MANTENIMIENTO EDIFICIO MEDIO AMBIENTE	100.00%
ACOND.A-495 UTE	60.00%
REDES BCN UTE	50.00%
UTE PRESA HORNACHUELOS	50.00%
UTE CABREIROS	70.00%
LOMA LA LATA - OFF	75.00%
REGADIO DURATON UTE	100.00%
UTE 3 EDAR SESEÑA	99.00%
ACOMETIDAS ATEWICC-4	33.33%
CARRETERA LEÓN CEMBRANOS	65.00%
DRATYP IX UTE	50.00%
T.RENFE 07-CENTRO UTE	50.00%
T.RENFE 07-NORTE UTE	50.00%
UTE PTO.RICO-MOGAN	30.00%
UTE L3 ROQUETES	100.00%
FACULTAD MEDICINA CTCS	50.00%
UTE CORONA F.ABAJON	50.00%
MANIPE ASTURIAS	100.00%
RAMBLA ALBOX	70.00%
MANTENIMIENTO COMUNICACION.L9	20.00%
METRO-R.METTAS/VAPES	50.00%

Joint ventures' name	% of interest
UTE TUNEL BIELSA	50.00%
PRESA GUADALMELLATO	60.00%
UTE GERONA I	50.00%
LAV PINOS PUENTE	80.00%
PCI L2 METRO BCN	50.00%
PLANTA TRATAMIENTO RSU	30.00%
ZAMORA LIMPIA	30.00%
AYUNTAMIENTO JARAIZ	50.00%
UTE AGUAS CILLEROS	60.00%
UTE AVICO	33.34%
HOSP.GR.DE LAFERRERE	40.00%
BALSA DE VICARIO	70.00%
UTE ZONA VERDE	60.00%
UTE MONUMENTO HISTORICO	60.00%
UTE ALICANTE I	40.00%
UTE RIO TURBIO C&S	50.00%
UTE AVE PORTO-MIAMAN	75.00%
UTE AYUNTAMIENTO MORALEJA	60.00%
UTE HOSPITAL ZUMARRAGA	80.00%
UTE TORIO-BERNESGA	50.00%
TOLOSA-HERNIALDE UTE	90.00%
RMS AEROPUERTO SANTIAGO	50.00%
UTE CEUTA APARCAMIENTO	50.00%
UTE CHUAC	50.00%
MTTO. VIA ADIF 2011	50.00%
CONSERVACIÓN CIUDAD REAL	50.00%
ACONDICIONAMIENTO LOS RODEOS	70.00%
CARCEL DE MENDOZA	50.00%
COMISARIA TARRAGONA	90.00%
MERCADO DE TARRAGONA	99.90%
UTE PALENCIA	50.00%
MEJORAS TENERIFE SUR	100.00%
UTE HOSPITAL DEL SUR	40.00%
PSFV EN INGLATERRA	100.00%
NUEVO APOYO TERMINAL BARCELONA UTE	100.00%
UTE VERDUGA	100.00%
CIS TENERIFE UTE	100.00%
CENTRO PENITENCIARIO ANDALUCIA ORIENTAL	100.00%
RIO TURBIO	91.00%
UTE EDAR TOMELLOSO	90.00%
UTE MURO	60.00%
LOMA LATA ON	75.00%
UTE RIO TURBIO OFF	91.00%
CERCANIAS PINTO UTE	40.00%

Appendix IV | Joint Ventures and Consortiums participated by companies included in the Consolidation Scope (Continuation)

Joint ventures' name	% of interest
UTE VALENCIA 1	50.00%
UTE IDAM MONCOFA	45.00%
ACTUACIONES MEDIAMBIENTALES AVE	33.34%
UTE LAVACOLLA	55.00%
QATAR	100.00%
UTE PLANTA ALGAR	99.00%
UTE ACCESO PRINCIPE	50.00%
UTE REMODELACIÓN L3 TMB	40.00%
MANTENIMIENTO UNIVERSIDAD ALCALA HENARES	100.00%
UTE NUEVO VIAL	50.00%
AUTOVIA A4 TRAMO MADRID R4	50.00%
AUTOVÍA ARANDA	70.00%
UTE FUENTE DE PIEDRA	70.00%
UTE VALENCIA III	50.00%
MANTENIMIENTO T4 BLOQUE 1	100.00%
MANTENIMIENTO EL MOLAR	100.00%
UTE GARABOLOS	80.00%
UTE CORIA-MORALEJA	60.00%
UTE AP7 MAÇANET	55.00%
UTE AVELE	28.00%
UTE AVELE 2	28.00%
UTE CABEZA DE BUEY	80.00%
BLOQ.OBSTETRICO HOSP	40.00%
EDIFICIO MUTUA MADRILEÑA	100.00%
TELECONTROL EDARES	60.00%
UTE COMPOST.ARAZURI	50.00%
UTE VICOTEL	50.00%
HOSPITAL DE PARANA	50.00%
UTE TENIENTE RUIZ	50.00%
UTE PLISAN	50.00%
UTE VARIANTE ALMANSA	50.00%
CONSTRUCCIÓN SUBESTACIONES LINEAS	50.00%

Joint ventures' name	% of interest
TELEMANDO DE ENERGIA	50.00%
UTE BENIDORM	49.00%
SUPLIDOS UTE HOSPITAL	40.00%
UTE LAS TERRAZAS	100.00%
UTE GIRONA	33.00%
UTE MIERA	50.00%
UTE PRESA MELONARES	50.00%
UTE GUADALOPE	50.00%
UTE EMPALME MANACOR	30.00%
LINEA 9 METRO BARCELONA	20.00%
INTERCAMBIADOR SAGRERA	25.00%
AEROPUERTO CIUDAD REAL UTE	65.00%
UTE COMAVE	28.33%
SAVE 3	26.20%
UTE BALIZAMIENTO	33.33%
INTEGRACIÓN SISTEMA	33.33%
SS/EE LINEA 3 METRO	50.00%
HOMOGENEIZACION C.P.	100.00%
UTE ATEWICC 3	33.34%
UTE MUNICIPIOS COSTEROS	100.00%
MTTO. INST. EDIFICIO	100.00%
MTTO.INT.DISTRITO SA	100.00%
HOSPITAL PRINCIPE ASTURIAS	37.61%
RESIDUOS SAN ROQUE	100.00%
Isolux, Soma and Unitech Maharashtra CJV	49.50%
ICI –Soma Maharashtra CJV	50.00%
C&C ICI Mep Services J.V.	50.00%
Isolux - Man J.V. Uttar Pradesh	99.99%
I.C.I. - C&C J.V. Uttar Pradesh	60.00%
I.C.I. - C&C J.V. Varanasi	60.00%
I.C.I. – C&C J.V. Mainpuri	74.00%



1 Economic Environment

During 2011 the gross domestic product (GDP) of the Spanish economy underwent an annual decrease of 0.7% a less sensitive decrease as compared to 0.1% reduction rate experienced during 2010. During 2011 an increase of 2.7% has taken place in the Euro Zone.

This decrease is due in particular to the decline in internal demand (1.4%), mainly caused by the reduction in public administration consumption and in the gross formation of fixed capital (4.8%), household consumption stagnation (0.0%) and a decline of the Public Administrations (-1.4%). The GDP growth of the year was positive due to the increased exports of goods and services by 9.0%.

Employment decreased by 1.9% compared with last year, which led to a sharp increase in the unemployment rate from 20.1% in 2010 to 21.6% in 2011. The consumer price index ended 2011 at 3.2%, which is higher than the 1.8% at which 2010 ended.

Regarding investment, the gross formation of fixed capital fell by 4.8% in 2011, reflecting a 2.1% increase in capital goods and 7.8% decline in construction.

The rapid deterioration of the economic situation during the second part of the year, has led to a slight downwards correction in forecasts for 2012 and 2013 years. The International Monetary Fund and the Bank of Spain paint a recessive scenario for the Spanish economy for 2012.

Economic forecasts for 2012 foresee a significant decline in the performance of the Spanish economy. GDP is expected to decrease by 1% to 2%, with a slight decrease in the public administration consumption due to governmental adjustments and investment. in construction

Economic forecasts for those countries in which the Company operates are quite positive. The expected growth of 2012 Gross Domestic Product is 5.4%, highlighting the forecast for Brazil (3%) and India (7%). These amounts gain greater importance due to the higher degree of internationalization of the Group.

2 Development and performance of the Group in 2011

With respect to Concessions, there was a marked increase in investments in the different areas operated:

- Car Parks: always in national territory, new concessions have been put in operation and investments in new concessions to be operated in future years
- Energy Infrastructures:
  - Significant investment in Brazilian concessions.
  - Beginning of the investments in United States and India.
- Toll roads:
  - Toll road in India has been put into operation (Varanasi),
  - Monterrey-Saltillo toll road in México has been put into operation
  - BR116 (Brazil) toll road has been put into operation.
  - Significant investments in concessions in India, Brazil, Mexico and Spain.
- Photovoltaic Solar Energy: During 2011 and through different corporate transactions, the Group took control of Grupo T-Solar Global, leader in the development and promotion of photovoltaic solar energy. At 31 December 2011 the Company holds 59% of the shares. This group of companies has made important investments in photovoltaic solar plants in Peru, India and Italy during 2011.

In Construction, our presence in traditional sectors in Spain such as land infrastructures (rail and road) was continued, promoting our presence in overseas markets where the Group is developing major infrastructure projects (in countries such as Mexico, Algeria and India). At the moment 50% of the portfolio projects of this business area are related to international sectors.

In Engineering and Services, regarding the international market, the Group has developed major international projects particularly in the transmission area and power generation in countries such as Brazil, Argentina, United States and Angola. As a relavant data, it must be highlighted that more than 80% of the portfolio projects of this business area are related to international projects.

In general the Group has increased its overseas presence which in 2011 reached more than 2/3 of Group's activity, as well as consolidating its leadership position in the domestic market.

Business performance in 2011

2.1. Financial Highlights

The development of the Group's main figures in 2010 and 2011 is as follows:

Key Figures Thousand euro	**2011**	**2010**	**Var (%)**
Total operating revenue	**3,371,940**	**3,239,786**	**4.08%**
Consolidated profit (before non-controlling interests)	5,476	63,960	(91.44%)
Operating profit	265,893	207,702	28.02%
Gross operating profit - EBITDA (1)	392,734	311,198	26.20%
Net financial results	(217,280)	(115,721)	87.76%
Debts associated with Projects (2)	2.616,165	1,235,010	111.83%
Net debt with financial entities (3)	690,175	310,513	122.27%
Total Portfolio (thousand euro)	43,110	30,180	42.84%

(1) Operating profit not taking into account amortization/ depreciation, impairment losses and changes in trade provisions.
(2) Includes short and long-term Project finance.
(3) Includes debts with financial entities net of cash, cash equivalents and short-term bank deposits.

There has been a slight increase in Gross Operating Profit (4.08%) and EBITDA (26.2%). Particularly noteworthy is the 42.84% portfolio increase which includes the T-Solar incorporation in the consolidation scope.

2.2. Group's results

2.2.1. Income Statement Performance

The performance of the income statement for 2011 and 2010, as well as the variation in the most important figures, is as follows:

Thousand euro	**2011**	**2010**	**Variation**
Total operating revenue	**3,371,940**	**3,239,786**	**4.08%**
Turnover	3,200,700	3,188,740	
Other operating income (1)	173,571	46,012	
Inventory changes	(2,331)	5,034	
External and operating expenses	(2,600,281)	(2,549,318)	
Staff costs	(378,925)	(379,270)	
Gross Operating Profit (EBITDA)	**392,734**	**311,198**	**26.20%**
% over turnover	**12.27%**	**9.76%**	
Depreciation and charges due to impairment losses	(119,169)	(86,692)	
Change in trade provisions	(7,672)	(16,804)	
Operating profits	**265,893**	**207,702**	**28.02%**
% over turnover	**8.31%**	**6.51%**	
Net Financial Results	**(217,280)**	**(115,721)**	**87.76%**
Shares in result of associates	(15,787)	(7,072)	
Profit before taxes	**32,826**	**84,909**	**(61.34%)**
Income tax	(27,350)	(20,949)	
Profit for the year	**5,476**	**63,960**	**(91.44%)**
Profit attributed to non-controlling interests	(18,593)	805	
Profit attributed to Company´s shareholders	**24,069**	**63,155**	**(61.89%)**

(1) Includes own work capitalized.

2.2.2. Development and composition of sales

Sales performance in 2011 and 2010 was as follows:

Thousand euro	2011	% of Total	2010	% of Total	% 2010-2011
Construction	1,084,485	33.9%	1,305,269	43.7%	(16.9%)
Engineering and Industrial Services	1,653,722	51.6%	1,514,871	50.8%	9.2%
Concessions	323,707	10.1%	163,577	5.5%	97.9%
Other (1)	138,786	4.4%	205,023	-	-
Total	**3,200,700**		**3,188,740**		**0.4%**

(1) Includes other business and consolidation adjustments

With respect to the breakdown into domestic and international markets, the Group's turnover has performed as follows:

Thousand euro	2011	% of Total	2010	% of Total	% 2010-2011
Domestic Market	1,214,470	37.9%	1,588,804	49.8%	(23.6%)
International Market	1,986,230	62.1%	1,599,936	50.2%	24.1%
America	1,389,171	69.9%	865,835	54.1%	60.4%
Rest of the world	597,059	30.1%	734,101	45.9%	(18.7%)
Total	**3,200,700**		**3,188,740**		**0.4%**

2.2.3. Development and Composition of Gross Operating Profit (EBITDA)

The development and composition of EBITDA during 2011 and 2010 is as follows:

Thousand euro	2011	% of Total	2010	% of Total	% 2010-2011
Construction	85,870	21.9%	104,712	33.6%	(18.0%)
Engineering and Industrial Services	179,042	45.6%	141,417	45.4%	26.6%
Concessions	180,982	46.1%	112,545	36.2%	60.8%
Other (1)	(53,160)	(13.6%)	(47,476)	(15.2%)	(1.6%)
Total	**392,734**		**311,198**		**26.2%**

(1) Includes other business and consolidation adjustments

3 Outlook 2012

The business volume of Grupo Isolux Corsán during 2011 exceeded 6,729 million euro, 17% of which relates to the domestic market and 83% to international markets.

Set out below is a by area-breakdown of business for 2011:

Thousand euro	2011	% of Total
Construction	903,898	13.4%
Ingeneering	2,623,924	39.0%
Concessions	3,066,481	45.6%
Other Sectors	134,916	2.0%
Total	**6,729,219**	

The Group's total portfolio at 31 December 2011 amounts to 43,110.2 million euro, 23% of which relates to domestic market and 77% to international ones.

Set out below is a breakdown of the portfolio by business area and performance with respect to 2010:

Thousand euro	2011	% of Total	2010	% of Total	% 2010-2011
Construction	3,364,273	7.8%	3,626,434	12.0%	(7.2%)
Ingeneering	3,711,196	8.6%	2,731,978	9.1%	35.8%
Concessions	35,805,290	83.1%	23,613,190	78.2%	51.6%
Other Sectors	229,439	0.5%	208,312	0.7%	10.1%
Total	**43,110,198**		**30,179,914**		**42.84%**

Despite the current macro-economic environment both in Spain and globally, Group portfolio figures, enable us to be reasonably optimistic about our prospects in 2012. Grupo Isolux Corsán expects to improve turnover by maintaining its profitability ratios and cash generation during 2012.

Of the contracts awarded to the Group in the first few months of 2012, the following are particularly noteworthy in view of their significance:

- Private initiative for the construction and operation of Loma Blanca 1º (50mw) wind farm. Argentina
- A high speed platform in Corredor Norte-Nordeste. High speed line Madrid-Galicia.
- Two lane road in La Paz - Oruro tramo IIB + IIA. Bolivia.
- National Roads in Argentina, Corredor nº 4.
- Turnkey provision of the fiber optic network in Red Federal Argentina. Tramo NEA Sur 1,579km.

4 Treasury stocks

There have been no movements in treasury stock during the year.

5 Research and development activities

Research, initial design, testing of new products and services, etc., as well as specific innovation initiatives involving these products, regardless of whether or not they are attributed to projects, are carried out in general by the employees of the Group's different departments within the framework of varying national and regional government aid programmes.

6 Human Resources

The average number of Group employees during 2011 stood at 8,904 instead of 7,640 employees of added average Group of year 2010. The composition of the average workforce by professional category is as follows:

Category	2011	2010
Graduates	2,872	2,647
Administrative Staff	786	794
Workers	5,246	4,199
	8,904	**7,640**

7 Use of Financial Instruments

The activities carried out by Group companies are exposed to various financial risks. The policies developed by Grupo Isolux Corsán concerning these risks are based on the establishment of hedges for exchange and interest rate risks.

Operations with financial derivatives at 31 December 2011 are as follows:

a) Exchange rate hedging operations

In order to hedge the exchange risk, the Group has arranged hedging transactions through which it insures:

1. The forward sale and purchase of US dollars (USD) against euro with different dates and at different exchange rates for a total amount of 77,620 thousand dollar and 114,255 thousand dollar, respectively.
2. The forward purchase of Swiss Francs against euro with different dates and exchange rates for a total amount of 309 thousand Swiss Francs.
3. The forward sale of Mexican pesos against euro with different dates and Exchange rates for a total amount of 9,837 thousand Mexican pesos.
4. The forward sale of Qatar riyals against the euro with different dates and exchange rates for a total amount of 99,597 thousand Qatar riyals.
5. The forward sale and purchase of Brazilian reals against the euro with different dates and at different exchange rates for a total amount of 51,409 thousand Brazilian reals and 23,581 thousand Brazilian reals, respectively.

The effect of these transactions has been valued at the year end.

b) Interest rate hedging operations

At 31 December 2010, the Group has entered into interest rate swaps with financial entities. These swaps were arranged on 10 September 2010, are in effective force until 14 February 2011 and mature on 29 June 2015, and insure a rate of 2.025% for a debt of 532,000 thousand euro, related to the long-term loan provided by a syndicate. This loan was renewed, extended and grouped into a unique contract amounting to 552,000 thousand euro which will be in force as from 14 February 2011.

The loan repayment is through the following amortization schedule:

Maturity date	Amount (thousand euro)
29/12/2012	11,051
29/06/2013	44,168
29/12/2013	55,183
29/06/2014	66,215
29/12/2014	99,368
29/06/2015	276,015
Total	**552,000**

The Group has signed a cross currency swap related to the R$20,000 loan to convert fixed interests rates into variable interest rates, based on DI to fix the exchange interest rates between the Brazilian real and the American dollar. The maturity date of the loan is June 2012. The swap market value at the end of year 2011 is R$2,746.

In addition, in 2011 the following interest rate swaps were in force:

Grupo T-Solar loan:

Contract date:	22 December 2008
Notional amount:	40,557 thousand euro
Interest rate:	3.96%
Maturity date:	31 December 2026
Contract date:	15 July 2008
Notional amount:	462,724 thousand euro
Interest rate:	5.09%
Maturity date:	31 December 2027
Contract date:	18 de junio de 2009
Notional amount:	11,098 thousand euro
Interest rate:	4.09%
Maturity date:	18 June 2021
Contract date:	4 January 2009
Notional amount:	6,572 thousand euro
Interest rate:	4%
Maturity date:	4 December 2023
Contract date:	31 December 2010
Notional amount:	10,673 thousand euro
Interest rate:	3.45%
Maturity date:	20 December 2023
Contract date:	18 March 2010
Notional amount:	2,090 thousand euro
Interest rate:	3.65%
Maturity date:	23 April 2026
Contract date:	22 December 2010
Notional amount:	22,367 thousand euro
Interest rate:	3.54%
Maturity date:	20 December 2023

HIXAM loan:

Contract date:	7 February 2007
Notional amount:	61,395 thousand euro
Interest rate:	4.36%
Maturity date:	29 December 2022

HIXAM II loan:

Contract date:	13 January 2010
Notional amount:	29,735 thousand euro
Interest rate:	3.6%
Maturity date:	23 December 2025

Sociedad Concesionaria Zona 8A loan:

Contract date:	25 February 2008
Notional amount:	7,140 thousand euro
Interest rate:	4.79%
Maturity date:	25 February 2024

Infinita Renovables loan:

Contract date:	5 January 2010
Notional amount:	167,368 thousand euro
Interest rate:	3.79%
Maturity rate:	30 December 2016

Concesionaria Saltillo - Monterrey S.A de C.V. loan:

Contract date:	28 September 2007
Notional amount:	2,314,546 thousand Mexican pesos
Interest rate:	8.20%
Maturity date:	30 May 2025

Concesionaria Perote-Xalapa S.A de C.V. loan:

Contract date:	13 February 2008
Notional amount:	1,893,760 thousand Mexican pesos
Interest rate:	8.20%
Maturity date:	14 January 2022

Concesionaria Perote-Xalapa S.A de C.V. loan:

Contract date:	18 August 2011
Notional amount:	475,000 thousand Mexican pesos
Interest rate:	5.02%
Maturity date:	14 December 2012

Sociedad Concesionaria Autovía A4 Madrid S.A. loan:

Contract date:	1 August 2008
Notional amount:	28,796 thousand euro
Interest rate:	5.05481%
Maturity date:	16 June 2025

Sociedad Concesionaria Autovía A4 Madrid S.A. loan:

Contract date:	1 August 2008
Notional amount:	28,796 thousand euro
Interest rate:	5.058%
Maturity date:	16 June 2025

Other loans/credits to the Group:

Contract date:	24 February 2009
Notional import:	20,000 thousand euro
Interest rate:	2.47%
Maturity date:	24 February 2012
Contract date:	23 June 2009
Notional import:	20,000 thousand euro
Interest rate:	2.44%
Maturity date:	23 June 2012
Contract date:	11 September 2009
Notional import:	50,000 thousand euro
Interest rate:	2.66%
Maturity rate:	3 June 2013
Contract date:	29 April 2010
Notional import:	50,000 thousand euro
Interest rate:	1.97%
Maturity date:	3 June 2013
Contract date:	22 June 2010
Notional import:	85,000 thousand euro
Interest rate:	1.80%
Maturity date:	18 June 2013
Contract date:	16 May 2011
Notional import:	45,000 thousand euro
Interest rate:	3.05%
Maturity date:	16 May 2015
Contract date:	28 June 2011
Notional import:	57,517 thousand euro
Interest rate:	2.20%
Maturity date:	28 June 2014
Contract date:	23 January 2012
Notional import:	13,718 thousand euro
Interest rate:	3.60%
Maturity date:	21 July 2025
Contract date:	29 July 2011
Notional import:	1,899 thousand dollar
Interest rate:	1.96%
Maturity date:	31 March 2016
Contract date:	29 July 2011
Notional import:	29,157 thousand dollar
Interest rate:	3.60%
Maturity date:	31 March 2016

ISOLUX CORSÁN

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“Exhibit J”

PUBLIC SECTOR PENSION INVESTMENT BOARD

2012 ANNUAL REPORT



2012

PSP INVESTMENTS

WHO WE ARE AND WHAT WE DO

CORPORATE PROFILE

The Public Sector Pension Investment Board ("PSP Investments" or the "Corporation") is a Canadian Crown corporation established to invest the amounts transferred by the Government of Canada equal to the proceeds of the net contributions since April 1, 2000, for the pension plans of the Public Service of Canada, the Canadian Forces and the Royal Canadian Mounted Police, and since March 1, 2007, for the Reserve Force Pension Plan (collectively the "Plans"). The amounts so transferred to the Corporation are to fund the liabilities under the Plans for service after the foregoing dates (the "Post-2000 Liabilities").

Its statutory objects are to manage the funds transferred to it in the best interests of the contributors and beneficiaries under the Plans and to maximize investment returns without undue risk of loss, having regard to the funding, policies and requirements of the Plans and their ability to meet their financial obligations.

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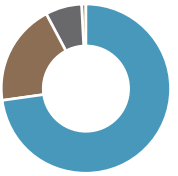
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AT A GLANCE



ASSET MIX
As at March 31, 2012

28.6%	Foreign Equity
23.2%	Real Return Assets
22.4%	Canadian Equity
15.8%	Nominal Fixed Income
10.0%	Private Equity



NET ASSETS PER PENSION PLAN ACCOUNT
As at March 31, 2012 ($ billions)

73.1%	Public Service	47.1
19.3%	Canadian Forces	12.4
7.1%	RCMP	4.6
0.5%	Reserve Force	0.4

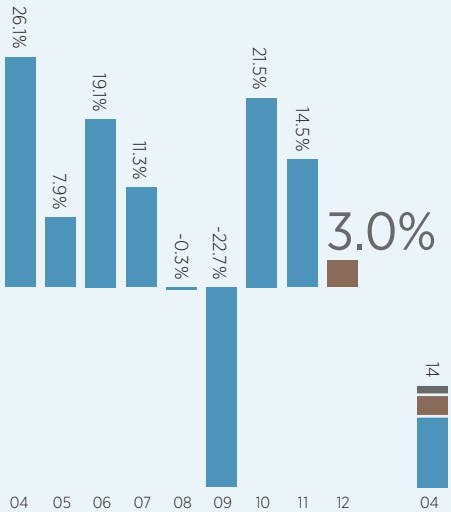
Net assets: $64.5 billion

2012

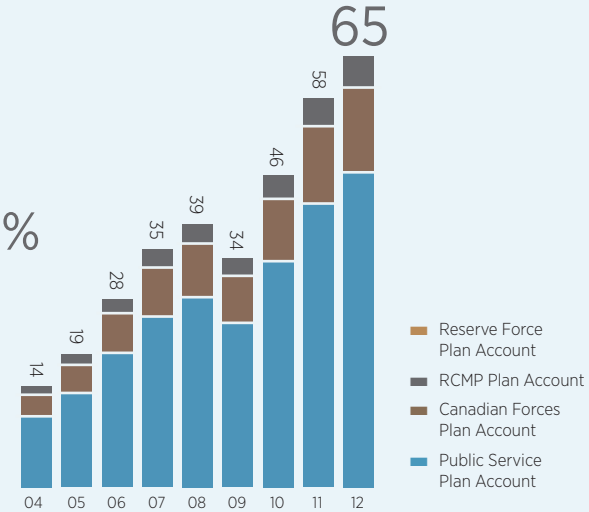
HIGHLIGHTS
FISCAL YEAR 2012

- Consolidated net assets increased 11% to $64.5 billion.
- Investment income of $1.7 billion after expenses. Total portfolio return of 3.0% compared to the benchmark return of 1.6%.
- Three-year annualized return of 12.7%, investment income of $16.5 billion and value-added above benchmark of $2.4 billion.
- A majority of portfolios outperformed their benchmarks.
- Implementation of changes to Policy Portfolio, including addition of Renewable Resources asset class.
- Assets managed internally reached approximately $48 billion, or 74% of total net assets. Assets actively managed internally totalled more than $23 billion, up from almost $18 billion in fiscal year 2011.

ANNUAL PERFORMANCE
As at March 31



CHANGES IN NET ASSETS (CONSOLIDATED)
As at March 31 ($ billions)



CORPORATE OBJECTIVES FISCAL YEAR 2012

INTERNAL AND ACTIVE MANAGEMENT

Increase investment activities and level of assets managed internally and actively with the aim of improving overall investment cost structure (expressed as a percentage of assets under management) and increasing the probability of meeting or exceeding the desired long-term actuarial rate of return.

ACHIEVEMENTS

- Assets managed internally totalled approximately $48 billion or 74% of assets. Of the almost $37 billion in assets actively managed, more than $23 billion or 63% are managed internally.
- Operating and asset management expenses as a percentage of assets decreased by almost 10%.
- Recruited 17 investment professionals to support growth in internal active management.

TALENT MANAGEMENT

Advance corporate-wide engagement initiatives that strengthen corporate culture. Implement the recruitment and development initiatives required to support the increased internal and active management initiatives in order to maximize our return without undue risk. Produce the programs that develop management capabilities to support the Succession Plan. Ensure that all employees have corporately aligned development plans in place. Implement the human resources systems that provide comprehensive accurate key performance indicators. Provide for Board of Directors transition.

ACHIEVEMENTS

- Achieved a high engagement level in the independent employee engagement survey.
- Completed the implementation of company-wide Integrated Talent Management Solution providing comprehensive information related to performance, compensation and recruitment.
- Reduced employee turnover ratio.
- Enhanced reporting of key human resources indicators to the Board of Directors.

ENTERPRISE RISK MANAGEMENT

Implement the enterprise risk management and reporting measures required for increased internal and active management in order to maximize our return without undue risk. Implement the recommendations from the Special Examination and the Risk Control Self Assessment completed in fiscal year 2011.

ACHIEVEMENTS

- Reviewed and refined, as required, all policies and procedures governing enterprise, operational and investment risk management in light of the Special Examination recommendations and Risk and Control Self Assessment findings.
- Evolved risk measurement and monitoring practices through ongoing development of risk metrics.
- Improved governance structure surrounding the management of operational risks.

STRATEGIC PLAN

Close the 2012 three-year Strategic Plan. Develop and approve the Vision 2015 three-year Strategic Plan recognizing the increasingly complex and challenging investment environment.

ACHIEVEMENTS

- Substantially completed Vision 2012 Strategic Plan.
- Adopted three-year Vision 2015 Strategic Plan in June 2012.

2012

KEY CORPORATE OBJECTIVES FISCAL YEAR 2013

Investments

Continue to execute the Private Markets' business plans towards the 42% target allocation and greater internal and active management in Public Markets. Increase network of international investment partners. Maintain a competitive total investment cost structure.

Enterprise Risk Management

Continue to refine risk management activities and reporting measures required for increased internal and active management. Ensure policies and procedures framework is aligned with changing economic and regulatory environment. Continue implementation of Responsible Investment Policy.

Strategic Plan

Implement first year of Vision 2015 three-year Strategic Plan. Ensure individual objectives are aligned with Strategic Plan. Communicate Vision 2015 to the organization.

Talent

Ensure proper teams are in place through internal appointments and recruitment of high performing employees to support the deployment of the investment strategies. Evolve leadership and development plans to extend succession planning at deeper levels in the organization. Develop and implement engagement initiatives to build upon the results of the fiscal 2012 employee survey.



2013

INTERIM CHAIR'S **REPORT**

PSP Investments achieved positive results and generated value added relative to its performance benchmark in fiscal year 2012, despite a volatile investment climate roiled by events ranging from debt concerns in the European Union and the United States to the Japanese earthquake and tsunami.

From a strategic perspective, fiscal year 2012 was a transitional year as investment teams began implementing changes to the Policy Portfolio, which had been approved by the Board of Directors following a comprehensive review and became effective April 1, 2011.

In essence, we reduced the allocation to World Equity and increased from 28% to 42% the overall target allocation to Private Markets — including Real Return assets such as Real Estate, Infrastructure and a new asset class, Renewable Resources, which are a good match for the inflation-sensitive nature of the Plans' long-term liabilities. The changes reflect our current expectations of long-term market conditions and were designed to further refine the alignment of the Policy Portfolio with the Plans' Post-2000 Liabilities, in addition to taking advantage of our exceptional liquidity.

Each year, PSP Investments receives an inflow of new funds in the magnitude of $4 billion, with net contributions projected to remain positive for at least the next 15 years. Consequently, we are in a rather favourable position with a degree of liquidity and flexibility that enables us to focus on a long-term investment horizon. During fiscal year 2012, the overall weighting of private-market investments increased from 22.8% to 27.0%, representing a net increase of $4.2 billion in Private Market asset classes.

Our Policy Portfolio is constructed to achieve a return at least equal to the "actuarial rate" over the long term — that is the rate of return required to maintain funding requirements and pension benefits at current levels. In his latest actuarial valuation of the Canadian Forces Pension Plan, the Chief Actuary of Canada reduced the actuarial rate of return from 4.3% after inflation to 4.2% after inflation.

Over the nine-year span since we began the move to diversification, PSP Investments has in fact exceeded the targeted actuarial rate despite the impact of the global financial crisis. One hundred dollars invested in PSP Investments nine years ago would have been worth $194 at the end of fiscal year 2012, whereas that same $100 earning the actuarial rate of return would have been worth $171.

ENHANCED RISK MANAGEMENT REPORTING

One of the Board's crucial on-going roles is to ensure that effective enterprise, investment and operations risk policies are in place. Mindful of the Corporation's mandate to maximize returns without undue risk, we worked closely with management this past year to implement changes designed to further enhance risk management and oversight and ensure that the risk framework is properly aligned with our revised strategy. That interaction not only yielded enhanced reporting procedures but also afforded an opportunity for Board members to continue developing a more dynamic vision of risk.

COST EFFECTIVENESS

Given the Corporation's continued rapid growth, the Board is committed to making certain that PSP Investments' resources are managed in an efficient, cost-effective manner that enables it to benefit from scalability. Cost efficiency is among the main benefits to be derived from PSP Investments' increased focus on internal management of the portfolio. Considering that the amount of assets internally managed has grown from approximately $21 billion to almost $48 billion since the end of fiscal year 2009, the scope of the inherent savings is considerable.

The effectiveness of both the Board's and management's efforts is reflected in the fact that, while assets have increased by some 91% over that same period, operating and asset-management expenses rose by only 11%.

ACKNOWLEDGEMENTS

On behalf of Board members past and present, I would like to pay tribute to former Chair Paul Cantor, who stepped down when his term expired just prior to the fiscal year-end after nine years as Chair. Determined to provide PSP Investments with nothing less than an exemplary level of governance, Paul set the tone at the top and led by example. Tough and decisive when called for, he encouraged frank discussion around the boardroom table and understood well the complementary roles of oversight and insight in fulfilling the Board's mandate. The solid core values and unrelenting commitment to excellence that have been embraced throughout PSP Investments are a legacy of Mr. Cantor's leadership.

Special thanks are due as well to Bob Baldwin, who has retired from the Board. His contribution to the Board and to PSP Investments has been extremely valuable. Like Paul, Mr. Baldwin had been a member of our Board from the very outset, serving with distinction for almost a dozen years as a director and committee chair.

I also wish to take this opportunity to formally welcome Micheline Bouchard and Garnet Garven, who joined the Board during fiscal year 2012. Ms. Bouchard and Mr. Garven both bring valuable knowledge and experience that are in keeping with PSP Investments' on-going commitment to strong governance. I welcome, as well, the reappointment of Léon Courville for an additional four-year term. At this writing, we are awaiting additional appointments that will bring the Board up to full strength as well as the naming of a new Chair.

In conclusion, I would like to express the appreciation of the entire Board to President and CEO Gordon J. Fyfe and his senior team, as well as to all employees, for delivering good results under challenging circumstances in fiscal year 2012, while keeping PSP Investments on a steady growth trajectory.



Cheryl Barker
Interim Chair



PRESIDENT'S **REPORT**

PSP Investments recorded a solid performance during fiscal year 2012 in a global marketplace characterized by continuing volatility and the debt crisis in Europe. We generated a total portfolio return of 3.0% versus 1.6% for the Policy Portfolio Benchmark.

For the three-year period since the financial meltdown of 2008-2009, PSP Investments had an annualized return of 12.7% generating $16.5 billion in investment income, and $2.4 billion of value added, over and above benchmark returns. It was the third consecutive year that we have outperformed our key benchmark. A majority of our portfolios outperformed their respective benchmarks during fiscal year 2012, highlighted by particularly strong relative performances from Real Estate, Public Markets equities and fixed income portfolios.

PSP Investments' overall performance for fiscal year 2012 was impacted by the negative performance of global equities, most notably in the Canadian, European and Emerging Markets. Fixed Income markets, on the other hand, posted one of their best performances of recent years.

During the year, we reduced our exposure to public equities and increased our exposure to Private Market and Real Return asset classes. Our Real Estate, Private Equity, Infrastructure and Renewable Resources asset classes all posted positive returns ranging from 2.7% to 13.4%.

While markets can be challenging in the short-term, we continued to diversify the portfolio and take advantage of PSP Investments' exceptional liquidity as markets offer attractive opportunities for patient investors with deep pockets to acquire some outstanding assets at very favourable valuations.

Taking into account investment income of $1.7 billion after expenses as well as $4.7 billion of funds transferred by the Plans, PSP Investments' consolidated net assets increased by 11% to a new peak of $64.5 billion as at March 31, 2012. Over the three years since the global financial crisis, the value of our total net assets has increased by 91% from their fiscal 2009 year-end level.

Another noteworthy event during the year was our capital market medium-term notes issuance in which we benefited from the lowest fixed coupon rate ever attained by a Canadian pension fund investment manager in the Canadian market. This is a further testament to the triple "A" credit rating that the organization continues to maintain.

INVESTING IN FUTURE GROWTH

Fiscal 2012 was noteworthy for the high level of investment activity and volume of transactions, as our teams continued pursuing opportunities to capitalize on our competitive advantages by investing in future growth.

Early in fiscal year 2012, we made our first investment in a new asset class — Renewable Resources — with the acquisition of a 50% interest in TimberWest Forest Corporation, the largest owner of private timberlands in Western Canada. TimberWest owns approximately 808,000 acres (*327,000 hectares*) of private land on Vancouver Island and additional crown rights to harvest on government timberlands. The Renewable Resources asset class will initially include farmland as well as timber.

Over the course of the fiscal year, our Real Estate team made more than 30 direct investments. Included were additional properties in Brazil and Colombia, reflecting PSP Investments' intensified focus on high-growth emerging markets where burgeoning middle-class populations are driving demand.

The acquisition of a strategically located lower-Manhattan office building — which ranks among the largest buildings in all of New York City — was one of a number of additions to our increasingly diversified portfolio of properties in the US which now also includes warehouse and industrial properties.

Other noteworthy real-estate transactions included office properties in key cities in Europe and North America in collaboration with local partners, further enhancing a portfolio that generated the second best returns of any asset class during the latest fiscal year.

Infrastructure is an asset class that tends to require both persistence and patience, given that attractive investment opportunities are limited in number and generally of a complex nature. Several years of hard work seeking out suitable opportunities and partners led to accelerated growth in fiscal year 2012, when our Infrastructure team made investments totalling some $1.5 billion. This brought the value of the portfolio to approximately $3.6 billion at year's end.

Included among the Infrastructure acquisitions was PSP Investments' second major investment in the ports sector — a participation in Forth Ports Limited, one of the United Kingdom's largest maritime operators with seven ports in London and Scotland. As well, we acquired an ownership interest in Gassled, one of the largest offshore pipeline systems in the world. Gassled transports the majority of the natural gas sourced from the Norwegian Continental Shelf to markets in the U.K. and Western Europe.

Private Equity is another area where we have increased our asset allocation. In November 2011, PSP Investments along with two partners acquired Kinetic Concepts, Inc. (KCI) in a transaction valued at approximately US$ 6.3 billion. Texas-based KCI, with some 7,000 employees and a market presence in more than 20 countries, has the leading global market share in negative pressure wound therapy. This is a very attractive asset that provides exceptional opportunities for growth and value creation.

The value of assets managed internally increased from approximately $21 billion to almost $48 billion over the last three years

FOCUSING ON INTERNAL ACTIVE MANAGEMENT

An on-going strategic thrust entails further increasing the level of PSP Investments' assets under internal active management.

During fiscal year 2012, the proportion of total assets being managed internally amounted to 74% — up sharply from 62% just three years ago at the end of fiscal year 2009. Over that same period, the value of assets managed internally increased from approximately $21 billion to almost $48 billion.

From another perspective, it is noteworthy that approximately 63% of all our actively managed assets now are being managed internally. When compared to external management, internal management brings two major benefits: lower costs and a closer alignment of investment managers' goals with PSP Investments' mandate.

With respect to Public Markets, where PSP Investments still has a majority of its assets invested, the volume of assets managed internally *and* actively increased from approximately $600 million in 2009 to almost $11 billion at the end of fiscal year 2012.

The strong performance of our Fixed Income team during fiscal year 2012 provides an excellent example of the advantages of internal active management. The team did an exceptional job managing the European debt crisis, not only avoiding the worst of the fallout but enabling PSP Investments to generate some solid returns, both in absolute terms and relative to the benchmark.

Lingering volatility made fiscal year 2012 a challenging one overall for our Public Markets teams. For instance, at the mid-point of the year, most major stock market indices were significantly lower — Standard & Poor's negative 7.6%, Emerging Markets negative 18.0%, and the TSX negative 16.5% — although they subsequently rebounded somewhat. The majority of our Public Markets teams managed to equal or better their respective benchmarks over the course of the fiscal year.

NEW STRATEGIC PLAN

Having a clearly defined strategic direction or vision is paramount to the success of our organization. Accordingly, another of our key corporate objectives this past year entailed the development of a new strategic plan that would build upon Vision 2012, our previous three-year road map which has now been fully implemented.

Vision 2015, approved by the Board of Directors in June 2012, reflects a continuation of the underlying strategies developed in fiscal year 2004 when we began to diversify the portfolio, which have been refined over the years to reflect the changing impact of the external environment.

The new three-year plan sets out four main strategic goals. They include: further refining our investment strategy and policies, including the Policy Portfolio, its structure and alignment with the sponsor and the beneficiaries; continuing to implement the active management philosophy; developing scalable and efficient operations that form an integral part of the investment process; and supporting the Corporation in its next development stage through talent management, leadership and total-reward strategies.

ENTERPRISE RISK MANAGEMENT (ERM)

An additional priority involved enhancing our enterprise risk management and reporting measures. To that end, working with the Board, we have improved the quality of our ERM reporting to further strengthen the Board's capabilities with respect to its oversight and governance roles.

ACKNOWLEDGEMENTS

I wish to take this opportunity to recognize outstanding efforts and thank employees throughout PSP Investments for their hard work and commitment during fiscal year 2012. I would also like to express my appreciation to the Board of Directors for their counsel and support over the course of a challenging year.

I also want to acknowledge Bob Baldwin who was among the first Directors appointed to our Board in March 2000 and who retired from the Board this year. Bob has made an enormous contribution to the organization, particularly in better understanding the liabilities of the Plans.

And finally, I wish to pay tribute to a truly remarkable individual, our long-time Chair Paul Cantor, who retired from PSP Investments' Board effective March 5, 2012, having served as a member from its inception in 2000 and as Chair since 2003. Mr. Cantor played an enormous role in nurturing PSP Investments from a fledgling organization into a robust, diversified fund that ranks among the largest pension investment managers in Canada and is highly regarded internationally. An indefatigable worker, he strove to be the best Chair of any public fund in the world and, in the process, made us all better. Thank you Paul.

WELL POSITIONED GOING FORWARD

Having adhered to our strategy and stayed the course through the financial crisis and subsequent period of uncertainty, we look forward with confidence to the point in the cycle where we will be able to realize substantial gains on the high-quality assets and investment opportunities we have availed ourselves of over the past several years.

Meanwhile, we are continuing to build and develop our world-class team of investment and leadership professionals and forge new partnerships around the globe, with a view to achieving the high-calibre performance and sustainable returns required to fulfill our mandate.



Gordon J. Fyfe
President and Chief Executive Officer

MANAGEMENT'S DISCUSSION OF FUND PERFORMANCE AND RESULTS

INVESTMENT APPROACH, OBJECTIVES, THE POLICY PORTFOLIO AND ACTIVE MANAGEMENT

INVESTMENT APPROACH AND OBJECTIVES

PSP Investments' mandate is described in Section 4 of the *Public Sector Pension Investment Board Act* (the "Act"):

- To manage the amounts transferred to it in the best interests of contributors and beneficiaries under the Plans; and to maximize returns without undue risk of loss, having regard to the funding, policies and requirements of the Plans and the ability of those Plans to meet their financial obligations.

Based on these statutory objects, PSP Investments' Board of Directors implemented an investment approach around two key pillars:

1. A Policy Portfolio (defining the asset mix — how assets will be allocated among various asset classes), which is expected to achieve a return at least equal to the long-term actuarial rate of return used by the Chief Actuary of Canada in his latest actuarial valuations of the Plans (i.e. a real return of 4.2%[1], after inflation). In the absence of other factors affecting the funding of the Plans as it relates to the Post-2000 Liabilities, it is the rate of return required to maintain funding requirements and pension benefits at current levels.
2. Active management activities, which are designed to generate returns over and above the Policy Portfolio and assist in attaining the actuarial rate of return within an active risk budget.

The following investment objectives were established to assess the performance of this investment approach:

- Absolute Return: achieve a long-term return (net of expenses) at least equal to the actuarial rate of return;
- Relative Performance: achieve a target return exceeding the Policy Portfolio return.

POLICY PORTFOLIO

A key pillar of PSP Investments' approach is the Policy Portfolio. The Policy Portfolio is reviewed at least annually within an asset-liability framework, affording a thorough understanding of the linkage between the Policy Portfolio and the Plans' Post-2000 Liabilities. Understanding this linkage helps ensure that PSP Investments' approach and results not only meet the actuarial rate of return, but also achieve this rate of return with an acceptable level of risk related to the funding of the Plans. This framework also ensures proper alignment of interests between PSP Investments and the Plans' stakeholders.

[1] In the actuarial reports on the Plans for the Canadian Forces as at March 31, 2010, tabled in Parliament in October 2011, the actuarial real rate of return was reduced from 4.3% to 4.2%.

– PSP Investments' Policy Portfolio is expected to achieve a return at least equal to the actuarial rate of return over the long term (i.e. a real return of 4.2%), with a level of funding risk that is deemed acceptable.

A risk-free real rate of return could be achieved with Canada Real Return Bonds (RRBs). However, the yield on RRBs is currently approximately 0%. This is well short of the 4.2% required to maintain funding requirements at their current level. Taking on market risk is therefore required to achieve this 4.2% real rate of return.

This market risk entails funding risk (whereby the value of the assets could fall below the value of the Post-2000 Liabilities). The level of risk deemed acceptable is the funding risk associated with a portfolio composed of public, liquid asset classes (debt and equity securities) which, based on PSP Investments' expectations of long-term market conditions, would be required to achieve this real rate of return over time.

– PSP Investments' Policy Portfolio recognizes the unique characteristics of the Plans' Post-2000 Liabilities and the net inflows expected to fund these liabilities.

A portfolio composed of public, liquid asset classes would miss out on opportunities afforded by the unique characteristics of the Plans' Post-2000 Liabilities and their funding. PSP Investments is expected to receive positive net inflows over at least the next 15 years, an exceptional situation that constitutes a significant competitive advantage. The high level of liquidity allows for further diversification into less-liquid asset classes such as Private Markets, including Private Equity, Infrastructure, Real Estate and Renewable Resources. The latter three provide for a diversified exposure to Real Return assets, recognizing the inflation-sensitive nature of the Post-2000 Liabilities.

Asset-liability studies conducted on behalf of the Board of Directors indicate that the increased diversification and the liability-matching characteristics of the Policy Portfolio should provide for a higher likelihood of meeting the actuarial target rate of return, with the same or an even lower level of funding risk over time.



POLICY PORTFOLIO
As at March 31, 2012

World Equity 54%	Public Market Equity	40%
	Private Equity	14%
Real Return Assets 33%	Real Estate	13%
	Infrastructure	13%
	World Inflation-Linked Bonds	5%
	Renewable Resources	2%
Nominal Fixed Income 13%	Fixed Income	11%
	Cash & Cash Equivalents	2%

– Renewable Resources added to the Policy Portfolio

Following a thorough review of the Policy Portfolio that began during fiscal year 2010, changes were made in April 2011, including a reduced allocation to World Equity and an increased allocation to Real Return assets and private asset classes. Those changes were followed by the addition of a new asset class during the fiscal year: Renewable Resources. This asset class, which initially includes timber and farmland, is expected to enhance the alignment of PSP's Policy Portfolio with the Post-2000 Liabilities of the Plans. It offers three significant advantages:

1. It is expected to provide diversification with regard to the sources and patterns of return versus current asset classes (e.g. returns are driven in part by biological growth – a unique attribute).
2. It is expected to offer an illiquidity premium, which PSP Investments is well positioned to capture given the positive net inflows expected over at least the next 15 years.
3. It is expected to provide long-term inflation-hedging characteristics particularly well-matched with the nature of the Plans' Post-2000 Liabilities.

ACTIVE MANAGEMENT

Active management activities form the second pillar of PSP Investments' approach. They are designed to generate returns over and above the Policy Portfolio and assist in attaining the actuarial rate of return within an active risk budget. These activities typically involve the creation of investment strategies that are different from the Policy Portfolio benchmarks. In equities, this is usually accomplished by overweighting or underweighting specific sectors or securities relative to the Policy Portfolio equity benchmarks.

PSP Investments believes that its size makes the deployment of active management strategies particularly advantageous. Notably, this approach offers economies of scale and allows for an increased scope of activities in selected asset classes. Accordingly, PSP Investments has been increasing the proportion of its assets under internal active management and expanding relationships with selected partners. Bringing more investment management in house provides for better control in terms of risk, investment cost savings and increased influence over major decisions.

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CHANGE IN NET ASSETS AND FUND PERFORMANCE

PERFORMANCE MEASUREMENT AND EVALUATION

Based on the Statement of Investment Policies, Standards and Procedures (SIP&P), PSP Investments evaluates its investment strategies, as well as individual investment mandates, through performance measurement. The performance for each investment strategy and mandate is compared to an appropriate benchmark.

BENCHMARKS

A combined Policy Portfolio benchmark ("Policy Benchmark") is constructed using the asset class benchmarks weighted by the actual portfolio asset class weightings. The return for each asset class is compared to the relevant benchmark return, while PSP Investments' overall return is compared to the Policy Benchmark return.

The following benchmarks were used to measure relative performance for each asset class and for the Policy Benchmark return for fiscal year 2012.

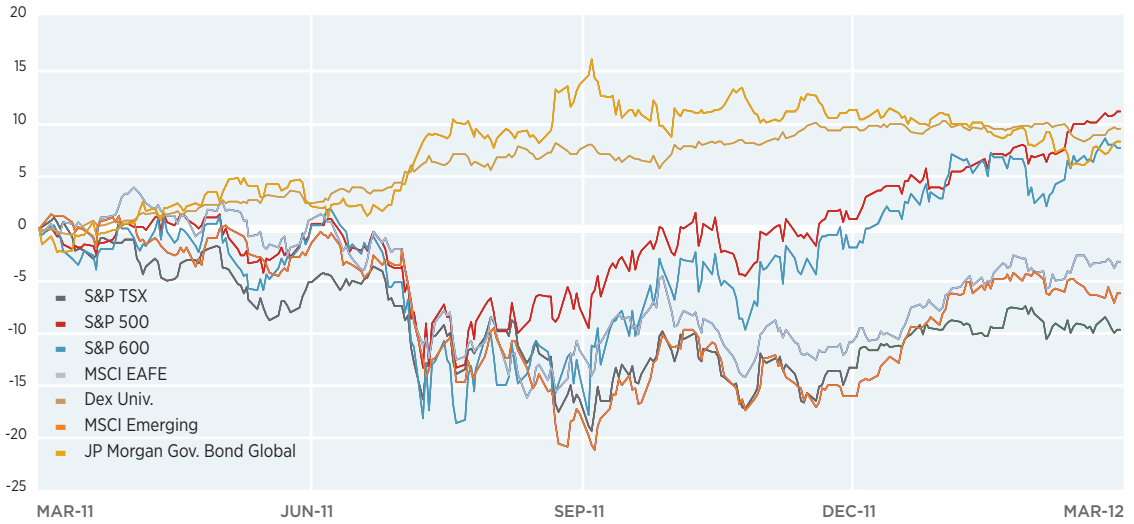
Asset Class	Benchmark
World Equity	
Canadian Equity	S&P/TSX Composite Index
Foreign Equity US Large Cap Equity EAFE Large Cap Equity Small Cap Developed World Equity Emerging Markets Equity	 S&P 500 Index MSCI EAFE Index S&P 600 Index and MSCI EAFE Small Cap Index MSCI EMF Index
Private Equity	Private Equity Fund Universe and Private Equity Cost of Capital[1]
Nominal Fixed Income	
Cash & Cash Equivalents	DEX 91 Day T-Bill Index
Fixed Income	JP Morgan Government Bond Index Global and DEX Universe Bond Index
Real Return Assets	
World Inflation-Linked Bonds	Four Country ILB Index[1]
Real Estate	Real Estate Cost of Capital[1]
Infrastructure	Inflation Adjusted Infrastructure Risk Premium and Infrastructure Cost of Capital[1]
Renewable Resources	Renewable Resources Cost of Capital[1]

[1] Customized benchmark

MARKET OVERVIEW

PERFORMANCE OF MAJOR WORLD INDICES

Fiscal year 2012 ($ CAD, percent)



The resilience of the global economy and markets' appetite for risk were severely tested over the past year with the landscape dominated by a succession of economic shocks, geopolitical events and adverse policy events. The Japanese earthquake and tsunami disrupted global supply chains, the lagging impact of rising oil prices weighed on consumer purchasing power, the US debt-ceiling negotiations thrust politics onto centre stage and the European debt crisis continued to escalate. As a result, global economic growth slowed noticeably, from an estimated 5.2% in calendar 2010 to 3.8% in 2011. The US economy came close to stalling in the early part of the year, raising fears of a double-dip recession, Europe fell into recession outright and many emerging economies – most notably China – downshifted as well. As a result, global equities fell sharply during the summer months and bond yields plunged to new cyclical lows, spurred in part by another round of purchases by the US Federal Reserve (Fed) and a commitment from the Fed to hold its policy rate unchanged through to the end of 2014. At the same time, however, a rash of ratings downgrades and mounting default risks sent peripheral European yields soaring to new highs.

Market performance varied widely by region. The U.S. rebounded forcefully as fears of a another double-dip recession dissipated, while European policymakers managed to inject massive amounts of liquidity into the banking system and cobble together a deal on Greek debt. But European stock markets had more ground to catch up and ended the year lower as a result. Emerging markets were also severely hit, with the MSCI Emerging Market Index losing 6.3% on the year, despite a strong recovery from the precipitous drop of the summer months. The MSCI World Index managed to erase the better part of its losses, finishing up 3.3%.

With bond yields falling to new lows, it was another good year for fixed income markets, with the notable exception of those countries at the heart of the European debt crisis. Correspondingly, the JP Morgan Government bond index returned a solid 8.6% over the course of the year.

CANADA

The Canadian economy was not immune to the shocks that plagued the global economy as the year got underway. Real Gross Domestic Product (GDP) actually contracted in the opening quarter of the fiscal year, reflecting in large part the supply disruptions following the Japanese earthquake and tsunami, but bounced back forcefully in the following quarter. More significant, however, is the fact that the domestic side of the economy, and consumer spending in particular, appeared to gradually lose steam as the year drew on. After a strong run following the end of the recession, consumers started to waver as job growth stalled, concerns about debt levels continued to mount and prospects for the housing market began to soften. Weaker commodity prices also weighed on Canada's performance. As a result, Canadian equities noticeably underperformed their US counterparts, with the S&P/TSX Composite Index losing 9.8% over the course of the year. Canadian bonds fared well, however, with the DEX Universe Index gaining 9.7% as the Bank of Canada kept its policy rate unchanged at 1% and credit spreads continued to shrink.

UNITED STATES

The US economy came dangerously close to "stall speed" in the early part of the year, as the lingering impact of the increase in oil prices and supply disruptions from the Japanese earthquake and tsunami lowered economic growth. Confidence was also severely eroded by ongoing budget issues, from a battle over the increase in the debt ceiling to the extension of the payroll tax credit and extended unemployment benefits. Nonetheless, the economy managed to pull itself back on its feet and job growth finally resumed towards the end of the calendar year. However, the legacy of the financial crisis remains – the US housing market has yet to fully turn the corner and the amount of slack built up in the economy and labour markets remains huge. With the economy still on a fragile footing, the Fed introduced another asset–purchase program dubbed "operation twist" and pledged to keep the Fed funds rate unchanged until the end of 2014. Equity markets responded favourably to the additional stimulus measures and, as a result, the S&P 500 recorded a gain of 11.5%.

EUROPE

The sovereign debt crisis was once again right, left and centre in Europe. Markets were severely buffeted – especially during the summer months – as fears of defaults and contagion to the financial sector sent peripheral bonds yields soaring and equity markets tumbling. In response, the European Central Bank flooded the banking system with liquidity through two long-term refinancing operations, which managed to stabilize markets. After keeping the markets at the edge of their seats, European authorities, private investors and the International Monetary Fund (IMF) finally agreed on a Greek debt swap and bail-out package as the year drew to a close. While this helped European markets regain some of the lost ground, they still ended the year in the red, accounting for a significant part of the 3.2% drop in the EAFE index.

JAPAN

The Japanese economy had a very rough ride over the past year. The earthquake and tsunami took a significant bite out of GDP growth, as the economy contracted sharply in the first half of the calendar year. Although GDP rebounded in the third quarter, a sharp drop in exports due mainly to the impact of floods in Thailand sent Japanese economic performance back into negative territory. With the global outlook souring and the economy still suffering from the side-effects of the shocks, the Bank of Japan continued to inject liquidity into the economy. As a result, bond yields have remained anchored at extremely low levels while equity markets have gained ground with the Nikkei up 8.8% on the fiscal year, although it remains below its pre-tsunami level.

EMERGING MARKETS

Although they rebounded during the final quarter of the fiscal year, emerging market equities lost ground, weighed down by concerns about the spillover effects of the European debt crisis and, just as importantly, by fears of a "hard landing" in China. While the Chinese economy has slowed, the pace of deceleration appears modest, providing some reassurance to the markets. Nonetheless, Chinese authorities have downgraded their expectations for growth and the central bank lowered its reserve requirements for banks by 50 basis points as inflation pressures began to subside. With growth prospects waning, many emerging Asian economies also put their policy settings on hold or started to ease up on credit. The same was true in Latin America, with Brazil's economy decelerating sharply and the central bank engineering a total of 275 basis points in rate cuts – telegraphing that further easing is in the pipeline.

PRIVATE MARKETS

Private Equity

On the private equity front, fundraising has been challenging. In the U.S., private equity firms have been more selective given the lack of funds. In Europe, the continuing uncertainty has brought opportunity but also significant risks. Credit markets are only flowing freely for best-of-breed companies and leverage for buy-outs is more difficult. Consequently, more equity has been required in capital structures.

Real Estate

Real estate markets in most developed economies continued to struggle. In the United States, residential markets have yet to show signs of life and on the commercial side, the revival in momentum in the first half of the year evaporated as economic uncertainty continued to build. While commercial vacancy rates have declined, they remain high, keeping a lid on rents. In Europe, property markets remained sluggish, reflecting the economic uncertainty and tight credit conditions. Overall, the economic uncertainty led institutional and retail investors to largely target lower risk "core" properties that have secure, predictable long-term cash flow streams. As a result, initial yields (cap rates) declined for the highest quality assets and prices increased accordingly. This was the case not only in the advanced economies but also many emerging markets as well.

Infrastructure

This last year has seen some slowdown in infrastructure investment activity in reaction to growing uncertainty in Europe and slightly reduced overall lending. Investors continued to rethink their regional allocation focusing on a reduced number of countries in Europe, mainly in the north, and increasing their focus on Australia and South America. Some governments have been moving faster towards asset privatizations or public-private partnerships to involve investors in their plan for financial recovery. The energy sector remained the most popular for infrastructure investment. Strategic corporate investors were noticeably active in M&A activity, repositioning themselves to finance future growth through asset sales, spinoffs or joint-ventures.

PSP INVESTMENTS as at March 31, 2012

One year rate of return
3.0%

Net income from operations
$1.7 billion

Contributions
$4.7 billion

Net assets
$64.5 billion

CHANGE IN NET ASSETS

The net assets of PSP Investments increased by $6.5 billion during fiscal year 2012, a gain of 11% that was attributable to fund contributions and investment performance. Net assets at the end of fiscal year 2012 were $64.5 billion, up from $58.0 billion at the end of the previous fiscal year.

PSP Investments generated net income from operations of $1.7 billion during the latest fiscal year, compared to $6.9 billion of income generated in fiscal year 2011. These results for fiscal year 2012 represent a consolidated rate of return of 3.0%, compared to 14.5% in fiscal year 2011. PSP Investments received $4.7 billion in contributions during fiscal year 2012.

CONSOLIDATED RETURNS

The 3.0% rate of return recorded by PSP Investments in fiscal year 2012 exceeded the Policy Benchmark rate of return by 1.4% and added $850 million in value over and above the Policy Benchmark return. Over the past five fiscal years, PSP Investments has recorded a compound annualized rate of return of 2.0%, compared to the Policy Benchmark rate of return of 2.7% for that same period.

The overall performance of 3.0% for fiscal year 2012 was driven primarily by strong results from the Real Estate, Private Equity and Fixed Income portfolios. Public Markets Equities benefited from favorable results from US Large Cap Equity and Small Cap Developed World Equity portfolios, each producing returns of 11.4% and 7.6%, respectively. This was partially offset by negative returns in the remaining Public Market Equity portfolios as a result of the negative performance of global stock markets, as outlined in the Market Overview. Canadian Equity was the worst performing asset class in fiscal year 2012 with an investment return of negative 9.8%. However, its impact on PSP Investments' overall return was mitigated as the exposure to this asset class was in the process of being reduced during the year, going from 32.2% of total assets under management at the end of fiscal year 2011 to 22.4% at fiscal year-end 2012.

The excess return of 1.4% (relative to the Policy Benchmark) achieved during fiscal year 2012 was generated primarily by absolute return mandates as well as the Real Estate, Emerging Market Equity and Fixed Income portfolios. For the fiscal year ended March 31, 2012, investments in asset-backed term notes, included in absolute-return mandates, generated investment income of $342 million. The improved credit profile of the asset-backed term notes portfolio, tightening credit spreads and continuing favorable market conditions were the primary reasons for the increase in value of these investments.

PORTFOLIO AND BENCHMARK RETURNS

As at March 31, 2012

Asset Class	Fiscal Year 2012				5-year	
	Fair Value ($ millions)[1]	Fair Value %	Portfolio Returns %	Benchmark Returns %	Portfolio Returns %	Benchmark Returns %
World Equity						
Canadian Equity	14,464	22.4	(9.8)	(9.8)	1.0	1.1
Foreign Equity						
US Large Cap Equity	5,294	8.2	11.4	11.5	(3.3)	(0.9)
EAFE Large Cap Equity	4,760	7.4	(2.7)	(3.2)	(5.7)	(6.2)
Small Cap Developed World Equity	3,641	5.6	7.6	7.1	(2.1)	0.0
Emerging Markets Equity	4,787	7.4	(4.3)	(6.3)	2.4	1.7
Private Equity	6,444	10.0	7.7	7.7	5.5	1.7
Nominal Fixed Income						
Cash & Cash Equivalents[2]	1,597	2.5	1.2	0.9	2.0	1.8
Fixed Income	8,569	13.3	10.1	9.4	5.9	5.7
Real Return Assets						
World Inflation-Linked Bonds	3,982	6.2	15.3	15.3	4.1	4.1
Real Estate	7,055	10.9	13.4	6.7	5.8	6.9
Infrastructure	3,607	5.6	2.7	9.6	3.5	5.6
Renewable Resources (0.75 year)[3]	325	0.5	5.1	3.8	–	–
Total	**64,525**	**100.0**	**3.0**	**1.6**	**2.0**	**2.7**

Except otherwise indicated, returns are time-weighted rate of return and have been calculated in accordance with the performance calculation methodology recommended by the CFA Institute.

The internal rate of return methodology is used to calculate the returns for the Real Estate, Private Equity, Infrastructure and Renewable Resources asset classes.

The total portfolio return includes the performance impact of asset allocation and absolute return strategies and is calculated gross of direct expenses. Hedging investment returns are netted against the return of the respective hedged assets for the Private Market asset classes, or included in Total Return, for the Public Markets.

[1] The investments are classified by asset mix category as set out in the SIP&P based on the economic intent of the investment strategies of the underlying assets.

[2] Fair value includes amounts related to absolute return and real estate debt strategies.

[3] The Renewable Resources asset class has existed for less than one year. The portfolio and benchmark returns presented are since inception.



PUBLIC MARKETS as at March 31, 2012

One year rate of return
1.4%

Investment income*
$640 million

Net assets
$45.5 billion

70.5% of total net assets

* Excluding external investment management fees

PUBLIC MARKETS

Public Markets is composed of Canadian Equity, Foreign Equity, Fixed Income and World Inflation-Linked Bonds. Net assets in Public Markets totalled $45.5 billion at the end of fiscal year 2012, an increase of $2.0 billion from $43.5 billion at the end of fiscal year 2011. Overall, Public Markets recorded investment income of $640 million, excluding external investment management fees, for a return of 1.4% compared to a benchmark return of 0.1%. Six of the seven Public Market portfolios equalled or outperformed their respective benchmarks.

External equity managers added $93 million of relative value during fiscal year 2012, mainly as a result of the outperformance by emerging markets managers. External global macro, fixed income and foreign currency absolute return strategies added $77 million of relative value, mainly as a result of the effect of positions in gold and US and German bonds. Internal active management added $71 million of relative value, generated mainly from equity and fixed income strategies. Asset-backed term notes contributed $330 million of relative value as PSP Investments fully benefited from a reduction of risk on the underlying assets as they approach maturity and were also positively impacted by the contraction of credit spreads.

Public Markets investments are overseen by both internal and external managers using a combination of active and index-replication strategies. Net assets managed in active strategies totalled $17.9 billion at the end of fiscal year 2012, an increase of $0.7 billion from $17.2 billion at the end of fiscal year 2011. The proportion of active strategies managed internally increased to 60%, from 53% at the end of the previous fiscal year.

EQUITIES

Net assets in Public Markets equities totalled $32.9 billion at the end of fiscal year 2012, an increase of $0.1 billion from the $32.8 billion total at the end of fiscal year 2011.

Public Markets equities recorded an investment loss of $1.2 billion for a negative return of 3.4% in fiscal year 2012, versus the benchmark return of negative 3.8%. The outperformance of the Public Markets equities portfolio vis-à-vis the benchmark was mainly due to a strong relative performance from emerging markets portfolios.

As noted in the Market Overview, economic concerns stemming primarily from monetary issues in Europe as well as weakening emerging market economies led many stock markets lower, although there were notable exceptions to this trend. As a result, the Canadian Equity portfolio was down 9.8% during fiscal year 2012, while the US Large Cap Equity portfolio gained 11.4%. Elsewhere, the EAFE Large Cap Equity portfolio was down 2.7%, while the Small Cap Developed World Equity and Emerging Markets Equity asset classes posted investment returns of 7.6% and negative 4.3%, respectively.

FIXED INCOME

Net assets in Fixed Income and World Inflation-Linked Bonds totalled $12.6 billion at the end of fiscal year 2012, up from $10.7 billion at the end of fiscal year 2011. Overall, these fixed income portfolios earned $1.3 billion in investment income for a return of 11.6% in fiscal year 2012, versus a benchmark return of 11.1%. The outperformance was mainly due to an overweight position in corporate credit, as well as directional and relative value strategies on interest rates and sovereign credit.

PRIVATE EQUITY

Net assets of the Private Equity portfolio totalled $6.4 billion at the end of fiscal year 2012, an increase of $0.8 billion from $5.6 billion at the end of fiscal year 2011.

Private Equity generated $453 million in investment income, excluding transaction costs, for a rate of return of 7.7% for fiscal year 2012, in line with the benchmark return of 7.7%. This income is further split between funds for $261 million and direct and co-investments for $192 million.

Gains in the fund segment were driven by exposures to the US market, while European funds lagged behind, confronted by a difficult credit and macroeconomic environment, and very slow mergers and acquisitions activity. The strong performance of the direct and co-investment strategy is mainly attributable to Telesat and China Network Systems among others, which recorded continued growth in revenue and EBITDA, creating added value in the portfolio. From a total portfolio perspective, exposures to both the US and Canadian markets performed particularly well, while our Asian and European exposures lagged behind. On a five-year basis, Private Equity investments generated a 5.5% annualized return, compared to the benchmark return of 1.7% for the same period.



PRIVATE EQUITY as at March 31, 2012

One year rate of return
7.7%

Investment income*
$453 million

Net assets
$6.4 billion

10.0% of total net assets

* Excluding transaction costs

The Private Equity portfolio has a long-term focus with investments held for an average of five to ten years. The portfolio is invested globally in collaboration with strategic partners with whom PSP Investments has established relationships. PSP Investments continues to diversify its Private Equity portfolio, with direct and co-investments playing an increasingly important role.

During the past fiscal year, the Private Equity Group committed strategically to fund opportunities, selectively making new commitments to managers with unique and specialized investment strategies underpinned by a strong alignment of interests and preferred terms and economics.

As at March 31, 2012, direct and co-investments accounted for 34% of assets of the Private Equity portfolio, up from 32% at the end of the previous fiscal year. Direct and co-investments amounted to $2.2 billion at the end of fiscal year 2012. Among the year's noteworthy transactions was the acquisition of Kinetic Concepts Inc. (US Health Care – Equipment & Services) which was partnered alongside Apax Partners and the CPP Investment Board.

Overall, the Private Equity portfolio is well diversified both from a geographic and sector perspective. As a result of the acquisition of Kinetic Concept Inc. and strong relative performance of the US market, there has been an increase in US exposure at the expense of other geographical markets.



PRIVATE EQUITY
DIVERSIFICATION BY GEOGRAPHY
As at March 31, 2012

United States	45.1%
Canada	23.4%
Europe	16.4%
Asia	15.1%

The majority of the Private Equity portfolio exposure is in North America.



PRIVATE EQUITY
DIVERSIFICATION BY SECTOR
As at March 31, 2012

Consumer Discretionary	28.6%
Telecom	26.4%
Health Care	11.1%
Information Technology	9.2%
Financial	7.4%
Materials and Industrial	6.8%
Energy	5.5%
Other	5.0%



REAL ESTATE as at March 31, 2012

One year rate of return
13.4%
Investment income*
$770 million
Net assets
$7.1 billion
10.9% of total net assets

*Excluding transaction costs

REAL ESTATE

Net assets of the Real Estate portfolio totalled $7.1 billion at the end of fiscal year 2012, an increase of $1.8 billion from the $5.3 billion at the end of fiscal year 2011.

Real Estate generated $770 million in investment income, excluding transaction costs, for a return of 13.4% in fiscal year 2012, compared to a benchmark of 6.7%.

The robust returns are attributable in part to consistent cash flows generated by a diversified portfolio, which includes very stable multi-family and seniors residential properties as well as office, retail and hotel assets in Canada, the U.S., Europe and Brazil. Also reflected in the results are increased valuations and realized gains stemming mainly from Canadian hotel, seniors and office assets, US multi-family assets and Brazilian office and retail assets, plus gains generated by strategic investments in high-yield real estate debt instruments.

On a five-year basis, Real Estate investments generated a 5.8% annualized return, compared to a benchmark return of 6.9% for the same period. Since the inception of the Real Estate portfolio in fiscal 2004, Real Estate investments have generated an annualized return of 9.2%, compared to a benchmark of 6.9%.

The year-over-year increase in net assets reflects both new investments and positive valuations of existing assets. New investments made during fiscal year 2012 included office properties in New York, London, Edmonton, California's Silicon Valley, Frankfurt, Madrid and Washington; retail properties in Sweden, France, the U.S. and Colombia; industrial properties in the U.S.; and multi-family properties in Canada. As well, the Real Estate Group increased its investments in high-yield and distressed debt strategies and in Canadian hotel properties.

As at March 31, 2012, direct ownership and co-investments accounted for 79% of the assets in Real Estate, up from 75% at the end of the previous fiscal year.



REAL ESTATE
DIVERSIFICATION BY GEOGRAPHY
As at March 31, 2012

Canada	43.7%
United States	32.9%
Europe	14.7%
Emerging countries	8.1%
Asia	0.6%

The majority of the Real Estate portfolio exposure is in North America, mainly in Canada.



REAL ESTATE
DIVERSIFICATION BY SECTOR
As at March 31, 2012

Retirement/Residential	31.4%
Office	24.0%
High-Yield Debt	9.7%
Retail	7.6%
Health Care	7.4%
Hotel	7.2%
Industrial	3.7%
Other	9.0%

INFRASTRUCTURE

The net assets of the Infrastructure portfolio totalled $3.6 billion at the end of fiscal year 2012, an increase of $1.2 billion from the $2.4 billion at the end of fiscal year 2011.

Infrastructure generated $81 million in investment income, excluding transaction costs, for a return of 2.7% in fiscal year 2012, compared to the benchmark return of 9.6%. The benchmark return was influenced by government intervention to keep interest rates low and a flight to quality in government bonds. The portfolio return was driven mainly by distributions from direct and co-investments. The performance of a majority of the investments in the utilities and transportation portfolio was above the benchmark. These investments are located outside North America. In the energy sector, the changing pattern in supply and demand of natural gas in North America continued to negatively affect the portfolio. Since inception, Infrastructure investments have generated a 3.7% annualized return, compared to a Policy Benchmark return of 5.0% for the same period.

The year-over-year increase in net assets in Infrastructure came from six new direct investments totalling $1.5 billion, the highest annual amount invested since the creation of the asset class. Opportunities came from sellers which were deleveraging or redeploying capital as well as new strategic partnerships. Over the course of the fiscal year, the Infrastructure Group acquired an interest in a joint venture that operates a major natural gas pipeline, a significant participation in hydroelectric facilities and a participation in a UK-based landlord ports operator, as well as various other investments related to the energy sector. These investments were mainly in Europe, Canada and the United States. Their diverse nature as well as the variety of sectors and regions involved contributed to enhanced portfolio diversification.

As at March 31, 2012, direct and co-investments accounted for 83% of the assets of the Infrastructure Portfolio, up from 76% at the end of the previous fiscal year.



INFRASTRUCTURE as at March 31, 2012

One year rate of return
2.7%

Investment income*
$81 million

Net assets
$3.6 billion

5.6% of total net assets

* Excluding transaction costs



INFRASTRUCTURE
DIVERSIFICATION BY GEOGRAPHY
As at March 31, 2012

United Kingdom	24.4%
Europe	22.3%
United States	17.7%
Canada	13.5%
Australia	12.0%
South America	10.1%

The Infrastructure portfolio is diversified mostly across the Americas and Europe.



INFRASTRUCTURE
DIVERSIFICATION BY SECTOR
As at March 31, 2012

Transportation	29.4%
Oil & Gas Storage and Transport	27.1%
Electric Generation & Transmission	20.8%
Water Utilities	12.1%
Oil & Gas Exploration and Production	9.9%
Other	0.7%

OPERATING AND ASSET MANAGEMENT EXPENSES

In fiscal year 2012, PSP Investments' cost ratio (i.e. operating expenses plus asset management expenses as a percentage of average net investment assets) decreased to 60.6 basis points, or 60.6 cents per $100 of average net investment assets, from 67.0 basis points, or 67 cents per $100 of average net investment assets in fiscal 2011, as a result of increased efficiencies and economies of scale driven by the increase in the internal active management of assets and higher net investment assets. Asset management expenses include management fees paid to external asset managers and transaction costs. Transaction costs can vary significantly year over year depending on the complexity and size of our Private Markets investment activities.

PSP Investments' cost ratio decreased for the fourth consecutive year, mainly as a result of the internal active management investment strategy adopted by PSP Investments in fiscal year 2004. Assets managed internally increased to approximately $48 billion at the end of fiscal year 2012 compared to $43 billion at the end of the previous year. Since the end of fiscal year 2009, assets managed internally have increased by almost $27 billion, or 128%. Although the shift does impact operating expenses, on balance, based on market data, the costs related to internal active management are approximately three to seven times less expensive than the costs related to management fees paid to external active managers, depending on the type of asset and implementation style involved.

PSP Investments' cost ratio includes operating expenses of $148 million for fiscal year 2012 compared to $114 million for fiscal year 2011. As a percentage of net investment assets, operating expenses amounted to 24.8 basis points, or 24.8 cents per $100 of average net investment assets, compared to 22.3 basis points, or 22.3 cents per $100 of average net investment assets in fiscal year 2011. The increase in operating expenses for the current fiscal year can be attributed to the increase in headcount and related expenses required to support the execution of the internal active investment strategy mentioned previously. The increase in operating expenses in basis points has been more than offset by the decrease in basis points in external asset management expenses.

STRATEGIC AND OPERATING REVIEW

During the fiscal year ended March 31, 2012, the Government of Canada launched its Strategic and Operating Review ("SOR") initiative. The SOR is primarily aimed at federally-appropriated Crown corporations and at government departments and programs. The goal of the SOR is to generate savings from operating expenditures and to improve productivity while also examining the efficiency and effectiveness of programs. Even though PSP Investments is a federally non-appropriated Crown Corporation, it undertook a review to adhere to the spirit and intent of the SOR initiative.

Net investment performance is the main contributor to reducing the cost to the Plans' sponsor (the Government of Canada). To this end, PSP Investments has increased investment activities and level of assets managed internally and actively with the aim of improving its overall investment cost structure (expressed as a percentage of average net investment assets) and has increased the probability of meeting the desired long-term actuarial rate of return. In this respect, PSP Investments' net performance over the past nine years has been 7.6%, surpassing the expected long-term rate of return requirements of the Plans.

From a cost perspective, PSP Investments has been carefully managing growth in investment activities by ensuring rigorous oversight as asset levels increased over the last several years. PSP Investments' strategy of increasing its proportion of assets managed internally has resulted in increased efficiencies and economies of scale. PSP Investments' cost ratio has declined in each of the past four fiscal years, going from 86.9 basis points, or 86.9 cents per $100 of average net investment assets, in fiscal year 2009 to 60.6 basis points, or 60.6 cents per $100 of average net investment assets, in the current fiscal year, a decrease of 30%. During this period, internally managed assets have increased by approximately $27 billion, while operating expenses grew by only $62 million. We estimate that for fiscal year 2012 alone, based on market data on investment implementation style, the increase in internally managed assets of $27 billion has resulted in savings ranging from $120 million to $180 million compared with what costs would have been had PSP Investments deployed these assets with external investment managers.

PSP Investments remains committed to maintaining an effective overall cost structure and has adhered to the spirit and intent of the SOR initiative by investing in scalable and cost-effective operations, managing its assets as efficiently as possible and by improving its cost ratio each year for the past four years.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February 2008, the Accounting Standards Board of Canada (AcSB) confirmed that Canadian Generally Accepted Accounting Principles (GAAP) for publicly accountable enterprises would converge with International Financial Reporting Standards (IFRS) effective January 1, 2011.

In 2011, the AcSB decided to defer the adoption of IFRS by investment companies, currently applying Accounting Guideline 18 "Investment Companies" (AcG-18) to annual periods starting on or after January 1, 2014. This deferral delays PSP Investments' transition to IFRS until the March 31, 2015 annual consolidated financial statements.

The AcSB's decision was in response to an announcement by the International Accounting Standards Board (IASB) in 2010, regarding an Exposure Draft (ED) being developed. The IASB proposed to define an investment entity and exempt it from consolidation by requiring it to measure all controlled investments at fair value, with changes recognized in profit or loss. The ED, Investment Entities, was published in August 2011 and is expected to be finalized in the second half of 2012. PSP Investments will complete the assessment of the impact of its transition to IFRS once the ED is finalized and a standard is issued.

The AcSB also announced in 2011 that it will evaluate whether entities like PSP Investments, which are separate from a pension plan and without a pension obligation, and whose sole purpose is to hold and invest assets received from one or more pension plans, would qualify as investment entities under the IASB's ED. Based on the result of this evaluation, the AcSB will then decide whether these entities would need to be included within the scope of Section 4600 "Pension Plans", where investments are accounted for at fair value.

RISK MANAGEMENT

ENTERPRISE RISK MANAGEMENT

As the manager of public pension assets, PSP Investments is responsible for acting in the best interest of the contributors and beneficiaries of the Plans and maximizing returns without undue risk of loss. PSP Investments acknowledges that it must take risks to achieve its legislated mandate and that the management of the full spectrum of risks must be integrated on an enterprise-wide basis.

PSP Investments faces risk in all aspects of its activities and places emphasis on continuous improvement of its risk management capabilities. As a result, PSP Investments has established an enterprise risk management framework to provide a structure for identifying, evaluating and managing its various investment and non-investment risks. The framework is a core component of PSP Investments' Enterprise Risk Management Policy. The policy also defines PSP Investments' responsibilities relating to its enterprise risks from the perspective of the Board and its committees, the management committees and the investment groups and support groups within the Corporation. In addition to the Enterprise Risk Management Policy, an Investment Risk Management Policy and an Operational Risk Management Policy deal with the specific characteristics of these risks.

PSP Investments' enterprise risk management framework is guided by the following principles:

- Promote a risk-aware culture;
- Establish and implement a risk management framework that enables PSP Investments to identify, evaluate, manage, monitor and report on enterprise risks;
- Integrate enterprise risk management into strategic and financial objectives;
- Operationalize sound risk management processes.

PSP Investments periodically reviews its risk management policies ensuring governance for all of the Corporation's risks. In fiscal year 2012, based on the results of the prior year's Risk and Control Self Assessment findings and Special Examination recommendations, the Risk Management Group identified opportunities to enhance its risk management policies.

Enterprise risks are categorized to facilitate a universal understanding of all the risks faced by PSP Investments. The Corporation's enterprise risk categories are defined as:

- Investment risk: the risk of loss inherent in achieving investment objectives, including market, liquidity, credit and counterparty, leverage and concentration risks.
- Governance risk: the risk of a lack of consistent corporate management, cohesive policies and organizational structure alignment.
- Strategic risk: the risk of not achieving strategic goals or business objectives.
- Operational risk: the risk of a direct or indirect loss resulting from inadequate or failed internal processes, people or systems, or from external events.
- Stakeholder risk: the risk of not maintaining efficient relations with PSP Investments' plan sponsors and key business partners.
- Legal and regulatory risk: the risk of non compliance with applicable regulations, or a change in legislation, regulations or other mandatory industry practices.
- Reputational risk: the risk that an activity undertaken by PSP Investments or its representatives impairs its image in the community or lowers public opinion and stakeholder confidence in it.

ENTERPRISE RISK MANAGEMENT FRAMEWORK

PSP Investments' Enterprise Risk Categories

INVESTMENT RISK					
Market Risk	**Liquidity Risk**	**Credit and Counterparty Risk**	**Leverage Risk**	**Concentration Risk**	
NON INVESTMENT RISK					
Governance Risk	**Strategic Risk**	**Operational Risk**	**Stakeholder Risk**	**Legal and Regulatory Risk**	**Reputational Risk**

In fiscal year 2012, PSP Investments continued the ongoing application of its enterprise risk management framework, aligned with its three-year strategic plan.

Key accomplishments for the fiscal year include the following:

- Further refined risk limits and attributed active risk across asset classes through a structured risk budget process and resulting information ratio for increased measurement of active returns;
- Enhanced and detailed monitoring and reporting of investment risk drivers by portfolio via new risk metrics; and
- Operationalized the process for the management and reporting of risks identified in the prior year's Risk and Control Self Assessment including enhanced risk measurement and reporting practices surrounding operational risks.

RISK MANAGEMENT GOVERNANCE MODEL

PSP Investments promotes a risk-aware culture involving all employees. Senior management and employees are not only active participants in risk identification, but also in risk evaluation, management, monitoring and reporting.

The Board of Directors contributes to risk oversight by:

- Establishing the investment objectives, Investment Policy and Policy Portfolio;
- Participating in the definition of PSP Investments' risk philosophy;
- Being aware of the extent to which PSP Investments' management has established effective enterprise risk management within the organization;
- Reviewing the corporate risk profile provided by management; and
- Being apprised of material risks and how PSP Investments' management is responding to them.

In order to oversee and manage risks related to its investments and operations, senior management has created various committees, including the Management Investment Committee, Management Operations Committee, Risk Steering Committee, Valuation Committee, New Business Activity Committee and Information Technology Governance Committee.

In fiscal year 2012, enhanced risk reporting was implemented at the various committees and sub-committees where warranted, for increased internal and active management. Additionally, the governance structure surrounding the introduction and monitoring of new business activities was enhanced.

INVESTMENT RISK MANAGEMENT

The Investment Risk Management Policy is an integral component of PSP Investments' risk management program to support the management of risks incurred through the fund's investment processes. The policy establishes an investment risk management framework, with a goal of ensuring that investment activities respect the risk philosophy of PSP Investments.

PSP Investments faces five principle investment risk types: (i) market risk; (ii) liquidity; (iii) credit and counterparty; (iv) leverage risk; and (v) concentration risk.

The framework covers the key elements required to establish a comprehensive investment risk management process.

The Investment Risk Management Policy also supplements the Statement of Investment Policies & Procedures ["SIP&P"]. As such, the Investment Risk Management Policy has been developed to effectively manage investment risks related to the policy portfolio and active management activities:

- Policy Portfolio
  The Policy Portfolio, as defined in the SIP&P and described on page 10 sets out a strategy to mitigate risk through a diversified investment portfolio;
- Active Management
  Active management is defined as the sum of investment strategies that deviate from the approved Policy Portfolio. It is designed to supplement the returns of the Policy Portfolio within an active risk budget.

The risks associated with these components are the Policy Portfolio risk and the active risk. The Policy Portfolio risk represents the investment risk arising from the exposure to approved asset classes in the approved weightings. Active risk refers to all market risk arising from active management activities, and is managed in accordance with the Investment Risk Management Policy.

OPERATIONAL RISK MANAGEMENT

Operational risk is one of the key enterprise risks that PSP Investments is exposed to. The Operational Risk Management Policy currently in place within PSP Investments defines the guiding principles and frames boundaries to prudently and proactively manage the risks to which PSP Investments is exposed.

Operational risk management at PSP Investments is structured around six types of risk: (i) people management; (ii) process and information management; (iii) systems and data management; (iv) theft and fraud; (v) business disruption; and (vi) model and valuation.

INTERNAL AUDIT AND COMPLIANCE

INTERNAL AUDIT

Internal Audit is an independent, objective assurance and consulting activity designed to add value and improve PSP Investments' operations. It helps to achieve PSP Investments' objectives by using a systematic disciplined approach to evaluate and improve the effectiveness of risk management, control and governance processes.

INTERNAL CONTROLS

The internal-controls environment is derived from the Committee of Sponsoring Organizations of the Treadway Commission (COSO) model. COSO defines internal control as a process, affected by an entity's Board of Directors, management and personnel, designed to provide reasonable assurance regarding the achievement of objectives in the following categories:

- Strategic – High-level goals, aligned with and supporting its mission;
- Operational – Effectiveness and efficiency of operations;
- Reporting – Reliability of financial reporting;
- Compliance – Compliance with applicable laws and regulations.

PSP Investments annually reviews its control environment as well as key controls in all departments, as required under Section 28 of the Act.

The control functions are carried out at various levels and in various departments. Each control is designed to ensure that PSP Investments' policies and procedures are respected and applied consistently. All policies are approved by the Board of Directors and are supported by procedures that provide a framework for their implementation.

COMPLIANCE

PSP Investments must act with integrity and maintain high ethical standards at all times. The objective of the Compliance Department, in conjunction with the Legal Affairs Department, is to ensure stringent compliance by PSP Investments and its employees with its policies and procedures, including the Code of Conduct for Officers, Employees and Others (the "Employee Code"), as well as relevant laws and statutory requirements.

Compliance with internal investment policies and procedures is achieved primarily through daily monitoring of transactions and quarterly reporting to the Audit Committee, which is responsible for monitoring the compliance function. Processes are also in place to monitor compliance with the Employee Code. The Employee Code describes PSP Investments' corporate principles and values, with the aim of assisting employees and those subject to its provisions in determining appropriate business practices and behavior.

Among other things, the Employee Code includes sections on: personal and professional conduct, which requires unwavering commitment to honesty and integrity; conflicts of interest; gifts, hospitality and other benefits; bribery; protecting PSP Investments' assets and; personal trading, which requires the pre-authorization and reporting of personal investment transactions.

PSP Investments takes the Employee Code seriously. Violations will be subject to appropriate discipline, including termination of employment or engagement. As such, the Employee Code also includes a whistle-blowing provision designed to encourage employees and those subject to its provisions to step forward and report any financial fraud or other fraudulent and inappropriate activities.

The Compliance Officer is responsible for the Employee Code's procedures and reports quarterly to the Governance Committee who is responsible for monitoring application of the Employee Code. The Employee Code may be viewed on PSP Investments' website **www.investpsp.ca**.

GOVERNANCE

Effective governance is essential to safeguard the capital entrusted to PSP Investments and to ensure that appropriate objectives are pursued and achieved, consistent with the fulfillment of the Corporation's legislated mandate. This section describes PSP Investments' governance framework, including its mandate, the roles of the Board of Directors and Board committees and key policies that guide the organization's activities and behaviour.

MANDATE

PSP Investments is a Crown corporation created in 1999 by Act of Parliament (the *Public Sector Pension Investment Board Act,* or the "Act"). PSP Investments' mandate is twofold: managing the funds transferred to it by the Government of Canada for the Canadian Forces, the Reserve Force, the Public Service and the Royal Canadian Mounted Police ("RCMP") pension plans (the "Plans") in the best interests of the contributors and beneficiaries; and investing its assets with a view to achieving a maximum rate of return without undue risk of loss, having regard to the funding, policies and requirements of the Plans and their ability to meet their financial obligations.

Effective April 1, 2000, the Government of Canada created three new pension fund accounts (the "Pension Funds"), one for each of the Public Service, the Canadian Forces and the RCMP Plans. On March 1, 2007, the Government established the Reserve Force Pension Plan and created a Pension Fund for it as well. Employer and employee contributions in respect of service after the date of creation of a particular Pension Fund ("post-funding service") are deposited to the relevant Pension Fund. Amounts equal to the net balances in these Pension Funds (that is contributions minus benefits payments for post-funding service, as well as plan administration expenses) are then transferred to separate accounts maintained at PSP Investments (the "Pension Plan Accounts") for each of the Pension Funds, to be invested in accordance with the approved investment policy and strategy.

The Government of Canada manages and administers the Plans. The President of the Treasury Board is responsible for the Public Service Pension Plan, the Minister of National Defence for the Canadian Forces Pension Plan and the Reserve Force Pension Plan, and the Minister of Public Safety for the RCMP Pension Plan. PSP Investments is the exclusive investment manager of the amounts transferred to the Pension Plan Accounts.

BOARD OF DIRECTORS

PSP Investments' operations and activities are overseen by a Board of Directors composed of 11 members, including the Chair of the Board. Directors are appointed by the Governor in Council on the recommendation of the President of the Treasury Board to hold office during good behaviour for a term not exceeding four years. Candidates for directorships are selected from a list of qualified individuals proposed by a nominating committee established by the President of the Treasury Board (the "Nominating Committee") pursuant to the Act. The Nominating Committee operates separately from the Board of Directors, the President of the Treasury Board and the Treasury Board Secretariat. Members of the Senate, the House of Commons and provincial legislatures, as well as employees of PSP Investments or the Government of Canada and those entitled to benefits from the Plans, are disqualified from serving as Directors. The Chair of the Board is designated from among the Directors by the Governor in Council on the recommendation of the President of the Treasury Board, after consultation with the Board of Directors, the Minister of National Defence and the Minister of Public Safety. On the expiry of the term of an incumbent Director, the incumbent may be reappointed and, in any event, continues in office until a successor is appointed.

The Board of Directors plays an active role in guiding PSP Investments. Therefore, a substantial time commitment is expected of Directors, particularly the Chair of the Board and the Chairs of Board committees, for meetings, travel and preparation for meetings.

In fiscal year 2012, two Directors were appointed and two Directors left PSP Investments' Board. On September 29, 2011, the Governor in Council appointed Ms. Micheline Bouchard and Mr. Garnet Garven as Directors for terms of four years, and the term of Mr. Bob Baldwin expired. On March 5, 2012, the date of the expiration of his term, Mr. Paul Cantor resigned both as a Director and Chair of the Board of PSP Investments. On March 27, 2012, the President of the Treasury Board designated Ms. Cheryl Barker as Interim Chair to exercise the powers and perform the duties and functions of the Chair until further notice or until such time as the Governor in Council designates a new Chair of the Board. On March 31, 2012, the Board was composed of the following nine Directors, with two vacant positions in the process of being filled:

- Cheryl Barker, Interim Chair
- Micheline Bouchard
- Anthony R. Gage
- Lynn Haight
- Michael P. Mueller
- Diane Bean
- Léon Courville
- Garnet Garven
- William A. MacKinnon

Canadian securities regulators have defined the concept of "independent director" applicable to publicly-listed issuers as an individual who has no direct or indirect material relationship with the issuer. A "material relationship" has been defined as a relationship which could, in the view of the issuer's board of directors, be reasonably expected to interfere with the exercise of an individual's independent judgment. Those regulations do not apply to PSP Investments, given that it is not a publicly-listed issuer. However, based on the same definitions, all Directors of PSP Investments would be considered independent directors.

All Directors of PSP Investments must have an excellent understanding of the role of a director and possess a general knowledge of pensions and a broad knowledge of investment management and its related risks.

In addition to investment management knowledge, the Directors of PSP Investments possess a wide range of professional experience in a variety of fields, including accounting, finance, economics and human resources. Biographies of each Director, as of March 31, 2012, can be found beginning on page 54.

ROLES AND RESPONSIBILITIES OF THE BOARD OF DIRECTORS AND BOARD COMMITTEES

BOARD OF DIRECTORS

In order to ensure that PSP Investments' statutory mandate is met, the Board of Directors, in addition to the requirements of the Act, has defined its role to include, among other responsibilities, the following:

- Appointment and termination of the President and CEO;
- Annual review and approval of proposed amendments to the written Statement of Investment Policies, Standards and Procedures ("SIP&P") for each Pension Plan Account;
- Approval of strategies for achieving investment performance objectives and benchmarks against which to measure performance;
- Adoption of appropriate policies for the proper conduct and management of PSP Investments, including a Code of Conduct for Officers, Employees and Others ("Employee Code"), and a Code of Conduct for Directors ("Director Code");
- Ensuring that effective enterprise, investment and operations risk policies are in place;
- Approval of human resources and compensation policies;
- Establishment of appropriate performance-evaluation processes for the Board of Directors, the President and CEO and other members of senior management; and
- Approval of quarterly and annual financial statements for each Pension Plan Account and for PSP Investments as a whole.

The Terms of Reference describing the roles and responsibilities of the Board of Directors and its committees and the Chair of the Board may be viewed in their entirety on PSP Investments' website **www.investpsp.ca**.

BOARD COMMITTEES

The Board of Directors has established the following four committees to assist in the fulfillment of its obligations:

- Investment Committee
- Governance Committee
- Audit Committee
- Human Resources and Compensation Committee

A special Chairperson Nominating Committee chaired by Ms. Cheryl Barker was created on September 30, 2011 to recommend to the President of Treasury Board a Director to serve as Chair of the Board in replacement of Mr. Paul Cantor whose term was expiring on March 5, 2012. The Special Chairperson Nominating Committee having fulfilled its mandate, was wound up on November 8, 2011.

INVESTMENT COMMITTEE

The Investment Committee is responsible for overseeing the investment management function of PSP Investments. The Investment Committee's duties assigned to it by the Board or provided for in the Act include the following:

- Approving all investment proposals and related borrowings above thresholds delegated by the Board to management for approval;
- Making annual and other recommendations to the Board of Directors on the SIP&P for each Pension Plan Account;
- Overseeing PSP Investments' investment risks and ensuring that an appropriate control environment is in place to govern the management of investment risks; and
- Approving the engagement of external investment managers having discretionary authority to invest PSP Investments' assets under management.

The Investment Committee is composed of all members of the Board of Directors[1] and is chaired by Mr. Anthony R. Gage.

[1] Ms. Micheline Bouchard and Mr. Garnet Garven were appointed to the Investment Committee on September 29, 2011, date of their appointment as Directors.

AUDIT COMMITTEE

The Audit Committee's role is generally to review financial statements and the adequacy and effectiveness of PSP Investments' systems of internal controls. This includes internal controls over the accounting and financial-reporting systems within PSP Investments, as well as internal information system controls and security. Many of the duties of the Audit Committee are set out in the Act. These duties include:

- Reviewing quarterly and annual financial statements for each Pension Plan Account and for PSP Investments as a whole, recommending them to the Board for approval and discussing any letters to management regarding any significant concerns on the part of the joint external auditors;
- Meeting separately with PSP Investments' joint external auditors and internal auditors, without management present, to discuss and review specific issues related to the Audit Committee;
- Overseeing PSP Investments' operational risks and ensuring that an appropriate control environment is in place to govern the management of operational risks inherent to PSP Investments' activities;
- Ensuring that internal audits are conducted in respect of PSP Investments and its subsidiaries; and
- Adopting and maintaining an appropriate whistle-blowing mechanism for reporting fraudulent, illegal or inappropriate activities.

On March 31, 2012, the Audit Committee was composed of the following Directors[2]:

- William A. MacKinnon, Chair
- Anthony R. Gage
- Lynn Haight
- Cheryl Barker
- Garnet Garven

All Audit Committee members are financially literate with accounting or finance expertise, and possess the requisite experience and knowledge to read and understand PSP Investments' and the Pension Plan Accounts' financial statements and properly fulfill their role. For more information on the experience of each committee member, as well as their occupations and education, please see their biographies on page 54.

GOVERNANCE COMMITTEE

The Governance Committee's role is generally to assist the Board of Directors in monitoring governance matters at PSP Investments and developing related policies. The Governance Committee has responsibility for the application of the Director Code and the Employee Code. The Governance Committee's duties also include the following:

- Monitoring and assessing the relationship between the Board of Directors and management, defining the limits to management's responsibilities and ensuring that the Board of Directors functions independently of management;
- Reviewing at least every two years, with the assistance and input of the President and CEO and the Chair of the Board of PSP Investments, the Terms of Reference for the Board of Directors and the committees of the Board, and recommending to the Board such amendments as may be necessary or advisable;
- Developing and recommending to the Board of Directors for approval new or amended by-laws and governance-related policies, including the Director Code and the Employee Code;

[2] Mr. Garnet Garven was appointed to the Audit Committee on October 6, 2011.

- Developing target recruitment skill sets and other recruiting capabilities to facilitate the identification by the independent Nominating Committee of suitable candidates for appointment as Directors of PSP Investments;
- Overseeing the implementation of procedures for assessing the effectiveness of the Board of Directors as a whole, as well as the performance of individual Directors; and
- Overseeing PSP Investments' governance risks and ensuring that an appropriate governance framework is in place.

On March 31, 2012, the Governance Committee was composed of the following Directors[3]:

- Cheryl Barker, Chair
- Michael P. Mueller
- Léon Courville

HUMAN RESOURCES AND COMPENSATION COMMITTEE

The Board of Directors strongly believes in the importance of human resources to the success of PSP Investments. Accordingly, the Human Resources and Compensation Committee assists the Board of Directors in ensuring that the necessary policies and procedures are in place to efficiently and effectively manage PSP Investments' human resources and to offer all employees fair and competitive compensation aligned with performance. The Human Resources and Compensation Committee is therefore responsible for:

- Making recommendations to the Board of Directors regarding PSP Investments' human resources, training and compensation policies, and periodically reviewing such policies and recommending changes as necessary;
- Reviewing annually, on an aggregate basis, the total compensation of all employees of PSP Investments;
- Reviewing annually, the performance evaluations of the President and CEO and other Officers of PSP Investments and making recommendations to the Board on the remuneration of these individuals;
- Overseeing PSP Investments' human resources risks and ensuring that an appropriate governance environment is in place to manage human resources risks inherent to PSP Investments' activities; and
- Reviewing and reporting to the Board on PSP Investments' succession planning.

On March 31, 2012, the Human Resources and Compensation Committee was composed of the following Directors[4].

- Michael P. Mueller, Chair
- Micheline Bouchard
- Diane Bean
- Léon Courville

All Human Resources and Compensation Committee members are knowledgeable about issues related to human resources, talent management, executive compensation and risk management. Understanding of such issues was gained by professional experience as former chief executives or senior officers with oversight of human resources functions. For more information on the experience of each committee member, as well as their occupations and education, please see their biographies on page 54.

[3] Mr. Bob Baldwin ceased to be a member of the Governance Committee on September 29, 2011.

[4] Mr. Bob Baldwin ceased to be a member of the Human Resources and Compensation Committee on September 29, 2011. Ms. Micheline Bouchard was appointed to the Human Resources and Compensation Committee on October 6, 2011.

ACCOUNTABILITY

PSP Investments is a Crown corporation with a unique governance and accountability regime which is set out in the Act. The Act provides that PSP Investments operates at arm's length from the Government of Canada and imposes on it reporting obligations to the Government of Canada and the contributors to the Plans.

The Board of Directors is responsible for the selection, appointment, performance evaluation and compensation of the President and CEO, who reports to the Board of Directors. PSP Investments reports to the ministers responsible for the Plans through its quarterly financial statements and annual report. The annual report must also be made available to contributors to the Plans and is tabled in each House of Parliament by the President of the Treasury Board, who is responsible for the Act.

The President and CEO and the Chair of the Board are required to meet once a year with advisory committees appointed to oversee the Plans. PSP Investments is also required to hold an annual public meeting. In addition, PSP Investments communicates on an ongoing basis with the Chief Actuary of the Office of the Superintendent of Financial Institutions Canada, Treasury Board officials and other Government of Canada officials in the execution of its statutory mandate.

Pursuant to the *Financial Administration Act* ("FAA"), the Auditor General of Canada and Deloitte & Touche LLP were appointed to serve as joint external auditors of PSP Investments, and are also responsible for conducting Special Examinations as stipulated in the FAA at least once every ten years. PSP Investments' joint auditors conducted a Special Examination in fiscal year 2011 to determine if PSP Investments' financial and management controls, information systems and management practices were maintained in a manner that provides reasonable assurance that they met the requirements of the FAA. The report on such Special Examination formed part of the annual report for fiscal year 2011 as required by the Act.

ASSESSMENT OF BOARD PERFORMANCE

The Governance Committee implemented a formal process to evaluate the performance of the Chair of the Board, the Chairs of Board committees, individual Directors and the Board as a whole. Every Director, as well as the President and CEO and certain members of senior management, participate in the evaluation process. The Chair of the Governance Committee presents the results of the evaluation to the Board of Directors. Ensuing Board discussions focus on concerns and opportunities for improvement, what is working properly and what has improved since previous assessments, following which any measures deemed necessary are implemented.

GOVERNANCE FRAMEWORK REVIEW

Every three years, an overall governance review is conducted to assess the extent to which PSP Investments' Terms of Reference for the Board, its committees and relevant officers are being fulfilled. Based on the review, a governance report is submitted to the Governance Committee which reports to the Board thereon. The purpose of this report is to assist the Board of Directors in ensuring that the duties and responsibilities set out in the Terms of Reference are carried out. The last governance review was conducted at the end of fiscal year 2010. The report, produced by an independent consultant, concluded that PSP Investments' Terms of Reference were consistent with the requirements of the Act and formed part of an internal framework reflecting best practices for organizations with mandates and structures similar to those of PSP Investments.

As part of the Special Examination conducted in fiscal year 2011, the Examiners reviewed PSP Investments' governance framework and concluded that the Board of Directors has clearly defined its roles and responsibilities and those of its committees in their respective Terms of Reference, and that PSP Investments has a corporate governance framework that performs well and meets industry practice expectations for board stewardship and oversight.

CODE OF CONDUCT FOR DIRECTORS

The Director Code together with the Employee Code were developed to establish and maintain a culture that guides decision-making throughout the Corporation. The purpose of the Director Code goes beyond complying with minimum statutory requirements; it reflects the expectation that Directors will have the highest level of integrity and ethical standards. The Director Code is designed to provide a workable process for identifying, minimizing and resolving potential conflicts of interest. Derived from the Act and the *Conflict of Interest Act*, the Director Code sets out in detail Directors' statutory and fiduciary duties relating to conflicts of interest and helps ensure that Directors have a full understanding and appreciation of PSP Investments' principles and values. Ultimately, the Director Code aims to assist Directors in determining appropriate business practices and behaviour.

Among other stipulations, the Director Code:

- Requires Directors to give written notice to the Board of Directors of the nature and extent of their interest in a transaction or proposed transaction;
- Prohibits Directors from voting on a resolution or participating in a discussion in any circumstances where they have a conflict of interest;
- Requires the disclosure of any other business activity in which they participate that directly or indirectly affects PSP Investments' activities or is in competition with PSP Investments' activities; and
- Requires the Directors to pre-clear all securities trades, except exempt trades, and to report quarterly to a PSP Investments auditor on their personal trading activities.

The Governance Committee is responsible for monitoring the application of the Director Code. The Director Code may be viewed in its entirety on PSP Investments' website **www.investpsp.ca**.

DIRECTOR EDUCATION AND ORIENTATION

The Act requires the Nominating Committee to have regard to the desirability of having on the Board of Directors a sufficient number of Directors with proven financial ability or relevant work experience such that PSP Investments will be able to effectively achieve its mandate. The Act also requires Directors with relevant expertise to use their knowledge or skills in exercising their duties.

To enhance Directors' financial knowledge and skills, PSP Investments created a Director Education Program. Each Director is allocated an individual education and training budget designed to be used primarily to strengthen Directors' understanding of investment management. As well as providing individual courses, conferences and reading material, the Director Education Program stages group training sessions the day before each regular Board of Directors meeting. During the sessions, industry speakers are invited to make presentations on a variety of topics that contribute to the individual and collective expertise of Board members.

Furthermore, newly appointed Directors are expected to complete an in-house Orientation Program. The purpose of the Orientation Program is to provide new Directors with the information necessary to acquaint them with the operations and culture of the organization and enable them to contribute effectively to the Board of Directors as soon as possible after their appointment.

Both the Director Education Program and the Orientation Program are monitored by the Governance Committee.

DIRECTORS' COMPENSATION

The approach to Director compensation adopted by the Board of Directors reflects the requirements of the Act. The first requirement is that the Board should include a sufficient number of Directors with proven financial ability or relevant work experience such that PSP Investments will be able to effectively achieve its mandate. The second requirement is that Directors' compensation should be set "having regard to the remuneration received by persons having similar responsibilities and engaged in similar activities".

The Board reviews Directors' compensation once every two years and considers any changes that may be warranted based on a report and recommendations provided by the Governance Committee. The following compensation for Directors was approved by the Board of Directors for FY2012:

- Annual retainer for the Board Chair: $150,000
- Annual retainer for each Director other than the Chair: $30,000
- Annual retainer for each Chair of a committee of the Board: $10,000
- Attendance fee for each Board meeting: $1,500[5]
- Attendance fee for each committee meeting: $1,500[5]
- Additional meeting fee for each Director who attends a meeting in person if the Director's primary residence is outside Québec or Ontario, or in any case where a Board of Directors or committee meeting is held in a location outside Québec and requires a Director to travel more than three hours away from his or her primary residence: $1,500.

The Chair of the Board is not entitled to any meeting fees. Directors of PSP Investments are not entitled to additional compensation in the form of retirement benefits or short-term or long-term incentives.

The Board met nine times during fiscal year 2012 and its Committees held 31 meetings. This translated into total remuneration for Directors in that capacity of $736,187. The tables on the following two pages illustrate and break down the above-mentioned information.

The Board of Directors met 9 times during fiscal year 2012 and its Committees held 31 meetings.

[5] $500 for a meeting of less than one hour.

ATTENDANCE OF DIRECTORS
BOARD AND COMMITTEE MEETINGS
FISCAL YEAR 2012

	Board of Directors		Investment Committee		Audit Committee		Governance Committee		Human Resources and Compensation Committee		Special Chairperson Nominating Committee [6]
	Regular	Special	Regular	Special	Regular	Special	Regular	Special	Regular	Special	Regular
Number of meetings Fiscal Year 2012	8	1[1]	6	4	6	N/A	4	2	6	1	2
Bob Baldwin [2]	3/3	1/1	2/2	3/3			2/2		3/3	1/1	
Cheryl Barker	8/8	1/1	6/6	4/4	6/6		4/4	2/2			2/2
Diane Bean	8/8	1/1	6/6	4/4					6/6	1/1	2/2
Micheline Bouchard [3]	2/5	–	2/4	1/1					2/3	–	
Paul Cantor [4]	7/7	1/1	4/5	4/4							
Léon Courville	8/8	0/1	6/6	3/4			4/4	2/2	6/6	1/1	
Anthony R. Gage	8/8	1/1	6/6	4/4	6/6						2/2
Garnet Garven [5]	3/5	–	3/4	1/1	3/3						
Lynn Haight	8/8	1/1	6/6	3/4	6/6						
William A. MacKinnon	7/8	1/1	5/6	4/4	6/6						
Michael P. Mueller	8/8	1/1	6/6	4/4			4/4	2/2	6/6	1/1	

[1] The special meeting of the Board was held concurrently with the special meeting of the Investment Committee.

[2] Mr. Baldwin ceased to be a Director and a member of the Investment Committee, Governance Committee and Human Resources and Compensation Committee on September 29, 2011.

[3] Ms. Bouchard was appointed to the Board of Directors on September 29, 2011 and became a member of the Investment Committee on the same date. She was appointed to the Human Resources and Compensation Committee on October 6, 2011.

[4] Mr. Cantor resigned from the Board of Directors on March 5, 2012. Mr. Cantor was not a member of the Audit Committee, the Governance Committee or the Human Resources and Compensation Committee, but as Board Chair he could attend all committee meetings.

[5] Mr. Garven was appointed to the Board of Directors on September 29, 2011 and became a member of the Investment Committee on the same date. He was appointed to the Audit Committee on October 6, 2011.

[6] The Special Chairperson Nominating Committee was wound up on November 8, 2011.

REMUNERATION OF DIRECTORS
FISCAL YEAR 2012

Name	Remuneration[1]				
	Annual Retainer	Chair of a Committee/ Annual Retainer	Boards/ Committees Meeting Fees	Travel Fees	Total
Bob Baldwin[2]	$15,000	–	$17,000	–	$32,000
Cheryl Barker	$30,000	$11,075	$38,000	$9,000	$88,075
Diane Bean	$30,000	–	$33,500	–	$63,500
Micheline Bouchard[3]	$15,163	–	$9,500	–	$24,663
Paul Cantor[4]	$139,286 (Board Chair)	–	–	–	$232,143[4]
Léon Courville	$30,000	–	$37,000	–	$67,000
Anthony R. Gage	$30,000	$10,000	$32,000	$9,000	$81,000
Garnet Garven[5]	$15,163	–	$14,000	$4,500	$33,663
Lynn Haight	$30,000	–	$30,500	–	$60,500
William A. MacKinnon	$30,000	$10,000	$28,000	–	$68,000
Michael P. Mueller	$30,000	$10,000	$38,500	–	$78,500

[1] The Directors are also entitled to reimbursement of their reasonable travel and related expenses when applicable.

[2] Mr. Baldwin ceased to be a Director and a member of the Investment Committee, Governance Committee and Human Resources and Compensation Committee on September 29, 2011.

[3] Ms. Bouchard was appointed to the Board of Directors on September 29, 2011 and became a member of the Investment Committee on the same date. She was appointed to the Human Resources and Compensation Committee on October 6, 2011.

[4] The aggregate amount includes $92,857 paid to Mr. Cantor as Chair of Revera Inc., a wholly-owned subsidiary of PSP Investments. During fiscal year 2012, the Board of Directors of PSP Investments asked Mr. Cantor to serve in that capacity on an exceptional basis to facilitate certain matters at Revera Inc. and fixed his compensation for that role, which was paid by PSP Investments and reimbursed to PSP Investments by Revera Inc. Mr. Cantor resigned from the PSP Investments' Board of Directors on March 5, 2012. Mr. Cantor continues to act as the Chair of Revera Inc. and his compensation for that role is now fixed by the Board of Directors of Revera Inc., and is paid by Revera Inc.

[5] Mr. Garven was appointed to the Board of Directors on September 29, 2011 and became a member of the Investment Committee on the same date. He was appointed to the Audit Committee on October 6, 2011.

INVESTMENT GOVERNANCE OVERSIGHT

As a long-term investor, PSP Investments believes in the importance of establishing strong governance oversight of its investments. PSP Investments actively uses its ownership positions to promote good corporate governance practices by exercising its proxy voting rights and actively engaging with companies, individually and through collaborative initiatives with other like-minded institutional investors.

PROXY VOTING

PSP Investments has adopted Proxy Voting Guidelines (the "Guidelines") addressing the areas of corporate governance with respect to which it may be requested to vote on from time to time, as well as the principles on which PSP Investments will rely in determining a response to such requests. PSP Investments will give due consideration to corporate governance principles when assessing the merits of an issue and will exercise its voting rights with a view to maximizing the value of its shareholdings.

In fiscal year 2012, PSP Investments reviewed and amended the Guidelines to take into consideration market trends.

As part of the active management of its proxy voting, PSP Investments reviews proxy circulars and research from service providers when voting the equities held in accounts managed internally as well as those in segregated accounts managed by external managers.

The Guidelines may be viewed on PSP Investments' website **www.investpsp.ca**.

PROXY VOTING ACTIVITIES

In fiscal year 2012, PSP Investments exercised its voting rights at 2,902 meetings, voting against or abstaining from management's recommendations on 11.1% of the 30,350 proposed resolutions.

The issues on which PSP Investments voted against management's recommendation or abstained on such resolutions are shown below:



ISSUES
Fiscal year 2012

Board Independence and Effectiveness	39%
Compensation	30%
Capital Structure	12%
Shareholder Proposals	8%
Other	5%
Auditors and Accounting Irregularity	4%
Amendments to Articles	2%

BOARD INDEPENDENCE AND EFFECTIVENESS

PSP Investments believes that a strong independent board of directors is best positioned to successfully direct and control a company in a way that ensures the creation of long-term shareholder value. This category includes resolutions where PSP Investments withheld its votes from nominees seeking election as directors. In the latest fiscal year, PSP Investments withheld its votes from nominees because of non-independence issues, non separation of the role of Chair and CEO, poor attendance records and director time-commitment issues.

COMPENSATION

PSP Investments believes that compensation incentives to executives should be suitably structured to enhance shareholder value while rewarding performance that meets or exceeds stated objectives. During the latest fiscal year, PSP Investments voted against several compensation plans that were misaligned with performance or that failed to adequately disclose performance conditions.

CAPITAL STRUCTURE

PSP Investments is generally supportive of changes to a company's capital structure, provided there are sound business reasons for the proposed changes. In the latest fiscal year, PSP Investments voted against certain changes to capital structures because of dilution issues not justified by business considerations.

SHAREHOLDER PROPOSALS

PSP Investments reviews all shareholder proposals on a case-by-case basis. PSP Investments generally supports shareholder proposals that increase the board of directors' level of accountability to shareholders and serve the company's financial interest, without putting excessive constraints on the company, its board of directors or its management. In the latest fiscal year, PSP Investments supported shareholder proposals relating to compensation, majority voting for the election of directors, and additional disclosure with respect to risks.

AUDITORS AND ACCOUNTING IRREGULARITIES

PSP Investments supports the election of auditors where they meet generally accepted independence standards and the integrity of an audit has not been compromised. On a limited number of occasions during the past fiscal year, PSP Investments voted against auditors who, in the opinion of PSP Investments, did not meet these standards.

AMENDMENT TO ARTICLES

From time to time, PSP Investments is asked to consider resolutions regarding amendments to the articles of a company. In the past fiscal year, PSP Investments was asked to vote on amendments to articles that would limit the right to call a special meeting, that called for the adoption or elimination of cumulative voting that amended or eliminated "supermajority" requirements, or that would change the jurisdiction of incorporation of a company. All resolutions amending articles are reviewed on a case-by-case basis in light of the proposed changes to the company's governance structure. PSP Investments generally votes against amendments to articles that reduce shareholders' rights.

TAKE-OVER PROTECTION

PSP Investments always evaluates takeover-protection policies and proposals as well as shareholder rights plans on a case-by-case basis. During the past fiscal year, PSP Investments voted against takeover proposals, policies and shareholder rights plans where it felt they did not provide for an equal treatment of shareholders in the event of a takeover offer or included anti-takeover measures such as the right to issue shares should the company be subject to a bid.

RESPONSIBLE INVESTING

PSP Investments recognizes that a broad range of financial and non-financial considerations can be relevant in terms of making investment decisions. PSP Investments has adopted a Responsible Investment Policy which embodies its belief that responsible corporate behaviour with respect to environmental, social and governance ("ESG") factors can generally have a positive influence on long-term financial performance. In analyzing the risks inherent in any investment, PSP Investments looks to identify, monitor and mitigate ESG issues that are, or could become, material to long-term financial performance. Consideration of ESG risks is part of the due diligence process with respect to potential investments and the assessment of the practices of external managers. The monitoring of these risks is part of an ongoing dialogue with external managers, boards of directors and senior management of the private and public companies in which PSP Investments invests.

PSP Investments' Responsible Investment Policy may be viewed on PSP Investments' website **www.investpsp.ca**.

DIRECT ENGAGEMENT ACTIVITIES

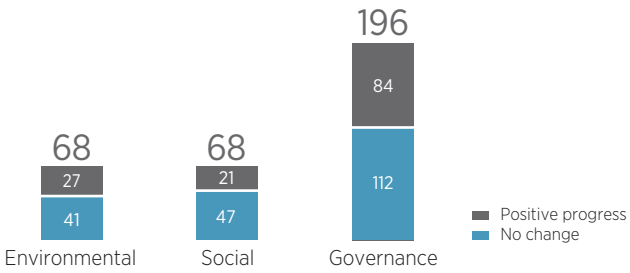
With the assistance of a service provider, PSP Investments actively engages in dialogue with public companies with a view to improving their ESG practices. Public companies are selected for engagement based on a process that takes into account elements such as a company's ability to create shareholder value, the prospects for successful engagement and the ESG issues at hand. The intensity of PSP Investments' involvement with public companies evolves over time: some engagements entail one or two meetings over a period of months, while others are more complex and entail multiple meetings with board members and senior management over several years. PSP Investments tracks its engagement objectives primarily in the context of issues where it feels changes in behavior are warranted. Often there are multiple ESG issues to be addressed within the same company, each of which may require different levels of effort and engagement approaches as well as different contact points.

When undertaking extensive engagements, a five step milestone approach is used to guide the engagement process and assess the success of the engagements:

Milestone 0	Milestone 1	Milestone 2	Milestone 3	Milestone 4
New Objective	**Raised Concerns**	**Acknowledgement of Issue**	**Develop Credible Strategy/Set Stretching Targets**	**Strategy Implemented**

In fiscal year 2012, PSP Investments made solid progress in delivering engagement objectives across regions and themes. The following chart describes for each engagement objective whether progress has been made through the achievement of new milestones:

ENGAGEMENT OBJECTIVES
Fiscal year 2012 (number)



In fiscal year 2012, PSP Investments directly engaged with 129 public companies held in PSP Investments' portfolios on a range of ESG issues.

Below is a breakdown of PSP Investments' engagement activities by issue:



ENGAGEMENTS
Fiscal year 2012

Governance	62%
Social	24%
Environmental	14%

GOVERNANCE

Governance can be defined as the framework of rules and practices by which a board of directors ensures accountability and transparency in the company's relationship with its shareholders. PSP Investments engaged with public companies on a number of governance issues during the past fiscal year. Examples of issues raised were director independence, majority voting, separation of Chair and CEO roles, succession planning, committee structures, risk management and disclosure quality.

Example of an Engagement with a Canadian Technology Company on Governance Issues

Engagement objectives

- Encourage the company to voluntarily adopt majority voting for director elections.
- Improvement in disclosure and transparency of environmental policy.

What we achieved

We met with the lead director of the company and were successful in securing the adoption of majority voting beginning at the 2012 Annual Meeting of the Shareholders. Furthermore, the company recently delivered its first sustainability report. Further to our comments on the report, the company has undertaken to improve the quality of the information available.

SOCIAL

PSP Investments engaged public companies on a variety of social issues, including labour activities in troubled regions and health-and-safety concerns.

Example of an Engagement with a Large Multinational European Food Company on Social Issues

Engagement objectives

– Pursue greater disclosure on and better management of the company's supply chain.

– Perform comprehensive review of the company's labour policies.

What we achieved

We discussed with executives of the company the commercial risks on child-labour issues resulting from the company's sourcing of certain products in African countries. Further to our discussions, the company has been collaborating with local governments and producers to implement a certification process for some products. We continue to work with the company to implement an effective monitoring of its supply chain in order to avoid significant reputational risks for the company.

We also expressed our concerns with the company's excessive decentralization of labour issues which resulted in inappropriate local management and a number of local labour disputes. The company has since introduced systematic third party audits on related issues, the findings of which are shared with the board. We welcome the progress made, and are continuing our intensive engagement to ensure the company's commitments are upheld.

ENVIRONMENTAL

PSP Investments met with a significant number of public companies on environmental-related issues in fiscal year 2012. These engagements focused mainly on climate change, water stress, oil extraction, forestry and biodiversity.

Example of an Engagement with a US Oil and Gas Company on Environmental Issues

Engagement objectives

– Test the company's risk management and disaster preparedness post Gulf of Mexico oil spill-like events.

What we achieved

As part of our engagement with major international oil companies in the wake of the Gulf of Mexico oil spill, through multiple meetings with senior health and safety executives of the company we were able to ensure that risk management and disaster-recovery strategies in place are appropriate.

Below is a breakdown of PSP Investments' engagement activities by country or region:



ENGAGEMENT ACTIVITIES BY COUNTRY OR REGION

Fiscal year 2012

US & Latin America	38%
Europe	25%
Asia Pacific, Australia & New Zealand	21%
Canada	11%
Africa & Middle East	5%

COLLABORATIVE INITIATIVES

In addition to its direct-engagement efforts with public companies, PSP Investments participates in collaborative governance initiatives and engagements with other like-minded institutional investors to strengthen its voice with regard to corporate governance issues. PSP Investments is an active member of the Canadian Coalition for Good Governance, which represents 48 institutional investors managing assets of nearly $2 trillion.

PSP Investments is also a signatory of the Carbon Disclosure Project. The Carbon Disclosure Project acts on behalf of 655 institutional investors representing over $78 trillion in assets under management, to encourage public companies to disclose how they are managing climate-change risks and opportunities that may be affecting their businesses.

Since fiscal year 2010, PSP Investments has been a signatory of the CDP Water Disclosure Project, which enables institutional investors to better understand the business risks and opportunities associated with water scarcity and other water-related risks by increasing the availability of high-quality information on this issue.

PSP Investments is also a member of the Pension Investment Association of Canada (PIAC). PIAC's mission is to promote sound investment practices and good governance for the benefit of pension plan sponsors and beneficiaries.

Finally, PSP Investments' Private Equity Group played an active role in the implementation of the Institutional Limited Partners Association's Private Equity Principles, a governance best-practices undertaking designed to guide institutional investors' future investments in the private-equity sector.

PSP Investments is an active member of the Canadian Coalition for Good Governance, which represents 48 institutional investors managing assets of nearly $2 trillion.

COMPENSATION

The Board of Directors approves PSP Investments' compensation framework as well as total compensation for the President and Chief Executive Officer and other officers upon recommendation by the Human Resources and Compensation Committee (HRCC). Other compensation matters, including the total aggregate compensation for all of the Corporation's employees, are the responsibility of the HRCC.

In a highly competitive market for qualified personnel, PSP Investments' Compensation Policy is designed to attract and retain talented employees, reward performance and reinforce business strategies and priorities. The Board of Directors recognizes the fundamental value of a motivated and committed team and strongly believes that the recruitment and retention of high-performing employees is critical to achieving PSP Investments' objectives.

To that end, the Board of Directors has established a Compensation Policy that aims to maintain total compensation at a fair and competitive level. Compensation plans are aligned with PSP Investments' strategic plan and integrated with business performance measurement. PSP Investments' Compensation Policy provides balanced performance-based compensation and is effectively designed to reward prudent risk taking. Total compensation is comprised of base salary, short-term and long-term incentives, benefits, pension and other remuneration.

The Corporation's Performance Management and Professional Development process also contributes to improving business performance and employee engagement.

As part of a Special Examination conducted in fiscal year 2011 by the Office of the Auditor General of Canada and Deloitte & Touche LLP, the Examiners reviewed PSP Investments' compensation framework and practices. They concluded that the short-term and long-term incentive programs are comparable to industry practices, are designed to reduce the potential for excessive risk-taking and are aligned with the Corporation's strategic objectives and investment policies. Furthermore, in fiscal year 2010, PSP Investments completed a thorough analysis of its overall compensation practices and procedures which led to the conclusion that PSP Investments' compensation programs and policies are consistent with the G20 Working Group Recommendations which are based on the Financial Stability Forum Principles for Sound Compensation.

In order to ensure that PSP Investments offers competitive compensation to its employees, managers and officers, their compensation levels are benchmarked with those of a select group of peers — Canadian organizations in the pension fund and investment management industry, the financial-services industry and other similar industries appropriate for the positions being benchmarked. The main comparator group in fiscal year 2012 was comprised of the following pension funds: Alberta Investment Management Corporation, British Columbia Investment Management Corporation, *Caisse de dépôt et placement du Québec*, Canada Pension Plan Investment Board, Ontario Municipal Employees Retirement System and Ontario Teachers' Pension Plan. These organizations were selected based on three main criteria: the size of the assets under management, their business sector (pension fund investment) and the commonality of the talent pool.

In addition, data from these peer organizations are gathered periodically and on an ad-hoc basis using compensation surveys published by well-established, specialized compensation consulting firms, such as McLagan's Investment Management Survey, Towers Watson's Investment Management Compensation Survey, Mercer's Canadian Investment Management Compensation Survey, Executive, Management and Professionals Compensation Survey, and Information Technology Compensation Survey.

To remain competitive, PSP Investments strives to offer:

1. base salaries at the median of the comparator group;
2. incentive compensation with potential payouts superior to the median of the comparator group for superior performance; and
3. benefits that are competitive.

On an annual basis, the Board of Directors ensures that PSP Investments' executive compensation is consistent with PSP Investments' Compensation Policy. For this purpose, the services of independent compensation consulting firms were retained in fiscal year 2012 to assist the HRCC in its review of executive compensation. These compensation consulting firms report solely to the HRCC when executing their mandates.

PRINCIPLES OF PSP INVESTMENTS' COMPENSATION FRAMEWORK

PSP Investments believes that its compensation framework should be driven by a pay-for-performance approach that:

- rewards long-term performance (see *Figure A* below);
- discourages short-term decision-making and undue risk-taking;
- establishes incentive compensation as the largest component of target total compensation for executives (see *Figure B* below); and
- ensures that total fund investment performance is a component of incentive compensation at all levels of PSP Investments, in order to encourage and reinforce the benefits of teamwork.

FIGURE A: SEVEN YEARS OF INVESTMENT PERFORMANCE ARE MEASURED BY THE STIP AND THE LTIP

Both the Short-Term Incentive Plan ("STIP") and the Long-Term Incentive Plan ("LTIP") are built around rolling four-year periods spanning a total of seven years of investment performance.



FIGURE B: COMPENSATION MIX OF TOTAL COMPENSATION FOR FISCAL YEAR 2012 (TARGET AWARDS)

Consistent with PSP Investments' pay-for-performance approach, total compensation for the President and Chief Executive Officer and for First Vice President (Investment) positions is composed primarily of incentive compensation tied to the performance of PSP Investments and, where applicable, to the investment performance of a particular asset class.



PRESIDENT AND CHIEF EXECUTIVE OFFICER

Base Salary	28%
Short-term Incentive Compensation	30%
Long-term Incentive Compensation	42%



FIRST VICE PRESIDENT POSITIONS – INVESTMENT

Base Salary	31%
Short-term Incentive Compensation	28%
Long-term Incentive Compensation	41%

BASE SALARY

Base salary reviews take place annually and any changes are effective from the beginning of each fiscal year. Adjustments to the base salary may also occur during the year to reflect significant changes in responsibility, market conditions or exceptional circumstances.

The annual budget for base salary increases in fiscal year 2012 was consistent with PSP Investments' comparator group and in accordance with the Compensation Policy.

INCENTIVE PLANS

Annually, PSP Investments reviews its incentive plans to ensure that total compensation remains competitive with the main comparator group and reflects PSP Investments' principles and objectives of attracting, retaining and motivating employees to achieve sustained high performance. The fiscal year 2012 review was conducted with the support and advice of an independent compensation consulting firm.

The following plans comprise incentive compensation at PSP Investments:

1) A Short-Term Incentive Plan ("STIP"), to recognize performance results for the current year and the previous three years;
2) A Long-Term Incentive Plan ("LTIP"), based on four-year, forward-looking cycles with possible payouts after the fourth year to recognize long-term results; and
3) A Restricted Fund Unit Plan ("RFU"), designed to help retain key employees.

SHORT-TERM INCENTIVE PLAN

PSP Investments' Short-Term Incentive Plan ("STIP") is designed to: (i) reward participants for the achievement of superior and sustained individual contributions and for PSP Investments' overall performance; (ii) help attract and retain high-calibre employees; and (iii) align the interests of participants with PSP Investments' stakeholders. PSP Investments' permanent salaried employees and any other employees designated by the President and CEO are eligible to participate in the STIP.

The STIP is a cash-based plan with a target incentive award based on a percentage of base salary. At the beginning of each fiscal year, each participant in the STIP is advised of his or her short-term incentive target amount. The target incentive amount, the performance measures and the weighting given to each measure will vary according to the participant's position level. The target incentive amount is measured on the achievement of individual objectives as well as on investment performance, which may include any combination of (i) the total fund investment performance of PSP Investments; (ii) the investment performance of a particular asset class; or (iii) the investment performance of a portfolio. Investment performance is measured against relative or absolute benchmarks (total fund, asset classes, portfolios) and thresholds below which no payments are made.

For the first four years of participation in the STIP, participants will go through a transition period building up to a rolling sequence of four consecutive years of performance. The investment performance measure is calculated on the current year as well as up to the three preceding years of investment performance, depending on the number of years an employee has participated in the STIP.

The STIP provides that the investment performance of each year is independently weighted. A greater weight is given to performance of the current year in order to more closely link shorter-term contribution and rewards, while still taking into account the investment performance of the previous three years. Investment performance floors and maximum levels are applied to the STIP calculation methodology, in order to ensure that the results of a single year's investment performance do not unduly impact the overall calculation. The HRCC reviews the annual incentive compensation payment process to ensure that payments are calculated in accordance with the terms of the STIP. In addition, the Board of Directors approves the annual incentive compensation payable to officers of PSP Investments.

FISCAL YEAR 2012 PERFORMANCE

In fiscal year 2012, the total fund investment performance of PSP Investments was above the incentive threshold and therefore, payouts were earned for that component of the STIP for eligible participants with one to four years of participation.

The one-year investment performance of Real Estate and Public Markets was above incentive thresholds and, therefore, payouts were earned for eligible participants in these asset classes. The one-year asset class performance for Infrastructure and Private Equity was below threshold and generated no incentive payout for eligible participants.

The four-year performance was above threshold for Real Estate, Private Equity and Public Markets and generated incentive payouts for eligible participants. This was not the case for participants in Infrastructure, whose performance over the same four-year period was below the threshold level.

The results of the individual objective component of the STIP were achieved and, therefore, generated, on an aggregate basis, the right for eligible employees to receive an incentive award.

The total incentive amount paid under the STIP was $23.1 million in fiscal year 2012 (362 employees), $18.8 million in fiscal year 2011 (317 employees), and $8.8 million in fiscal year 2010 (293 employees).

LONG-TERM INCENTIVE PLAN

PSP Investments' Long-Term Incentive Plan ("LTIP") is designed to: (i) reward participants for the achievement of superior and sustained investment performance by PSP Investments; (ii) attract and retain high-calibre employees; and (iii) align the interests of participants with those of PSP Investments' stakeholders. The LTIP was introduced in fiscal year 2009, replacing the former long term incentive plan, the Deferred Incentive Plan.

The LTIP is a cash-based plan that pays a percentage of base salary to participants holding senior positions, solely taking into account the achievement of investment performance on the assets managed by PSP Investments. It requires above-threshold performance over a four-year period before a payout is earned.

At the beginning of each fiscal year, each participant in the LTIP is advised of his or her target incentive amount. This target incentive amount is measured on a forward-looking, four-year investment performance, which may include any combination of: (i) the total fund investment performance of PSP Investments and (ii) for investment professionals, the investment performance of a particular asset class. The target incentive level, performance measures and the weighting given to each measure depend on the participant's position level.

The LTIP was amended in fiscal year 2012 to introduce investment performance floors and maximum levels to the LTIP calculation methodology in order to ensure that the results of a single year's investment performance do not unduly impact the overall calculation. These floors and maximums are applied to all performance years where each year has equal weight.

The incentive amount payable is determined at the end of the four-year performance period based on the amount by which the total fund actual value added and (if applicable) the asset class actual value added exceeded the incentive thresholds. In addition, the incentive amount calculated for the participant is either increased or decreased based on the total fund rate of return over the four-year performance period.

The HRCC reviews the long-term incentive compensation process to ensure that the grants are calculated in accordance with the terms of the LTIP. In addition, the Board of Directors approves long-term incentive grants to officers of PSP Investments.

LONG-TERM INCENTIVE PLAN PAYMENTS

Fiscal year 2012 represented the first potential payment opportunity as per the terms of the LTIP.

In fiscal year 2012, the four-year total fund investment performance of PSP Investments was above the incentive threshold and therefore, payouts were earned for that component of the LTIP for eligible participants.

The four-year performance was above threshold for Real Estate, Private Equity and Public Markets and generated incentive payouts for eligible participants. This was not the case for participants in Infrastructure, whose performance over the same four-year period was below the threshold level.

The total incentive amount paid under the LTIP was $6.7 million In fiscal year 2012 (42 employees).

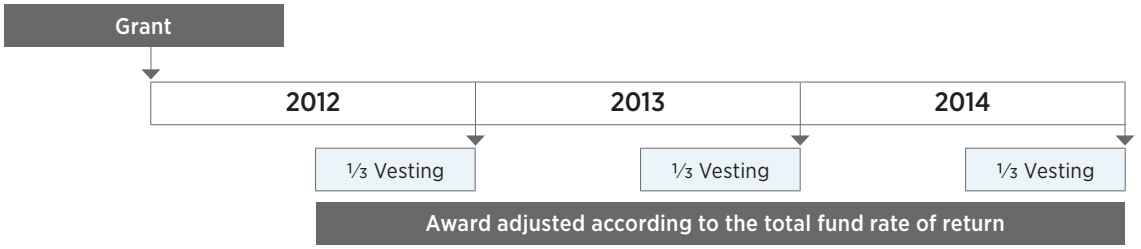
RESTRICTED FUND UNIT PLAN

PSP Investments' Restricted Fund Unit ("RFU") Plan is an incentive component of total compensation to retain key individuals in the organization.

Under the RFU Plan, grants of restricted fund units can be made to the President and Chief Executive Officer and, upon recommendation of the President and Chief Executive Officer, to other members of the senior management team. Grants may also be made to other key senior employees based on performance or market-related considerations. The HRCC reviews and approves the grants of restricted fund units. In addition, the Board of Directors approves grants to officers of PSP Investments.

Restricted fund units are a nominal investment whose value fluctuates in accordance with the total fund performance over a three-year period. One third of the award vests and is paid each year over this period, unless the participants elected to defer payment. Participants may elect to defer payment of RFUs until the end of the third year following the grant, as long as their election is made prior to the end of the fiscal year of the year of grant (see *Figure C* below).

FIGURE C: RESTRICTED FUND UNIT FRAMEWORK



The total incentive amount paid under the RFU in fiscal year 2012 was $4.0 million to recognize the contribution of key individuals to the performance of PSP Investments' results. The amount paid in fiscal year 2011 was $2.5 million.

GROUP INSURANCE BENEFITS

The Group Insurance Plan provides the following group insurance benefits: health and dental care, long-term disability, critical illness, life insurance, accidental death and dismemberment, and an employee-assistance program. The Group Insurance Plan is intended to ensure a proper balance between employee needs and competitiveness with the peer group.

OTHER REMUNERATION

PSP Investments' executives are provided with a perquisites allowance. In addition, PSP Investments offers its executives a health-and-lifestyle assessment.

RETIREMENT PLANS

All PSP Investments' eligible employees participate in the Public Sector Pension Investment Board Pension Plan (the "Employee Pension Plan") and all eligible employees participate in the Supplemental Employee Retirement Plan of the Public Sector Pension Investment Board (the "SERP").

The Employee Pension Plan provides partially indexed post-retirement pension benefits for each year of participation, calculated using 2% of the participant's average of the best consecutive three years of salary.

The benefits payable under the Employee Pension Plan are limited by the *Income Tax Act* (Canada). The SERP has been established for all employees, as an unfunded arrangement, to provide defined benefits in excess of the Employee Pension Plan, where such benefits are so limited. Employees participating in the Employee Pension Plan and the SERP contribute 3.5% of their base salary, up to the maximum contribution allowable under the *Income Tax Act* (Canada).

RETIREMENT BENEFITS

Name	Number of Years of Credited Service [1]	Annual Benefit		Accrued Obligation at Start of Year (Final Regulations) [2, 4]	Compensatory Increase [5]	Non-Compensatory Increase [6]	Accrued Obligation at Year End [2, 7]
		At Year End [2]	At Age 65 [2, 3]				
Gordon J. Fyfe	8.5	$83,200	$191,700	$921,700	$102,300	$215,400	$1,239,400
Derek Murphy	8.1	$51,200	$116,100	$576,300	$59,200	$119,000	$754,500
John Valentini	7.0	$50,400	$161,400	$488,800	$83,900	$128,900	$701,600
Daniel Garant	3.6	$20,600	$130,600	$158,700	$47,200	$69,600	$275,500
Neil Cunningham	4.4	$25,200	$92,200	$252,900	$58,500	$76,200	$387,600

[1] Number of credited years of service used for both the Employee Pension Plan and the Supplemental Employee Retirement Plan.

[2] Sum of benefits accrued under the Employee Pension Plan and the Supplemental Employee Retirement Plan.

[3] For the purpose of calculating the annual benefits payable at age 65, the final average earnings are calculated as at March 31, 2012.

[4] Accrued obligation using a discount rate of 5.4%. The obligations are calculated as at March 31, 2011 using the assumptions and methods that were used for the accounting disclosures as at December 31, 2010.

[5] Includes employer service cost at the beginning of the year, the impact arising from the difference between actual pensionable earnings and those anticipated at the prior year-end and the impact of amendments to the pension plans if any.

[6] Includes employee contributions and benefit payments made in the year, change in assumptions, non-pay-related experience and the interest cost for the year.

[7] Accrued obligation using a discount rate of 4.7%. The obligations are calculated as at March 31, 2012 using the assumptions and methods that were used for the accounting disclosures as at December 31, 2011.

SUMMARY COMPENSATION TABLE

Total compensation paid to PSP Investments' five highest-paid officers in fiscal year 2012 totalled $10,872,612 compared to the $8,809,249 reported in the 2011 annual report. The increase is mainly due to the strong performance above benchmarks of the total fund, Public Markets and Real Estate asset classes. It was the third consecutive year that the total fund outperformed its benchmark. For the three-year period ended March 31, 2012, PSP investments generated $2.4 billion of value added over and above benchmarks returns. The strong relative performance of each of the past three years has had a positive impact on both the short – and long-term incentive compensation which are calculated over four-year periods.

Name	Fiscal Year	Base Salary	Short-term Incentive Plan	Long-Term Incentive Plan[1]	Restricted Fund Units	Benefits and Other Compensation	Pension andSERP Plans	Total Compensation
Gordon J. Fyfe President and Chief Executive Officer	2012 2011 2010	$500,000 $485,000 $485,000	$1,285,656 $1,276,763 $552,900	$1,010,092 $484,927 $37,280	$471,020 $292,238 $0	$35,678 $35,681 $35,768	$102,300 $60,800 $53,800	$3,404,746 $2,635,409 $1,164,748
Derek Murphy First Vice President, Private Equity Investments	2012 2011 2010	$320,000 $314,000 $314,000	$487,213 $716,772 $749,178	$662,516 $194,339 $400,851	$348,235 $243,278 $17,117	$25,656 $43,256 $25,619	$59,200 $41,400 $36,500	$1,902,820 $1,553,045 $1,543,265
John Valentini Executive Vice President, Chief Operating Officer and Chief Financial Officer	2012 2011 2010	$375,000 $355,000 $355,000	$667,702 $744,415 $357,840	$459,618 $220,234 $0	$261,572 $189,219 $25,150	$30,662 $30,675 $130,667	$83,900 $40,900 $33,700	$1,878,454 $1,580,443 $902,357
Daniel Garant First Vice President, Public Markets Investments	2012 2011 2010	$306,000 $300,000 $265,000	$822,578 $813,909 $393,525	$348,915 n/a n/a	$320,533 $220,489 $24,076	$23,604 $23,609 $23,656	$47,200 $49,400 $24,700	$1,868,830 $1,407,407 $730,957
Neil Cunningham First Vice President, Real Estate Investments	2012 2011 2010	$306,000 $300,000 $260,000	$789,693 $605,996 $158,600	$363,594 $345,839 $555,153	$274,321 $175,465 $9,449	$25,654 $34,663 $25,710	$58,500 $72,800 $34,100	$1,817,762 $1,534,763 $1,043,012

[1] PSP Investments' Long-Term Incentive Plan ("LTIP") was introduced in fiscal year 2009, replacing the former Long-Term Incentive Plan known as the Deferred Incentive Plan ("DIP"). The fiscal 2010 and 2011 Long-Term Incentive payments were made under the DIP. The DIP has since been discontinued. The first LTIP amounts are payable in fiscal year 2012.

LONG-TERM INCENTIVE PLAN AWARDS GRANTED FOR FISCAL YEAR 2012

The following table shows the range of future potential payouts. Payments will be based on PSP Investments' total fund investment and asset class performance.

Name	Award Type	Fiscal Year 2012 Grant	Vesting Period	Estimated Future Payouts[1]		
				Threshold[2]	Target	Maximum
Gordon J. Fyfe	LTIP RFU	$500,000 $500,000	4 years 3 years	$0 n/a	$500,000 $500,000	$2,500,000 $500,000
Derek Murphy	LTIP RFU	$288,000 $288,000	4 years 3 years	$0 n/a	$288,000 $288,000	$1,440,000 $288,000
John Valentini	LTIP RFU	$262,500 $196,875	4 years 3 years	$0 n/a	$262,500 $196,875	$656,250 $196,875
Daniel Garant	LTIP RFU	$275,400 $275,400	4 years 3 years	$0 n/a	$275,400 $275,400	$1,377,000 $275,400
Neil Cunningham	LTIP RFU	$275,400 $275,400	4 years 3 years	$0 n/a	$275,400 $275,400	$1,377,000 $275,400

[1] Actual payouts will be adjusted upwards or downwards by PSP Investments' compounded rate of return over the performance vesting periods.

[2] Threshold refers to the minimum amount payable for a certain level of performance, below which level no award is payable.

LONG-TERM INCENTIVE PLAN AWARDS CUMULATIVE VALUE

The total cumulative value[1] as at March 31, 2012 of all long-term incentive awards granted but not yet vested or paid to PSP Investments' five highest-paid officers is shown in the following table.

Name	Plan	Awards paying out at the end of fiscal year			Total
		2013	2014	2015	
Gordon J. Fyfe	LTIP RFU	$1,411,350 $471,020	$1,086,400 $254,400	$730,000 $166,667	$3,227,750 $892,087
Derek Murphy	LTIP RFU	$676,827 $352,187	$440,856 $170,534	$316,800 $120,000	$1,434,483 $642,721
John Valentini	LTIP RFU	$621,250 $232,191	$556,640 $111,108	$383,250 $87,500	$1,561,140 $430,779
Daniel Garant	LTIP RFU	$781,088 $391,335	$658,800 $242,724	$451,656 $198,000	$1,891,544 $832,059
Neil Cunningham	LTIP RFU	$574,470 $311,254	$707,400 $190,224	$476,442 $144,000	$1,758,312 $645,478

[1] LTIPs' accumulated values are estimated using actual total fund and asset class performance for those years where performance is known, and a multiplier of one (1.0x) is applied for future years. RFUs' accumulated values reflect PSP Investments' total fund rate of return for fiscal years 2011 and 2012 but no returns for future years.

POST-EMPLOYMENT POLICIES

The President and CEO's severance pay is equivalent to two times his annual base salary, plus two times the average annual amount earned under the short-term and long-term incentive plans for the three-year period prior to the termination.

For First Vice Presidents, the severance pay is set at 12 months of base salary and target STIP award, plus one month of salary and target STIP award (one-twelfth of the full-year target STIP award) for every year of service, up to a maximum of 18 months. Insured benefits such as health, dental and life insurance are continued during the severance period.

The next table shows the potential payments that would be made upon termination (without cause) for the five highest-paid officers at PSP Investments.

Name	Years of service [1]	Severance [2]	Resignation
Gordon J. Fyfe	8.6 years	$3,101,395	$0
Derek Murphy	8.1 years	$912,000	$0
John Valentini	7.0 years	$1,068,750	$0
Daniel Garant	3.6 years	$726,750	$0
Neil Cunningham	7.8 years	$872,100	$0

[1] Assumes a notional termination as at March 31, 2012.

[2] Excludes incentive compensation amounts payable for the current year, which are included in the Summary Compensation Table.

DIRECTORS' BIOGRAPHIES

CHERYL BARKER
Interim Chair, PSP Investments

MEMBER:
Investment Committee /
Audit Committee /
Governance Committee – Chair

Board member since December 18, 2006

Ms. Barker is a member of the Board of Directors and Chair of the Audit Committee of Canada Media Fund and also serves as a trustee and Chair of the Audit Committee of Lanesborough REIT. She was President of Manitoba Telecom Services Inc. (MTS) from 2004 until her retirement in February 2006. Ms. Barker's career at MTS spanned 19 years, during which she served in a variety of key positions, including President and COO of MTS Communications Inc.; Chair, President and CEO of Bell Intrigna Inc.; and CFO and Treasurer of MTS. A Chartered Accountant (CA), Ms. Barker holds a Bachelor of Science as well as a Certificate in Education from the University of Manitoba.

DIANE BEAN
Corporate Director

MEMBER:
Investment Committee /
Human Resources and
Compensation Committee

Board member since June 18, 2010

Ms. Bean is a member of the Boards of Directors of Manulife International Ltd (Asia), The Insurance Company of the West Indies and Roy Thomson Hall/Massey Hall, and was founding Co-Chair of the Toronto Region Immigrant Employment Council. Until her retirement in 2011, she was Executive Vice-President of Manulife Financial where, over 30 years, she also served as its Regional Executive in Canada, the United States, Asia and Europe, and held senior positions in IT, Business Development, Corporate Communications and, most recently, as head of Global HR. Ms. Bean holds a Bachelor of Commerce from the University of Toronto.

MICHELINE BOUCHARD
Corporate Director

MEMBER:
Investment Committee /
Human Resources and
Compensation Committee

Board member since September 29, 2011

Ms. Bouchard is a member of the Boards of Directors of Telus and Harry Winston Diamond Corp. She has extensive experience as a director with public and private companies and volunteer boards. Past board memberships include Banque Nationale de Paris, Ford Motor Canada, London Insurance Group and Home Capital/Home Trust. Ms. Bouchard was Global Corporate Vice-President of Motorola Inc. in the U.S., after having served as President and CEO of Motorola Canada Inc. She holds a Bachelor's Degree in Applied Sciences (Engineering Physics) and a Master's Degree in Applied Sciences (Electrical Engineering) from École Polytechnique. Ms. Bouchard is a Member of the Order of Canada, a Member of the National Order of Quebec and a certified member of the Institute of Corporate Directors.

LÉON COURVILLE
Corporate Director

MEMBER:
Investment Committee /
Governance Committee /
Human Resources and
Compensation Committee

Board member since March 5, 2007

Mr. Courville has devoted his entire career to the sciences of management and finance, serving as a professor and researcher at universities in Canada and the United States before being appointed President of the National Bank of Canada. He is enjoying an active "retirement" as a corporate director, an Associate Professor at l'École des Hautes Études Commerciales and proprietor of the Domaine Les Brome vineyard, which he founded in 1999. Mr. Courville is a member of the Boards of Directors of the Institut de tourisme et d'hôtellerie du Québec and the Institut économique de Montréal. His research and publications have garnered awards and bursaries in Canada and abroad, including the Coopers & Lybrand Award for his work entitled "The Storm – Navigating the New Economy". Mr. Courville holds a Ph.D. in Economics from Carnegie-Mellon University.

ANTHONY R. GAGE
Corporate Director

MEMBER:
Investment Committee – Chair /
Audit Committee

Board member since June 27, 2006

Mr. Gage is Vice Chair of the Board of Governors of the University of Victoria, a Director of Sky Investment Counsel and Head of the Management Committee of JEA Pension System Solutions. He is a former Chair of the Board of Phillips, Hager & North Investment Management. His career at Phillips, Hager & North, where he served as President and CEO from 1994 to 1999, spanned more than 20 years. Previously, Mr. Gage was Assistant Vice-President and Director of Confed Investment Counseling, the pension fund management arm of Confederation Life. Mr. Gage holds a Bachelor of Arts (Economics) from the University of Victoria and an MBA (Finance) from the University of British Columbia. He is a Chartered Financial Analyst (CFA) and an accredited Chartered Director (McMaster University).

GARNET GARVEN
Corporate Director

MEMBER:
Investment Committee /
Audit Committee

Board member since September 29, 2011

Mr. Garven is Senior Fellow at Canada's Public Policy Forum, a think tank focusing on governance and public-service issues. He previously served as Deputy Minister to the Premier and Saskatchewan Cabinet Secretary. Educated in Business Administration at the Universities of Regina, Saskatchewan and Western Ontario, he holds an Honourary CMA from the Society of Management Accountants. A long-time Dean of Business at the University of Regina, Mr. Garven also was a Research Fellow in corporate governance at the Richard Ivey School of Business. A founding director of the Investment Corporation of Saskatchewan (now Greystone Managed Investments Inc.) and former Chairman and CEO of the Saskatchewan Workers' Compensation Board, he has served on a variety of other public, private and not-for-profit boards.

LYNN HAIGHT
Corporate Director

MEMBER:
Investment Committee /
Audit Committee

Board member since January 14, 2010

Ms. Haight is a member of the Board of Directors and Chair of the Audit Committee of World Bank's Consultative Group on International Agricultural Research (CGIAR) and Green Shield Canada. She also sits on the Boards of the Bank of India (Canada) and Somerville College, Oxford University. Ms. Haight recently retired as Chief Operating Officer and Chief Financial Officer of the Foresters insurance organization. She previously served as Vice President, US Fixed Annuities, and Chief Accountant of Manulife Financial. She has also served as a Trustee and Chair of the Audit Committee of the Ontario Arts Council, Chair of Foresters Holdings Europe, Chair of the World Agroforestry Centre in Nairobi, Kenya, and Chair of the Sectoral Advisory Group for business services to the federal Minister of Trade. Ms. Haight holds an MA Honours from Oxford. She is a Fellow of the Canadian Institute of Chartered Accountants, a Fellow of the Canadian Association of Management Consultants and a Certified Corporate Director.

DIRECTORS' BIOGRAPHIES

WILLIAM A. MACKINNON
Corporate Director

MEMBER:
Investment Committee /
Audit Committee – Chair

Board member since January 14, 2010

Mr. MacKinnon is a member of the Boards of Directors of Telus, Pioneer Petroleum, Osisko Mining Corporation and Novadaq Technologies. Very active in professional and community circles, he serves as Chair of the Board of the Canadian Institute of Chartered Accountants and Chair of The Toronto East General Hospital Board. He is also a member of the Boards of the Toronto Community Foundation and Roy Thomson Hall and a former Campaign Chair for the Toronto United Way. Mr. MacKinnon joined KPMG Canada in 1968, became a Partner in 1977 and was the firm's Chief Executive Officer from 1999 until his retirement at the end of 2008. As well, he served on the KPMG International Board of Directors. Mr. MacKinnon holds a Bachelor of Commerce from the University of Manitoba. He obtained his Chartered Accountant (CA) designation in 1971 and became a FCA in 1994.

MICHAEL P. MUELLER
Corporate Director

MEMBER:
Investment Committee /
Governance Committee /
Human Resources and
Compensation Committee – Chair

Board member since December 18, 2006

Mr. Mueller is Chairman of Annidis Corporation and a member of the Boards of Directors of the Scarborough Hospital (past Chair), AIM Therapeutics Inc. and Biovest Corp I. He also serves as a strategic advisor to a number of Canadian, US and European companies. From 2003 to 2005, he was President and CEO of MDS Capital Corporation. Mr. Mueller previously held a series of senior executive positions at TD Bank, including Vice Chairman and Global Head of Investment and Corporate Banking. He is a former member of the Boards of Directors of the Scarborough Hospital Foundation, Budco, TM BioScience, MDS Capital and Canadian Medical Discoveries Funds I and II. Mr. Mueller holds a Bachelor of Science from the University of Western Ontario and an MBA from York University.

MANAGEMENT TEAM AND OFFICERS

GORDON J. FYFE
President and Chief Executive Officer

JOHN VALENTINI
Executive Vice President, Chief Operating Officer and Chief Financial Officer

GUY ARCHAMBAULT
First Vice President, Human Resources

NEIL CUNNINGHAM
First Vice President, Real Estate Investments

DANIEL GARANT
First Vice President, Public Market Investments

BRUNO GUILMETTE
First Vice President, Infrastructure Investments

DEREK MURPHY
First Vice President, Private Equity

MARC LACOURCIÈRE
First Vice President and Chief Legal Officer

STÉPHANIE LACHANCE
Vice President, Responsible Investment and Corporate Secretary

CONSOLIDATED TEN YEAR FINANCIAL REVIEW

($ millions)	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003
CHANGE IN NET ASSETS										
Investment income (loss)	**$ 1,888**	$ 7,043	$ 7,605	$ (9,493)	$ (197)	$ 3,414	$ 4,097	$ 1,334	$ 2,453	$ (924)
Operating expenses	**148**	114	92	86	77	52	39	21	12	9
Net income (loss) from operations and comprehensive income	**$ 1,740**	$ 6,929	$ 7,513	$ (9,579)	$ (274)	$ 3,362	$ 4,058	$ 1,313	$ 2,441	$ (933)
Fund transfers	**4,733**	4,814	4,980	4,431	4,237	3,990	4,197	3,816	3,696	3,382
Increase/(decrease) in net assets	**$ 6,473**	$11,743	$12,493	$ (5,148)	$ 3,963	$ 7,352	$ 8,255	$ 5,129	$ 6,137	$ 2,449
NET INVESTMENT ASSETS										
Investments										
World Equity										
Canadian Equity	**$14,464**	$18,665	$13,547	$ 8,815	$11,538	$10,328	$ 9,346	$ 7,758	$ 5,332	$ 3,162
Foreign Equity:										
US Large Cap Equity	**5,294**	3,829	2,111	926	1,763	2,498	2,618	2,314	2,125	1,225
EAFE Large Cap Equity	**4,760**	3,052	2,043	1,043	1,831	1,720	3,217	2,506	1,738	855
Small Cap Developed World Equity	**3,641**	3,221	1,977	781	1,930	2,936	2,006	105	65	–
Emerging Markets Equity	**4,787**	4,062	2,987	2,122	2,726	2,501	1,943	354	–	–
Private Equity	**6,444**	5,582	5,426	4,191	3,972	1,669	301	3	–	–
Nominal Fixed Income										
Cash & Cash Equivalents[1]	**1,597**	1,254	1,892	73	533	468	967	537	109	245
Fixed Income	**8,569**	7,685	6,958	6,358	7,097	7,089	5,243	5,143	4,790	2,615
Real Return Assets										
World Inflation-Linked Bonds	**3,982**	3,022	2,145	2,389	2,211	1,714	421	219	–	–
Real Estate	**7,055**	5,312	5,118	4,653	4,029	3,596	1,584	429	74	–
Infrastructure	**3,607**	2,356	2,073	2,446	1,343	479	–	–	–	–
Renewable Resources	**325**	–	–	–	–	–	–	–	–	–
Net investments	**$64,525**	**$58,040**	**$46,277**	**$33,797**	**$38,973**	**$34,998**	**$27,646**	**$19,368**	**$14,233**	**$ 8,102**
PERFORMANCE (%)										
Annual rate of return	**3.0**	14.5	21.5	(22.7)	(0.3)	11.3	19.1	7.9	26.1	(13.5)
Benchmark	**1.6**	12.7	19.8	(17.6)	1.2	10.1	18.0	7.2	25.4	(12.9)

PSP Investments' total rate of return since inception (April 2000) is 4.5%.

[1] Includes amounts related to absolute return and real estate debt strategies.

FINANCIAL STATEMENTS AND NOTES TO THE FINANCIAL STATEMENTS

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The consolidated financial statements of the Public Sector Pension Investment Board ("PSP Investments") as well as the financial statements of the Public Service, the Canadian Forces, the Royal Canadian Mounted Police, and the Reserve Forces Pension Plan Accounts (the "financial statements") have been prepared by management and approved by the Board of Directors. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Management is responsible for the contents of the financial statements and the financial information contained in the annual report.

PSP Investments maintains records and systems of internal control and supporting procedures to provide reasonable assurance that PSP Investments' assets are safeguarded and controlled, and that transactions are in accordance with the applicable provisions of Part X of the *Financial Administration Act* and, as appropriate, the *Public Sector Pension Investment Board Act* (the "Act"), the accompanying regulations, the by-laws, and the Statement of Investment Policies, Standards and Procedures (the "SIP&P").

In this regard, investments of PSP Investments held during the year ended March 31, 2012, were in accordance with the Act and the SIP&P.

The Audit Committee ("Committee") assists the Board of Directors in discharging its responsibility to approve the annual financial statements. The Committee meets regularly with both management and the external auditors to discuss the scope and findings of audits and other work that the external auditors may be requested to perform from time to time, to review financial information, and to discuss the adequacy of internal controls. The Committee reviews the annual financial statements and recommends them to the Board of Directors for approval.

PSP Investments' external "joint" auditors, the Office of the Auditor General of Canada and Deloitte & Touche LLP (the "External Auditors"), have conducted an independent examination of the financial statements in accordance with Canadian generally accepted auditing standards, performing such tests and other procedures as they consider necessary to express an opinion in their Auditors' Report. The External Auditors have full and unrestricted access to management and the Committee to discuss findings related to the integrity of PSP Investments' financial reporting and the adequacy of internal control systems.



Gordon J. Fyfe
President and
Chief Executive Officer
May 14, 2012



John Valentini
Executive Vice President,
Chief Operating Officer and Chief Financial Officer
May 14, 2012

INVESTMENT CERTIFICATE

The *Public Sector Pension Investment Board Act* (the "Act") requires that a certificate be signed by a director on behalf of the Board of Directors, stating that the investments of the Public Sector Pension Investment Board ("PSP Investments") held during the financial year were in accordance with the Act and PSP Investments' investment policies, standards and procedures. Accordingly, the Investment Certificate follows:

"The investments of PSP Investments held during the year ended March 31, 2012, were in accordance with the Act and PSP Investments' Statement of Investment Policies, Standards and Procedures".



Cheryl Barker
Interim Chair of the Board
May 14, 2012

PUBLIC SECTOR PENSION INVESTMENT BOARD CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

To the President of the Treasury Board

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of the Public Sector Pension Investment Board (PSP Investments) and its subsidiaries, which comprise the consolidated balance sheet as at March 31, 2012, and the consolidated statement of net income from operations and comprehensive income and consolidated statement of changes in net assets for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of PSP Investments and its subsidiaries as at March 31, 2012, and the results of their operations and changes in their net assets for the year then ended in accordance with Canadian generally accepted accounting principles.

REPORT ON OTHER LEGAL AND REGULATORY REQUIREMENTS

As required by the *Financial Administration Act,* we report that, in our opinion, Canadian generally accepted accounting principles have been applied on a basis consistent with that of the preceding year.

Further, in our opinion, the transactions of PSP Investments and its wholly-owned subsidiaries that have come to our notice during our audit of the consolidated financial statements have, in all significant respects, been in accordance with the applicable provisions of Part X of the *Financial Administration Act* and regulations, the *Public Sector Pension Investment Board Act* and regulations and the by-laws of PSP Investments and its wholly-owned subsidiaries.

Deloitte & Touche LLP[1]

[1] Chartered accountant auditor permit No. 18527

May 14, 2012
Montréal, Canada

Michael Ferguson, FCA
Auditor General of Canada

May 14, 2012
Ottawa, Canada

CONSOLIDATED BALANCE SHEET

As at March 31

($ millions)	2012	2011
ASSETS		
Investments (Note 3 (A))	**$ 70,275**	$ 60,872
Investment-related assets (Note 3 (A))	**1,258**	1,475
Cash	**8**	4
Other assets	**65**	52
	$ 71,606	$ 62,403
LIABILITIES		
Investment-related liabilities (Note 3 (A))	**$ 7,008**	$ 4,307
Accounts payable and other liabilities	**112**	83
	$ 7,120	$ 4,390
NET ASSETS	**$ 64,486**	$ 58,013
Share capital (Note 5)	**$ –**	$ –
Public Service Pension Plan Account	**47,128**	42,299
Canadian Forces Pension Plan Account	**12,438**	11,289
Royal Canadian Mounted Police Pension Plan Account	**4,556**	4,102
Reserve Force Pension Plan Account	**364**	323
NET ASSETS	**$ 64,486**	$ 58,013

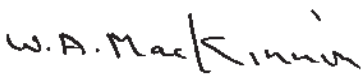
Commitments (Note 13)

The accompanying notes are an integral part of the consolidated financial statements.

On behalf of the Board of Directors:



Cheryl Barker
Interim Chair of the Board



William A. Mackinnon
Chair of the Audit Committee

CONSOLIDATED STATEMENT OF NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME

For the years ended March 31

($ millions)	2012	2011
INVESTMENT INCOME (Note 7)	**$ 1,888**	$ 7,043
OPERATING EXPENSES (Note 8)	**$ 148**	$ 114
NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME (Note 9)	**$ 1,740**	$ 6,929

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN NET ASSETS

For the years ended March 31

($ millions)	2012	2011
NET ASSETS, BEGINNING OF YEAR	**$ 58,013**	$ 46,270
Fund transfers (Note 6)	**4,733**	4,814
Net income from operations and comprehensive income	**1,740**	6,929
Increase in net assets for the year	**6,473**	11,743
NET ASSETS, END OF YEAR	**$ 64,486**	$ 58,013

The accompanying notes are an integral part of the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2012

ORGANIZATION

The Public Sector Pension Investment Board (PSP Investments) is a Crown corporation created under the *Public Sector Pension Investment Board Act* (the "Act") to manage and invest amounts that are transferred to it, under the *Superannuation Acts*, by the funds (as defined in the Act) of the pension plans established under the *Public Service Superannuation Act*, the *Canadian Forces Superannuation Act* (CFSA), the *Royal Canadian Mounted Police Superannuation Act* (collectively the "*Superannuation Acts*"), and certain regulations under the CFSA (the "CFSA Regulations"). The pension plans established under the *Superannuation Acts* consist of the Public Service pension plan, the Canadian Forces pension plan, and the Royal Canadian Mounted Police pension plan, whereas the pension plan established under the CFSA Regulations is the Reserve Force pension plan. They are herein referred to individually as the "Plan" and collectively as the "Plans".

The funds from which amounts are currently transferred to PSP Investments (individually the "Fund" and collectively the "Funds") relate to pension obligations under the Plans for service on or after April 1, 2000 except, in the case of the Reserve Force Plan, they relate to service on or after March 1, 2007. The accounts managed by PSP Investments for the Funds are herein referred to individually as the "Plan Account" and collectively as the "Plan Accounts".

PSP Investments is responsible for managing amounts that are transferred to it in the best interests of the beneficiaries and contributors under the *Superannuation Acts*. The amounts are to be invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the Plans and the ability of the Plans to meet their financial obligations.

Pursuant to the *Superannuation Acts*, the Government of Canada, which administers the Funds, may call upon PSP Investments for amounts required for the purpose of paying benefits under the Plans in respect of service on or after April 1, 2000. Amounts remitted by PSP Investments for such purpose cannot exceed, at any time, the net assets of PSP Investments.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These consolidated financial statements present the financial position and operations of PSP Investments and its wholly-owned subsidiaries as they pertain to the investment of the net contributions transferred to it from the Funds. Accordingly, they do not reflect all of the assets or the details of the pension contributions, payments and liabilities of all the Funds. The consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). PSP Investments qualifies as an Investment Company and therefore reports its investments at fair value, in accordance with Accounting Guideline 18, "Investment Companies" (AcG-18). All changes in fair value are included in investment income (loss) as net unrealized gains (losses).

Comparative figures have been reclassified to conform to the current year's presentation.

PLAN ACCOUNTS

PSP Investments maintains records of each of the Funds' net contributions, as well as the allocation of its investments and the results of its operations to each of the Plan Accounts. Separate financial statements for each Plan Account are prepared.

VALUATION OF INVESTMENTS

Investments, investment-related assets and investment-related liabilities are recorded at the date upon which PSP Investments becomes a party to the associated contractual provisions, and are carried at fair value. Purchases and sales are recorded as of the trade date. Fair value is an estimate of the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

At trade date, the best evidence of fair value is the transaction price. At each subsequent reporting year-end, market prices are used to determine fair value where an active market exists (such as a recognized securities exchange), as they reflect actual and regularly occurring market transactions on an arm's length basis. If quoted market prices are not available, then fair values are estimated using present value or other valuation techniques, using inputs existing at the end of the reporting year that are derived from observable market data.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

VALUATION OF INVESTMENTS (continued)

Valuation techniques are generally applied to investments in real estate, private equity, infrastructure and renewable resources, over-the-counter (OTC) derivatives and certain fixed income securities. The values derived from applying these techniques are impacted by the choice of valuation model and the underlying assumptions made concerning factors such as the amounts and timing of future cash flows, discount rates, volatility and credit risk. In certain cases, such assumptions are not supported by market observable data.

The valuation methods of the investments are described in Notes 3 (A) and (B).

TRANSACTION COSTS

Transaction costs are incremental costs directly attributable to the acquisition, due diligence, issue, or disposal of a financial asset or financial liability. Transaction costs are expensed as incurred and recorded as a component of investment income (loss).

INVESTMENT MANAGEMENT FEES

Investment management fees are directly attributable to the external management of assets on behalf of PSP Investments. Management fees incurred for investments in private markets and certain private debt portfolios are paid by the investment directly, through capital contributions by PSP Investments or offset against distributions received from the investment. Management fees are also incurred for certain public markets and alternative investments and are paid either directly by PSP Investments or offset against distributions received from pooled fund investments. In both cases, they are recorded against investment income (loss).

INCOME RECOGNITION

Investment income (loss) is made up of interest income, dividends, realized gains (losses) on the disposal of investments and unrealized gains (losses) which reflect the change in unrealized appreciation (depreciation) of investments held at the end of the year. Interest income is recognized as earned. Dividends are recognized on the ex-dividend date and are reflected as dividend income. Dividends paid or payable on securities sold short are reflected as dividend expense. Other income includes securities lending income (net of fees on securities borrowed), as well as private markets distributions from pooled funds, limited partnerships or from direct investments and co-investments. Co-investments are investments in private entities where the investment is made in conjunction with an external manager with whom PSP Investments already has committed and delegated funds.

TRANSLATION OF FOREIGN CURRENCIES

Investment transactions in foreign currencies are recorded at exchange rates prevailing on the transaction date. Investments denominated in foreign currencies and held at the end of the year are translated at exchange rates in effect at the year-end date. Any realized and unrealized gains (losses) on foreign exchange are included in investment income (loss).

FUND TRANSFERS

Amounts received from the Funds are recorded in their respective Plan Account.

INCOME TAXES

PSP Investments and the majority of its subsidiaries are exempt from Part I tax under paragraphs 149(1)*(d)* and 149(1)*(d.2)* of the *Income Tax Act* (Canada), respectively.

USE OF ESTIMATES

In preparing these consolidated financial statements, management makes certain estimates and assumptions which can affect the reported values of assets and liabilities. This is principally reflected in the valuation of private markets investments, certain fixed income securities, related income and expenses as well as note disclosures. Although estimates and assumptions reflect management's best judgment, actual results may differ from these estimates.

2. FUTURE CHANGES IN ACCOUNTING POLICIES

In February 2008, the Accounting Standards Board of Canada (AcSB) confirmed that Canadian GAAP for publicly accountable enterprises would converge with International Financial Reporting Standards (IFRS) effective January 1, 2011.

In 2011, the AcSB decided to defer the adoption of IFRS by investment companies, currently applying AcG-18 to annual periods starting on or after January 1, 2014. This deferral delays PSP Investments' transition to IFRS until the March 31, 2015 annual consolidated financial statements.

The AcSB's decision was in response to an announcement by the International Accounting Standards Board (IASB) in 2010, regarding an Exposure Draft (ED) being developed. The IASB proposed to define an investment entity and exempt it from consolidation by requiring it to measure all controlled investments at fair value, with changes recognized in profit or loss. The ED, *Investment Entities*, was published in August 2011 and is expected to be finalized in the second half of 2012. PSP Investments will complete the assessment of the impact of its transition to IFRS once the ED is finalized and a standard is issued.

The AcSB also announced in 2011 that it will evaluate whether entities like PSP Investments, which are separate from a pension plan and without a pension obligation, and whose sole purpose is to hold and invest assets received from one or more pension plans, would qualify as investment entities under the IASB's ED. Based on the result of this evaluation, the AcSB will then decide whether these entities would need to be included within the scope of Section 4600, "Pension Plans", where investments are accounted for at fair value.

3. INVESTMENTS

(A) INVESTMENT PORTFOLIO

The investment portfolio is organized according to the nature and common characteristics associated with the investments held. The following table presents the investment portfolio as at March 31:

	2012		2011	
($ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Public markets				
Canadian equity	**$ 9,141**	**$ 8,867**	$ 14,135	$ 11,603
Foreign equity	**16,225**	**14,996**	12,977	11,845
Private markets				
Real estate	**7,452**	**6,451**	5,451	4,994
Private equity	**6,180**	**5,269**	5,189	4,502
Infrastructure	**4,268**	**4,475**	2,706	2,934
Renewable resources	**376**	**376**	–	–
Fixed income				
Cash and money market securities	**2,390**	**2,390**	2,563	2,563
Government and corporate bonds	**12,748**	**12,480**	8,075	8,126
Inflation-linked bonds	**3,950**	**3,609**	2,981	3,066
Other fixed income securities	**6,370**	**5,739**	5,681	5,467
Alternative investments	**1,175**	**927**	1,114	902
INVESTMENTS	**$ 70,275**	**$ 65,579**	$ 60,872	$ 56,002
Investment-related assets				
Amounts receivable from pending trades	**$ 629**	**$ 629**	$ 697	$ 697
Interest receivable	**160**	**160**	140	140
Dividends receivable	**59**	**59**	50	50
Derivative-related receivables	**410**	**81**	588	28
	$ 1,258	**$ 929**	$ 1,475	$ 915
Investment-related liabilities				
Amounts payable from pending trades	**$ (989)**	**$ (989)**	$ (1,084)	$ (1,084)
Interest payable	**(24)**	**(24)**	(21)	(21)
Securities sold short	**(429)**	**(415)**	(43)	(37)
Securities sold under repurchase agreements	**(1,272)**	**(1,268)**	(511)	(511)
Derivative-related payables	**(370)**	**(82)**	(198)	(24)
Capital market debt financing:				
Short-term	**(901)**	**(901)**	(702)	(702)
Long-term	**(3,023)**	**(2,959)**	(1,748)	(1,709)
	$ (7,008)	**$ (6,638)**	$ (4,307)	$ (4,088)
NET INVESTMENTS	**$ 64,525**	**$ 59,870**	$ 58,040	$ 52,829

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(i) Public Markets

Public markets consist of Canadian and foreign investments in the following securities: common shares, American depository receipts, global depository receipts, participation notes, preferred shares, income trust units, exchange traded funds units, pooled funds units, and securities convertible into common shares of publicly listed issuers.

Valuation Techniques

Direct investments in Canadian and foreign equities are measured at fair value using quoted market prices, namely, the bid price.

In the case of investments in pooled funds, fair value is measured using unit values obtained from each of the funds' administrators, which are derived from the fair value of the underlying investments in each pooled fund. Where necessary, the impact of restrictions on the sale or redemption of such investments is taken into consideration in determining fair value.

(ii) Private Markets

Private markets consist of investments in real estate, private equity, infrastructure and renewable resources.

Real estate investments are comprised of direct equity positions in various private entities, properties, as well as fund investments in the real estate sector. Real estate investments focus on properties, partnerships and companies operating in the office, retail, industrial, hospitality and residential sectors, as well as private funds invested in real estate assets. Real estate investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of real estate contracted by direct investments controlled by PSP Investments was $2,662 million (2011 – $2,113 million).

Private equity investments are comprised of direct equity positions and co-investments in private entities as well as fund investments with similar objectives.

Infrastructure investments are comprised of direct equity positions and co-investments in various private entities and fund investments. Infrastructure investments focus on entities engaged in the management, ownership or operation of assets in energy, transportation and other regulated businesses. Infrastructure investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of infrastructure contracted by direct investments controlled by PSP Investments was $285 million (2011 – $51 million).

Renewable resources investments are comprised of properties involving the production and harvesting of replenishable resources. As at March 31, 2012, renewable resources included one investment in timberlands.

Valuation Techniques

The fair value of private markets investments is determined at least annually, using acceptable industry valuation methods. During the year, the fair value is reviewed and adjusted, as appropriate, to reflect the impact of any significant market or investment-specific events or circumstances. For each investment, the relevant methodology is applied consistently over time as appropriate in the prevailing circumstances.

In cases where the services of third-party appraisers are used, management ensures their independence and that valuation methods used are consistent with professional appraisal standards. Such standards include the *International Private Equity and Venture Capital Valuation Guidelines*, the *Canadian Uniform Standards of Professional Appraisal Practice* and the *Uniform Standards of Professional Appraisal Practice* in the United States of America. In validating the work performed by appraisers, management ensures that the assumptions used correspond to financial information and forecasts of the underlying investment.

For direct investments in real estate, valuation methods used include discounted cash flows, prices of recent comparable transactions and the direct capitalization approach. Assumptions used in such valuations include discount rates, capitalization rates, projected cash flows and/or net operating income, which are not fully supported by prices from market observable transactions.

For direct investments in private equity, direct investments and co-investments in infrastructure and in renewable resources, valuation methods used include discounted cash flows, earnings multiples, prices of recent comparable transactions and publicly traded comparables. Assumptions used in such valuations include discount rates and projected cash flows, which are not fully supported by prices from market observable transactions.

In the case of private equity, real estate and infrastructure fund investments as well as private equity co-investments, the annual fair value is generally determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(iii) Fixed Income

Fixed income consists of cash and money market securities, government and corporate bonds, inflation-linked bonds and other fixed income securities.

Cash and money market securities include instruments having a maximum term to maturity of one year, such as treasury bills, certificates of deposit and bankers' acceptances.

Government and corporate bonds include Canadian and foreign, federal, provincial, territorial and municipal bonds. Inflation-linked bonds are fixed income securities that earn inflation adjusted returns.

Other fixed income securities consist of asset-backed securities, floating rate notes as well as private debt portfolios.

Asset-backed securities consist mainly of asset-backed term notes (ABTNs) and mortgage-backed securities. The ABTNs were received in exchange for third-party or non-bank sponsored asset-backed commercial paper (ABCP) that suffered a liquidity disruption in mid-August 2007 and were subsequently restructured in January 2009. Potential margin calls on the ABTNs are supported by funding facilities, as described in Note 12.

Private debt portfolios consist mainly of investments in the real estate sector in the form of third-party loans such as junior and senior debts, construction loans, bridge loans, income-participating loans, as well as other structured finance products. They also include real estate debt funds where significant portions of the value are attributed to the underlying real estate assets.

Private debt portfolios also include debt securities of private companies or other entities such as venture capital organizations, held mainly through private funds. Such debt securities take the form of senior debt, mezzanine and distressed debt.

Valuation Techniques

Cash and money market securities include short-term instruments that are recorded at cost plus accrued interest, which approximates fair value.

Fair values of government and corporate bonds, inflation-linked bonds, floating rate notes and mortgage-backed securities are based on prices obtained from third-party pricing sources. Such prices are determined using either an appropriate interest rate curve with a spread associated with the credit quality of the issuer or other generally accepted pricing methodologies.

ABTNs are measured at fair value whereby management relies on the valuation work performed by a recognized third-party expert. Management ensures that the valuation conducted by such expert uses acceptable industry methods. Financial information used in the valuation of ABTNs includes interest rates, credit spreads and the underlying investments' terms to maturity. In addition to the values determined by the expert, management integrated certain assumptions in the fair value of ABTNs that are not fully supported by market observable data, such as liquidity estimates and the impact of the funding facilities described in Note 12.

The fair value of private debt portfolios in the real estate sector is determined using either a yield-based or collateral-based valuation technique. The yield-based valuation technique involves discounting expected future cash flows that incorporate assumptions with respect to interest rates offered for similar loans to borrowers with similar credit ratings. The collateral-based valuation technique involves assessing the recoverable value of the collateral in question, net of disposal fees.

The fair value of fund investments included as part of private debt portfolios is determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

(iv) Alternative Investments

Alternative investments consist mainly of units of funds that hold a mix of equity, fixed income and derivative instruments as well as hedge funds.

Valuation Techniques

The fair value of these investments is obtained from the investment's external manager and reflects the fair value of the underlying equity, fixed income or derivative instruments, as applicable.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(v) Amounts Receivable and Payable from Pending Trades

Amounts receivable from pending trades consist of proceeds on sales of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Amounts payable from pending trades consist of the cost of purchases of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Valuation Techniques

The fair value of amounts receivable and payable from pending trades reflects the value at which their underlying original sale or purchase transactions were undertaken.

(vi) Interest and Dividends Receivable

Interest and dividends are recorded at the amounts expected to be received as at the reporting date, which approximates fair value.

(vii) Interest Payable

Interest is accrued at the amount expected to be paid as at the reporting date, which approximates fair value.

(viii) Securities Sold Short

Securities sold short reflect PSP Investments' obligation to purchase securities pursuant to short selling transactions. In such transactions, PSP Investments sells securities it does not own with an obligation to purchase similar securities on the market to cover its position.

Valuation Techniques

Using ask prices as inputs, the fair value of securities sold short is measured using the same method as the similar long positions presented within public markets and fixed income.

(ix) Securities Sold under Repurchase Agreements

PSP Investments is party to agreements which involve the sale of securities with a simultaneous agreement to repurchase such securities at a specified price and at a specified future date.

Securities sold under the repurchase agreements are not derecognized as PSP Investments retains all related risks and rewards of ownership. As such, all related income (loss) continues to be reported in investment income (loss).

Obligations to repurchase the securities sold are accounted for as investment-related liabilities. Interest expense related to such obligations is reported in investment income (loss).

Valuation Techniques

Obligations to repurchase the securities sold under repurchase agreements are recorded at cost plus accrued interest, which approximates fair value.

(x) Derivative-Related Receivables and Payables

The description and valuation of derivative-related receivables and payables are described in Note 3 (B).

(xi) Capital Market Debt Financing

PSP Investments' capital market debt program is described in Note 10. Short-term promissory notes are recorded at cost plus accrued interest, which approximates fair value. The fair value of PSP Investments' medium-term notes is based on prices that are obtained from third-party pricing sources. Such prices are determined using an interest rate curve with a spread consistent with PSP Investments' credit quality.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS

Derivative financial instruments are financial contracts that are settled at a future date. The value of such instruments is derived from changes in underlying assets, interest or exchange rates. Derivative financial instruments do not, typically, require an initial net investment. In certain cases, they require an initial net investment that is less than what would be required to hold the underlying position directly. PSP Investments uses derivative financial instruments to enhance returns or to replicate investments synthetically. Derivatives are also used to reduce the risk associated with existing investments.

PSP Investments uses the following types of derivative financial instruments:

(i) Swaps

Swaps are transactions whereby two counterparties exchange cash flow streams with each other based on predetermined conditions that include a notional amount and a term. Swaps are used to increase returns or to adjust exposures of certain assets without directly purchasing or selling the underlying assets.

(ii) Futures

Futures are standardized contracts to take or make delivery of an asset (buy or sell) at a predefined price and predefined future date. Futures are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iii) Forwards

Forwards are contracts involving the sale by one party and the purchase by another party of a predefined amount of an underlying instrument, at a predefined price and at a predefined date in the future. Forwards are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iv) Options

Options are the right, but not the obligation, to buy or sell a given amount of an underlying security, index, or commodity, at an agreed-upon price stipulated in advance, either at a determined date or at any time before the predefined maturity date.

(v) Warrants and Rights

Warrants are options to purchase an underlying asset which is in the form of a transferable security and which can be listed on an exchange.

Rights are securities giving shareholders entitlement to purchase new shares issued by a corporation at a predetermined price (normally less than the current market price) in proportion to the number of shares already owned. Rights are issued only for a short period of time, after which they expire.

(vi) Collateralized Debt Obligations

Collateralized debt obligations are a type of asset-backed security that is constructed from a portfolio of credit-related assets. Collateralized debt obligations are usually divided into several tranches with different credit risk levels and corresponding interest payments. Any losses are applied first to the more junior tranches (lowest risk rating) before moving up in seniority.

Valuation Techniques

All listed derivative financial instruments are recorded at fair value using quoted market prices with the bid price for long positions and the ask price for short positions. OTC derivatives are valued using appropriate valuation techniques, such as discounted cash flows using current market yields. The assumptions used include the statistical behaviour of the underlying instruments and the ability of the model to correlate with observed market transactions. Although pricing models used are widely accepted and used by other market participants, in the case of collaterized debt obligations, the nature of such instruments requires more significant assumptions about the behaviour of the default correlation. Such assumptions are not observable in the market.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

Notional values of derivative financial instruments are not recorded as assets or liabilities as they represent the face amount of the contract. Except for credit derivatives[1], notional values do not represent the potential gain or loss associated with the market or credit risk of such transactions disclosed below. Rather, they serve as the basis upon which the cash flows and the fair value of the contracts are determined.

The following table summarizes the derivatives portfolio as at March 31:

	2012				2011			
		Fair Value				Fair Value		
($ millions)	Notional Value	Assets	Liabilities	Net	Notional Value	Assets	Liabilities	Net
Equity and commodity derivatives								
Futures	**$ 1,012**	**$ –**	**$ –**	**$ –**	$ 430	$ –	$ –	$ –
Total return swaps	**8,157**	**131**	**(43)**	**88**	5,541	191	–	191
Warrants and rights	**1**	**–**	**–**	**–**	2	2	–	2
Options:								
Listed-purchased	**1,128**	**15**	**–**	**15**	442	12	–	12
Listed-written	**965**	**–**	**(11)**	**(11)**	395	–	(19)	(19)
OTC-purchased	**538**	**6**	**–**	**6**	–	–	–	–
OTC-written	**495**	**–**	**(9)**	**(9)**	–	–	–	–
Currency derivatives								
Forwards	**23,088**	**156**	**(185)**	**(29)**	17,101	316	(121)	195
Futures	**152**	**–**	**–**	**–**	–	–	–	–
Swaps	**940**	**3**	**(18)**	**(15)**	1,673	24	(11)	13
Options:								
OTC-purchased	**491**	**5**	**–**	**5**	1,010	6	–	6
OTC-written	**819**	**–**	**(6)**	**(6)**	183	–	(2)	(2)
Interest rate derivatives								
Bond forwards	**1,800**	**4**	**(3)**	**1**	993	5	(3)	2
Futures	**1,564**	**–**	**–**	**–**	1,770	–	–	–
Interest rate swaps	**7,578**	**27**	**(30)**	**(3)**	17,546	14	(17)	(3)
Total return swaps	**–**	**–**	**–**	**–**	646	–	–	–
Swaptions	**808**	**15**	**(6)**	**9**	3,522	6	(3)	3
Options:								
Listed-purchased	**8,254**	**3**	**–**	**3**	5,347	7	–	7
Listed-written	**8,331**	**–**	**(5)**	**(5)**	7,512	–	(7)	(7)
OTC-purchased	**799**	**15**	**–**	**15**	–	–	–	–
OTC-written	**3,853**	**–**	**(24)**	**(24)**	–	–	–	–
Credit derivatives[1]:								
Purchased	**1,206**	**28**	**(9)**	**19**	418	3	(4)	(1)
Sold	**584**	**2**	**(21)**	**(19)**	409	2	(11)	(9)
Total	**$ 72,563**	**$ 410**	**$ (370)**	**$ 40**	$ 64,940	$ 588	$ (198)	$ 390

[1] Credit derivatives include credit default swaps and collateralized debt obligations. PSP Investments, through sold credit derivatives, indirectly guarantees the underlying reference obligations. The maximum potential exposure is the notional amount of the sold credit derivatives as shown in the table above.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

The term to maturity based on notional value for the derivatives was as follows as at March 31, 2012:

($ millions)	
Less than 3 months	**$ 41,579**
3 to 12 months	**17,750**
Over 1 year	**13,234**
Total	**$ 72,563**

(C) FAIR VALUE MEASUREMENT

Investments, investment-related assets and investment-related liabilities are classified according to the following hierarchy based on the significant inputs used in measuring their fair value.

Level 1: Valuation is based on quoted prices in active markets for identical assets or liabilities.

Level 2: Valuation is based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active. Level 2 also includes model-based valuation techniques for which all significant assumptions are observable in the market.

Level 3: Valuation is based on model-based techniques for which significant assumptions are not observable in the market. They reflect management's assessment of the assumptions that market participants would use in pricing the assets or liabilities.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2012:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 9,141	$ –	$ –	$ –	$ 9,141
Foreign equity	15,243	812	170	–	16,225
Private markets					
Real estate	–	–	7,452	–	7,452
Private equity	–	–	6,180	–	6,180
Infrastructure	–	–	4,268	–	4,268
Renewable resources	–	–	376	–	376
Fixed income					
Cash and money market securities	763	1,627	–	–	2,390
Government and corporate bonds	–	12,748	–	–	12,748
Inflation-linked bonds	–	3,950	–	–	3,950
Other fixed income securities	–	2,384	3,986	–	6,370
Alternative investments	–	871	304	–	1,175
INVESTMENTS	$ 25,147	$ 22,392	$ 22,736	$ –	$ 70,275
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 629	$ 629
Interest receivable[1]	–	–	–	160	160
Dividends receivable[1]	–	–	–	59	59
Derivative-related receivables	18	392	–	–	410
	$ 18	$ 392	$ –	$ 848	$ 1,258
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (989)	$ (989)
Interest payable[1]	–	–	–	(24)	(24)
Securities sold short	(429)	–	–	–	(429)
Securities sold under repurchase agreements	–	(1,272)	–	–	(1,272)
Derivative-related payables	(15)	(345)	(10)	–	(370)
Capital market debt financing:					
Short-term	–	(901)	–	–	(901)
Long-term	–	(3,023)	–	–	(3,023)
	$ (444)	$ (5,541)	$ (10)	$ (1,013)	$ (7,008)
NET INVESTMENTS	$ 24,721	$ 17,243	$ 22,726	$ (165)	$ 64,525

[1] No fair value hierarchy classification is required for these items.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2011:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 14,078	$ 57	$ –	$ –	$ 14,135
Foreign equity	10,896	2,081	–	–	12,977
Private markets					
Real estate	–	–	5,451	–	5,451
Private equity	–	–	5,189	–	5,189
Infrastructure	–	–	2,706	–	2,706
Fixed income					
Cash and money market securities	583	1,980	–	–	2,563
Government and corporate bonds	–	8,075	–	–	8,075
Inflation-linked bonds	–	2,981	–	–	2,981
Other fixed income securities	–	2,003	3,678	–	5,681
Alternative investments	–	1,114	–	–	1,114
INVESTMENTS	$ 25,557	$ 18,291	$ 17,024	$ –	$ 60,872
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 697	$ 697
Interest receivable[1]	–	–	–	140	140
Dividends receivable[1]	–	–	–	50	50
Derivative-related receivables	20	566	2	–	588
	$ 20	$ 566	$ 2	$ 887	$ 1,475
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (1,084)	$ (1,084)
Interest payable[1]	–	–	–	(21)	(21)
Securities sold short	(43)	–	–	–	(43)
Securities sold under repurchase agreements	–	(511)	–	–	(511)
Derivative-related payables	(27)	(161)	(10)	–	(198)
Capital market debt financing:					
Short-term	–	(702)	–	–	(702)
Long-term	–	(1,748)	–	–	(1,748)
	$ (70)	$ (3,122)	$ (10)	$ (1,105)	$ (4,307)
NET INVESTMENTS	$ 25,507	$ 15,735	$ 17,016	$ (218)	$ 58,040

[1] No fair value hierarchy classification is required for these items.

The classification within the levels of the hierarchy is established at the time of the initial valuation of the asset or liability and reviewed on each subsequent reporting year-end.

There were no significant transfers between Level 1 and Level 2 during the year ended March 31, 2012 (no significant transfers during the year ended March 31, 2011).

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Reconciliation

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2012:

($ millions)	Opening Balance	Purchases	Sales	Settlements	Realized Gains	Unrealized Gains (Losses)	Transfer out of Level 3	Closing Balance
Public markets	$ –	$ 152	$ (16)	$ –	$ 2	$ 32	$ –	$ 170
Private markets	13,346	6,255	(2,257)	–	204	749	(21)	18,276
Fixed income	3,678	1,054	(978)	(221)	42	411	–	3,986
Alternative investments	–	296	–	–	–	8	–	304
Derivative-related receivables/payables (net)	(8)	–	–	(3)	3	(2)	–	(10)
Total	**$ 17,016**	**$ 7,757**	**$ (3,251)**	**$ (224)**	**$ 251**	**$ 1,198**	**$ (21)**	**$ 22,726**

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2011:

($ millions)	Opening Balance	Purchases	Sales	Settlements	Realized Losses	Unrealized Gains	Transfer out of Level 3	Closing Balance
Private markets	$ 12,195	$ 2,596	$ (2,365)	$ –	$ (69)	$ 1,005	$ (16)	$ 13,346
Fixed income	3,963	545	(872)	(215)	(75)	332	–	3,678
Derivative-related receivables/payables (net)	(326)	251	(4)	–	(247)	318	–	(8)
Total	$ 15,832	$ 3,392	$ (3,241)	$ (215)	$ (391)	$ 1,655	$ (16)	$ 17,016

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Sensitivity Analysis

In the course of measuring fair value of financial instruments classified as Level 3, valuation techniques used incorporate assumptions that are based on non-observable data. Significant assumptions used for each asset class are described in Notes 3 (A) and (B). Although such assumptions reflect management's best judgment, the use of reasonably possible alternative assumptions could yield different fair value measures representing, at a minimum, a 2% increase/decrease (2011 – 2% increase/decrease) in the fair value of financial instruments categorized as Level 3. This excludes private debt portfolios in the real estate sector and certain fund investments, where a sensitivity analysis is not possible given the underlying assumptions used are not available to PSP Investments. In the case of fund investments, the fair value is determined based on the audited financial statements of the fund's general partner as indicated in Note 3 (A). With respect to private debt portfolios in the real estate sector, the fair value is obtained from third-party appraisers as described in Note 3 (A).

(D) SECURITIES LENDING AND BORROWING PROGRAMS

PSP Investments participates in securities lending and borrowing programs whereby it lends and borrows securities in order to enhance portfolio returns. Lending and borrowing transactions under such programs do not transfer the risks or rewards of ownership of the securities to the counterparty. Consequently, PSP Investments does not derecognize securities lent or recognize securities borrowed.

The securities lending and borrowing programs require collateral in cash, high-quality debt instruments or securities. Collateral transactions are conducted under terms that are usual and customary in standard securities lending and borrowing programs. PSP Investments and its counterparties are authorized to sell, repledge or otherwise use collateral held. The same securities or equivalent securities must be returned to the counterparty at the end of the contract, unless an event of default occurs. As at March 31, 2012, PSP Investments has re-invested $1,735 million of collateral held (2011 – $1,498 million).

The following table illustrates the fair values of PSP Investments' securities and collateral associated with the lending and borrowing programs as at March 31:

($ millions)	2012	2011
Securities lending		
Securities lent	**$ 6,991**	$ 5,775
Collateral contractually receivable[1]	**7,369**	6,041
Securities borrowing		
Securities borrowed	**429**	43
Collateral contractually payable[2]	**478**	46

[1] The minimum fair value of collateral required is equal to 102% of the fair value of the securities lent.

[2] The minimum fair value of collateral required is equal to 100% of the fair value of the securities borrowed.

(E) SECURITIES SOLD AND COLLATERAL PLEDGED UNDER REPURCHASE AGREEMENTS

Securities sold under repurchase agreements are described in Note 3 (A) (ix) and involve pledging collateral consisting of cash or securities deemed acceptable by the counterparties. Collateral transactions are conducted under terms that are usual and customary in standard repurchase arrangements. Such terms require the relevant counterparty to pledge additional collateral based on the changes in the fair value of the existing collateral pledged. The counterparties are authorized to sell, repledge or otherwise use collateral held. The securities pledged as collateral must be returned to the relevant counterparty at the end of the contract, unless an event of default occurs. PSP Investments does not sell, repledge or otherwise use collateral held.

PSP Investments pledged collateral under the repurchase agreements with a fair value of $1,272 million at March 31, 2012 (2011 – $511 million).

4. INVESTMENT RISK MANAGEMENT

Risk Management is a central part of PSP Investments' operations. Included in the overall risk management framework is a continuous process whereby PSP Investments systematically addresses the investment risks related to its various investment activities with the goal of achieving a maximum rate of return without undue risk of loss.

A risk governance framework that includes required reporting on risk to all levels of the organization ensures that appropriate investment objectives are pursued and achieved in line with the fulfillment of PSP Investments' legislated mandate. The Board of Directors and its committees oversee all risk matters and receive assurances from senior management, including the Chief Risk Officer, as well as PSP Investments' independent internal auditor reporting directly to the Audit Committee.

PSP Investments has adopted an Investment Risk Management Policy which is an integral part of its risk control system and supplements the Statement of Investment Policies, Standards and Procedures (SIP&P). The objective of this policy is to provide a framework to manage the risks that PSP Investments is exposed to, namely, market, credit and liquidity risks.

(A) MARKET RISK

Market risk is the risk that the value of an investment will fluctuate as a result of changes in market prices, whether those changes are caused by factors specific to the individual investment, volatility in share and commodity prices, interest rate, foreign exchange or other factors affecting similar securities traded in the market.

Market risk management focuses on the following two key components:

– Policy Portfolio
The Policy Portfolio (long-term asset mix), as defined in the SIP&P, determines a diversification strategy to mitigate risk whereby PSP Investments invests in a diversified portfolio expected to achieve a return at least equal to the Actuarial Rate of Return (ARR); defined as the rate of return assumption used by the Chief Actuary of Canada in the latest actuarial valuation reports of the Plans. In the absence of other factors affecting the funding of the Plans or changes to pension benefits under the Plans, the ARR is the rate of return required to maintain funding requirements and pension benefits at their current levels.

– Active Management
Active management is defined as the sum of investment strategies that deviate from the approved Policy Portfolio. It is designed to supplement the returns of the Policy Portfolio within an active risk budget.

The risks associated with these components are the Policy Portfolio market risk and the active risk. The Policy Portfolio market risk represents the investment risk arising from the exposure to approved asset classes in the approved weightings. In establishing its Policy Portfolio, PSP Investments also takes into consideration the impact of the Policy Portfolio market risk on funding risk. Funding risk is the risk that the assets under management will be insufficient to meet the relevant pension liabilities of the Plans, which may require the contributions to the Funds of the Plans to be increased. The Policy Portfolio is reviewed at least annually as part of the review of the SIP&P, and this review includes changes, if any, to PSP Investments' long-term expectations of market conditions and other factors that may affect the funding levels of the Plans.

Active risk refers to all market risk arising from active management activities. It is managed in accordance with the Investment Risk Management Policy.

Measurement of Market Risk

The Value-at-Risk (VaR) is one of the methods used to measure market risk and is reported on a quarterly basis. It is not the maximum potential loss, but rather the maximum loss not exceeded with a given confidence level, over a given period of time. PSP Investments uses a Historical VaR model incorporating ten years' worth of market returns scaled to a twelve-month holding period at a 95% confidence level. For investments that are not actively traded, the calculation of VaR uses securities with similar risk attributes as proxy.

In measuring Policy Portfolio risk, VaR represents the absolute loss expected from the Policy Portfolio (Policy Portfolio VaR). Whereas in terms of measuring the active risk, VaR reflects the loss relative to the Policy Portfolio benchmark (Active VaR).

VaR is statistically valid under normal market conditions and does not specifically consider losses from severe market events. It also assumes that the future will behave in a pattern similar to the past. Consequently, if future market conditions differ significantly from those of the past, potential losses may differ from those originally estimated.

The following table shows the Total VaR consisting of the Policy Portfolio VaR, the Active VaR and the diversification effect, calculated as a percentage of net investments, as at March 31. The diversification effect captures the impact of holding different types of assets which may react differently in various types of situations and thus reduces the Total VaR.

	2012	2011
Policy Portfolio VaR	**21.7 %**	22.4 %
Active VaR	**2.6**	2.2
Total VaR (undiversified)	**24.3**	24.6
Diversification effect	**(1.6)**	(2.9)
Total VaR	**22.7 %**	21.7 %

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

Stress Testing

Although VaR is a widely accepted risk measure, it is complemented by other risk measurement methodologies that provide greater insight on market risk. PSP Investments uses stress testing and scenario analysis to examine the impact on financial results of abnormally large movements in risk factors. Stress testing and scenario analysis are used to test a portfolio's sensitivity to various risk factors and key model assumptions. These methods also use historically stressed periods to evaluate how a current portfolio reacts under such circumstances. Stress testing and scenario analysis are also deployed to assess new product performance.

(i) Interest Rate Risk

Interest rate risk refers to the risk that fluctuations in interest rates will directly affect the fair value of PSP Investments' net asset values.

The terms to maturity of the investments with the most significant exposure to interest rate risk were as follows as at March 31, 2012:

($ millions)	Less than 1 Year	1 to 5 Years	5 to 10 Years	Over 10 Years	Other	Total
Government bonds	$ 1,345	$ 4,751	$ 1,710	$ 1,813	$ –	$ 9,619
Corporate bonds	624	1,329	870	306	–	3,129
Inflation-linked bonds	–	1,042	980	1,928	–	3,950
Asset-backed securities	–	1,798	31	3	–	1,832
Private debt portfolios:						
Directly held	52	405	6	–	–	463
Held through funds [1]	–	–	–	–	1,837	1,837
Total investments with significant exposure to interest rate risk	$ 2,021	$ 9,325	$ 3,597	$ 4,050	$ 1,837	$ 20,830
Other investments [2]	$ –	$ –	$ –	$ –	$ 4,628	$ 4,628
Total fixed income	$ 2,021	$ 9,325	$ 3,597	$ 4,050	$ 6,465	$ 25,458

[1] Due to their nature, information in connection with the terms to maturity of fund investments included in the private debt portfolios is not available.

[2] Consists of $2,390 million in cash and money market securities and $2,238 million in floating rate notes, which, due to their nature, are not significantly exposed to interest rate risk.

The terms to maturity of PSP Investments' capital market debt financing are disclosed in Note 10.

Alternative investments as well as derivative contracts described in Notes 3 (A) (iv) and (B), respectively, are also subject to interest rate risk exposures. These exposures are reflected in the VaR calculation described in Note 4 (A).

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

(ii) Foreign Currency Risk

PSP Investments and its subsidiaries are exposed to currency risk through holdings of securities, units in pooled funds and units in limited partnerships of non-Canadian assets. Fluctuations in the relative value of the Canadian dollar against these foreign currencies can result in a positive or a negative effect on the fair value of the investments. To mitigate this risk, PSP Investments may take, through foreign forward contracts or cross currency swaps, positions in foreign currencies. PSP Investments' policy is to hedge a target of 50% of its foreign currency investments in non-emerging countries. Additional factors are considered when implementing the hedging target for investments in emerging countries, namely, total relative exposure and cost effectiveness.

The underlying net foreign currency exposures, after allocating the effect of derivative contracts and investment-related assets and liabilities for both monetary and non-monetary items were as follows as at March 31:

(in millions of Canadian $)	2012		2011	
Currency	**Fair Value**	**% of Total**	Fair Value	% of Total
US Dollar	**$ 12,978**	**57.9 %**	$ 9,493	54.0 %
Euro	**2,660**	**11.9**	2,385	13.6
British Pound	**1,756**	**7.8**	1,331	7.6
Japanese Yen	**1,012**	**4.5**	708	4.0
Brazilian Real	**908**	**4.0**	881	5.0
Hong Kong Dollar	**675**	**3.0**	664	3.8
Korean Won	**490**	**2.2**	470	2.7
Australian Dollar	**404**	**1.8**	306	1.7
Norwegian Krone	**344**	**1.5**	104	0.6
Indian Rupee	**192**	**0.9**	141	0.8
Others	**1,012**	**4.5**	1,078	6.2
Total	**$ 22,431**	**100.0 %**	$ 17,561	100.0 %

PSP Investments and its subsidiaries also had commitments, denominated in foreign currencies of $6,471 million (US$5,667 million, €519 million, R121 million South African Rands and R186 million Brazilian Reals) which were not included in the foreign currency exposure table.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK

PSP Investments is exposed to credit risk, that is, the risk that the issuer of a debt security or that the counterparty to a derivative contract, to a securities lending and borrowing transaction or to securities sold under repurchase agreements, is unable to meet its financial obligations.

Credit risk encompasses the risk of a deterioration of creditworthiness and the relevant concentration risk. Credit risk monitoring entails an evaluation of the credit quality of each issuer and counterparty that transacts with PSP Investments. To perform this evaluation, PSP Investments relies on four recognized credit rating agencies. A minimum of two credit ratings are used to classify each security. Except for ABTNs, securities rated by only one agency are classified as "not rated". If the agencies disagree as to a security's credit quality, PSP Investments uses the lowest of the available ratings.

As at March 31, 2012, PSP Investments' maximum exposure to credit risk amounted to approximately $22 billion (2011 – approximately $16 billion). This amount excludes investments in distressed debt in the amount of approximately $1.4 billion as at March 31, 2012 (2011 – approximately $1.5 billion). The maximum exposure to credit risk also excludes collateralized debt obligations, collateral held as disclosed in Notes 3 (D), 3 (E) and 4 (B) and the impact of guarantees and indemnities disclosed in Note 12.

As at March 31, 2012, PSP Investments had a net notional exposure of $168 million (2011 – $261 million) to various tranches of collateralized debt obligations, of which approximately 61% (2011 – approximately 44%) of the underlying dollar exposure was rated "Investment grade", as well as funding facilities, as described in Note 12, to support potential margin calls on the ABTNs.

To monitor the evolution of credit risk, PSP Investments periodically produces a concentration report by credit rating of all credit-sensitive financial securities with the exception of securities held in pooled funds or for private markets investments.

PSP Investments' concentration of credit risk by credit rating, excluding the items described above and any other credit enhancement, was as follows as at March 31:

	2012	2011
Investment grade (AAA to BBB–)	**98.2 %**	97.9 %
Below investment grade (BB+ and below)	**0.7**	0.4
Not rated:		
Rated by a single credit rating agency	**0.1**	0.1
Not rated by credit rating agencies	**1.0**	1.6
Total	**100.0 %**	100.0 %

Counterparty Risk

Counterparty risk represents the credit risk from current and potential exposure related to transactions involving derivative contracts, securities lending and borrowing as well as securities sold under repurchase agreements. In order to minimize counterparty risk, PSP Investments requires that counterparties provide adequate collateral and meet its credit rating requirements. PSP Investments frequently monitors the credit rating of its counterparties as determined by recognized credit rating agencies. With respect to derivative contracts, PSP Investments has the ability to terminate all trades with most counterparties whose credit rating is downgraded below its requirements.

PSP Investments' policy also requires the use of the International Swaps and Derivative Association (ISDA) Master Agreement with all counterparties to derivative contracts. The ISDA Master Agreement provides the contractual framework within which dealing activities across a full range of OTC products are conducted.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK (continued)

Counterparty Risk (continued)

As a credit mitigation technique, the ISDA Master Agreement contractually binds both parties to use master-netting arrangements and, in the case of default of the counterparty, close-out netting. Additionally, the Credit Support Annex (CSA) to the ISDA Master Agreement enables PSP Investments to realize any collateral placed with it in the case of default of the counterparty. The CSA also requires PSP Investments to contribute further collateral when requested. All collateral transactions are in high-quality debt instruments or securities. The CSA also regulates the exchange of collateral when the credit exposure to a counterparty exceeds a predetermined threshold. In certain cases, counterparties are authorized to sell, repledge or otherwise use collateral held. PSP Investments pledged securities with a fair value of $3 million as collateral with respect to derivative contracts at March 31, 2012 (2011 – nil). Securities with a fair value of $104 million were received from counterparties as collateral at March 31, 2012 (2011 – $137 million). PSP Investments does not sell, repledge or otherwise use any collateral held with respect to derivative contracts.

With respect to transactions involving securities lending and borrowing as well as securities sold under repurchase agreements, collateral requirements are in place to mitigate counterparty risk. Notes 3 (D) and 3 (E) describe collateral requirements in securities lending and borrowing programs as well as securities sold under repurchase agreements, respectively.

In the case of the securities lending program, PSP Investments' exposure to counterparty risk is further mitigated as the custodian of the securities lent assumes the risk that a counterparty will be unable to meet its obligations associated with the collateral requirements.

Management is responsible for counterparty risk monitoring and mitigation as well as maintaining a comprehensive, disciplined, and enterprise-wide process for tracking and managing counterparty risk. As such, Management measures counterparty risk on an ongoing basis, evaluates and tracks the creditworthiness of current counterparties and mitigates counterparty risk through collateral management.

(C) LIQUIDITY RISK

Liquidity risk corresponds to PSP Investments' ability to meet its financial obligations when they come due with sufficient and readily available cash resources. PSP Investments' cash position is monitored on a daily basis. In general, investments in cash, cash equivalents, floating rate notes, bonds and public equities are expected to be highly liquid as they will be invested in securities that are actively traded. Management utilizes appropriate measures and controls to monitor liquidity risk in order to ensure that there is sufficient liquidity to meet financial obligations as they come due. A liquidity report taking into consideration future forecasted cash flows is prepared and presented to senior management on a weekly basis. This ensures that sufficient cash reserves are available to meet forecasted cash outflows. Additionally, sufficient sources of liquidity are maintained for deployment in case of market disruption.

PSP Investments has the ability to raise additional capital through the use of its capital market debt program. This program allows PSP Investments to issue short-term promissory notes and medium-term notes. Note 10 provides additional information on the usage of the capital market debt program.

The terms to maturity of the notional amount of derivatives are disclosed in Note 3 (B).

4. INVESTMENT RISK MANAGEMENT (continued)

(C) LIQUIDITY RISK (continued)

Financial Liabilities

The following tables present the fair value of non-derivative-related financial liabilities as well as derivative-related financial instruments, aggregated according to their maturities as at March 31, 2012:

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Non-derivative-related financial liabilities[1]				
Amounts payable from pending trades	**$ (989)**	**$ –**	**$ –**	**$ (989)**
Interest payable	**(21)**	**(3)**	**–**	**(24)**
Securities sold short	**(429)**	**–**	**–**	**(429)**
Securities sold under repurchase agreements	**(1,272)**	**–**	**–**	**(1,272)**
Capital market debt financing	**(832)**	**(69)**	**(3,023)**	**(3,924)**
Accounts payable and other liabilities	**(81)**	**–**	**(31)**	**(112)**
Total	**$ (3,624)**	**$ (72)**	**$ (3,054)**	**$ (6,750)**

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Derivative-related financial instruments				
Derivative-related receivables	**$ 151**	**$ 170**	**$ 89**	**$ 410**
Derivative-related payables[1]	**(159)**	**(103)**	**(108)**	**(370)**
Total	**$ (8)**	**$ 67**	**$ (19)**	**$ 40**

[1] Liabilities are presented in the earliest period in which the counterparty can request payment.

5. SHARE CAPITAL

Share capital consists of 10 shares having a par value of $10 that were issued to the President of the Treasury Board, to be held on behalf of Her Majesty in Right of Canada.

6. FUND TRANSFERS

PSP Investments received fund transfers of $4,733 million for the year ended March 31, 2012 (2011 – $4,814 million) from the Funds.

The breakdown of the fund transfers, for the years ended March 31, was as follows:

($ millions)	2012	2011
Public Service Pension Fund	**$ 3,556**	$ 3,591
Canadian Forces Pension Fund	**815**	828
Royal Canadian Mounted Police Pension Fund	**331**	341
Reserve Force Pension Fund	**31**	54
Total	**$ 4,733**	$ 4,814

7. INVESTMENT INCOME

Investment income, for the years ended March 31, was as follows:

($ millions)	2012	2011
Interest income	**$ 664**	$ 513
Dividend income	**773**	601
Other income	**198**	182
Dividend expense	**(24)**	(19)
Interest expense (Note 10)	**(82)**	(61)
Transaction costs	**(64)**	(57)
External investment management fees [1]	**(33)**	(39)
	1,432	1,120
Net realized gains [2]	**1,013**	1,822
Net unrealized (losses) gains	**(557)**	4,101
Investment income	**$ 1,888**	$ 7,043

[1] Consists of amounts incurred for investments in public markets that are paid directly by PSP Investments. This excludes investments fees related to certain pooled fund investments classified under alternative investments primarily related to performance, in the amount of $56 million for the year ended March 31, 2012 (2011 – $84 million). This also excludes management fees related to investments in private markets and other fixed income securities that are not paid directly by PSP Investments.

Such fees, which generally vary between 0.1% and 2.0% of the total invested and/or committed amount, totalled $119 million for the year ended March 31, 2012 (2011 – $140 million).

[2] Includes foreign currency losses of $45 million for the year ended March 31, 2012 (2011 – gains of $114 million).

8. OPERATING EXPENSES

Operating expenses consisted of the following for the years ended March 31:

($ thousands)	2012	2011
Salaries and benefits	**$ 96,683**	$ 70,134
Professional and consulting fees	**10,816**	8,066
Office supplies and equipment	**15,050**	12,593
Other operating expenses	**6,433**	4,893
Depreciation of fixed assets	**9,257**	9,841
Occupancy costs	**5,531**	4,804
Custodial fees	**3,060**	2,365
Remuneration earned by Directors	**802**	763
Travel and related expenses for Directors	**274**	189
Communication expenses	**218**	197
Total	**$148,124**	$113,845

Professional and consulting fees paid or accrued to the external auditors include audit fees of $406 thousand (2011 – $461 thousand), audit-related fees of $196 thousand (2011 – $681 thousand) and non-audit fees of $147 thousand (2011 – $498 thousand).

9. ALLOCATION OF NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME

The net income from operations and comprehensive income of PSP Investments is allocated to each Plan Account as follows:

(A) INVESTMENT INCOME

The investment income is allocated proportionately based upon the asset value held by each Plan Account.

(B) EXPENSES

The Act requires that the costs of operation of PSP Investments be charged to the Plan Accounts for which it provides investment services. Under section 4(3) of the Act, the President of the Treasury Board shall determine to which Plan Account these costs will be charged, in consultation with the Minister of National Defence and the Minister of Public Safety. An allocation policy was developed which allocates the direct costs of investment activities, such as external investment management fees and custodial fees, to each Plan Account, based upon the asset value of each Plan Account at the time the expense was incurred.

All other operating expenses, excluding the direct cost of investment activities listed above, for the years ended March 31, were allocated in proportion to the annual amount of net assets in each Plan Account as follows:

	2012	2011
Public Service Pension Fund	**72.9 %**	72.7 %
Canadian Forces Pension Fund	**19.4**	19.7
Royal Canadian Mounted Police Pension Fund	**7.1**	7.1
Reserve Force Pension Fund	**0.6**	0.5
Total	**100.0 %**	100.0 %

Expenses are paid by PSP Investments by way of advances from the Public Service Pension Plan Account, which are reimbursed by the other Plan Accounts on a quarterly basis.

10. CAPITAL MARKET DEBT FINANCING

PSP Investments' capital market debt program consists of the private placement of short-term promissory notes as well as medium-term notes issued by PSP Capital Inc., a wholly-owned subsidiary of PSP Investments. The capital raised is primarily used to finance investments in real estate, infrastructure and renewable resources. It is unconditionally and irrevocably guaranteed by PSP Investments in accordance with its corporate leverage policy.

The maximum amount authorized by the Board of Directors for the capital market debt program is 7.5% of the net investments plus all recourse debt outstanding of PSP Investments. Under this limit, the short-term promissory note component cannot exceed $3 billion.

The following outlines the terms as well as the fair value of the notes issued under the capital market debt program as at March 31:

		2012	2011
($ millions)	**Capital amounts to be paid at maturity**	**Fair Value**	Fair Value
Short-term promissory notes, bearing interest between 1% and 1.42% and maturing within 31 and 364 days of issuance (March 31, 2011 – 29 and 363 days)	**$ 902**	**$ 901**	$ 702
Medium-term notes Series 1, bearing interest of 4.57% per annum and maturing on December 9, 2013	**$ 1,000**	**$ 1,052**	$ 1,056
Medium-term notes Series 2, bearing interest of 2.94% per annum and maturing on December 3, 2015	**$ 700**	**$ 722**	$ 692
Medium-term notes Series 3, bearing variable interest of 3-month CDOR + 39 basis points and maturing on February 16, 2015	**$ 350**	**$ 350**	$ –
Medium-term notes Series 4, bearing interest of 2.26% per annum and maturing on February 16, 2017	**$ 900**	**$ 899**	$ –
Total	**$ 3,852**	**$ 3,924**	$ 2,450

Interest expense, for the years ended March 31, was as follows:

	2012	2011
($ thousands)		
Short-term promissory notes	**$ 12,675**	$ 8,933
Medium-term notes	**69,618**	52,353
Total	**$ 82,293**	$ 61,286

The operating expenses incurred by PSP Capital Inc. were allocated to each Plan Account as described in Note 9 (B).

11. CAPITAL MANAGEMENT

As an investment company, PSP Investments' objectives in managing its capital are:

- To invest fund transfers, outlined in Note 6, in the best interests of the beneficiaries and contributors under the *Superannuation Acts*. The funds received are invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the Plans established under the *Superannuation Acts* and the ability of the Plans to meet their financial obligations. The funds are also invested in accordance with the Investment Risk Management policies which are outlined in Note 4.
- To maintain an appropriate credit rating to achieve access to the capital markets at the lowest cost of capital. Through PSP Capital Inc. and its leverage policies, PSP Investments has the ability to raise capital by issuing short-term promissory notes and medium-term notes. Note 10 provides information on the capital market debt financing and Note 4 (C) provides information on PSP Investments' liquidity.

The capital structure of PSP Investments consists of fund transfers and capital market debt financing. PSP Investments has no externally imposed restrictions on capital.

12. GUARANTEES AND INDEMNITIES

PSP Investments provides indemnification to its Directors, its Officers, its vice-presidents and to certain PSP Investments representatives who are asked to serve on boards of directors (or like bodies) or investment advisory boards (or like bodies) of entities in which PSP Investments or its wholly-owned subsidiaries have made an investment or have a financial interest. As a result, but subject to the Act, PSP Investments may be required to indemnify these representatives for costs incurred, such as claims, actions or litigations in connection with the exercise of their duties, unless the liability of such a representative relates to a failure to act honestly and in good faith. To date, PSP Investments has not received any claims or made any payment for such indemnity.

In certain cases, PSP Investments also provides indemnification to third parties in the normal course of business. As a result, PSP Investments may be required to indemnify such third parties in connection with the performance of their contractual obligations. To date, PSP Investments has not received any claims nor made any payments for such indemnities.

PSP Investments unconditionally and irrevocably guarantees all credit facilities, short-term promissory notes and medium-term notes issued by PSP Capital Inc.

PSP Capital Inc. provided funding facilities of a maximum amount of $969 million to support potential margin calls on the ABTNs. As at March 31, 2012, the margin funding facilities have not been drawn upon since inception.

In certain investment transactions, PSP Investments provided guarantees or indemnifications to third parties, the most significant of which are as follows:

As at March 31, 2012, PSP Investments agreed to guarantee, as part of an investment transaction, a non-revolving term loan. In the event of a default, PSP Investments could assume the obligation up to $403 million (2011 – $403 million) plus interest and other related costs. The loan matures in March 2015.

As at March 31, 2012, a wholly-owned subsidiary of PSP Investments has agreed to provide indemnification with respect to the contractual obligations and commitments of a third-party. In the event of a default by such third-party, the subsidiary may be required to assume an obligation of up to $195 million (2011 – $195 million) as estimated at the time of the completion of the investment transaction. The subsidiary would also have direct recourse against the defaulting third party in all circumstances. The guarantee expires in April 2012.

13. COMMITMENTS

PSP Investments and its subsidiaries have committed to enter into investment transactions, which will be funded over the next several years in accordance with agreed terms and conditions. The commitments were as follows as at March 31, 2012:

($ millions)	
Real estate	$ 1,507
Private equity	4,079
Infrastructure	870
Other fixed income securities	578
Total	**$ 7,034**

PUBLIC SERVICE PENSION PLAN ACCOUNT

INDEPENDENT AUDITORS' REPORT

To the President of the Treasury Board

REPORT ON THE FINANCIAL STATEMENTS

We have audited the accompanying financial statements of the Public Sector Pension Investment Board – Public Service Pension Plan Account (the Public Service Pension Plan Account), which comprise the balance sheet as at March 31, 2012, and the statement of net income from operations and comprehensive income and statement of changes in net assets for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Public Service Pension Plan Account as at March 31, 2012, and the results of its operations and changes in its net assets for the year then ended in accordance with Canadian generally accepted accounting principles.

REPORT ON OTHER LEGAL AND REGULATORY REQUIREMENTS

As required by the *Financial Administration Act*, we report that, in our opinion, Canadian generally accepted accounting principles have been applied on a basis consistent with that of the preceding year.

Further, in our opinion, the transactions of the Public Service Pension Plan Account that have come to our notice during our audit of the financial statements have, in all significant respects, been in accordance with the applicable provisions of Part X of the *Financial Administration Act* and regulations, the *Public Sector Pension Investment Board Act* and regulations and the by-laws of the Public Sector Pension Investment Board and its wholly-owned subsidiaries.

Deloitte & Touche LLP[1]

[1] Chartered accountant auditor permit No. 18527

May 14, 2012
Montréal, Canada

Michael Ferguson, FCA
Auditor General of Canada

May 14, 2012
Ottawa, Canada

BALANCE SHEET

As at March 31

($ millions)	2012	2011
ASSETS		
Investments (Note 3 (A))	**$ 51,345**	$ 44,375
Investment-related assets (Note 3 (A))	**919**	1,075
Other assets	**55**	36
Due from the Canadian Forces Pension Plan Account	**8**	9
Due from the Royal Canadian Mounted Police Pension Plan Account	**3**	3
	$ 52,330	$ 45,498
LIABILITIES		
Investment-related liabilities (Note 3 (A))	**$ 5,120**	$ 3,140
Accounts payable and other liabilities	**82**	59
	$ 5,202	$ 3,199
NET ASSETS	**$ 47,128**	$ 42,299
Accumulated net income from operations and comprehensive income	**$ 11,962**	$ 10,689
Accumulated fund transfers	**35,166**	31,610
NET ASSETS	**$ 47,128**	$ 42,299

Commitments (Note 11)

The accompanying notes are an integral part of the financial statements.

On behalf of the Board of Directors:



Cheryl Barker
Interim Chair of the Board



William A. Mackinnon
Chair of the Audit Committee

STATEMENT OF NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME

For the years ended March 31

($ millions)	2012	2011
INVESTMENT INCOME (Note 6)	**$ 1,381**	$ 5,130
OPERATING EXPENSES (Note 7)	**$ 108**	$ 83
NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME	**$ 1,273**	$ 5,047

The accompanying notes are an integral part of the financial statements.

STATEMENT OF CHANGES IN NET ASSETS

For the years ended March 31

($ millions)	2012	2011
NET ASSETS, BEGINNING OF YEAR	**$ 42,299**	$ 33,661
Fund transfers (Note 5)	**3,556**	3,591
Net income from operations and comprehensive income	**1,273**	5,047
Increase in net assets for the year	**4,829**	8,638
NET ASSETS, END OF YEAR	**$ 47,128**	$ 42,299

The accompanying notes are an integral part of the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the year ended March 31, 2012

ORGANIZATION

The Public Sector Pension Investment Board (PSP Investments) is a Crown corporation created under the *Public Sector Pension Investment Board Act* (the "Act") to manage and invest amounts that are transferred to it, under the *Superannuation Acts*, by the funds (as defined in the Act) of the pension plans established under the *Public Service Superannuation Act*, the *Canadian Forces Superannuation Act* (CFSA), the *Royal Canadian Mounted Police Superannuation Act* (collectively the "*Superannuation Acts*"), and certain regulations under the CFSA (the "CFSA Regulations"). The pension plans established under the *Superannuation Acts* consist of the Public Service pension plan, the Canadian Forces pension plan, and the Royal Canadian Mounted Police pension plan, whereas the pension plan established under the CFSA Regulations is the Reserve Force pension plan. They are herein referred to individually as the "Plan" and collectively as the "Plans".

The fund from which amounts are currently transferred to PSP Investments (the "Fund") relates to pension obligations under the Public Service pension plan for service on or after April 1, 2000. The account managed by PSP Investments for the Fund is herein referred to as the "Plan Account". PSP Investments maintains records of the Fund's net contributions, as well as the allocation of its investments and the results of its operations in the Plan Account.

PSP Investments is responsible for managing amounts that are transferred to it from the Fund in the best interests of the beneficiaries and contributors under the *Public Service Superannuation Act.* The amounts are to be invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the *Public Service Superannuation Act* and the Public Service pension plan's ability to meet its financial obligations.

Pursuant to the *Public Service Superannuation Act*, the Government of Canada, which administers the Fund, may call upon PSP Investments for amounts required for the purpose of paying benefits under the Plan in respect of service on or after April 1, 2000. Amounts remitted by PSP Investments for such purpose cannot exceed, at any time, the net assets of PSP Investments allocated to the Plan Account.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These financial statements present the financial position and operations of PSP Investments and its wholly-owned subsidiaries as they pertain to the investment of the net contributions transferred to it from the Fund in respect of member service after April 1, 2000. Accordingly, they do not reflect all of the assets or the details of the pension contributions, payments and liabilities of the Fund. The financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). PSP Investments qualifies as an Investment Company and therefore reports its investments at fair value, in accordance with Accounting Guideline 18, "Investment Companies" (AcG-18). All changes in fair value are included in investment income (loss) as net unrealized gains (losses).

Comparative figures have been reclassified to conform to the current year's presentation.

VALUATION OF INVESTMENTS

Investments, investment-related assets and investment-related liabilities are recorded at the date upon which PSP Investments becomes a party to the associated contractual provisions, and are carried at fair value. Purchases and sales are recorded as of the trade date. Fair value is an estimate of the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

At trade date, the best evidence of fair value is the transaction price. At each subsequent reporting year-end, market prices are used to determine fair value where an active market exists (such as a recognized securities exchange), as they reflect actual and regularly occurring market transactions on an arm's length basis. If quoted market prices are not available, then fair values are estimated using present value or other valuation techniques, using inputs existing at the end of the reporting year that are derived from observable market data.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

VALUATION OF INVESTMENTS (continued)

Valuation techniques are generally applied to investments in real estate, private equity, infrastructure and renewable resources, over-the-counter (OTC) derivatives and certain fixed income securities. The values derived from applying these techniques are impacted by the choice of valuation model and the underlying assumptions made concerning factors such as the amounts and timing of future cash flows, discount rates, volatility and credit risk. In certain cases, such assumptions are not supported by market observable data.

The valuation methods of the investments are described in Notes 3 (A) and (B).

TRANSACTION COSTS

Transaction costs are incremental costs directly attributable to the acquisition, due diligence, issue, or disposal of a financial asset or financial liability. Transaction costs are expensed as incurred and recorded as a component of investment income (loss).

INVESTMENT MANAGEMENT FEES

Investment management fees are directly attributable to the external management of assets on behalf of PSP Investments. Management fees incurred for investments in private markets and certain private debt portfolios are paid by the investment directly, through capital contributions by PSP Investments or offset against distributions received from the investment. Management fees are also incurred for certain public markets and alternative investments and are paid either directly by PSP Investments or offset against distributions received from pooled fund investments. In both cases, they are recorded against investment income (loss).

INCOME RECOGNITION

The investment income (loss) has been allocated proportionately based on the asset value held by the Plan Account.

Investment income (loss) is made up of interest income, dividends, realized gains (losses) on the disposal of investments and unrealized gains (losses) which reflect the change in unrealized appreciation (depreciation) of investments held at the end of the year. Interest income is recognized as earned. Dividends are recognized on the ex-dividend date and are reflected as dividend income. Dividends paid or payable on securities sold short are reflected as dividend expense. Other income includes securities lending income (net of fees on securities borrowed), as well as private markets distributions from pooled funds, limited partnerships or from direct investments and co-investments. Co-investments are investments in private entities where the investment is made in conjunction with an external manager with whom PSP Investments already has committed and delegated funds.

TRANSLATION OF FOREIGN CURRENCIES

Investment transactions in foreign currencies are recorded at exchange rates prevailing on the transaction date. Investments denominated in foreign currencies and held at the end of the year are translated at exchange rates in effect at the year-end date. Any realized and unrealized gains (losses) on foreign exchange are included in investment income (loss).

FUND TRANSFERS

Amounts received from the Fund are recorded in the Plan Account.

INCOME TAXES

PSP Investments and the majority of its subsidiaries are exempt from Part I tax under paragraphs 149(1)*(d)* and 149(1)*(d.2)* of the *Income Tax Act* (Canada), respectively.

USE OF ESTIMATES

In preparing these financial statements, management makes certain estimates and assumptions which can affect the reported values of assets and liabilities. This is principally reflected in the valuation of private markets investments, certain fixed income securities, related income and expenses as well as note disclosures. Although estimates and assumptions reflect management's best judgment, actual results may differ from these estimates.

2. FUTURE CHANGES IN ACCOUNTING POLICIES

In February 2008, the Accounting Standards Board of Canada (AcSB) confirmed that Canadian GAAP for publicly accountable enterprises would converge with International Financial Reporting Standards (IFRS) effective January 1, 2011.

In 2011, the AcSB decided to defer the adoption of IFRS by investment companies, currently applying AcG-18 to annual periods starting on or after January 1, 2014. This deferral delays PSP Investments' transition to IFRS until the March 31, 2015 annual consolidated financial statements.

The AcSB's decision was in response to an announcement by the International Accounting Standards Board (IASB) in 2010, regarding an Exposure Draft (ED) being developed. The IASB proposed to define an investment entity and exempt it from consolidation by requiring it to measure all controlled investments at fair value, with changes recognized in profit or loss. The ED, *Investment Entities*, was published in August 2011 and is expected to be finalized in the second half of 2012. PSP Investments will complete the assessment of the impact of its transition to IFRS once the ED is finalized and a standard is issued.

The AcSB also announced in 2011 that it will evaluate whether entities like PSP Investments, which are separate from a pension plan and without a pension obligation, and whose sole purpose is to hold and invest assets received from one or more pension plans, would qualify as investment entities under the IASB's ED. Based on the result of this evaluation, the AcSB will then decide whether these entities would need to be included within the scope of Section 4600, "Pension Plans", where investments are accounted for at fair value.

3. INVESTMENTS

(A) INVESTMENT PORTFOLIO

The investment portfolio is organized according to the nature and common characteristics associated with the investments held. The following table presents the investment portfolio as at March 31:

	2012		2011	
($ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Public markets				
Canadian equity	**$ 6,679**	**$ 6,488**	$ 10,304	$ 8,466
Foreign equity	**11,854**	**10,961**	9,460	8,638
Private markets				
Real estate	**5,445**	**4,714**	3,974	3,639
Private equity	**4,515**	**3,848**	3,783	3,279
Infrastructure	**3,119**	**3,270**	1,973	2,139
Renewable resources	**275**	**275**	–	–
Fixed income				
Cash and money market securities	**1,746**	**1,746**	1,868	1,868
Government and corporate bonds	**9,314**	**9,118**	5,887	5,924
Inflation-linked bonds	**2,886**	**2,637**	2,173	2,236
Other fixed income securities	**4,654**	**4,193**	4,141	3,986
Alternative investments	**858**	**678**	812	657
INVESTMENTS	**$ 51,345**	**$ 47,928**	$ 44,375	$ 40,832
Investment-related assets				
Amounts receivable from pending trades	**$ 460**	**$ 460**	$ 508	$ 508
Interest receivable	**117**	**117**	102	102
Dividends receivable	**43**	**43**	36	36
Derivative-related receivables	**299**	**59**	429	21
	$ 919	**$ 679**	$ 1,075	$ 667
Investment-related liabilities				
Amounts payable from pending trades	**$ (722)**	**$ (722)**	$ (790)	$ (790)
Interest payable	**(18)**	**(18)**	(16)	(16)
Securities sold short	**(314)**	**(304)**	(32)	(27)
Securities sold under repurchase agreements	**(929)**	**(926)**	(372)	(372)
Derivative-related payables	**(270)**	**(60)**	(144)	(17)
Capital market debt financing:				
Short-term	**(658)**	**(658)**	(512)	(512)
Long-term	**(2,209)**	**(2,162)**	(1,274)	(1,246)
	$ (5,120)	**$ (4,850)**	$ (3,140)	$ (2,980)
NET INVESTMENTS	**$ 47,144**	**$ 43,757**	$ 42,310	$ 38,519

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(i) Public Markets

Public markets consist of Canadian and foreign investments in the following securities: common shares, American depository receipts, global depository receipts, participation notes, preferred shares, income trust units, exchange traded funds units, pooled funds units, and securities convertible into common shares of publicly listed issuers.

Valuation Techniques

Direct investments in Canadian and foreign equities are measured at fair value using quoted market prices, namely, the bid price.

In the case of investments in pooled funds, fair value is measured using unit values obtained from each of the funds' administrators, which are derived from the fair value of the underlying investments in each pooled fund. Where necessary, the impact of restrictions on the sale or redemption of such investments is taken into consideration in determining fair value.

(ii) Private Markets

Private markets consist of investments in real estate, private equity, infrastructure and renewable resources.

Real estate investments are comprised of direct equity positions in various private entities, properties, as well as fund investments in the real estate sector. Real estate investments focus on properties, partnerships and companies operating in the office, retail, industrial, hospitality and residential sectors, as well as private funds invested in real estate assets. Real estate investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of real estate contracted by direct investments controlled by PSP Investments for the Plan Account was $1,945 million (2011 – $1,540 million).

Private equity investments are comprised of direct equity positions and co-investments in private entities as well as fund investments with similar objectives.

Infrastructure investments are comprised of direct equity positions and co-investments in various private entities and fund investments. Infrastructure investments focus on entities engaged in the management, ownership or operation of assets in energy, transportation and other regulated businesses. Infrastructure investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of infrastructure contracted by direct investments controlled by PSP Investments for the Plan Account was $208 million (2011 – $37 million).

Renewable resources investments are comprised of properties involving the production and harvesting of replenishable resources. As at March 31, 2012, renewable resources included one investment in timberlands.

Valuation Techniques

The fair value of private markets investments is determined at least annually, using acceptable industry valuation methods. During the year, the fair value is reviewed and adjusted, as appropriate, to reflect the impact of any significant market or investment-specific events or circumstances. For each investment, the relevant methodology is applied consistently over time as appropriate in the prevailing circumstances.

In cases where the services of third-party appraisers are used, management ensures their independence and that valuation methods used are consistent with professional appraisal standards. Such standards include the *International Private Equity and Venture Capital Valuation Guidelines*, the *Canadian Uniform Standards of Professional Appraisal Practice* and the *Uniform Standards of Professional Appraisal Practice* in the United States of America. In validating the work performed by appraisers, management ensures that the assumptions used correspond to financial information and forecasts of the underlying investment.

For direct investments in real estate, valuation methods used include discounted cash flows, prices of recent comparable transactions and the direct capitalization approach. Assumptions used in such valuations include discount rates, capitalization rates, projected cash flows and/or net operating income, which are not fully supported by prices from market observable transactions.

For direct investments in private equity, direct investments and co-investments in infrastructure and in renewable resources, valuation methods used include discounted cash flows, earnings multiples, prices of recent comparable transactions and publicly traded comparables. Assumptions used in such valuations include discount rates and projected cash flows, which are not fully supported by prices from market observable transactions.

In the case of private equity, real estate and infrastructure fund investments as well as private equity co-investments, the annual fair value is generally determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(iii) Fixed Income

Fixed income consists of cash and money market securities, government and corporate bonds, inflation-linked bonds and other fixed income securities.

Cash and money market securities include instruments having a maximum term to maturity of one year, such as treasury bills, certificates of deposit and bankers' acceptances.

Government and corporate bonds include Canadian and foreign, federal, provincial, territorial and municipal bonds. Inflation-linked bonds are fixed income securities that earn inflation adjusted returns.

Other fixed income securities consist of asset-backed securities, floating rate notes as well as private debt portfolios.

Asset-backed securities consist mainly of asset-backed term notes (ABTNs) and mortgage-backed securities. The ABTNs were received in exchange for third-party or non-bank sponsored asset-backed commercial paper (ABCP) that suffered a liquidity disruption in mid-August 2007 and were subsequently restructured in January 2009. Potential margin calls on the ABTNs are supported by funding facilities, as described in Note 10.

Private debt portfolios consist mainly of investments in the real estate sector in the form of third-party loans such as junior and senior debts, construction loans, bridge loans, income-participating loans, as well as other structured finance products. They also include real estate debt funds where significant portions of the value are attributed to the underlying real estate assets.

Private debt portfolios also include debt securities of private companies or other entities such as venture capital organizations, held mainly through private funds. Such debt securities take the form of senior debt, mezzanine and distressed debt.

Valuation Techniques

Cash and money market securities include short-term instruments that are recorded at cost plus accrued interest, which approximates fair value.

Fair values of government and corporate bonds, inflation-linked bonds, floating rate notes and mortgage-backed securities are based on prices obtained from third-party pricing sources. Such prices are determined using either an appropriate interest rate curve with a spread associated with the credit quality of the issuer or other generally accepted pricing methodologies.

ABTNs are measured at fair value whereby management relies on the valuation work performed by a recognized third-party expert. Management ensures that the valuation conducted by such expert uses acceptable industry methods. Financial information used in the valuation of ABTNs includes interest rates, credit spreads and the underlying investments' terms to maturity. In addition to the values determined by the expert, management integrated certain assumptions in the fair value of ABTNs that are not fully supported by market observable data, such as liquidity estimates and the impact of the funding facilities described in Note 10.

The fair value of private debt portfolios in the real estate sector is determined using either a yield-based or collateral-based valuation technique. The yield-based valuation technique involves discounting expected future cash flows that incorporate assumptions with respect to interest rates offered for similar loans to borrowers with similar credit ratings. The collateral-based valuation technique involves assessing the recoverable value of the collateral in question, net of disposal fees.

The fair value of fund investments included as part of private debt portfolios is determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

(iv) Alternative Investments

Alternative investments consist mainly of units of funds that hold a mix of equity, fixed income and derivative instruments as well as hedge funds.

Valuation Techniques

The fair value of these investments is obtained from the investment's external manager and reflects the fair value of the underlying equity, fixed income or derivative instruments, as applicable.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(v) Amounts Receivable and Payable from Pending Trades

Amounts receivable from pending trades consist of proceeds on sales of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Amounts payable from pending trades consist of the cost of purchases of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Valuation Techniques

The fair value of amounts receivable and payable from pending trades reflects the value at which their underlying original sale or purchase transactions were undertaken.

(vi) Interest and Dividends Receivable

Interest and dividends are recorded at the amounts expected to be received as at the reporting date, which approximates fair value.

(vii) Interest Payable

Interest is accrued at the amount expected to be paid as at the reporting date, which approximates fair value.

(viii) Securities Sold Short

Securities sold short reflect PSP Investments' obligation to purchase securities pursuant to short selling transactions. In such transactions, PSP Investments sells securities it does not own with an obligation to purchase similar securities on the market to cover its position.

Valuation Techniques

Using ask prices as inputs, the fair value of securities sold short is measured using the same method as the similar long positions presented within public markets and fixed income.

(ix) Securities Sold under Repurchase Agreements

PSP Investments is party to agreements which involve the sale of securities with a simultaneous agreement to repurchase such securities at a specified price and at a specified future date.

Securities sold under the repurchase agreements are not derecognized as PSP Investments retains all related risks and rewards of ownership. As such, all related income (loss) continues to be reported in investment income (loss).

Obligations to repurchase the securities sold are accounted for as investment-related liabilities. Interest expense related to such obligations is reported in investment income (loss).

Valuation Techniques

Obligations to repurchase the securities sold under repurchase agreements are recorded at cost plus accrued interest, which approximates fair value.

(x) Derivative-Related Receivables and Payables

The description and valuation of derivative-related receivables and payables are described in Note 3 (B).

(xi) Capital Market Debt Financing

PSP Investments' capital market debt program is described in Note 8. Short-term promissory notes are recorded at cost plus accrued interest, which approximates fair value. The fair value of PSP Investments' medium-term notes is based on prices that are obtained from third-party pricing sources. Such prices are determined using an interest rate curve with a spread consistent with PSP Investments' credit quality.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS

Derivative financial instruments are financial contracts that are settled at a future date. The value of such instruments is derived from changes in underlying assets, interest or exchange rates. Derivative financial instruments do not, typically, require an initial net investment. In certain cases, they require an initial net investment that is less than what would be required to hold the underlying position directly. PSP Investments uses derivative financial instruments to enhance returns or to replicate investments synthetically. Derivatives are also used to reduce the risk associated with existing investments.

PSP Investments uses the following types of derivative financial instruments:

(i) Swaps

Swaps are transactions whereby two counterparties exchange cash flow streams with each other based on predetermined conditions that include a notional amount and a term. Swaps are used to increase returns or to adjust exposures of certain assets without directly purchasing or selling the underlying assets.

(ii) Futures

Futures are standardized contracts to take or make delivery of an asset (buy or sell) at a predefined price and predefined future date. Futures are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iii) Forwards

Forwards are contracts involving the sale by one party and the purchase by another party of a predefined amount of an underlying instrument, at a predefined price and at a predefined date in the future. Forwards are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iv) Options

Options are the right, but not the obligation, to buy or sell a given amount of an underlying security, index, or commodity, at an agreed-upon price stipulated in advance, either at a determined date or at any time before the predefined maturity date.

(v) Warrants and Rights

Warrants are options to purchase an underlying asset which is in the form of a transferable security and which can be listed on an exchange.

Rights are securities giving shareholders entitlement to purchase new shares issued by a corporation at a predetermined price (normally less than the current market price) in proportion to the number of shares already owned. Rights are issued only for a short period of time, after which they expire.

(vi) Collateralized Debt Obligations

Collateralized debt obligations are a type of asset-backed security that is constructed from a portfolio of credit-related assets. Collateralized debt obligations are usually divided into several tranches with different credit risk levels and corresponding interest payments. Any losses are applied first to the more junior tranches (lowest risk rating) before moving up in seniority.

Valuation Techniques

All listed derivative financial instruments are recorded at fair value using quoted market prices with the bid price for long positions and the ask price for short positions. OTC derivatives are valued using appropriate valuation techniques, such as discounted cash flows using current market yields. The assumptions used include the statistical behaviour of the underlying instruments and the ability of the model to correlate with observed market transactions. Although pricing models used are widely accepted and used by other market participants, in the case of collaterized debt obligations, the nature of such instruments requires more significant assumptions about the behaviour of the default correlation. Such assumptions are not observable in the market.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

Notional values of derivative financial instruments are not recorded as assets or liabilities as they represent the face amount of the contract. Except for credit derivatives [1], notional values do not represent the potential gain or loss associated with the market or credit risk of such transactions disclosed below. Rather, they serve as the basis upon which the cash flows and the fair value of the contracts are determined.

The following table summarizes the derivatives portfolio as at March 31:

	2012				2011			
		Fair Value				Fair Value		
($ millions)	Notional Value	Assets	Liabilities	Net	Notional Value	Assets	Liabilities	Net
Equity and commodity derivatives								
Futures	**$ 739**	**$ –**	**$ –**	**$ –**	$ 314	$ –	$ –	$ –
Total return swaps	**5,960**	**96**	**(32)**	**64**	4,039	139	–	139
Warrants and rights	**1**	**–**	**–**	**–**	2	2	–	2
Options:								
Listed-purchased	**824**	**11**	**–**	**11**	322	9	–	9
Listed-written	**706**	**–**	**(8)**	**(8)**	288	–	(14)	(14)
OTC-purchased	**393**	**4**	**–**	**4**	–	–	–	–
OTC-written	**362**	**–**	**(6)**	**(6)**	–	–	–	–
Currency derivatives								
Forwards	**16,869**	**114**	**(135)**	**(21)**	12,466	230	(88)	142
Futures	**111**	**–**	**–**	**–**	–	–	–	–
Swaps	**687**	**2**	**(13)**	**(11)**	1,219	18	(8)	10
Options:								
OTC-purchased	**358**	**4**	**–**	**4**	736	4	–	4
OTC-written	**598**	**–**	**(5)**	**(5)**	133	–	(2)	(2)
Interest rate derivatives								
Bond forwards	**1,315**	**3**	**(2)**	**1**	724	4	(2)	2
Futures	**1,143**	**–**	**–**	**–**	1,290	–	–	–
Interest rate swaps	**5,536**	**19**	**(22)**	**(3)**	12,791	10	(12)	(2)
Total return swaps	**–**	**–**	**–**	**–**	471	–	–	–
Swaptions	**590**	**11**	**(4)**	**7**	2,568	5	(2)	3
Options:								
Listed-purchased	**6,030**	**2**	**–**	**2**	3,898	5	–	5
Listed-written	**6,087**	**–**	**(4)**	**(4)**	5,476	–	(5)	(5)
OTC-purchased	**584**	**11**	**–**	**11**	–	–	–	–
OTC-written	**2,815**	**–**	**(17)**	**(17)**	–	–	–	–
Credit derivatives [1]:								
Purchased	**881**	**20**	**(6)**	**14**	305	2	(3)	(1)
Sold	**427**	**2**	**(16)**	**(14)**	298	1	(8)	(7)
Total	**$ 53,016**	**$ 299**	**$ (270)**	**$ 29**	$ 47,340	$ 429	$ (144)	$ 285

[1] Credit derivatives include credit default swaps and collateralized debt obligations. PSP Investments, through sold credit derivatives, indirectly guarantees the underlying reference obligations. The maximum potential exposure is the notional amount of the sold credit derivatives as shown in the table above.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

The term to maturity based on notional value for the derivatives was as follows as at March 31, 2012:

($ millions)

Less than 3 months	**$ 30,378**
3 to 12 months	**12,969**
Over 1 year	**9,669**
Total	**$ 53,016**

(C) FAIR VALUE MEASUREMENT

Investments, investment-related assets and investment-related liabilities are classified according to the following hierarchy based on the significant inputs used in measuring their fair value.

Level 1: Valuation is based on quoted prices in active markets for identical assets or liabilities.

Level 2: Valuation is based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active. Level 2 also includes model-based valuation techniques for which all significant assumptions are observable in the market.

Level 3: Valuation is based on model-based techniques for which significant assumptions are not observable in the market. They reflect management's assessment of the assumptions that market participants would use in pricing the assets or liabilities.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2012:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 6,679	$ –	$ –	$ –	$ 6,679
Foreign equity	11,137	593	124	–	11,854
Private markets					
Real estate	–	–	5,445	–	5,445
Private equity	–	–	4,515	–	4,515
Infrastructure	–	–	3,119	–	3,119
Renewable resources	–	–	275	–	275
Fixed income					
Cash and money market securities	557	1,189	–	–	1,746
Government and corporate bonds	–	9,314	–	–	9,314
Inflation-linked bonds	–	2,886	–	–	2,886
Other fixed income securities	–	1,742	2,912	–	4,654
Alternative investments	–	636	222	–	858
INVESTMENTS	$ 18,373	$ 16,360	$ 16,612	$ –	$ 51,345
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 460	$ 460
Interest receivable[1]	–	–	–	117	117
Dividends receivable[1]	–	–	–	43	43
Derivative-related receivables	13	286	–	–	299
	$ 13	$ 286	$ –	$ 620	$ 919
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (722)	$ (722)
Interest payable[1]	–	–	–	(18)	(18)
Securities sold short	(314)	–	–	–	(314)
Securities sold under repurchase agreements	–	(929)	–	–	(929)
Derivative-related payables	(11)	(252)	(7)	–	(270)
Capital market debt financing:					
Short-term	–	(658)	–	–	(658)
Long-term	–	(2,209)	–	–	(2,209)
	$ (325)	$ (4,048)	$ (7)	$ (740)	$ (5,120)
NET INVESTMENTS	$ 18,061	$ 12,598	$ 16,605	$ (120)	$ 47,144

[1] No fair value hierarchy classification is required for these items.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2011:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 10,262	$ 42	$ –	$ –	$ 10,304
Foreign equity	7,943	1,517	–	–	9,460
Private markets					
Real estate	–	–	3,974	–	3,974
Private equity	–	–	3,783	–	3,783
Infrastructure	–	–	1,973	–	1,973
Fixed income					
Cash and money market securities	425	1,443	–	–	1,868
Government and corporate bonds	–	5,887	–	–	5,887
Inflation-linked bonds	–	2,173	–	–	2,173
Other fixed income securities	–	1,461	2,680	–	4,141
Alternative investments	–	812	–	–	812
INVESTMENTS	$ 18,630	$ 13,335	$ 12,410	$ –	$ 44,375
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 508	$ 508
Interest receivable[1]	–	–	–	102	102
Dividends receivable[1]	–	–	–	36	36
Derivative-related receivables	15	412	2	–	429
	$ 15	$ 412	$ 2	$ 646	$ 1,075
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (790)	$ (790)
Interest payable[1]	–	–	–	(16)	(16)
Securities sold short	(32)	–	–	–	(32)
Securities sold under repurchase agreements	–	(372)	–	–	(372)
Derivative-related payables	(19)	(118)	(7)	–	(144)
Capital market debt financing:					
Short-term	–	(512)	–	–	(512)
Long-term	–	(1,274)	–	–	(1,274)
	$ (51)	$ (2,276)	$ (7)	$ (806)	$ (3,140)
NET INVESTMENTS	$ 18,594	$ 11,471	$ 12,405	$ (160)	$ 42,310

[1] No fair value hierarchy classification is required for these items.

The classification within the levels of the hierarchy is established at the time of the initial valuation of the asset or liability and reviewed on each subsequent reporting year-end.

There were no significant transfers between Level 1 and Level 2 during the year ended March 31, 2012 (no significant transfers during the year ended March 31, 2011).

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Reconciliation

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2012:

($ millions)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Gains	Unrealized Gains (Losses)	Transfer out of Level 3	Closing Balance
Public markets	$ –	$ 110	$ (12)	$ –	$ 2	$ 24	$ –	$ 124
Private markets	9,730	4,571	(1,648)	–	149	568	(16)	13,354
Fixed income	2,680	770	(713)	(161)	30	306	–	2,912
Alternative investments	–	216	–	–	–	6	–	222
Derivative-related receivables/payables (net)	(5)	–	–	(2)	2	(2)	–	(7)
Total	**$ 12,405**	**$ 5,667**	**$ (2,373)**	**$ (163)**	**$ 183**	**$ 902**	**$ (16)**	**$ 16,605**

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2011:

($ millions)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Losses	Unrealized Gains	Transfer out of Level 3	Closing Balance
Private markets	$ 8,870	$ 1,932	$ (1,744)	$ –	$ (49)	$ 733	$ (12)	$ 9,730
Fixed income	2,883	411	(642)	(161)	(55)	244	–	2,680
Derivative-related receivables/payables (net)	(237)	193	(3)	–	(180)	222	–	(5)
Total	$ 11,516	$ 2,536	$ (2,389)	$ (161)	$ (284)	$ 1,199	$ (12)	$ 12,405

[1] Includes Plan Account allocation adjustments.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Sensitivity Analysis

In the course of measuring fair value of financial instruments classified as Level 3, valuation techniques used incorporate assumptions that are based on non-observable data. Significant assumptions used for each asset class are described in Notes 3 (A) and (B). Although such assumptions reflect management's best judgment, the use of reasonably possible alternative assumptions could yield different fair value measures representing, at a minimum, a 2% increase/decrease (2011 - 2% increase/decrease) in the fair value of financial instruments categorized as Level 3. This excludes private debt portfolios in the real estate sector and certain fund investments, where a sensitivity analysis is not possible given the underlying assumptions used are not available to PSP Investments. In the case of fund investments, the fair value is determined based on the audited financial statements of the fund's general partner as indicated in Note 3 (A). With respect to private debt portfolios in the real estate sector, the fair value is obtained from third-party appraisers as described in Note 3 (A).

(D) SECURITIES LENDING AND BORROWING PROGRAMS

PSP Investments participates in securities lending and borrowing programs whereby it lends and borrows securities in order to enhance portfolio returns. Lending and borrowing transactions under such programs do not transfer the risks or rewards of ownership of the securities to the counterparty. Consequently, PSP Investments does not derecognize securities lent or recognize securities borrowed.

The securities lending and borrowing programs require collateral in cash, high-quality debt instruments or securities. Collateral transactions are conducted under terms that are usual and customary in standard securities lending and borrowing programs. PSP Investments and its counterparties are authorized to sell, repledge or otherwise use collateral held. The same securities or equivalent securities must be returned to the counterparty at the end of the contract, unless an event of default occurs. As at March 31, 2012, PSP Investments, on behalf of the Plan Account, has re-invested $1,268 million of collateral held (2011 – $1,092 million).

The following table illustrates the fair values of the Plan Account's allocated securities and collateral associated with the lending and borrowing programs as at March 31:

($ millions)	2012	2011
Securities lending		
Securities lent	**$ 5,108**	$ 4,210
Collateral contractually receivable[1]	**5,384**	4,404
Securities borrowing		
Securities borrowed	**314**	32
Collateral contractually payable[2]	**349**	34

[1] The minimum fair value of collateral required is equal to 102% of the fair value of the securities lent.

[2] The minimum fair value of collateral required is equal to 100% of the fair value of the securities borrowed.

(E) SECURITIES SOLD AND COLLATERAL PLEDGED UNDER REPURCHASE AGREEMENTS

Securities sold under repurchase agreements are described in Note 3 (A) (ix) and involve pledging collateral consisting of cash or securities deemed acceptable by the counterparties. Collateral transactions are conducted under terms that are usual and customary in standard repurchase arrangements. Such terms require the relevant counterparty to pledge additional collateral based on the changes in the fair value of the existing collateral pledged. The counterparties are authorized to sell, repledge or otherwise use collateral held. The securities pledged as collateral must be returned to the relevant counterparty at the end of the contract, unless an event of default occurs. PSP Investments does not sell, repledge or otherwise use collateral held.

On behalf of the Plan Account, PSP Investments pledged collateral under the repurchase agreements with a fair value of $929 million at March 31, 2012 (2011 – $372 million).

4. INVESTMENT RISK MANAGEMENT

Risk Management is a central part of PSP Investments' operations. Included in the overall risk management framework is a continuous process whereby PSP Investments systematically addresses the investment risks related to its various investment activities with the goal of achieving a maximum rate of return without undue risk of loss.

A risk governance framework that includes required reporting on risk to all levels of the organization ensures that appropriate investment objectives are pursued and achieved in line with the fulfillment of PSP Investments' legislated mandate. The Board of Directors and its committees oversee all risk matters and receive assurances from senior management, including the Chief Risk Officer, as well as PSP Investments' independent internal auditor reporting directly to the Audit Committee.

PSP Investments has adopted an Investment Risk Management Policy which is an integral part of its risk control system and supplements the Statement of Investment Policies, Standards and Procedures (SIP&P). The objective of this policy is to provide a framework to manage the risks that PSP Investments is exposed to, namely, market, credit and liquidity risks.

(A) MARKET RISK

Market risk is the risk that the value of an investment will fluctuate as a result of changes in market prices, whether those changes are caused by factors specific to the individual investment, volatility in share and commodity prices, interest rate, foreign exchange or other factors affecting similar securities traded in the market.

Market risk management focuses on the following two key components:

– Policy Portfolio
The Policy Portfolio (long-term asset mix), as defined in the SIP&P, determines a diversification strategy to mitigate risk whereby PSP Investments invests in a diversified portfolio expected to achieve a return at least equal to the Actuarial Rate of Return (ARR); defined as the rate of return assumption used by the Chief Actuary of Canada in the latest actuarial valuation reports of the Plans. In the absence of other factors affecting the funding of the Plans or changes to pension benefits under the Plans, the ARR is the rate of return required to maintain funding requirements and pension benefits at their current levels.

– Active Management
Active management is defined as the sum of investment strategies that deviate from the approved Policy Portfolio. It is designed to supplement the returns of the Policy Portfolio within an active risk budget.

The risks associated with these components are the Policy Portfolio market risk and the active risk. The Policy Portfolio market risk represents the investment risk arising from the exposure to approved asset classes in the approved weightings. In establishing its Policy Portfolio, PSP Investments also takes into consideration the impact of the Policy Portfolio market risk on funding risk. Funding risk is the risk that the assets under management will be insufficient to meet the relevant pension liabilities of the Plans, which may require the contributions to the Funds of the Plans to be increased. The Policy Portfolio is reviewed at least annually as part of the review of the SIP&P, and this review includes changes, if any, to PSP Investments' long-term expectations of market conditions and other factors that may affect the funding levels of the Plans.

Active risk refers to all market risk arising from active management activities. It is managed in accordance with the Investment Risk Management Policy.

Measurement of Market Risk

The Value-at-Risk (VaR) is one of the methods used to measure market risk and is reported on a quarterly basis. It is not the maximum potential loss, but rather the maximum loss not exceeded with a given confidence level, over a given period of time. PSP Investments uses a Historical VaR model incorporating ten years' worth of market returns scaled to a twelve-month holding period at a 95% confidence level. For investments that are not actively traded, the calculation of VaR uses securities with similar risk attributes as proxy.

In measuring Policy Portfolio risk, VaR represents the absolute loss expected from the Policy Portfolio (Policy Portfolio VaR). Whereas in terms of measuring the active risk, VaR reflects the loss relative to the Policy Portfolio benchmark (Active VaR).

VaR is statistically valid under normal market conditions and does not specifically consider losses from severe market events. It also assumes that the future will behave in a pattern similar to the past. Consequently, if future market conditions differ significantly from those of the past, potential losses may differ from those originally estimated.

The following table shows the Total VaR consisting of the Policy Portfolio VaR, the Active VaR and the diversification effect, calculated as a percentage of net investments, as at March 31. The diversification effect captures the impact of holding different types of assets which may react differently in various types of situations and thus reduces the Total VaR.

	2012	2011
Policy Portfolio VaR	**21.7 %**	22.4 %
Active VaR	**2.6**	2.2
Total VaR (undiversified)	**24.3**	24.6
Diversification effect	**(1.6)**	(2.9)
Total VaR	**22.7 %**	21.7 %

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

Stress Testing

Although VaR is a widely accepted risk measure, it is complemented by other risk measurement methodologies that provide greater insight on market risk. PSP Investments uses stress testing and scenario analysis to examine the impact on financial results of abnormally large movements in risk factors. Stress testing and scenario analysis are used to test a portfolio's sensitivity to various risk factors and key model assumptions. These methods also use historically stressed periods to evaluate how a current portfolio reacts under such circumstances. Stress testing and scenario analysis are also deployed to assess new product performance.

(i) Interest Rate Risk

Interest rate risk refers to the risk that fluctuations in interest rates will directly affect the fair value of the Plan Account's net asset values.

The terms to maturity of the investments with the most significant exposure to interest rate risk were as follows as at March 31, 2012:

($ millions)	Less than 1 Year	1 to 5 Years	5 to 10 Years	Over 10 Years	Other	Total
Government bonds	$ 983	$ 3,471	$ 1,249	$ 1,325	$ –	$ 7,028
Corporate bonds	456	971	636	223	–	2,286
Inflation-linked bonds	–	761	716	1,409	–	2,886
Asset-backed securities	–	1,314	23	2	–	1,339
Private debt portfolios:						
Directly held	38	296	4	–	–	338
Held through funds[1]	–	–	–	–	1,342	1,342
Total investments with significant exposure to interest rate risk	$ 1,477	$ 6,813	$ 2,628	$ 2,959	$ 1,342	$ 15,219
Other investments[2]	$ –	$ –	$ –	$ –	$ 3,381	$ 3,381
Total fixed income	$ 1,477	$ 6,813	$ 2,628	$ 2,959	$ 4,723	$ 18,600

[1] Due to their nature, information in connection with the terms to maturity of fund investments included in the private debt portfolios is not available.

[2] Consists of $1,746 million in cash and money market securities and $1,635 million in floating rate notes, which, due to their nature, are not significantly exposed to interest rate risk.

The terms to maturity of PSP Investments' capital market debt financing are disclosed in Note 8.

Alternative investments as well as derivative contracts described in Notes 3 (A) (iv) and (B), respectively, are also subject to interest rate risk exposures. These exposures are reflected in the VaR calculation described in Note 4 (A).

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

(ii) Foreign Currency Risk

PSP Investments and its subsidiaries are exposed to currency risk through holdings of securities, units in pooled funds and units in limited partnerships of non-Canadian assets. Fluctuations in the relative value of the Canadian dollar against these foreign currencies can result in a positive or a negative effect on the fair value of the investments. To mitigate this risk, PSP Investments may take, through foreign forward contracts or cross currency swaps, positions in foreign currencies. PSP Investments' policy is to hedge a target of 50% of its foreign currency investments in non-emerging countries. Additional factors are considered when implementing the hedging target for investments in emerging countries, namely, total relative exposure and cost effectiveness.

The underlying net foreign currency exposures for the Plan Account, after allocating the effect of derivative contracts and investment-related assets and liabilities for both monetary and non-monetary items were as follows as at March 31:

(in millions of Canadian $)	2012		2011	
Currency	**Fair Value**	**% of Total**	Fair Value	% of Total
US Dollar	**$ 9,482**	**57.9 %**	$ 6,920	54.0 %
Euro	**1,943**	**11.9**	1,739	13.6
British Pound	**1,283**	**7.8**	971	7.6
Japanese Yen	**740**	**4.5**	516	4.0
Brazilian Real	**664**	**4.0**	642	5.0
Hong Kong Dollar	**493**	**3.0**	484	3.8
Korean Won	**358**	**2.2**	342	2.7
Australian Dollar	**295**	**1.8**	223	1.7
Norwegian Krone	**252**	**1.5**	76	0.6
Indian Rupee	**140**	**0.9**	103	0.8
Others	**739**	**4.5**	786	6.2
Total	**$ 16,389**	**100.0 %**	$ 12,802	100.0 %

PSP Investments and its subsidiaries also had commitments, denominated in foreign currencies of $4,728 million (US$4,140 million, €379 million, R88 million South African Rands and R136 million Brazilian Reals) for the Plan Account which were not included in the foreign currency exposure table.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK

PSP Investments is exposed to credit risk, that is, the risk that the issuer of a debt security or that the counterparty to a derivative contract, to a securities lending and borrowing transaction or to securities sold under repurchase agreements, is unable to meet its financial obligations.

Credit risk encompasses the risk of a deterioration of creditworthiness and the relevant concentration risk. Credit risk monitoring entails an evaluation of the credit quality of each issuer and counterparty that transacts with PSP Investments. To perform this evaluation, PSP Investments relies on four recognized credit rating agencies. A minimum of two credit ratings are used to classify each security. Except for ABTNs, securities rated by only one agency are classified as "not rated". If the agencies disagree as to a security's credit quality, PSP Investments uses the lowest of the available ratings.

As at March 31, 2012, the Plan Account's maximum exposure to credit risk amounted to approximately $16 billion (2011 – approximately $12 billion). This amount excludes investments in distressed debt in the amount of approximately $1 billion as at March 31, 2012 (2011 – approximately $1.1 billion). The maximum exposure to credit risk also excludes collateralized debt obligations, collateral held as disclosed in Notes 3 (D), 3 (E) and 4 (B) and the impact of guarantees and indemnities disclosed in Note 10.

As at March 31, 2012, the Plan Account had a net notional exposure of $123 million (2011 – $190 million) to various tranches of collateralized debt obligations, of which approximately 61% (2011 – approximately 44%) of the underlying dollar exposure was rated "Investment grade", as well as funding facilities, as described in Note 10, to support potential margin calls on the ABTNs.

To monitor the evolution of credit risk, PSP Investments periodically produces a concentration report by credit rating of all credit-sensitive financial securities with the exception of securities held in pooled funds or for private markets investments.

PSP Investments' concentration of credit risk by credit rating, excluding the items described above and any other credit enhancement, for the Plan Account was as follows as at March 31:

	2012	2011
Investment grade (AAA to BBB–)	**98.2 %**	97.9 %
Below investment grade (BB+ and below)	**0.7**	0.4
Not rated:		
Rated by a single credit rating agency	**0.1**	0.1
Not rated by credit rating agencies	**1.0**	1.6
Total	**100.0 %**	100.0 %

Counterparty Risk

Counterparty risk represents the credit risk from current and potential exposure related to transactions involving derivative contracts, securities lending and borrowing as well as securities sold under repurchase agreements. In order to minimize counterparty risk, PSP Investments requires that counterparties provide adequate collateral and meet its credit rating requirements. PSP Investments frequently monitors the credit rating of its counterparties as determined by recognized credit rating agencies. With respect to derivative contracts, PSP Investments has the ability to terminate all trades with most counterparties whose credit rating is downgraded below its requirements.

PSP Investments' policy also requires the use of the International Swaps and Derivative Association (ISDA) Master Agreement with all counterparties to derivative contracts. The ISDA Master Agreement provides the contractual framework within which dealing activities across a full range of OTC products are conducted.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK (continued)

Counterparty Risk (continued)

As a credit mitigation technique, the ISDA Master Agreement contractually binds both parties to use master-netting arrangements and, in the case of default of the counterparty, close-out netting. Additionally, the Credit Support Annex (CSA) to the ISDA Master Agreement enables PSP Investments to realize any collateral placed with it in the case of default of the counterparty. The CSA also requires PSP Investments to contribute further collateral when requested. All collateral transactions are in high-quality debt instruments or securities. The CSA also regulates the exchange of collateral when the credit exposure to a counterparty exceeds a predetermined threshold. In certain cases, counterparties are authorized to sell, repledge or otherwise use collateral held. On behalf of the Plan Account, PSP Investments pledged securities with a fair value of $2 million as collateral with respect to derivative contracts at March 31, 2012 (2011 – nil). Securities with a fair value of $76 million were received from counterparties as collateral at March 31, 2012 (2011 – $100 million). PSP Investments does not sell, repledge or otherwise use any collateral held with respect to derivative contracts.

With respect to transactions involving securities lending and borrowing as well as securities sold under repurchase agreements, collateral requirements are in place to mitigate counterparty risk. Notes 3 (D) and 3 (E) describe collateral requirements in securities lending and borrowing programs as well as securities sold under repurchase agreements, respectively.

In the case of the securities lending program, PSP Investments' exposure to counterparty risk is further mitigated as the custodian of the securities lent assumes the risk that a counterparty will be unable to meet its obligations associated with the collateral requirements.

Management is responsible for counterparty risk monitoring and mitigation as well as maintaining a comprehensive, disciplined, and enterprise-wide process for tracking and managing counterparty risk. As such, Management measures counterparty risk on an ongoing basis, evaluates and tracks the creditworthiness of current counterparties and mitigates counterparty risk through collateral management.

(C) LIQUIDITY RISK

Liquidity risk corresponds to PSP Investments' ability to meet its financial obligations when they come due with sufficient and readily available cash resources. PSP Investments' cash position is monitored on a daily basis. In general, investments in cash, cash equivalents, floating rate notes, bonds and public equities are expected to be highly liquid as they will be invested in securities that are actively traded. Management utilizes appropriate measures and controls to monitor liquidity risk in order to ensure that there is sufficient liquidity to meet financial obligations as they come due. A liquidity report taking into consideration future forecasted cash flows is prepared and presented to senior management on a weekly basis. This ensures that sufficient cash reserves are available to meet forecasted cash outflows. Additionally, sufficient sources of liquidity are maintained for deployment in case of market disruption.

PSP Investments has the ability to raise additional capital through the use of its capital market debt program. This program allows PSP Investments to issue short-term promissory notes and medium-term notes. Note 8 provides additional information on the usage of the capital market debt program.

The terms to maturity of the notional amount of derivatives are disclosed in Note 3 (B).

4. INVESTMENT RISK MANAGEMENT (continued)

(C) LIQUIDITY RISK (continued)

Financial Liabilities

The following tables present the fair value of non-derivative-related financial liabilities as well as derivative-related financial instruments, aggregated according to their maturities as at March 31, 2012:

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Non-derivative-related financial liabilities[1]				
Amounts payable from pending trades	$ (722)	$ –	$ –	$ (722)
Interest payable	(16)	(2)	–	(18)
Securities sold short	(314)	–	–	(314)
Securities sold under repurchase agreements	(929)	–	–	(929)
Capital market debt financing	(607)	(51)	(2,209)	(2,867)
Accounts payable and other liabilities	(59)	–	(23)	(82)
Total	$ (2,647)	$ (53)	$ (2,232)	$ (4,932)

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Derivative-related financial instruments				
Derivative-related receivables	$ 110	$ 124	$ 65	$ 299
Derivative-related payables[1]	(116)	(75)	(79)	(270)
Total	$ (6)	$ 49	$ (14)	$ 29

[1] Liabilities are presented in the earliest period in which the counterparty can request payment.

5. FUND TRANSFERS

On behalf of the Plan Account, PSP Investments received fund transfers of $3,556 million for the year ended March 31, 2012 (2011 – $3,591 million) from the Fund.

6. INVESTMENT INCOME

Investment income, for the years ended March 31, was as follows:

($ millions)	2012	2011
Interest income	**$ 485**	$ 374
Dividend income	**565**	438
Other income	**145**	132
Dividend expense	**(18)**	(14)
Interest expense (Note 8)	**(60)**	(45)
Transaction costs	**(47)**	(41)
External investment management fees[1]	**(24)**	(28)
	1,046	816
Net realized gains[2]	**740**	1,328
Net unrealized (losses) gains	**(405)**	2,986
Investment income	**$ 1,381**	$ 5,130

[1] Consists of amounts incurred for investments in public markets that are paid directly by PSP Investments. This excludes investments fees related to certain pooled fund investments classified under alternative investments primarily related to performance, in the amount of $41 million for the year ended March 31, 2012 (2011 – $62 million). This also excludes management fees related to investments in private markets and other fixed income securities that are not paid directly by PSP Investments.

Such fees, which generally vary between 0.1% and 2.0% of the total invested and/or committed amount, totalled $87 million for the year ended March 31, 2012 (2011 – $102 million).

[2] Includes foreign currency losses of $34 million for the year ended March 31, 2012 (2011 – gains of $83 million).

7. EXPENSES

(A) ALLOCATION OF EXPENSES

The Act requires that the costs of operation of PSP Investments be charged to the Plan Accounts for which it provides investment services. Under section 4(3) of the Act, the President of the Treasury Board shall determine to which Plan Account these costs will be charged, in consultation with the Minister of National Defence and the Minister of Public Safety. An allocation policy was developed which allocates the direct costs of investment activities, such as external investment management fees and custodial fees, to each Plan Account, based upon the asset value of each Plan Account at the time the expense was incurred.

All other operating expenses, excluding the direct cost of investment activities listed above, for the years ended March 31, were allocated in proportion to the annual amount of net assets in each Plan Account as follows:

	2012	2011
Public Service Pension Plan Account	**72.9 %**	72.7 %
Canadian Forces Pension Plan Account	**19.4**	19.7
Royal Canadian Mounted Police Pension Plan Account	**7.1**	7.1
Reserve Force Pension Plan Account	**0.6**	0.5
Total	**100.0 %**	100.0 %

Expenses are paid by PSP Investments by way of advances from the Public Service Pension Plan Account, which are reimbursed by the other Plan Accounts on a quarterly basis.

(B) OPERATING EXPENSES

Operating expenses allocated to this Plan Account, for the years ended March 31, consisted of the following:

($ thousands)	2012	2011
Salaries and benefits	**$ 70,482**	$ 51,015
Professional and consulting fees	**7,885**	5,867
Office supplies and equipment	**10,971**	9,160
Other operating expenses	**4,690**	3,559
Depreciation of fixed assets	**6,749**	7,158
Occupancy costs	**4,032**	3,495
Custodial fees	**2,231**	1,720
Remuneration earned by Directors	**585**	556
Travel and related expenses for Directors	**199**	138
Communication expenses	**160**	144
Total	**$107,984**	$ 82,812

8. CAPITAL MARKET DEBT FINANCING

PSP Investments' capital market debt program consists of the private placement of short-term promissory notes as well as medium-term notes issued by PSP Capital Inc., a wholly-owned subsidiary of PSP Investments. The capital raised is primarily used to finance investments in real estate, infrastructure and renewable resources. It is unconditionally and irrevocably guaranteed by PSP Investments in accordance with its corporate leverage policy.

The maximum amount authorized by the Board of Directors for the capital market debt program is 7.5% of the net investments plus all recourse debt outstanding of PSP Investments. Under this limit, the short-term promissory note component cannot exceed $3 billion.

The following outlines the terms as well as the fair value of the notes issued under the capital market debt program allocated to the Plan Account as at March 31:

		2012	2011
($ millions)	**Capital amounts to be paid at maturity**	**Fair Value**	Fair Value
Short-term promissory notes, bearing interest between 1% and 1.42% and maturing within 31 and 364 days of issuance (March 31, 2011 – 29 and 363 days)	**$ 659**	**$ 658**	$ 512
Medium-term notes Series 1, bearing interest of 4.57% per annum and maturing on December 9, 2013	**$ 730**	**$ 769**	$ 770
Medium-term notes Series 2, bearing interest of 2.94% per annum and maturing on December 3, 2015	**$ 512**	**$ 528**	$ 504
Medium-term notes Series 3, bearing variable interest of 3-month CDOR + 39 basis points and maturing on February 16, 2015	**$ 256**	**$ 255**	$ –
Medium-term notes Series 4, bearing interest of 2.26% per annum and maturing on February 16, 2017	**$ 658**	**$ 657**	$ –
Total	**$ 2,815**	**$ 2,867**	$ 1,786

The operating expenses incurred by PSP Capital Inc. were allocated to each Plan Account as described in Note 7 (A).

Interest expense, for the years ended March 31, was as follows:

($ thousands)	**2012**	2011
Short-term promissory notes	**$ 9,252**	$ 6,508
Medium-term notes	**50,816**	38,133
Total	**$ 60,068**	$ 44,641

9. CAPITAL MANAGEMENT

As an investment company, PSP Investments' objectives in managing its capital are:

- To invest fund transfers, outlined in Note 5, in the best interests of the beneficiaries and contributors under the *Superannuation Acts*. The funds received are invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the Plans established under the *Superannuation Acts* and the ability of the Plans to meet their financial obligations. The funds are also invested in accordance with the Investment Risk Management policies which are outlined in Note 4.
- To maintain an appropriate credit rating to achieve access to the capital markets at the lowest cost of capital. Through PSP Capital Inc. and its leverage policies, PSP Investments has the ability to raise capital by issuing short-term promissory notes and medium-term notes. Note 8 provides information on the capital market debt financing and Note 4 (C) provides information on PSP Investments' liquidity.

The capital structure of PSP Investments consists of fund transfers and capital market debt financing. PSP Investments has no externally imposed restrictions on capital.

10. GUARANTEES AND INDEMNITIES

PSP Investments provides indemnification to its Directors, its Officers, its vice-presidents and to certain PSP Investments representatives who are asked to serve on boards of directors (or like bodies) or investment advisory boards (or like bodies) of entities in which PSP Investments or its wholly-owned subsidiaries have made an investment or have a financial interest. As a result, but subject to the Act, PSP Investments may be required to indemnify these representatives for costs incurred, such as claims, actions or litigations in connection with the exercise of their duties, unless the liability of such a representative relates to a failure to act honestly and in good faith. To date, PSP Investments has not received any claims or made any payment for such indemnity.

In certain cases, PSP Investments also provides indemnification to third parties in the normal course of business. As a result, PSP Investments may be required to indemnify such third parties in connection with the performance of their contractual obligations. To date, PSP Investments has not received any claims nor made any payments for such indemnities.

PSP Investments unconditionally and irrevocably guarantees all credit facilities, short-term promissory notes and medium-term notes issued by PSP Capital Inc.

PSP Capital Inc. provided funding facilities of a maximum amount of $969 million to support potential margin calls on the ABTNs, of which $705 million has been allocated to the Plan Account. As at March 31, 2012, the margin funding facilities have not been drawn upon since inception.

In certain investment transactions, PSP Investments provided guarantees or indemnifications to third parties, the most significant of which are as follows:

As at March 31, 2012, PSP Investments agreed to guarantee, as part of an investment transaction, a non-revolving term loan. In the event of a default, the Plan Account could assume the obligation up to $292 million (2011 – $292 million) plus interest and other related costs. The loan matures in March 2015.

As at March 31, 2012, a wholly-owned subsidiary of PSP Investments has agreed to provide indemnification with respect to the contractual obligations and commitments of a third-party. In the event of a default by such third-party, the subsidiary may be required to assume an obligation of up to $195 million (2011 – $195 million), of which $142 million (2011 – $142 million) may be allocated to the Plan Account, as estimated at the time of the completion of the investment transaction. The subsidiary would also have direct recourse against the defaulting third party in all circumstances. The guarantee expires in April 2012.

11. COMMITMENTS

PSP Investments and its subsidiaries have committed to enter into investment transactions, which will be funded over the next several years in accordance with agreed terms and conditions. The portion of PSP Investments' commitments that would be assumed by the Plan Account was as follows as at March 31, 2012:

($ millions)	
Real estate	$ 1,101
Private equity	2,980
Infrastructure	636
Other fixed income securities	422
Total	**$ 5,139**

CANADIAN FORCES PENSION PLAN ACCOUNT

INDEPENDENT AUDITORS' REPORT

To the Minister of National Defence

REPORT ON THE FINANCIAL STATEMENTS

We have audited the accompanying financial statements of the Public Sector Pension Investment Board – Canadian Forces Pension Plan Account (the Canadian Forces Pension Plan Account), which comprise the balance sheet as at March 31, 2012, and the statement of net income from operations and comprehensive income and statement of changes in net assets for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Canadian Forces Pension Plan Account as at March 31, 2012, and the results of its operations and changes in its net assets for the year then ended in accordance with Canadian generally accepted accounting principles.

REPORT ON OTHER LEGAL AND REGULATORY REQUIREMENTS

As required by the *Financial Administration Act,* we report that, in our opinion, Canadian generally accepted accounting principles have been applied on a basis consistent with that of the preceding year.

Further, in our opinion, the transactions of the Canadian Forces Pension Plan Account that have come to our notice during our audit of the financial statements have, in all significant respects, been in accordance with the applicable provisions of Part X of the *Financial Administration Act* and regulations, the *Public Sector Pension Investment Board Act* and regulations and the by-laws of the Public Sector Pension Investment Board and its wholly-owned subsidiaries.

Deloitte & Touche LLP[1]

[1] Chartered accountant auditor permit No. 18527

May 14, 2012
Montréal, Canada

Michael Ferguson, FCA
Auditor General of Canada

May 14, 2012
Ottawa, Canada

BALANCE SHEET

As at March 31

($ millions)	2012	2011
ASSETS		
Investments (Note 3 (A))	**$ 13,565**	$ 11,852
Investment-related assets (Note 3 (A))	**243**	287
Other assets	**13**	10
	$ 13,821	$ 12,149
LIABILITIES		
Investment-related liabilities (Note 3 (A))	**$ 1,353**	$ 839
Accounts payable and other liabilities	**22**	12
Due to the Public Service Pension Plan Account	**8**	9
	$ 1,383	$ 860
NET ASSETS	**$ 12,438**	$ 11,289
Accumulated net income from operations and comprehensive income	**$ 3,275**	$ 2,941
Accumulated fund transfers	**9,163**	8,348
NET ASSETS	**$ 12,438**	$ 11,289

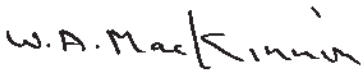
Commitments (Note 11)

The accompanying notes are an integral part of the financial statements.

On behalf of the Board of Directors:



Cheryl Barker
Interim Chair of the Board



William A. Mackinnon
Chair of the Audit Committee

STATEMENT OF NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME

For the years ended March 31

($ millions)	2012	2011
INVESTMENT INCOME (Note 6)	**$ 363**	$ 1,376
OPERATING EXPENSES (Note 7)	**$ 29**	$ 22
NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME	**$ 334**	$ 1,354

The accompanying notes are an integral part of the financial statements.

STATEMENT OF CHANGES IN NET ASSETS

For the years ended March 31

($ millions)	2012	2011
NET ASSETS, BEGINNING OF YEAR	**$ 11,289**	$ 9,107
Fund transfers (Note 5)	**815**	828
Net income from operations and comprehensive income	**334**	1,354
Increase in net assets for the year	**1,149**	2,182
NET ASSETS, END OF YEAR	**$ 12,438**	$ 11,289

The accompanying notes are an integral part of the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the year ended March 31, 2012

ORGANIZATION

The Public Sector Pension Investment Board (PSP Investments) is a Crown corporation created under the *Public Sector Pension Investment Board Act* (the "Act") to manage and invest amounts that are transferred to it, under the *Superannuation Acts*, by the funds (as defined in the Act) of the pension plans established under the *Public Service Superannuation Act*, the *Canadian Forces Superannuation Act* (CFSA), the *Royal Canadian Mounted Police Superannuation Act* (collectively the "*Superannuation Acts*"), and certain regulations under the CFSA (the "CFSA Regulations"). The pension plans established under the *Superannuation Acts* consist of the Public Service pension plan, the Canadian Forces pension plan, and the Royal Canadian Mounted Police pension plan, whereas the pension plan established under the CFSA Regulations is the Reserve Force pension plan. They are herein referred to individually as the "Plan" and collectively as the "Plans".

The fund from which amounts are currently transferred to PSP Investments (the "Fund") relates to pension obligations under the Canadian Forces pension plan for service on or after April 1, 2000. The account managed by PSP Investments for the Fund is herein referred to as the "Plan Account". PSP Investments maintains records of the Fund's net contributions, as well as the allocation of its investments and the results of its operations in the Plan Account.

PSP Investments is responsible for managing amounts that are transferred to it from the Fund in the best interests of the beneficiaries and contributors under the *Canadian Forces Superannuation Act.* The amounts are to be invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the *Canadian Forces Superannuation Act* and the Canadian Forces pension plan's ability to meet its financial obligations.

Pursuant to the *Canadian Forces Superannuation Act*, the Government of Canada, which administers the Fund, may call upon PSP Investments for amounts required for the purpose of paying benefits under the Plan in respect of service on or after April 1, 2000. Amounts remitted by PSP Investments for such purpose cannot exceed, at any time, the net assets of PSP Investments allocated to the Plan Account.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These financial statements present the financial position and operations of PSP Investments and its wholly-owned subsidiaries as they pertain to the investment of the net contributions transferred to it from the Fund in respect of member service after April 1, 2000. Accordingly, they do not reflect all of the assets or the details of the pension contributions, payments and liabilities of the Fund. The financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). PSP Investments qualifies as an Investment Company and therefore reports its investments at fair value, in accordance with Accounting Guideline 18, "Investment Companies" (AcG-18). All changes in fair value are included in investment income (loss) as net unrealized gains (losses).

Comparative figures have been reclassified to conform to the current year's presentation.

VALUATION OF INVESTMENTS

Investments, investment-related assets and investment-related liabilities are recorded at the date upon which PSP Investments becomes a party to the associated contractual provisions, and are carried at fair value. Purchases and sales are recorded as of the trade date. Fair value is an estimate of the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

At trade date, the best evidence of fair value is the transaction price. At each subsequent reporting year-end, market prices are used to determine fair value where an active market exists (such as a recognized securities exchange), as they reflect actual and regularly occurring market transactions on an arm's length basis. If quoted market prices are not available, then fair values are estimated using present value or other valuation techniques, using inputs existing at the end of the reporting year that are derived from observable market data.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

VALUATION OF INVESTMENTS (continued)

Valuation techniques are generally applied to investments in real estate, private equity, infrastructure and renewable resources, over-the-counter (OTC) derivatives and certain fixed income securities. The values derived from applying these techniques are impacted by the choice of valuation model and the underlying assumptions made concerning factors such as the amounts and timing of future cash flows, discount rates, volatility and credit risk. In certain cases, such assumptions are not supported by market observable data.

The valuation methods of the investments are described in Notes 3 (A) and (B).

TRANSACTION COSTS

Transaction costs are incremental costs directly attributable to the acquisition, due diligence, issue, or disposal of a financial asset or financial liability. Transaction costs are expensed as incurred and recorded as a component of investment income (loss).

INVESTMENT MANAGEMENT FEES

Investment management fees are directly attributable to the external management of assets on behalf of PSP Investments. Management fees incurred for investments in private markets and certain private debt portfolios are paid by the investment directly, through capital contributions by PSP Investments or offset against distributions received from the investment. Management fees are also incurred for certain public markets and alternative investments and are paid either directly by PSP Investments or offset against distributions received from pooled fund investments. In both cases, they are recorded against investment income (loss).

INCOME RECOGNITION

The investment income (loss) has been allocated proportionately based on the asset value held by the Plan Account.

Investment income (loss) is made up of interest income, dividends, realized gains (losses) on the disposal of investments and unrealized gains (losses) which reflect the change in unrealized appreciation (depreciation) of investments held at the end of the year. Interest income is recognized as earned. Dividends are recognized on the ex-dividend date and are reflected as dividend income. Dividends paid or payable on securities sold short are reflected as dividend expense. Other income includes securities lending income (net of fees on securities borrowed), as well as private markets distributions from pooled funds, limited partnerships or from direct investments and co-investments. Co-investments are investments in private entities where the investment is made in conjunction with an external manager with whom PSP Investments already has committed and delegated funds.

TRANSLATION OF FOREIGN CURRENCIES

Investment transactions in foreign currencies are recorded at exchange rates prevailing on the transaction date. Investments denominated in foreign currencies and held at the end of the year are translated at exchange rates in effect at the year-end date. Any realized and unrealized gains (losses) on foreign exchange are included in investment income (loss).

FUND TRANSFERS

Amounts received from the Fund are recorded in the Plan Account.

INCOME TAXES

PSP Investments and the majority of its subsidiaries are exempt from Part I tax under paragraphs 149(1)*(d)* and 149(1)*(d.2)* of the *Income Tax Act* (Canada), respectively.

USE OF ESTIMATES

In preparing these financial statements, management makes certain estimates and assumptions which can affect the reported values of assets and liabilities. This is principally reflected in the valuation of private markets investments, certain fixed income securities, related income and expenses as well as note disclosures. Although estimates and assumptions reflect management's best judgment, actual results may differ from these estimates.

2. FUTURE CHANGES IN ACCOUNTING POLICIES

In February 2008, the Accounting Standards Board of Canada (AcSB) confirmed that Canadian GAAP for publicly accountable enterprises would converge with International Financial Reporting Standards (IFRS) effective January 1, 2011.

In 2011, the AcSB decided to defer the adoption of IFRS by investment companies, currently applying AcG-18 to annual periods starting on or after January 1, 2014. This deferral delays PSP Investments' transition to IFRS until the March 31, 2015 annual consolidated financial statements.

The AcSB's decision was in response to an announcement by the International Accounting Standards Board (IASB) in 2010, regarding an Exposure Draft (ED) being developed. The IASB proposed to define an investment entity and exempt it from consolidation by requiring it to measure all controlled investments at fair value, with changes recognized in profit or loss. The ED, *Investment Entities*, was published in August 2011 and is expected to be finalized in the second half of 2012. PSP Investments will complete the assessment of the impact of its transition to IFRS once the ED is finalized and a standard is issued.

The AcSB also announced in 2011 that it will evaluate whether entities like PSP Investments, which are separate from a pension plan and without a pension obligation, and whose sole purpose is to hold and invest assets received from one or more pension plans, would qualify as investment entities under the IASB's ED. Based on the result of this evaluation, the AcSB will then decide whether these entities would need to be included within the scope of Section 4600, "Pension Plans", where investments are accounted for at fair value.

3. INVESTMENTS

(A) INVESTMENT PORTFOLIO

The investment portfolio is organized according to the nature and common characteristics associated with the investments held. The following table presents the investment portfolio as at March 31:

	2012		2011	
($ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Public markets				
Canadian equity	**$ 1,764**	**$ 1,706**	$ 2,752	$ 2,255
Foreign equity	**3,132**	**2,894**	2,527	2,306
Private markets				
Real estate	**1,438**	**1,241**	1,061	970
Private equity	**1,193**	**1,017**	1,010	878
Infrastructure	**823**	**864**	527	571
Renewable resources	**72**	**72**	–	–
Fixed income				
Cash and money market securities	**462**	**462**	500	500
Government and corporate bonds	**2,461**	**2,408**	1,572	1,581
Inflation-linked bonds	**763**	**696**	580	596
Other fixed income securities	**1,230**	**1,108**	1,106	1,064
Alternative investments	**227**	**182**	217	181
INVESTMENTS	**$ 13,565**	**$ 12,650**	$ 11,852	$ 10,902
Investment-related assets				
Amounts receivable from pending trades	**$ 121**	**$ 121**	$ 136	$ 136
Interest receivable	**31**	**31**	27	27
Dividends receivable	**12**	**12**	10	10
Derivative-related receivables	**79**	**16**	114	5
	$ 243	**$ 180**	$ 287	$ 178
Investment–related liabilities				
Amounts payable from pending trades	**$ (191)**	**$ (191)**	$ (211)	$ (211)
Interest payable	**(5)**	**(5)**	(4)	(4)
Securities sold short	**(83)**	**(80)**	(8)	(7)
Securities sold under repurchase agreements	**(246)**	**(245)**	(100)	(100)
Derivative-related payables	**(71)**	**(15)**	(39)	(5)
Capital market debt financing:				
Short-term	**(174)**	**(174)**	(137)	(137)
Long-term	**(583)**	**(571)**	(340)	(332)
	$ (1,353)	**$ (1,281)**	$ (839)	$ (796)
NET INVESTMENTS	**$ 12,455**	**$ 11,549**	$ 11,300	$ 10,284

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(i) Public Markets

Public markets consist of Canadian and foreign investments in the following securities: common shares, American depository receipts, global depository receipts, participation notes, preferred shares, income trust units, exchange traded funds units, pooled funds units, and securities convertible into common shares of publicly listed issuers.

Valuation Techniques

Direct investments in Canadian and foreign equities are measured at fair value using quoted market prices, namely, the bid price.

In the case of investments in pooled funds, fair value is measured using unit values obtained from each of the funds' administrators, which are derived from the fair value of the underlying investments in each pooled fund. Where necessary, the impact of restrictions on the sale or redemption of such investments is taken into consideration in determining fair value.

(ii) Private Markets

Private markets consist of investments in real estate, private equity, infrastructure and renewable resources.

Real estate investments are comprised of direct equity positions in various private entities, properties, as well as fund investments in the real estate sector. Real estate investments focus on properties, partnerships and companies operating in the office, retail, industrial, hospitality and residential sectors, as well as private funds invested in real estate assets. Real estate investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of real estate contracted by direct investments controlled by PSP Investments for the Plan Account was $514 million (2011 – $411 million).

Private equity investments are comprised of direct equity positions and co-investments in private entities as well as fund investments with similar objectives.

Infrastructure investments are comprised of direct equity positions and co-investments in various private entities and fund investments. Infrastructure investments focus on entities engaged in the management, ownership or operation of assets in energy, transportation and other regulated businesses. Infrastructure investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of infrastructure contracted by direct investments controlled by PSP Investments for the Plan Account was $55 million (2011 – $10 million).

Renewable resources investments are comprised of properties involving the production and harvesting of replenishable resources. As at March 31, 2012, renewable resources included one investment in timberlands.

Valuation Techniques

The fair value of private markets investments is determined at least annually, using acceptable industry valuation methods. During the year, the fair value is reviewed and adjusted, as appropriate, to reflect the impact of any significant market or investment-specific events or circumstances. For each investment, the relevant methodology is applied consistently over time as appropriate in the prevailing circumstances.

In cases where the services of third-party appraisers are used, management ensures their independence and that valuation methods used are consistent with professional appraisal standards. Such standards include the *International Private Equity and Venture Capital Valuation Guidelines*, the *Canadian Uniform Standards of Professional Appraisal Practice* and the *Uniform Standards of Professional Appraisal Practice* in the United States of America. In validating the work performed by appraisers, management ensures that the assumptions used correspond to financial information and forecasts of the underlying investment.

For direct investments in real estate, valuation methods used include discounted cash flows, prices of recent comparable transactions and the direct capitalization approach. Assumptions used in such valuations include discount rates, capitalization rates, projected cash flows and/or net operating income, which are not fully supported by prices from market observable transactions.

For direct investments in private equity, direct investments and co-investments in infrastructure and in renewable resources, valuation methods used include discounted cash flows, earnings multiples, prices of recent comparable transactions and publicly traded comparables. Assumptions used in such valuations include discount rates and projected cash flows, which are not fully supported by prices from market observable transactions.

In the case of private equity, real estate and infrastructure fund investments as well as private equity co-investments, the annual fair value is generally determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(iii) Fixed Income

Fixed income consists of cash and money market securities, government and corporate bonds, inflation-linked bonds and other fixed income securities.

Cash and money market securities include instruments having a maximum term to maturity of one year, such as treasury bills, certificates of deposit and bankers' acceptances.

Government and corporate bonds include Canadian and foreign, federal, provincial, territorial and municipal bonds. Inflation-linked bonds are fixed income securities that earn inflation adjusted returns.

Other fixed income securities consist of asset-backed securities, floating rate notes as well as private debt portfolios.

Asset-backed securities consist mainly of asset-backed term notes (ABTNs) and mortgage-backed securities. The ABTNs were received in exchange for third-party or non-bank sponsored asset-backed commercial paper (ABCP) that suffered a liquidity disruption in mid-August 2007 and were subsequently restructured in January 2009. Potential margin calls on the ABTNs are supported by funding facilities, as described in Note 10.

Private debt portfolios consist mainly of investments in the real estate sector in the form of third-party loans such as junior and senior debts, construction loans, bridge loans, income-participating loans, as well as other structured finance products. They also include real estate debt funds where significant portions of the value are attributed to the underlying real estate assets.

Private debt portfolios also include debt securities of private companies or other entities such as venture capital organizations, held mainly through private funds. Such debt securities take the form of senior debt, mezzanine and distressed debt.

Valuation Techniques

Cash and money market securities include short-term instruments that are recorded at cost plus accrued interest, which approximates fair value.

Fair values of government and corporate bonds, inflation-linked bonds, floating rate notes and mortgage-backed securities are based on prices obtained from third-party pricing sources. Such prices are determined using either an appropriate interest rate curve with a spread associated with the credit quality of the issuer or other generally accepted pricing methodologies.

ABTNs are measured at fair value whereby management relies on the valuation work performed by a recognized third-party expert. Management ensures that the valuation conducted by such expert uses acceptable industry methods. Financial information used in the valuation of ABTNs includes interest rates, credit spreads and the underlying investments' terms to maturity. In addition to the values determined by the expert, management integrated certain assumptions in the fair value of ABTNs that are not fully supported by market observable data, such as liquidity estimates and the impact of the funding facilities described in Note 10.

The fair value of private debt portfolios in the real estate sector is determined using either a yield-based or collateral-based valuation technique. The yield-based valuation technique involves discounting expected future cash flows that incorporate assumptions with respect to interest rates offered for similar loans to borrowers with similar credit ratings. The collateral-based valuation technique involves assessing the recoverable value of the collateral in question, net of disposal fees.

The fair value of fund investments included as part of private debt portfolios is determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

(iv) Alternative Investments

Alternative investments consist mainly of units of funds that hold a mix of equity, fixed income and derivative instruments as well as hedge funds.

Valuation Techniques

The fair value of these investments is obtained from the investment's external manager and reflects the fair value of the underlying equity, fixed income or derivative instruments, as applicable.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(v) Amounts Receivable and Payable from Pending Trades

Amounts receivable from pending trades consist of proceeds on sales of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Amounts payable from pending trades consist of the cost of purchases of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Valuation Techniques

The fair value of amounts receivable and payable from pending trades reflects the value at which their underlying original sale or purchase transactions were undertaken.

(vi) Interest and Dividends Receivable

Interest and dividends are recorded at the amounts expected to be received as at the reporting date, which approximates fair value.

(vii) Interest Payable

Interest is accrued at the amount expected to be paid as at the reporting date, which approximates fair value.

(viii) Securities Sold Short

Securities sold short reflect PSP Investments' obligation to purchase securities pursuant to short selling transactions. In such transactions, PSP Investments sells securities it does not own with an obligation to purchase similar securities on the market to cover its position.

Valuation Techniques

Using ask prices as inputs, the fair value of securities sold short is measured using the same method as the similar long positions presented within public markets and fixed income.

(ix) Securities Sold under Repurchase Agreements

PSP Investments is party to agreements which involve the sale of securities with a simultaneous agreement to repurchase such securities at a specified price and at a specified future date.

Securities sold under the repurchase agreements are not derecognized as PSP Investments retains all related risks and rewards of ownership. As such, all related income (loss) continues to be reported in investment income (loss).

Obligations to repurchase the securities sold are accounted for as investment-related liabilities. Interest expense related to such obligations is reported in investment income (loss).

Valuation Techniques

Obligations to repurchase the securities sold under repurchase agreements are recorded at cost plus accrued interest, which approximates fair value.

(x) Derivative-Related Receivables and Payables

The description and valuation of derivative-related receivables and payables are described in Note 3 (B).

(xi) Capital Market Debt Financing

PSP Investments' capital market debt program is described in Note 8. Short-term promissory notes are recorded at cost plus accrued interest, which approximates fair value. The fair value of PSP Investments' medium-term notes is based on prices that are obtained from third-party pricing sources. Such prices are determined using an interest rate curve with a spread consistent with PSP Investments' credit quality.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS

Derivative financial instruments are financial contracts that are settled at a future date. The value of such instruments is derived from changes in underlying assets, interest or exchange rates. Derivative financial instruments do not, typically, require an initial net investment. In certain cases, they require an initial net investment that is less than what would be required to hold the underlying position directly. PSP Investments uses derivative financial instruments to enhance returns or to replicate investments synthetically. Derivatives are also used to reduce the risk associated with existing investments.

PSP Investments uses the following types of derivative financial instruments:

(i) Swaps

Swaps are transactions whereby two counterparties exchange cash flow streams with each other based on predetermined conditions that include a notional amount and a term. Swaps are used to increase returns or to adjust exposures of certain assets without directly purchasing or selling the underlying assets.

(ii) Futures

Futures are standardized contracts to take or make delivery of an asset (buy or sell) at a predefined price and predefined future date. Futures are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iii) Forwards

Forwards are contracts involving the sale by one party and the purchase by another party of a predefined amount of an underlying instrument, at a predefined price and at a predefined date in the future. Forwards are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iv) Options

Options are the right, but not the obligation, to buy or sell a given amount of an underlying security, index, or commodity, at an agreed-upon price stipulated in advance, either at a determined date or at any time before the predefined maturity date.

(v) Warrants and Rights

Warrants are options to purchase an underlying asset which is in the form of a transferable security and which can be listed on an exchange.

Rights are securities giving shareholders entitlement to purchase new shares issued by a corporation at a predetermined price (normally less than the current market price) in proportion to the number of shares already owned. Rights are issued only for a short period of time, after which they expire.

(vi) Collateralized Debt Obligations

Collateralized debt obligations are a type of asset-backed security that is constructed from a portfolio of credit-related assets. Collateralized debt obligations are usually divided into several tranches with different credit risk levels and corresponding interest payments. Any losses are applied first to the more junior tranches (lowest risk rating) before moving up in seniority.

Valuation Techniques

All listed derivative financial instruments are recorded at fair value using quoted market prices with the bid price for long positions and the ask price for short positions. OTC derivatives are valued using appropriate valuation techniques, such as discounted cash flows using current market yields. The assumptions used include the statistical behaviour of the underlying instruments and the ability of the model to correlate with observed market transactions. Although pricing models used are widely accepted and used by other market participants, in the case of collaterized debt obligations, the nature of such instruments requires more significant assumptions about the behaviour of the default correlation. Such assumptions are not observable in the market.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

Notional values of derivative financial instruments are not recorded as assets or liabilities as they represent the face amount of the contract. Except for credit derivatives[1], notional values do not represent the potential gain or loss associated with the market or credit risk of such transactions disclosed below. Rather, they serve as the basis upon which the cash flows and the fair value of the contracts are determined.

The following table summarizes the derivatives portfolio as at March 31:

	2012				2011			
		Fair Value				Fair Value		
($ millions)	Notional Value	Assets	Liabilities	Net	Notional Value	Assets	Liabilities	Net
Equity and commodity derivatives								
Futures	**$ 195**	**$ –**	**$ –**	**$ –**	$ 84	$ –	$ –	$ –
Total return swaps	**1,574**	**25**	**(8)**	**17**	1,079	37	–	37
Options:								
Listed-purchased	**218**	**3**	**–**	**3**	86	2	–	2
Listed-written	**186**	**–**	**(2)**	**(2)**	77	–	(4)	(4)
OTC-purchased	**104**	**1**	**–**	**1**	–	–	–	–
OTC-written	**95**	**–**	**(2)**	**(2)**	–	–	–	–
Currency derivatives								
Forwards	**4,457**	**30**	**(36)**	**(6)**	3,330	62	(24)	38
Futures	**29**	**–**	**–**	**–**	–	–	–	–
Swaps	**182**	**1**	**(3)**	**(2)**	326	4	(2)	2
Options:								
OTC-purchased	**95**	**1**	**–**	**1**	197	1	–	1
OTC-written	**158**	**–**	**(1)**	**(1)**	36	–	–	–
Interest rate derivatives								
Bond forwards	**348**	**1**	**(1)**	**–**	193	1	(1)	–
Futures	**301**	**–**	**–**	**–**	345	–	–	–
Interest rate swaps	**1,463**	**5**	**(6)**	**(1)**	3,416	3	(3)	–
Total return swaps	**–**	**–**	**–**	**–**	125	–	–	–
Swaptions	**156**	**3**	**(1)**	**2**	685	1	(1)	–
Options:								
Listed-purchased	**1,593**	**1**	**–**	**1**	1,041	1	–	1
Listed-written	**1,608**	**–**	**(1)**	**(1)**	1,463	–	(1)	(1)
OTC-purchased	**154**	**3**	**–**	**3**	–	–	–	–
OTC-written	**744**	**–**	**(5)**	**(5)**	–	–	–	–
Credit derivatives[1]:								
Purchased	**233**	**5**	**(1)**	**4**	81	1	(1)	–
Sold	**113**	**–**	**(4)**	**(4)**	80	1	(2)	(1)
Total	**$ 14,006**	**$ 79**	**$ (71)**	**$ 8**	$ 12,644	$ 114	$ (39)	$ 75

[1] Credit derivatives include credit default swaps and collateralized debt obligations. PSP Investments, through sold credit derivatives, indirectly guarantees the underlying reference obligations. The maximum potential exposure is the notional amount of the sold credit derivatives as shown in the table above.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

The term to maturity based on notional value for the derivatives was as follows as at March 31, 2012:

($ millions)

Less than 3 months	**$ 8,026**
3 to 12 months	**3,426**
Over 1 year	**2,554**
Total	**$ 14,006**

(C) FAIR VALUE MEASUREMENT

Investments, investment-related assets and investment-related liabilities are classified according to the following hierarchy based on the significant inputs used in measuring their fair value.

Level 1: Valuation is based on quoted prices in active markets for identical assets or liabilities.

Level 2: Valuation is based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active. Level 2 also includes model-based valuation techniques for which all significant assumptions are observable in the market.

Level 3: Valuation is based on model-based techniques for which significant assumptions are not observable in the market. They reflect management's assessment of the assumptions that market participants would use in pricing the assets or liabilities.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2012:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 1,764	$ –	$ –	$ –	$ 1,764
Foreign equity	2,942	157	33	–	3,132
Private markets					
Real estate	–	–	1,438	–	1,438
Private equity	–	–	1,193	–	1,193
Infrastructure	–	–	823	–	823
Renewable resources	–	–	72	–	72
Fixed income					
Cash and money market securities	148	314	–	–	462
Government and corporate bonds	–	2,461	–	–	2,461
Inflation-linked bonds	–	763	–	–	763
Other fixed income securities	–	460	770	–	1,230
Alternative investments	–	168	59	–	227
INVESTMENTS	$ 4,854	$ 4,323	$ 4,388	$ –	$ 13,565
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 121	$ 121
Interest receivable[1]	–	–	–	31	31
Dividends receivable[1]	–	–	–	12	12
Derivative-related receivables	4	75	–	–	79
	$ 4	$ 75	$ –	$ 164	$ 243
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (191)	$ (191)
Interest payable[1]	–	–	–	(5)	(5)
Securities sold short	(83)	–	–	–	(83)
Securities sold under repurchase agreements	–	(246)	–	–	(246)
Derivative-related payables	(3)	(66)	(2)	–	(71)
Capital market debt financing:					
Short-term	–	(174)	–	–	(174)
Long-term	–	(583)	–	–	(583)
	$ (86)	$ (1,069)	$ (2)	$ (196)	$ (1,353)
NET INVESTMENTS	$ 4,772	$ 3,329	$ 4,386	$ (32)	$ 12,455

[1] No fair value hierarchy classification is required for these items.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2011:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 2,741	$ 11	$ –	$ –	$ 2,752
Foreign equity	2,122	405	–	–	2,527
Private markets					
Real estate	–	–	1,061	–	1,061
Private equity	–	–	1,010	–	1,010
Infrastructure	–	–	527	–	527
Fixed income					
Cash and money market securities	113	387	–	–	500
Government and corporate bonds	–	1,572	–	–	1,572
Inflation-linked bonds	–	580	–	–	580
Other fixed income securities	–	389	717	–	1,106
Alternative investments	–	217	–	–	217
INVESTMENTS	$ 4,976	$ 3,561	$ 3,315	$ –	$ 11,852
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 136	$ 136
Interest receivable[1]	–	–	–	27	27
Dividends receivable[1]	–	–	–	10	10
Derivative-related receivables	4	110	–	–	114
	$ 4	$ 110	$ –	$ 173	$ 287
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (211)	$ (211)
Interest payable[1]	–	–	–	(4)	(4)
Securities sold short	(8)	–	–	–	(8)
Securities sold under repurchase agreements	–	(100)	–	–	(100)
Derivative-related payables	(6)	(31)	(2)	–	(39)
Capital market debt financing:					
Short-term	–	(137)	–	–	(137)
Long-term	–	(340)	–	–	(340)
	$ (14)	$ (608)	$ (2)	$ (215)	$ (839)
NET INVESTMENTS	$ 4,966	$ 3,063	$ 3,313	$ (42)	$ 11,300

[1] No fair value hierarchy classification is required for these items.

The classification within the levels of the hierarchy is established at the time of the initial valuation of the asset or liability and reviewed on each subsequent reporting year-end.

There were no significant transfers between Level 1 and Level 2 during the year ended March 31, 2012 (no significant transfers during the year ended March 31, 2011).

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Reconciliation

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2012:

($ millions)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Gains	Unrealized Gains	Transfer out of Level 3	Closing Balance
Public markets	$ –	$ 30	$ (3)	$ –	$ –	$ 6	$ –	$ 33
Private markets	2,598	1,208	(437)	–	40	121	(4)	3,526
Fixed income	717	204	(190)	(43)	8	74	–	770
Alternative investments	–	57	–	–	–	2	–	59
Derivative-related receivables/payables (net)	(2)	–	–	(1)	1	–	–	(2)
Total	$ 3,313	$ 1,499	$ (630)	$ (44)	$ 49	$ 203	$ (4)	$ 4,386

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2011:

($ millions)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Losses	Unrealized Gains	Transfer out of Level 3	Closing Balance
Private markets	$ 2,401	$ 451	$ (422)	$ –	$ (14)	$ 185	$ (3)	$ 2,598
Fixed income	780	93	(152)	(37)	(15)	48	–	717
Derivative-related receivables/payables (net)	(64)	40	(1)	–	(48)	71	–	(2)
Total	$ 3,117	$ 584	$ (575)	$ (37)	$ (77)	$ 304	$ (3)	$ 3,313

[1] Includes Plan Account allocation adjustments.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Sensitivity Analysis

In the course of measuring fair value of financial instruments classified as Level 3, valuation techniques used incorporate assumptions that are based on non-observable data. Significant assumptions used for each asset class are described in Notes 3 (A) and (B). Although such assumptions reflect management's best judgment, the use of reasonably possible alternative assumptions could yield different fair value measures representing, at a minimum, a 2% increase/decrease (2011 - 2% increase/decrease) in the fair value of financial instruments categorized as Level 3. This excludes private debt portfolios in the real estate sector and certain fund investments, where a sensitivity analysis is not possible given the underlying assumptions used are not available to PSP Investments. In the case of fund investments, the fair value is determined based on the audited financial statements of the fund's general partner as indicated in Note 3 (A). With respect to private debt portfolios in the real estate sector, the fair value is obtained from third-party appraisers as described in Note 3 (A).

(D) SECURITIES LENDING AND BORROWING PROGRAMS

PSP Investments participates in securities lending and borrowing programs whereby it lends and borrows securities in order to enhance portfolio returns. Lending and borrowing transactions under such programs do not transfer the risks or rewards of ownership of the securities to the counterparty. Consequently, PSP Investments does not derecognize securities lent or recognize securities borrowed.

The securities lending and borrowing programs require collateral in cash, high-quality debt instruments or securities. Collateral transactions are conducted under terms that are usual and customary in standard securities lending and borrowing programs. PSP Investments and its counterparties are authorized to sell, repledge or otherwise use collateral held. The same securities or equivalent securities must be returned to the counterparty at the end of the contract, unless an event of default occurs. As at March 31, 2012, PSP Investments, on behalf of the Plan Account, has re-invested $335 million of collateral held (2011 – $292 million).

The following table illustrates the fair values of the Plan Account's allocated securities and collateral associated with the lending and borrowing programs as at March 31:

($ millions)	2012	2011
Securities lending		
Securities lent	**$ 1,350**	$ 1,124
Collateral contractually receivable[1]	**1,422**	1,176
Securities borrowing		
Securities borrowed	**83**	8
Collateral contractually payable[2]	**92**	9

[1] The minimum fair value of collateral required is equal to 102% of the fair value of the securities lent.

[2] The minimum fair value of collateral required is equal to 100% of the fair value of the securities borrowed.

(E) SECURITIES SOLD AND COLLATERAL PLEDGED UNDER REPURCHASE AGREEMENTS

Securities sold under repurchase agreements are described in Note 3 (A) (ix) and involve pledging collateral consisting of cash or securities deemed acceptable by the counterparties. Collateral transactions are conducted under terms that are usual and customary in standard repurchase arrangements. Such terms require the relevant counterparty to pledge additional collateral based on the changes in the fair value of the existing collateral pledged. The counterparties are authorized to sell, repledge or otherwise use collateral held. The securities pledged as collateral must be returned to the relevant counterparty at the end of the contract, unless an event of default occurs. PSP Investments does not sell, repledge or otherwise use collateral held.

On behalf of the Plan Account, PSP Investments pledged collateral under the repurchase agreements with a fair value of $246 million at March 31, 2012 (2011 – $100 million).

4. INVESTMENT RISK MANAGEMENT

Risk Management is a central part of PSP Investments' operations. Included in the overall risk management framework is a continuous process whereby PSP Investments systematically addresses the investment risks related to its various investment activities with the goal of achieving a maximum rate of return without undue risk of loss.

A risk governance framework that includes required reporting on risk to all levels of the organization ensures that appropriate investment objectives are pursued and achieved in line with the fulfillment of PSP Investments' legislated mandate. The Board of Directors and its committees oversee all risk matters and receive assurances from senior management, including the Chief Risk Officer, as well as PSP Investments' independent internal auditor reporting directly to the Audit Committee.

PSP Investments has adopted an Investment Risk Management Policy which is an integral part of its risk control system and supplements the Statement of Investment Policies, Standards and Procedures (SIP&P). The objective of this policy is to provide a framework to manage the risks that PSP Investments is exposed to, namely, market, credit and liquidity risks.

(A) MARKET RISK

Market risk is the risk that the value of an investment will fluctuate as a result of changes in market prices, whether those changes are caused by factors specific to the individual investment, volatility in share and commodity prices, interest rate, foreign exchange or other factors affecting similar securities traded in the market.

Market risk management focuses on the following two key components:

– Policy Portfolio
The Policy Portfolio (long-term asset mix), as defined in the SIP&P, determines a diversification strategy to mitigate risk whereby PSP Investments invests in a diversified portfolio expected to achieve a return at least equal to the Actuarial Rate of Return (ARR); defined as the rate of return assumption used by the Chief Actuary of Canada in the latest actuarial valuation reports of the Plans. In the absence of other factors affecting the funding of the Plans or changes to pension benefits under the Plans, the ARR is the rate of return required to maintain funding requirements and pension benefits at their current levels.

– Active Management
Active management is defined as the sum of investment strategies that deviate from the approved Policy Portfolio. It is designed to supplement the returns of the Policy Portfolio within an active risk budget.

The risks associated with these components are the Policy Portfolio market risk and the active risk. The Policy Portfolio market risk represents the investment risk arising from the exposure to approved asset classes in the approved weightings. In establishing its Policy Portfolio, PSP Investments also takes into consideration the impact of the Policy Portfolio market risk on funding risk. Funding risk is the risk that the assets under management will be insufficient to meet the relevant pension liabilities of the Plans, which may require the contributions to the Funds of the Plans to be increased. The Policy Portfolio is reviewed at least annually as part of the review of the SIP&P, and this review includes changes, if any, to PSP Investments' long-term expectations of market conditions and other factors that may affect the funding levels of the Plans.

Active risk refers to all market risk arising from active management activities. It is managed in accordance with the Investment Risk Management Policy.

Measurement of Market Risk

The Value-at-Risk (VaR) is one of the methods used to measure market risk and is reported on a quarterly basis. It is not the maximum potential loss, but rather the maximum loss not exceeded with a given confidence level, over a given period of time. PSP Investments uses a Historical VaR model incorporating ten years' worth of market returns scaled to a twelve-month holding period at a 95% confidence level. For investments that are not actively traded, the calculation of VaR uses securities with similar risk attributes as proxy.

In measuring Policy Portfolio risk, VaR represents the absolute loss expected from the Policy Portfolio (Policy Portfolio VaR). Whereas in terms of measuring the active risk, VaR reflects the loss relative to the Policy Portfolio benchmark (Active VaR).

VaR is statistically valid under normal market conditions and does not specifically consider losses from severe market events. It also assumes that the future will behave in a pattern similar to the past. Consequently, if future market conditions differ significantly from those of the past, potential losses may differ from those originally estimated.

The following table shows the Total VaR consisting of the Policy Portfolio VaR, the Active VaR and the diversification effect, calculated as a percentage of net investments, as at March 31. The diversification effect captures the impact of holding different types of assets which may react differently in various types of situations and thus reduces the Total VaR.

	2012	2011
Policy Portfolio VaR	**21.7 %**	22.4 %
Active VaR	**2.6**	2.2
Total VaR (undiversified)	**24.3**	24.6
Diversification effect	**(1.6)**	(2.9)
Total VaR	**22.7 %**	21.7 %

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

Stress Testing

Although VaR is a widely accepted risk measure, it is complemented by other risk measurement methodologies that provide greater insight on market risk. PSP Investments uses stress testing and scenario analysis to examine the impact on financial results of abnormally large movements in risk factors. Stress testing and scenario analysis are used to test a portfolio's sensitivity to various risk factors and key model assumptions. These methods also use historically stressed periods to evaluate how a current portfolio reacts under such circumstances. Stress testing and scenario analysis are also deployed to assess new product performance.

(i) Interest Rate Risk

Interest rate risk refers to the risk that fluctuations in interest rates will directly affect the fair value of the Plan Account's net asset values.

The terms to maturity of the investments with the most significant exposure to interest rate risk were as follows as at March 31, 2012:

($ millions)	Less than 1 Year	1 to 5 Years	5 to 10 Years	Over 10 Years	Other	Total
Government bonds	$ 260	$ 917	$ 330	$ 350	$ –	$ 1,857
Corporate bonds	120	257	168	59	–	604
Inflation-linked bonds	–	201	190	372	–	763
Asset-backed securities	–	347	6	1	–	354
Private debt portfolios:						
Directly held	10	78	1	–	–	89
Held through funds[1]	–	–	–	–	355	355
Total investments with significant exposure to interest rate risk	$ 390	$ 1,800	$ 695	$ 782	$ 355	$ 4,022
Other investments[2]	$ –	$ –	$ –	$ –	$ 894	$ 894
Total fixed income	$ 390	$ 1,800	$ 695	$ 782	$ 1,249	$ 4,916

[1] Due to their nature, information in connection with the terms to maturity of fund investments included in the private debt portfolios is not available.

[2] Consists of $462 million in cash and money market securities and $432 million in floating rate notes, which, due to their nature, are not significantly exposed to interest rate risk.

The terms to maturity of PSP Investments' capital market debt financing are disclosed in Note 8.

Alternative investments as well as derivative contracts described in Notes 3 (A) (iv) and (B), respectively, are also subject to interest rate risk exposures. These exposures are reflected in the VaR calculation described in Note 4 (A).

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

(ii) Foreign Currency Risk

PSP Investments and its subsidiaries are exposed to currency risk through holdings of securities, units in pooled funds and units in limited partnerships of non-Canadian assets. Fluctuations in the relative value of the Canadian dollar against these foreign currencies can result in a positive or a negative effect on the fair value of the investments. To mitigate this risk, PSP Investments may take, through foreign forward contracts or cross currency swaps, positions in foreign currencies. PSP Investments' policy is to hedge a target of 50% of its foreign currency investments in non-emerging countries. Additional factors are considered when implementing the hedging target for investments in emerging countries, namely, total relative exposure and cost effectiveness.

The underlying net foreign currency exposures for the Plan Account, after allocating the effect of derivative contracts and investment-related assets and liabilities for both monetary and non-monetary items were as follows as at March 31:

(in millions of Canadian $)	2012		2011	
Currency	**Fair Value**	**% of Total**	Fair Value	% of Total
US Dollar	**$ 2,505**	**57.9 %**	$ 1,848	54.0 %
Euro	**514**	**11.9**	464	13.6
British Pound	**339**	**7.8**	259	7.6
Japanese Yen	**195**	**4.5**	138	4.0
Brazilian Real	**175**	**4.0**	172	5.0
Hong Kong Dollar	**130**	**3.0**	129	3.8
Korean Won	**95**	**2.2**	92	2.7
Australian Dollar	**78**	**1.8**	60	1.7
Norwegian Krone	**66**	**1.5**	20	0.6
Indian Rupee	**37**	**0.9**	27	0.8
Others	**195**	**4.5**	210	6.2
Total	**$ 4,329**	**100.0 %**	$ 3,419	100.0 %

PSP Investments and its subsidiaries also had commitments, denominated in foreign currencies of $1,249 million (US$1,094 million, €100 million, R23 million South African Rands and R36 million Brazilian Reals) for the Plan Account which were not included in the foreign currency exposure table.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK

PSP Investments is exposed to credit risk, that is, the risk that the issuer of a debt security or that the counterparty to a derivative contract, to a securities lending and borrowing transaction or to securities sold under repurchase agreements, is unable to meet its financial obligations.

Credit risk encompasses the risk of a deterioration of creditworthiness and the relevant concentration risk. Credit risk monitoring entails an evaluation of the credit quality of each issuer and counterparty that transacts with PSP Investments. To perform this evaluation, PSP Investments relies on four recognized credit rating agencies. A minimum of two credit ratings are used to classify each security. Except for ABTNs, securities rated by only one agency are classified as "not rated". If the agencies disagree as to a security's credit quality, PSP Investments uses the lowest of the available ratings.

As at March 31, 2012, the Plan Account's maximum exposure to credit risk amounted to approximately $4 billion (2011 – approximately $3 billion). This amount excludes investments in distressed debt in the amount of approximately $0.3 billion as at March 31, 2012 (2011 – approximately $0.3 billion). The maximum exposure to credit risk also excludes collateralized debt obligations, collateral held as disclosed in Notes 3 (D), 3 (E) and 4 (B) and the impact of guarantees and indemnities disclosed in Note 10.

As at March 31, 2012, the Plan Account had a net notional exposure of $32 million (2011 – $51 million) to various tranches of collateralized debt obligations, of which approximately 61% (2011 – approximately 44%) of the underlying dollar exposure was rated "Investment grade", as well as funding facilities, as described in Note 10, to support potential margin calls on the ABTNs.

To monitor the evolution of credit risk, PSP Investments periodically produces a concentration report by credit rating of all credit-sensitive financial securities with the exception of securities held in pooled funds or for private markets investments.

PSP Investments' concentration of credit risk by credit rating, excluding the items described above and any other credit enhancement, for the Plan Account was as follows as at March 31:

	2012	2011
Investment grade (AAA to BBB–)	**98.2 %**	97.9 %
Below investment grade (BB+ and below)	**0.7**	0.4
Not rated:		
Rated by a single credit rating agency	**0.1**	0.1
Not rated by credit rating agencies	**1.0**	1.6
Total	**100.0 %**	100.0 %

Counterparty Risk

Counterparty risk represents the credit risk from current and potential exposure related to transactions involving derivative contracts, securities lending and borrowing as well as securities sold under repurchase agreements. In order to minimize counterparty risk, PSP Investments requires that counterparties provide adequate collateral and meet its credit rating requirements. PSP Investments frequently monitors the credit rating of its counterparties as determined by recognized credit rating agencies. With respect to derivative contracts, PSP Investments has the ability to terminate all trades with most counterparties whose credit rating is downgraded below its requirements.

PSP Investments' policy also requires the use of the International Swaps and Derivative Association (ISDA) Master Agreement with all counterparties to derivative contracts. The ISDA Master Agreement provides the contractual framework within which dealing activities across a full range of OTC products are conducted.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK (continued)

Counterparty Risk (continued)

As a credit mitigation technique, the ISDA Master Agreement contractually binds both parties to use master-netting arrangements and, in the case of default of the counterparty, close-out netting. Additionally, the Credit Support Annex (CSA) to the ISDA Master Agreement enables PSP Investments to realize any collateral placed with it in the case of default of the counterparty. The CSA also requires PSP Investments to contribute further collateral when requested. All collateral transactions are in high-quality debt instruments or securities. The CSA also regulates the exchange of collateral when the credit exposure to a counterparty exceeds a predetermined threshold. In certain cases, counterparties are authorized to sell, repledge or otherwise use collateral held. On behalf of the Plan Account, PSP Investments pledged securities with a fair value of $1 million as collateral with respect to derivative contracts at March 31, 2012 (2011 – nil). Securities with a fair value of $20 million were received from counterparties as collateral at March 31, 2012 (2011 – $26 million). PSP Investments does not sell, repledge or otherwise use any collateral held with respect to derivative contracts.

With respect to transactions involving securities lending and borrowing as well as securities sold under repurchase agreements, collateral requirements are in place to mitigate counterparty risk. Notes 3 (D) and 3 (E) describe collateral requirements in securities lending and borrowing programs as well as securities sold under repurchase agreements, respectively.

In the case of the securities lending program, PSP Investments' exposure to counterparty risk is further mitigated as the custodian of the securities lent assumes the risk that a counterparty will be unable to meet its obligations associated with the collateral requirements.

Management is responsible for counterparty risk monitoring and mitigation as well as maintaining a comprehensive, disciplined, and enterprise-wide process for tracking and managing counterparty risk. As such, Management measures counterparty risk on an ongoing basis, evaluates and tracks the creditworthiness of current counterparties and mitigates counterparty risk through collateral management.

(C) LIQUIDITY RISK

Liquidity risk corresponds to PSP Investments' ability to meet its financial obligations when they come due with sufficient and readily available cash resources. PSP Investments' cash position is monitored on a daily basis. In general, investments in cash, cash equivalents, floating rate notes, bonds and public equities are expected to be highly liquid as they will be invested in securities that are actively traded. Management utilizes appropriate measures and controls to monitor liquidity risk in order to ensure that there is sufficient liquidity to meet financial obligations as they come due. A liquidity report taking into consideration future forecasted cash flows is prepared and presented to senior management on a weekly basis. This ensures that sufficient cash reserves are available to meet forecasted cash outflows. Additionally, sufficient sources of liquidity are maintained for deployment in case of market disruption.

PSP Investments has the ability to raise additional capital through the use of its capital market debt program. This program allows PSP Investments to issue short-term promissory notes and medium-term notes. Note 8 provides additional information on the usage of the capital market debt program.

The terms to maturity of the notional amount of derivatives are disclosed in Note 3 (B).

4. INVESTMENT RISK MANAGEMENT (continued)

(C) LIQUIDITY RISK (continued)

Financial Liabilities

The following tables present the fair value of non-derivative-related financial liabilities as well as derivative-related financial instruments, aggregated according to their maturities as at March 31, 2012:

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Non-derivative-related financial liabilities[1]				
Amounts payable from pending trades	$ (191)	$ –	$ –	$ (191)
Interest payable	(4)	(1)	–	(5)
Securities sold short	(83)	–	–	(83)
Securities sold under repurchase agreements	(246)	–	–	(246)
Capital market debt financing	(161)	(13)	(583)	(757)
Accounts payable and other liabilities	(16)	–	(6)	(22)
Total	$ (701)	$ (14)	$ (589)	$ (1,304)

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Derivative-related financial instruments				
Derivative-related receivables	$ 29	$ 33	$ 17	$ 79
Derivative-related payables[1]	(31)	(20)	(20)	(71)
Total	$ (2)	$ 13	$ (3)	$ 8

[1] Liabilities are presented in the earliest period in which the counterparty can request payment.

5. FUND TRANSFERS

On behalf of the Plan Account, PSP Investments received fund transfers of $815 million for the year ended March 31, 2012 (2011 – $828 million) from the Fund.

6. INVESTMENT INCOME

Investment income, for the years ended March 31, was as follows:

($ millions)	2012	2011
Interest income	**$ 128**	$ 100
Dividend income	**150**	118
Other income	**38**	36
Dividend expense	**(5)**	(4)
Interest expense (Note 8)	**(16)**	(12)
Transaction costs	**(12)**	(11)
External investment management fees[1]	**(7)**	(8)
	276	219
Net realized gains[2]	**197**	355
Net unrealized (losses) gains	**(110)**	802
Investment income	**$ 363**	$ 1,376

[1] Consists of amounts incurred for investments in public markets that are paid directly by PSP Investments. This excludes investments fees related to certain pooled fund investments classified under alternative investments primarily related to performance, in the amount of $11 million for the year ended March 31, 2012 (2011 – $16 million). This also excludes management fees related to investments in private markets and other fixed income securities that are not paid directly by PSP Investments.

Such fees, which generally vary between 0.1% and 2.0% of the total invested and/or committed amount, totalled $23 million for the year ended March 31, 2012 (2011 – $27 million).

[2] Includes foreign currency losses of $8 million for the year ended March 31, 2012 (2011 – gains of $22 million).

7. EXPENSES

(A) ALLOCATION OF EXPENSES

The Act requires that the costs of operation of PSP Investments be charged to the Plan Accounts for which it provides investment services. Under section 4(3) of the Act, the President of the Treasury Board shall determine to which Plan Account these costs will be charged, in consultation with the Minister of National Defence and the Minister of Public Safety. An allocation policy was developed which allocates the direct costs of investment activities, such as external investment management fees and custodial fees, to each Plan Account, based upon the asset value of each Plan Account at the time the expense was incurred.

All other operating expenses, excluding the direct cost of investment activities listed above, for the years ended March 31, were allocated in proportion to the annual amount of net assets in each Plan Account as follows:

	2012	2011
Public Service Pension Plan Account	**72.9 %**	72.7 %
Canadian Forces Pension Plan Account	**19.4**	19.7
Royal Canadian Mounted Police Pension Plan Account	**7.1**	7.1
Reserve Force Pension Plan Account	**0.6**	0.5
Total	**100.0 %**	100.0 %

Expenses are paid by PSP Investments by way of advances from the Public Service Pension Plan Account, which are reimbursed by the other Plan Accounts on a quarterly basis.

(B) OPERATING EXPENSES

Operating expenses allocated to this Plan Account, for the years ended March 31, consisted of the following:

($ thousands)	2012	2011
Salaries and benefits	**$ 18,824**	$ 13,810
Professional and consulting fees	**2,106**	1,588
Office supplies and equipment	**2,930**	2,479
Other operating expenses	**1,252**	963
Depreciation of fixed assets	**1,801**	1,938
Occupancy costs	**1,077**	946
Custodial fees	**596**	465
Remuneration earned by Directors	**156**	150
Travel and related expenses for Directors	**54**	37
Communication expenses	**42**	38
Total	**$ 28,838**	$ 22,414

8. CAPITAL MARKET DEBT FINANCING

PSP Investments' capital market debt program consists of the private placement of short-term promissory notes as well as medium-term notes issued by PSP Capital Inc., a wholly-owned subsidiary of PSP Investments. The capital raised is primarily used to finance investments in real estate, infrastructure and renewable resources. It is unconditionally and irrevocably guaranteed by PSP Investments in accordance with its corporate leverage policy.

The maximum amount authorized by the Board of Directors for the capital market debt program is 7.5% of the net investments plus all recourse debt outstanding of PSP Investments. Under this limit, the short-term promissory note component cannot exceed $3 billion.

The following outlines the terms as well as the fair value of the notes issued under the capital market debt program allocated to the Plan Account as at March 31:

		2012	2011
($ millions)	**Capital amounts to be paid at maturity**	**Fair Value**	Fair Value
Short-term promissory notes, bearing interest between 1% and 1.42% and maturing within 31 and 364 days of issuance (March 31, 2011 – 29 and 363 days)	**$ 174**	**$ 174**	$ 137
Medium-term notes Series 1, bearing interest of 4.57% per annum and maturing on December 9, 2013	**$ 193**	**$ 203**	$ 205
Medium-term notes Series 2, bearing interest of 2.94% per annum and maturing on December 3, 2015	**$ 135**	**$ 139**	$ 135
Medium-term notes Series 3, bearing variable interest of 3-month CDOR + 39 basis points and maturing on February 16, 2015	**$ 67**	**$ 68**	$ –
Medium-term notes Series 4, bearing interest of 2.26% per annum and maturing on February 16, 2017	**$ 174**	**$ 173**	$ –
Total	**$ 743**	**$ 757**	$ 477

The operating expenses incurred by PSP Capital Inc. were allocated to each Plan Account as described in Note 7 (A).

Interest expense, for the years ended March 31, was as follows:

($ thousands)	**2012**	2011
Short-term promissory notes	**$ 2,454**	$ 1,745
Medium-term notes	**13,483**	10,235
Total	**$ 15,937**	$ 11,980

9. CAPITAL MANAGEMENT

As an investment company, PSP Investments' objectives in managing its capital are:

- To invest fund transfers, outlined in Note 5, in the best interests of the beneficiaries and contributors under the *Superannuation Acts*. The funds received are invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the Plans established under the *Superannuation Acts* and the ability of the Plans to meet their financial obligations. The funds are also invested in accordance with the Investment Risk Management policies which are outlined in Note 4.
- To maintain an appropriate credit rating to achieve access to the capital markets at the lowest cost of capital. Through PSP Capital Inc. and its leverage policies, PSP Investments has the ability to raise capital by issuing short-term promissory notes and medium-term notes. Note 8 provides information on the capital market debt financing and Note 4 (C) provides information on PSP Investments' liquidity.

The capital structure of PSP Investments consists of fund transfers and capital market debt financing. PSP Investments has no externally imposed restrictions on capital.

10. GUARANTEES AND INDEMNITIES

PSP Investments provides indemnification to its Directors, its Officers, its vice-presidents and to certain PSP Investments representatives who are asked to serve on boards of directors (or like bodies) or investment advisory boards (or like bodies) of entities in which PSP Investments or its wholly-owned subsidiaries have made an investment or have a financial interest. As a result, but subject to the Act, PSP Investments may be required to indemnify these representatives for costs incurred, such as claims, actions or litigations in connection with the exercise of their duties, unless the liability of such a representative relates to a failure to act honestly and in good faith. To date, PSP Investments has not received any claims or made any payment for such indemnity.

In certain cases, PSP Investments also provides indemnification to third parties in the normal course of business. As a result, PSP Investments may be required to indemnify such third parties in connection with the performance of their contractual obligations. To date, PSP Investments has not received any claims nor made any payments for such indemnities.

PSP Investments unconditionally and irrevocably guarantees all credit facilities, short-term promissory notes and medium-term notes issued by PSP Capital Inc.

PSP Capital Inc. provided funding facilities of a maximum amount of $969 million to support potential margin calls on the ABTNs, of which $190 million has been allocated to the Plan Account. As at March 31, 2012, the margin funding facilities have not been drawn upon since inception.

In certain investment transactions, PSP Investments provided guarantees or indemnifications to third parties, the most significant of which are as follows:

As at March 31, 2012, PSP Investments agreed to guarantee, as part of an investment transaction, a non-revolving term loan. In the event of a default, the Plan Account could assume the obligation up to $81 million (2011 – $81 million) plus interest and other related costs. The loan matures in March 2015.

As at March 31, 2012, a wholly-owned subsidiary of PSP Investments has agreed to provide indemnification with respect to the contractual obligations and commitments of a third-party. In the event of a default by such third-party, the subsidiary may be required to assume an obligation of up to $195 million (2011 – $195 million), of which $38 million (2011 – $38 million) may be allocated to the Plan Account, as estimated at the time of the completion of the investment transaction. The subsidiary would also have direct recourse against the defaulting third party in all circumstances. The guarantee expires in April 2012.

11. COMMITMENTS

PSP Investments and its subsidiaries have committed to enter into investment transactions, which will be funded over the next several years in accordance with agreed terms and conditions. The portion of PSP Investments' commitments that would be assumed by the Plan Account was as follows as at March 31, 2012:

($ millions)	
Real estate	$ 290
Private equity	788
Infrastructure	168
Other fixed income securities	112
Total	**$ 1,358**

ROYAL CANADIAN MOUNTED POLICE PENSION PLAN ACCOUNT

INDEPENDENT AUDITORS' REPORT

To the Minister of Public Safety

REPORT ON THE FINANCIAL STATEMENTS

We have audited the accompanying financial statements of the Public Sector Pension Investment Board – Royal Canadian Mounted Police Pension Plan Account (the Royal Canadian Mounted Police Pension Plan Account), which comprise the balance sheet as at March 31, 2012, and the statement of net income from operations and comprehensive income and statement of changes in net assets for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Royal Canadian Mounted Police Pension Plan Account as at March 31, 2012, and the results of its operations and changes in its net assets for the year then ended in accordance with Canadian generally accepted accounting principles.

REPORT ON OTHER LEGAL AND REGULATORY REQUIREMENTS

As required by the *Financial Administration Act,* we report that, in our opinion, Canadian generally accepted accounting principles have been applied on a basis consistent with that of the preceding year.

Further, in our opinion, the transactions of the Royal Canadian Mounted Police Pension Plan Account that have come to our notice during our audit of the financial statements have, in all significant respects, been in accordance with the applicable provisions of Part X of the *Financial Administration Act* and regulations, the *Public Sector Pension Investment Board Act* and regulations and the by-laws of the Public Sector Pension Investment Board and its wholly-owned subsidiaries.

Deloitte & Touche LLP[1]

[1] Chartered accountant auditor permit No. 18527

May 14, 2012
Montréal, Canada

Michael Ferguson, FCA
Auditor General of Canada

May 14, 2012
Ottawa, Canada

BALANCE SHEET

As at March 31

($ millions)	2012	2011
ASSETS		
Investments (Note 3 (A))	**$ 4,968**	$ 4,306
Investment-related assets (Note 3 (A))	**89**	105
Other assets	**5**	3
	$ 5,062	$ 4,414
LIABILITIES		
Investment-related liabilities (Note 3 (A))	**$ 495**	$ 305
Accounts payable and other liabilities	**8**	4
Due to the Public Service Pension Plan Account	**3**	3
	$ 506	$ 312
NET ASSETS	**$ 4,556**	$ 4,102
Accumulated net income from operations and comprehensive income	**$ 1,181**	$ 1,058
Accumulated fund transfers	**3,375**	3,044
NET ASSETS	**$ 4,556**	$ 4,102

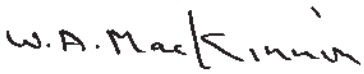
Commitments (Note 11)

The accompanying notes are an integral part of the financial statements.

On behalf of the Board of Directors:



Cheryl Barker
Interim Chair of the Board



William A. Mackinnon
Chair of the Audit Committee

STATEMENT OF NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME

For the years ended March 31

($ millions)	2012	2011
INVESTMENT INCOME (Note 6)	**$ 133**	$ 498
OPERATING EXPENSES (Note 7)	**$ 10**	$ 8
NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME	**$ 123**	$ 490

The accompanying notes are an integral part of the financial statements.

STATEMENT OF CHANGES IN NET ASSETS

For the years ended March 31

($ millions)	2012	2011
NET ASSETS, BEGINNING OF YEAR	**$ 4,102**	$ 3,271
Fund transfers (Note 5)	**331**	341
Net income from operations and comprehensive income	**123**	490
Increase in net assets for the year	**454**	831
NET ASSETS, END OF YEAR	**$ 4,556**	$ 4,102

The accompanying notes are an integral part of the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the year ended March 31, 2012

ORGANIZATION

The Public Sector Pension Investment Board (PSP Investments) is a Crown corporation created under the *Public Sector Pension Investment Board Act* (the "Act") to manage and invest amounts that are transferred to it, under the *Superannuation Acts*, by the funds (as defined in the Act) of the pension plans established under the *Public Service Superannuation Act*, the *Canadian Forces Superannuation Act* (CFSA), the *Royal Canadian Mounted Police Superannuation Act* (collectively the "*Superannuation Acts*"), and certain regulations under the CFSA (the "CFSA Regulations"). The pension plans established under the *Superannuation Acts* consist of the Public Service pension plan, the Canadian Forces pension plan, and the Royal Canadian Mounted Police pension plan, whereas the pension plan established under the CFSA Regulations is the Reserve Force pension plan. They are herein referred to individually as the "Plan" and collectively as the "Plans".

The fund from which amounts are currently transferred to PSP Investments (the "Fund") relates to pension obligations under the Royal Canadian Mounted Police pension plan for service on or after April 1, 2000. The account managed by PSP Investments for the Fund is herein referred to as the "Plan Account". PSP Investments maintains records of the Fund's net contributions, as well as the allocation of its investments and the results of its operations in the Plan Account.

PSP Investments is responsible for managing amounts that are transferred to it from the Fund in the best interests of the beneficiaries and contributors under the *Royal Canadian Mounted Police Superannuation Act*. The amounts are to be invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the *Royal Canadian Mounted Police Superannuation Act* and the Royal Canadian Mounted Police pension plan's ability to meet its financial obligations.

Pursuant to the *Royal Canadian Mounted Police Superannuation Act*, the Government of Canada, which administers the Fund, may call upon PSP Investments for amounts required for the purpose of paying benefits under the Plan in respect of service on or after April 1, 2000. Amounts remitted by PSP Investments for such purpose cannot exceed, at any time, the net assets of PSP Investments allocated to the Plan Account.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These financial statements present the financial position and operations of PSP Investments and its wholly-owned subsidiaries as they pertain to the investment of the net contributions transferred to it from the Fund in respect of member service after April 1, 2000. Accordingly, they do not reflect all of the assets or the details of the pension contributions, payments and liabilities of the Fund. The financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). PSP Investments qualifies as an Investment Company and therefore reports its investments at fair value, in accordance with Accounting Guideline 18, "Investment Companies" (AcG-18). All changes in fair value are included in investment income (loss) as net unrealized gains (losses).

Comparative figures have been reclassified to conform to the current year's presentation.

VALUATION OF INVESTMENTS

Investments, investment-related assets and investment-related liabilities are recorded at the date upon which PSP Investments becomes a party to the associated contractual provisions, and are carried at fair value. Purchases and sales are recorded as of the trade date. Fair value is an estimate of the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

At trade date, the best evidence of fair value is the transaction price. At each subsequent reporting year-end, market prices are used to determine fair value where an active market exists (such as a recognized securities exchange), as they reflect actual and regularly occurring market transactions on an arm's length basis. If quoted market prices are not available, then fair values are estimated using present value or other valuation techniques, using inputs existing at the end of the reporting year that are derived from observable market data.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

VALUATION OF INVESTMENTS (continued)

Valuation techniques are generally applied to investments in real estate, private equity, infrastructure and renewable resources, over-the-counter (OTC) derivatives and certain fixed income securities. The values derived from applying these techniques are impacted by the choice of valuation model and the underlying assumptions made concerning factors such as the amounts and timing of future cash flows, discount rates, volatility and credit risk. In certain cases, such assumptions are not supported by market observable data.

The valuation methods of the investments are described in Notes 3 (A) and (B).

TRANSACTION COSTS

Transaction costs are incremental costs directly attributable to the acquisition, due diligence, issue, or disposal of a financial asset or financial liability. Transaction costs are expensed as incurred and recorded as a component of investment income (loss).

INVESTMENT MANAGEMENT FEES

Investment management fees are directly attributable to the external management of assets on behalf of PSP Investments. Management fees incurred for investments in private markets and certain private debt portfolios are paid by the investment directly, through capital contributions by PSP Investments or offset against distributions received from the investment. Management fees are also incurred for certain public markets and alternative investments and are paid either directly by PSP Investments or offset against distributions received from pooled fund investments. In both cases, they are recorded against investment income (loss).

INCOME RECOGNITION

The investment income (loss) has been allocated proportionately based on the asset value held by the Plan Account.

Investment income (loss) is made up of interest income, dividends, realized gains (losses) on the disposal of investments and unrealized gains (losses) which reflect the change in unrealized appreciation (depreciation) of investments held at the end of the year. Interest income is recognized as earned. Dividends are recognized on the ex-dividend date and are reflected as dividend income. Dividends paid or payable on securities sold short are reflected as dividend expense. Other income includes securities lending income (net of fees on securities borrowed), as well as private markets distributions from pooled funds, limited partnerships or from direct investments and co-investments. Co-investments are investments in private entities where the investment is made in conjunction with an external manager with whom PSP Investments already has committed and delegated funds.

TRANSLATION OF FOREIGN CURRENCIES

Investment transactions in foreign currencies are recorded at exchange rates prevailing on the transaction date. Investments denominated in foreign currencies and held at the end of the year are translated at exchange rates in effect at the year-end date. Any realized and unrealized gains (losses) on foreign exchange are included in investment income (loss).

FUND TRANSFERS

Amounts received from the Fund are recorded in the Plan Account.

INCOME TAXES

PSP Investments and the majority of its subsidiaries are exempt from Part I tax under paragraphs 149(1)*(d)* and 149(1)*(d.2)* of the *Income Tax Act* (Canada), respectively.

USE OF ESTIMATES

In preparing these financial statements, management makes certain estimates and assumptions which can affect the reported values of assets and liabilities. This is principally reflected in the valuation of private markets investments, certain fixed income securities, related income and expenses as well as note disclosures. Although estimates and assumptions reflect management's best judgment, actual results may differ from these estimates.

2. FUTURE CHANGES IN ACCOUNTING POLICIES

In February 2008, the Accounting Standards Board of Canada (AcSB) confirmed that Canadian GAAP for publicly accountable enterprises would converge with International Financial Reporting Standards (IFRS) effective January 1, 2011.

In 2011, the AcSB decided to defer the adoption of IFRS by investment companies, currently applying AcG-18 to annual periods starting on or after January 1, 2014. This deferral delays PSP Investments' transition to IFRS until the March 31, 2015 annual consolidated financial statements.

The AcSB's decision was in response to an announcement by the International Accounting Standards Board (IASB) in 2010, regarding an Exposure Draft (ED) being developed. The IASB proposed to define an investment entity and exempt it from consolidation by requiring it to measure all controlled investments at fair value, with changes recognized in profit or loss. The ED, *Investment Entities*, was published in August 2011 and is expected to be finalized in the second half of 2012. PSP Investments will complete the assessment of the impact of its transition to IFRS once the ED is finalized and a standard is issued.

The AcSB also announced in 2011 that it will evaluate whether entities like PSP Investments, which are separate from a pension plan and without a pension obligation, and whose sole purpose is to hold and invest assets received from one or more pension plans, would qualify as investment entities under the IASB's ED. Based on the result of this evaluation, the AcSB will then decide whether these entities would need to be included within the scope of Section 4600, "Pension Plans", where investments are accounted for at fair value.

3. INVESTMENTS

(A) INVESTMENT PORTFOLIO

The investment portfolio is organized according to the nature and common characteristics associated with the investments held. The following table presents the investment portfolio as at March 31:

	2012		2011	
($ millions)	**Fair Value**	**Cost**	Fair Value	Cost
Public markets				
Canadian equity	**$ 646**	**$ 620**	$ 1,001	$ 815
Foreign equity	**1,147**	**1,058**	919	837
Private markets				
Real estate	**527**	**456**	386	353
Private equity	**437**	**375**	367	321
Infrastructure	**302**	**316**	191	207
Renewable resources	**27**	**27**	–	–
Fixed income				
Cash and money market securities	**169**	**169**	181	181
Government and corporate bonds	**901**	**884**	571	576
Inflation-linked bonds	**279**	**256**	211	217
Other fixed income securities	**450**	**406**	401	387
Alternative investments	**83**	**65**	78	64
INVESTMENTS	**$ 4,968**	**$ 4,632**	$ 4,306	$ 3,958
Investment-related assets				
Amounts receivable from pending trades	**$ 44**	**$ 44**	$ 49	$ 49
Interest receivable	**11**	**11**	10	10
Dividends receivable	**4**	**4**	4	4
Derivative-related receivables	**30**	**6**	42	2
	$ 89	**$ 65**	$ 105	$ 65
Investment-related liabilities				
Amounts payable from pending trades	**$ (70)**	**$ (70)**	$ (77)	$ (77)
Interest payable	**(1)**	**(1)**	(1)	(1)
Securities sold short	**(30)**	**(29)**	(4)	(3)
Securities sold under repurchase agreements	**(90)**	**(90)**	(36)	(36)
Derivative-related payables	**(26)**	**(6)**	(14)	(2)
Capital market debt financing:				
Short-term	**(64)**	**(64)**	(49)	(49)
Long-term	**(214)**	**(209)**	(124)	(121)
	$ (495)	**$ (469)**	$ (305)	$ (289)
NET INVESTMENTS	**$ 4,562**	**$ 4,228**	$ 4,106	$ 3,734

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(i) Public Markets

Public markets consist of Canadian and foreign investments in the following securities: common shares, American depository receipts, global depository receipts, participation notes, preferred shares, income trust units, exchange traded funds units, pooled funds units, and securities convertible into common shares of publicly listed issuers.

Valuation Techniques

Direct investments in Canadian and foreign equities are measured at fair value using quoted market prices, namely, the bid price.

In the case of investments in pooled funds, fair value is measured using unit values obtained from each of the funds' administrators, which are derived from the fair value of the underlying investments in each pooled fund. Where necessary, the impact of restrictions on the sale or redemption of such investments is taken into consideration in determining fair value.

(ii) Private Markets

Private markets consist of investments in real estate, private equity, infrastructure and renewable resources.

Real estate investments are comprised of direct equity positions in various private entities, properties, as well as fund investments in the real estate sector. Real estate investments focus on properties, partnerships and companies operating in the office, retail, industrial, hospitality and residential sectors, as well as private funds invested in real estate assets. Real estate investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of real estate contracted by direct investments controlled by PSP Investments for the Plan Account was $188 million (2011 – $150 million).

Private equity investments are comprised of direct equity positions and co-investments in private entities as well as fund investments with similar objectives.

Infrastructure investments are comprised of direct equity positions and co-investments in various private entities and fund investments. Infrastructure investments focus on entities engaged in the management, ownership or operation of assets in energy, transportation and other regulated businesses. Infrastructure investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of infrastructure contracted by direct investments controlled by PSP Investments for the Plan Account was $20 million (2011 – $4 million).

Renewable resources investments are comprised of properties involving the production and harvesting of replenishable resources. As at March 31, 2012, renewable resources included one investment in timberlands.

Valuation Techniques

The fair value of private markets investments is determined at least annually, using acceptable industry valuation methods. During the year, the fair value is reviewed and adjusted, as appropriate, to reflect the impact of any significant market or investment-specific events or circumstances. For each investment, the relevant methodology is applied consistently over time as appropriate in the prevailing circumstances.

In cases where the services of third-party appraisers are used, management ensures their independence and that valuation methods used are consistent with professional appraisal standards. Such standards include the *International Private Equity and Venture Capital Valuation Guidelines*, the *Canadian Uniform Standards of Professional Appraisal Practice* and the *Uniform Standards of Professional Appraisal Practice* in the United States of America. In validating the work performed by appraisers, management ensures that the assumptions used correspond to financial information and forecasts of the underlying investment.

For direct investments in real estate, valuation methods used include discounted cash flows, prices of recent comparable transactions and the direct capitalization approach. Assumptions used in such valuations include discount rates, capitalization rates, projected cash flows and/or net operating income, which are not fully supported by prices from market observable transactions.

For direct investments in private equity, direct investments and co-investments in infrastructure and in renewable resources, valuation methods used include discounted cash flows, earnings multiples, prices of recent comparable transactions and publicly traded comparables. Assumptions used in such valuations include discount rates and projected cash flows, which are not fully supported by prices from market observable transactions.

In the case of private equity, real estate and infrastructure fund investments as well as private equity co-investments, the annual fair value is generally determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(iii) Fixed Income

Fixed income consists of cash and money market securities, government and corporate bonds, inflation-linked bonds and other fixed income securities.

Cash and money market securities include instruments having a maximum term to maturity of one year, such as treasury bills, certificates of deposit and bankers' acceptances.

Government and corporate bonds include Canadian and foreign, federal, provincial, territorial and municipal bonds. Inflation-linked bonds are fixed income securities that earn inflation adjusted returns.

Other fixed income securities consist of asset-backed securities, floating rate notes as well as private debt portfolios.

Asset-backed securities consist mainly of asset-backed term notes (ABTNs) and mortgage-backed securities. The ABTNs were received in exchange for third-party or non-bank sponsored asset-backed commercial paper (ABCP) that suffered a liquidity disruption in mid-August 2007 and were subsequently restructured in January 2009. Potential margin calls on the ABTNs are supported by funding facilities, as described in Note 10.

Private debt portfolios consist mainly of investments in the real estate sector in the form of third-party loans such as junior and senior debts, construction loans, bridge loans, income-participating loans, as well as other structured finance products. They also include real estate debt funds where significant portions of the value are attributed to the underlying real estate assets.

Private debt portfolios also include debt securities of private companies or other entities such as venture capital organizations, held mainly through private funds. Such debt securities take the form of senior debt, mezzanine and distressed debt.

Valuation Techniques

Cash and money market securities include short-term instruments that are recorded at cost plus accrued interest, which approximates fair value.

Fair values of government and corporate bonds, inflation-linked bonds, floating rate notes and mortgage-backed securities are based on prices obtained from third-party pricing sources. Such prices are determined using either an appropriate interest rate curve with a spread associated with the credit quality of the issuer or other generally accepted pricing methodologies.

ABTNs are measured at fair value whereby management relies on the valuation work performed by a recognized third-party expert. Management ensures that the valuation conducted by such expert uses acceptable industry methods. Financial information used in the valuation of ABTNs includes interest rates, credit spreads and the underlying investments' terms to maturity. In addition to the values determined by the expert, management integrated certain assumptions in the fair value of ABTNs that are not fully supported by market observable data, such as liquidity estimates and the impact of the funding facilities described in Note 10.

The fair value of private debt portfolios in the real estate sector is determined using either a yield-based or collateral-based valuation technique. The yield-based valuation technique involves discounting expected future cash flows that incorporate assumptions with respect to interest rates offered for similar loans to borrowers with similar credit ratings. The collateral-based valuation technique involves assessing the recoverable value of the collateral in question, net of disposal fees.

The fair value of fund investments included as part of private debt portfolios is determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

(iv) Alternative Investments

Alternative investments consist mainly of units of funds that hold a mix of equity, fixed income and derivative instruments as well as hedge funds.

Valuation Techniques

The fair value of these investments is obtained from the investment's external manager and reflects the fair value of the underlying equity, fixed income or derivative instruments, as applicable.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(v) Amounts Receivable and Payable from Pending Trades

Amounts receivable from pending trades consist of proceeds on sales of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Amounts payable from pending trades consist of the cost of purchases of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Valuation Techniques

The fair value of amounts receivable and payable from pending trades reflects the value at which their underlying original sale or purchase transactions were undertaken.

(vi) Interest and Dividends Receivable

Interest and dividends are recorded at the amounts expected to be received as at the reporting date, which approximates fair value.

(vii) Interest Payable

Interest is accrued at the amount expected to be paid as at the reporting date, which approximates fair value.

(viii) Securities Sold Short

Securities sold short reflect PSP Investments' obligation to purchase securities pursuant to short selling transactions. In such transactions, PSP Investments sells securities it does not own with an obligation to purchase similar securities on the market to cover its position.

Valuation Techniques

Using ask prices as inputs, the fair value of securities sold short is measured using the same method as the similar long positions presented within public markets and fixed income.

(ix) Securities Sold under Repurchase Agreements

PSP Investments is party to agreements which involve the sale of securities with a simultaneous agreement to repurchase such securities at a specified price and at a specified future date.

Securities sold under the repurchase agreements are not derecognized as PSP Investments retains all related risks and rewards of ownership. As such, all related income (loss) continues to be reported in investment income (loss).

Obligations to repurchase the securities sold are accounted for as investment-related liabilities. Interest expense related to such obligations is reported in investment income (loss).

Valuation Techniques

Obligations to repurchase the securities sold under repurchase agreements are recorded at cost plus accrued interest, which approximates fair value.

(x) Derivative-Related Receivables and Payables

The description and valuation of derivative-related receivables and payables are described in Note 3 (B).

(xi) Capital Market Debt Financing

PSP Investments' capital market debt program is described in Note 8. Short-term promissory notes are recorded at cost plus accrued interest, which approximates fair value. The fair value of PSP Investments' medium-term notes is based on prices that are obtained from third-party pricing sources. Such prices are determined using an interest rate curve with a spread consistent with PSP Investments' credit quality.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS

Derivative financial instruments are financial contracts that are settled at a future date. The value of such instruments is derived from changes in underlying assets, interest or exchange rates. Derivative financial instruments do not, typically, require an initial net investment. In certain cases, they require an initial net investment that is less than what would be required to hold the underlying position directly. PSP Investments uses derivative financial instruments to enhance returns or to replicate investments synthetically. Derivatives are also used to reduce the risk associated with existing investments.

PSP Investments uses the following types of derivative financial instruments:

(i) Swaps

Swaps are transactions whereby two counterparties exchange cash flow streams with each other based on predetermined conditions that include a notional amount and a term. Swaps are used to increase returns or to adjust exposures of certain assets without directly purchasing or selling the underlying assets.

(ii) Futures

Futures are standardized contracts to take or make delivery of an asset (buy or sell) at a predefined price and predefined future date. Futures are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iii) Forwards

Forwards are contracts involving the sale by one party and the purchase by another party of a predefined amount of an underlying instrument, at a predefined price and at a predefined date in the future. Forwards are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iv) Options

Options are the right, but not the obligation, to buy or sell a given amount of an underlying security, index, or commodity, at an agreed-upon price stipulated in advance, either at a determined date or at any time before the predefined maturity date.

(v) Warrants and Rights

Warrants are options to purchase an underlying asset which is in the form of a transferable security and which can be listed on an exchange.

Rights are securities giving shareholders entitlement to purchase new shares issued by a corporation at a predetermined price (normally less than the current market price) in proportion to the number of shares already owned. Rights are issued only for a short period of time, after which they expire.

(vi) Collateralized Debt Obligations

Collateralized debt obligations are a type of asset-backed security that is constructed from a portfolio of credit-related assets. Collateralized debt obligations are usually divided into several tranches with different credit risk levels and corresponding interest payments. Any losses are applied first to the more junior tranches (lowest risk rating) before moving up in seniority.

Valuation Techniques

All listed derivative financial instruments are recorded at fair value using quoted market prices with the bid price for long positions and the ask price for short positions. OTC derivatives are valued using appropriate valuation techniques, such as discounted cash flows using current market yields. The assumptions used include the statistical behaviour of the underlying instruments and the ability of the model to correlate with observed market transactions. Although pricing models used are widely accepted and used by other market participants, in the case of collaterized debt obligations, the nature of such instruments requires more significant assumptions about the behaviour of the default correlation. Such assumptions are not observable in the market.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

Notional values of derivative financial instruments are not recorded as assets or liabilities as they represent the face amount of the contract. Except for credit derivatives[1], notional values do not represent the potential gain or loss associated with the market or credit risk of such transactions disclosed below. Rather, they serve as the basis upon which the cash flows and the fair value of the contracts are determined.

The following table summarizes the derivatives portfolio as at March 31:

	2012				2011			
		Fair Value				Fair Value		
($ millions)	Notional Value	Assets	Liabilities	Net	Notional Value	Assets	Liabilities	Net
Equity and commodity derivatives								
Futures	**$ 72**	**$ –**	**$ –**	**$ –**	$ 30	$ –	$ –	$ –
Total return swaps	**577**	**10**	**(3)**	**7**	392	14	–	14
Options:								
Listed-purchased	**80**	**1**	**–**	**1**	32	1	–	1
Listed-written	**68**	**–**	**(1)**	**(1)**	28	–	(1)	(1)
OTC-purchased	**38**	**1**	**–**	**1**	–	–	–	–
OTC-written	**35**	**–**	**(1)**	**(1)**	–	–	–	–
Currency derivatives								
Forwards	**1,632**	**11**	**(13)**	**(2)**	1,210	22	(8)	14
Futures	**11**	**–**	**–**	**–**	–	–	–	–
Swaps	**67**	**–**	**(2)**	**(2)**	119	2	(1)	1
Options:								
OTC-purchased	**35**	**–**	**–**	**–**	71	1	–	1
OTC-written	**58**	**–**	**–**	**–**	13	–	–	–
Interest rate derivatives								
Bond forwards	**127**	**–**	**–**	**–**	70	–	–	–
Futures	**111**	**–**	**–**	**–**	125	–	–	–
Interest rate swaps	**536**	**3**	**(2)**	**1**	1,241	1	(2)	(1)
Total return swaps	**–**	**–**	**–**	**–**	46	–	–	–
Swaptions	**57**	**1**	**–**	**1**	249	–	–	–
Options:								
Listed-purchased	**584**	**–**	**–**	**–**	378	1	–	1
Listed-written	**589**	**–**	**–**	**–**	531	–	(1)	(1)
OTC-purchased	**56**	**1**	**–**	**1**	–	–	–	–
OTC-written	**272**	**–**	**(2)**	**(2)**	–	–	–	–
Credit derivatives[1]:								
Purchased	**85**	**2**	**(1)**	**1**	30	–	–	–
Sold	**41**	**–**	**(1)**	**(1)**	29	–	(1)	(1)
Total	**$ 5,131**	**$ 30**	**$ (26)**	**$ 4**	$ 4,594	$ 42	$ (14)	$ 28

[1] Credit derivatives include credit default swaps and collateralized debt obligations. PSP Investments, through sold credit derivatives, indirectly guarantees the underlying reference obligations. The maximum potential exposure is the notional amount of the sold credit derivatives as shown in the table above.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

The term to maturity based on notional value for the derivatives was as follows as at March 31, 2012:

($ millions)

Less than 3 months	**$ 2,940**
3 to 12 months	**1,255**
Over 1 year	**936**
Total	**$ 5,131**

(C) FAIR VALUE MEASUREMENT

Investments, investment-related assets and investment-related liabilities are classified according to the following hierarchy based on the significant inputs used in measuring their fair value.

Level 1: Valuation is based on quoted prices in active markets for identical assets or liabilities.

Level 2: Valuation is based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active. Level 2 also includes model-based valuation techniques for which all significant assumptions are observable in the market.

Level 3: Valuation is based on model-based techniques for which significant assumptions are not observable in the market. They reflect management's assessment of the assumptions that market participants would use in pricing the assets or liabilities.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2012:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 646	$ –	$ –	$ –	$ 646
Foreign equity	1,078	57	12	–	1,147
Private markets					
Real estate	–	–	527	–	527
Private equity	–	–	437	–	437
Infrastructure	–	–	302	–	302
Renewable resources	–	–	27	–	27
Fixed income					
Cash and money market securities	54	115	–	–	169
Government and corporate bonds	–	901	–	–	901
Inflation-linked bonds	–	279	–	–	279
Other fixed income securities	–	168	282	–	450
Alternative investments	–	62	21	–	83
INVESTMENTS	$ 1,778	$ 1,582	$ 1,608	$ –	$ 4,968
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 44	$ 44
Interest receivable[1]	–	–	–	11	11
Dividends receivable[1]	–	–	–	4	4
Derivative-related receivables	1	29	–	–	30
	$ 1	$ 29	$ –	$ 59	$ 89
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (70)	$ (70)
Interest payable[1]	–	–	–	(1)	(1)
Securities sold short	(30)	–	–	–	(30)
Securities sold under repurchase agreements	–	(90)	–	–	(90)
Derivative-related payables	(1)	(24)	(1)	–	(26)
Capital market debt financing:					
Short-term	–	(64)	–	–	(64)
Long-term	–	(214)	–	–	(214)
	$ (31)	$ (392)	$ (1)	$ (71)	$ (495)
NET INVESTMENTS	$ 1,748	$ 1,219	$ 1,607	$ (12)	$ 4,562

[1] No fair value hierarchy classification is required for these items.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2011:

($ millions)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 997	$ 4	$ –	$ –	$ 1,001
Foreign equity	771	148	–	–	919
Private markets					
Real estate	–	–	386	–	386
Private equity	–	–	367	–	367
Infrastructure	–	–	191	–	191
Fixed income					
Cash and money market securities	41	140	–	–	181
Government and corporate bonds	–	571	–	–	571
Inflation-linked bonds	–	211	–	–	211
Other fixed income securities	–	141	260	–	401
Alternative investments	–	78	–	–	78
INVESTMENTS	$ 1,809	$ 1,293	$ 1,204	$ –	$ 4,306
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 49	$ 49
Interest receivable[1]	–	–	–	10	10
Dividends receivable[1]	–	–	–	4	4
Derivative-related receivables	1	41	–	–	42
	$ 1	$ 41	$ –	$ 63	$ 105
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (77)	$ (77)
Interest payable[1]	–	–	–	(1)	(1)
Securities sold short	(4)	–	–	–	(4)
Securities sold under repurchase agreements	–	(36)	–	–	(36)
Derivative-related payables	(1)	(12)	(1)	–	(14)
Capital market debt financing:					
Short-term	–	(49)	–	–	(49)
Long-term	–	(124)	–	–	(124)
	$ (5)	$ (221)	$ (1)	$ (78)	$ (305)
NET INVESTMENTS	$ 1,805	$ 1,113	$ 1,203	$ (15)	$ 4,106

[1] No fair value hierarchy classification is required for these items.

The classification within the levels of the hierarchy is established at the time of the initial valuation of the asset or liability and reviewed on each subsequent reporting year-end.

There were no significant transfers between Level 1 and Level 2 during the year ended March 31, 2012 (no significant transfers during the year ended March 31, 2011).

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Reconciliation

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2012:

($ millions)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Gains	Unrealized Gains	Transfer out of Level 3	Closing Balance
Public markets	$ –	$ 11	$ (1)	$ –	$ –	$ 2	$ –	$ 12
Private markets	944	440	(159)	–	14	55	(1)	1,293
Fixed income	260	74	(69)	(16)	4	29	–	282
Alternative investments	–	21	–	–	–	–	–	21
Derivative-related receivables/payables (net)	(1)	–	–	–	–	–	–	(1)
Total	$ 1,203	$ 546	$ (229)	$ (16)	$ 18	$ 86	$ (1)	$ 1,607

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2011:

($ millions)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Losses	Unrealized Gains	Transfer out of Level 3	Closing Balance
Private markets	$ 863	$ 179	$ (170)	$ –	$ (5)	$ 78	$ (1)	$ 944
Fixed income	280	34	(69)	(15)	(5)	35	–	260
Derivative-related receivables/payables (net)	(23)	16	–	–	(18)	24	–	(1)
Total	$ 1,120	$ 229	$ (239)	$ (15)	$ (28)	$ 137	$ (1)	$ 1,203

[1] Includes Plan Account allocation adjustments.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Sensitivity Analysis

In the course of measuring fair value of financial instruments classified as Level 3, valuation techniques used incorporate assumptions that are based on non-observable data. Significant assumptions used for each asset class are described in Notes 3 (A) and (B). Although such assumptions reflect management's best judgment, the use of reasonably possible alternative assumptions could yield different fair value measures representing, at a minimum, a 2% increase/decrease (2011 - 2% increase/decrease) in the fair value of financial instruments categorized as Level 3. This excludes private debt portfolios in the real estate sector and certain fund investments, where a sensitivity analysis is not possible given the underlying assumptions used are not available to PSP Investments. In the case of fund investments, the fair value is determined based on the audited financial statements of the fund's general partner as indicated in Note 3 (A). With respect to private debt portfolios in the real estate sector, the fair value is obtained from third-party appraisers as described in Note 3 (A).

(D) SECURITIES LENDING AND BORROWING PROGRAMS

PSP Investments participates in securities lending and borrowing programs whereby it lends and borrows securities in order to enhance portfolio returns. Lending and borrowing transactions under such programs do not transfer the risks or rewards of ownership of the securities to the counterparty. Consequently, PSP Investments does not derecognize securities lent or recognize securities borrowed.

The securities lending and borrowing programs require collateral in cash, high-quality debt instruments or securities. Collateral transactions are conducted under terms that are usual and customary in standard securities lending and borrowing programs. PSP Investments and its counterparties are authorized to sell, repledge or otherwise use collateral held. The same securities or equivalent securities must be returned to the counterparty at the end of the contract, unless an event of default occurs. As at March 31, 2012, PSP Investments, on behalf of the Plan Account, has re-invested $122 million of collateral held (2011 – $106 million).

The following table illustrates the fair values of the Plan Account's allocated securities and collateral associated with the lending and borrowing programs as at March 31:

($ millions)	2012	2011
Securities lending		
Securities lent	**$ 494**	$ 409
Collateral contractually receivable[1]	**521**	427
Securities borrowing		
Securities borrowed	**30**	4
Collateral contractually payable[2]	**34**	3

[1] The minimum fair value of collateral required is equal to 102% of the fair value of the securities lent.

[2] The minimum fair value of collateral required is equal to 100% of the fair value of the securities borrowed.

(E) SECURITIES SOLD AND COLLATERAL PLEDGED UNDER REPURCHASE AGREEMENTS

Securities sold under repurchase agreements are described in Note 3 (A) (ix) and involve pledging collateral consisting of cash or securities deemed acceptable by the counterparties. Collateral transactions are conducted under terms that are usual and customary in standard repurchase arrangements. Such terms require the relevant counterparty to pledge additional collateral based on the changes in the fair value of the existing collateral pledged. The counterparties are authorized to sell, repledge or otherwise use collateral held. The securities pledged as collateral must be returned to the relevant counterparty at the end of the contract, unless an event of default occurs. PSP Investments does not sell, repledge or otherwise use collateral held.

On behalf of the Plan Account, PSP Investments pledged collateral under the repurchase agreements with a fair value of $90 million at March 31, 2012 (2011 – $36 million).

4. INVESTMENT RISK MANAGEMENT

Risk Management is a central part of PSP Investments' operations. Included in the overall risk management framework is a continuous process whereby PSP Investments systematically addresses the investment risks related to its various investment activities with the goal of achieving a maximum rate of return without undue risk of loss.

A risk governance framework that includes required reporting on risk to all levels of the organization ensures that appropriate investment objectives are pursued and achieved in line with the fulfillment of PSP Investments' legislated mandate. The Board of Directors and its committees oversee all risk matters and receive assurances from senior management, including the Chief Risk Officer, as well as PSP Investments' independent internal auditor reporting directly to the Audit Committee.

PSP Investments has adopted an Investment Risk Management Policy which is an integral part of its risk control system and supplements the Statement of Investment Policies, Standards and Procedures (SIP&P). The objective of this policy is to provide a framework to manage the risks that PSP Investments is exposed to, namely, market, credit and liquidity risks.

(A) MARKET RISK

Market risk is the risk that the value of an investment will fluctuate as a result of changes in market prices, whether those changes are caused by factors specific to the individual investment, volatility in share and commodity prices, interest rate, foreign exchange or other factors affecting similar securities traded in the market.

Market risk management focuses on the following two key components:

– Policy Portfolio
The Policy Portfolio (long-term asset mix), as defined in the SIP&P, determines a diversification strategy to mitigate risk whereby PSP Investments invests in a diversified portfolio expected to achieve a return at least equal to the Actuarial Rate of Return (ARR); defined as the rate of return assumption used by the Chief Actuary of Canada in the latest actuarial valuation reports of the Plans. In the absence of other factors affecting the funding of the Plans or changes to pension benefits under the Plans, the ARR is the rate of return required to maintain funding requirements and pension benefits at their current levels.

– Active Management
Active management is defined as the sum of investment strategies that deviate from the approved Policy Portfolio. It is designed to supplement the returns of the Policy Portfolio within an active risk budget.

The risks associated with these components are the Policy Portfolio market risk and the active risk. The Policy Portfolio market risk represents the investment risk arising from the exposure to approved asset classes in the approved weightings. In establishing its Policy Portfolio, PSP Investments also takes into consideration the impact of the Policy Portfolio market risk on funding risk. Funding risk is the risk that the assets under management will be insufficient to meet the relevant pension liabilities of the Plans, which may require the contributions to the Funds of the Plans to be increased. The Policy Portfolio is reviewed at least annually as part of the review of the SIP&P, and this review includes changes, if any, to PSP Investments' long-term expectations of market conditions and other factors that may affect the funding levels of the Plans.

Active risk refers to all market risk arising from active management activities. It is managed in accordance with the Investment Risk Management Policy.

Measurement of Market Risk

The Value-at-Risk (VaR) is one of the methods used to measure market risk and is reported on a quarterly basis. It is not the maximum potential loss, but rather the maximum loss not exceeded with a given confidence level, over a given period of time. PSP Investments uses a Historical VaR model incorporating ten years' worth of market returns scaled to a twelve-month holding period at a 95% confidence level. For investments that are not actively traded, the calculation of VaR uses securities with similar risk attributes as proxy.

In measuring Policy Portfolio risk, VaR represents the absolute loss expected from the Policy Portfolio (Policy Portfolio VaR). Whereas in terms of measuring the active risk, VaR reflects the loss relative to the Policy Portfolio benchmark (Active VaR).

VaR is statistically valid under normal market conditions and does not specifically consider losses from severe market events. It also assumes that the future will behave in a pattern similar to the past. Consequently, if future market conditions differ significantly from those of the past, potential losses may differ from those originally estimated.

The following table shows the Total VaR consisting of the Policy Portfolio VaR, the Active VaR and the diversification effect, calculated as a percentage of net investments, as at March 31. The diversification effect captures the impact of holding different types of assets which may react differently in various types of situations and thus reduces the Total VaR.

	2012	2011
Policy Portfolio VaR	**21.7 %**	22.4 %
Active VaR	**2.6**	2.2
Total VaR (undiversified)	**24.3**	24.6
Diversification effect	**(1.6)**	(2.9)
Total VaR	**22.7 %**	21.7 %

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

Stress Testing

Although VaR is a widely accepted risk measure, it is complemented by other risk measurement methodologies that provide greater insight on market risk. PSP Investments uses stress testing and scenario analysis to examine the impact on financial results of abnormally large movements in risk factors. Stress testing and scenario analysis are used to test a portfolio's sensitivity to various risk factors and key model assumptions. These methods also use historically stressed periods to evaluate how a current portfolio reacts under such circumstances. Stress testing and scenario analysis are also deployed to assess new product performance.

(i) Interest Rate Risk

Interest rate risk refers to the risk that fluctuations in interest rates will directly affect the fair value of the Plan Account's net asset values.

The terms to maturity of the investments with the most significant exposure to interest rate risk were as follows as at March 31, 2012:

($ millions)	Less than 1 Year	1 to 5 Years	5 to 10 Years	Over 10 Years	Other	Total
Government bonds	$ 95	$ 336	$ 121	$ 128	$ –	$ 680
Corporate bonds	44	93	62	22	–	221
Inflation-linked bonds	–	74	69	136	–	279
Asset-backed securities	–	127	2	–	–	129
Private debt portfolios:						
Directly held	4	29	–	–	–	33
Held through funds[1]	–	–	–	–	130	130
Total investments with significant exposure to interest rate risk	$ 143	$ 659	$ 254	$ 286	$ 130	$ 1,472
Other investments[2]	$ –	$ –	$ –	$ –	$ 327	$ 327
Total fixed income	$ 143	$ 659	$ 254	$ 286	$ 457	$ 1,799

[1] Due to their nature, information in connection with the terms to maturity of fund investments included in the private debt portfolios is not available.

[2] Consists of $169 million in cash and money market securities and $158 million in floating rate notes, which, due to their nature, are not significantly exposed to interest rate risk.

The terms to maturity of PSP Investments' capital market debt financing are disclosed in Note 8.

Alternative investments as well as derivative contracts described in Notes 3 (A) (iv) and (B), respectively, are also subject to interest rate risk exposures. These exposures are reflected in the VaR calculation described in Note 4 (A).

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

(ii) Foreign Currency Risk

PSP Investments and its subsidiaries are exposed to currency risk through holdings of securities, units in pooled funds and units in limited partnerships of non-Canadian assets. Fluctuations in the relative value of the Canadian dollar against these foreign currencies can result in a positive or a negative effect on the fair value of the investments. To mitigate this risk, PSP Investments may take, through foreign forward contracts or cross currency swaps, positions in foreign currencies. PSP Investments' policy is to hedge a target of 50% of its foreign currency investments in non-emerging countries. Additional factors are considered when implementing the hedging target for investments in emerging countries, namely, total relative exposure and cost effectiveness.

The underlying net foreign currency exposures for the Plan Account, after allocating the effect of derivative contracts and investment-related assets and liabilities for both monetary and non-monetary items were as follows as at March 31:

(in millions of Canadian $)	2012		2011	
Currency	**Fair Value**	**% of Total**	Fair Value	% of Total
US Dollar	**$ 918**	**57.9 %**	$ 672	54.0 %
Euro	**188**	**11.9**	169	13.6
British Pound	**124**	**7.8**	94	7.6
Japanese Yen	**71**	**4.5**	50	4.0
Brazilian Real	**64**	**4.0**	62	5.0
Hong Kong Dollar	**48**	**3.0**	47	3.8
Korean Won	**34**	**2.2**	33	2.7
Australian Dollar	**29**	**1.8**	21	1.7
Norwegian Krone	**24**	**1.5**	7	0.6
Indian Rupee	**14**	**0.9**	10	0.8
Others	**72**	**4.5**	77	6.2
Total	**$ 1,586**	**100.0 %**	$ 1,242	100.0 %

PSP Investments and its subsidiaries also had commitments, denominated in foreign currencies of $457 million (US$401 million, €37 million, R9 million South African Rands and R13 million Brazilian Reals) for the Plan Account which were not included in the foreign currency exposure table.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK

PSP Investments is exposed to credit risk, that is, the risk that the issuer of a debt security or that the counterparty to a derivative contract, to a securities lending and borrowing transaction or to securities sold under repurchase agreements, is unable to meet its financial obligations.

Credit risk encompasses the risk of a deterioration of creditworthiness and the relevant concentration risk. Credit risk monitoring entails an evaluation of the credit quality of each issuer and counterparty that transacts with PSP Investments. To perform this evaluation, PSP Investments relies on four recognized credit rating agencies. A minimum of two credit ratings are used to classify each security. Except for ABTNs, securities rated by only one agency are classified as "not rated". If the agencies disagree as to a security's credit quality, PSP Investments uses the lowest of the available ratings.

As at March 31, 2012, the Plan Account's maximum exposure to credit risk amounted to approximately $2 billion (2011 – approximately $1 billion). This amount excludes investments in distressed debt in the amount of approximately $0.1 billion as at March 31, 2012 (2011 – approximately $0.1 billion). The maximum exposure to credit risk also excludes collateralized debt obligations, collateral held as disclosed in Notes 3 (D), 3 (E) and 4 (B) and the impact of guarantees and indemnities disclosed in Note 10.

As at March 31, 2012, the Plan Account had a net notional exposure of $12 million (2011 – $19 million) to various tranches of collateralized debt obligations, of which approximately 61% (2011 – approximately 44%) of the underlying dollar exposure was rated "Investment grade", as well as funding facilities, as described in Note 10, to support potential margin calls on the ABTNs.

To monitor the evolution of credit risk, PSP Investments periodically produces a concentration report by credit rating of all credit-sensitive financial securities with the exception of securities held in pooled funds or for private markets investments.

PSP Investments' concentration of credit risk by credit rating, excluding the items described above and any other credit enhancement, for the Plan Account was as follows as at March 31:

	2012	2011
Investment grade (AAA to BBB–)	**98.2 %**	97.9 %
Below investment grade (BB+ and below)	**0.7**	0.4
Not rated:		
Rated by a single credit rating agency	**0.1**	0.1
Not rated by credit rating agencies	**1.0**	1.6
Total	**100.0 %**	100.0 %

Counterparty Risk

Counterparty risk represents the credit risk from current and potential exposure related to transactions involving derivative contracts, securities lending and borrowing as well as securities sold under repurchase agreements. In order to minimize counterparty risk, PSP Investments requires that counterparties provide adequate collateral and meet its credit rating requirements. PSP Investments frequently monitors the credit rating of its counterparties as determined by recognized credit rating agencies. With respect to derivative contracts, PSP Investments has the ability to terminate all trades with most counterparties whose credit rating is downgraded below its requirements.

PSP Investments' policy also requires the use of the International Swaps and Derivative Association (ISDA) Master Agreement with all counterparties to derivative contracts. The ISDA Master Agreement provides the contractual framework within which dealing activities across a full range of OTC products are conducted.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK (continued)

Counterparty Risk (continued)

As a credit mitigation technique, the ISDA Master Agreement contractually binds both parties to use master-netting arrangements and, in the case of default of the counterparty, close-out netting. Additionally, the Credit Support Annex (CSA) to the ISDA Master Agreement enables PSP Investments to realize any collateral placed with it in the case of default of the counterparty. The CSA also requires PSP Investments to contribute further collateral when requested. All collateral transactions are in high-quality debt instruments or securities. The CSA also regulates the exchange of collateral when the credit exposure to a counterparty exceeds a predetermined threshold. In certain cases, counterparties are authorized to sell, repledge or otherwise use collateral held. On behalf of the Plan Account, PSP Investments pledged securities with a fair value of $193 thousand as collateral with respect to derivative contracts at March 31, 2012 (2011 – nil). Securities with a fair value of $7 million were received from counterparties as collateral at March 31, 2012 (2011 – $10 million). PSP Investments does not sell, repledge or otherwise use any collateral held with respect to derivative contracts.

With respect to transactions involving securities lending and borrowing as well as securities sold under repurchase agreements, collateral requirements are in place to mitigate counterparty risk. Notes 3 (D) and 3 (E) describe collateral requirements in securities lending and borrowing programs as well as securities sold under repurchase agreements, respectively.

In the case of the securities lending program, PSP Investments' exposure to counterparty risk is further mitigated as the custodian of the securities lent assumes the risk that a counterparty will be unable to meet its obligations associated with the collateral requirements.

Management is responsible for counterparty risk monitoring and mitigation as well as maintaining a comprehensive, disciplined, and enterprise-wide process for tracking and managing counterparty risk. As such, Management measures counterparty risk on an ongoing basis, evaluates and tracks the creditworthiness of current counterparties and mitigates counterparty risk through collateral management.

(C) LIQUIDITY RISK

Liquidity risk corresponds to PSP Investments' ability to meet its financial obligations when they come due with sufficient and readily available cash resources. PSP Investments' cash position is monitored on a daily basis. In general, investments in cash, cash equivalents, floating rate notes, bonds and public equities are expected to be highly liquid as they will be invested in securities that are actively traded. Management utilizes appropriate measures and controls to monitor liquidity risk in order to ensure that there is sufficient liquidity to meet financial obligations as they come due. A liquidity report taking into consideration future forecasted cash flows is prepared and presented to senior management on a weekly basis. This ensures that sufficient cash reserves are available to meet forecasted cash outflows. Additionally, sufficient sources of liquidity are maintained for deployment in case of market disruption.

PSP Investments has the ability to raise additional capital through the use of its capital market debt program. This program allows PSP Investments to issue short-term promissory notes and medium-term notes. Note 8 provides additional information on the usage of the capital market debt program.

The terms to maturity of the notional amount of derivatives are disclosed in Note 3 (B).

4. INVESTMENT RISK MANAGEMENT (continued)

(C) LIQUIDITY RISK (continued)

Financial Liabilities

The following tables present the fair value of non-derivative-related financial liabilities as well as derivative-related financial instruments, aggregated according to their maturities as at March 31, 2012:

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Non-derivative-related financial liabilities[1]				
Amounts payable from pending trades	$ (70)	$ –	$ –	$ (70)
Interest payable	(1)	–	–	(1)
Securities sold short	(30)	–	–	(30)
Securities sold under repurchase agreements	(90)	–	–	(90)
Capital market debt financing	(59)	(5)	(214)	(278)
Accounts payable and other liabilities	(6)	–	(2)	(8)
Total	$ (256)	$ (5)	$ (216)	$ (477)

($ millions)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Derivative-related financial instruments				
Derivative-related receivables	$ 11	$ 12	$ 7	$ 30
Derivative-related payables[1]	(11)	(7)	(8)	(26)
Total	$ –	$ 5	$ (1)	$ 4

[1] Liabilities are presented in the earliest period in which the counterparty can request payment.

5. FUND TRANSFERS

On behalf of the Plan Account, PSP Investments received fund transfers of $331 million for the year ended March 31, 2012 (2011 – $341 million) from the Fund.

6. INVESTMENT INCOME

Investment income, for the years ended March 31, was as follows:

($ millions)	2012	2011
Interest income	**$ 47**	$ 36
Dividend income	**54**	42
Other income	**14**	13
Dividend expense	**(1)**	(1)
Interest expense (Note 8)	**(6)**	(4)
Transaction costs	**(5)**	(4)
External investment management fees [1]	**(2)**	(3)
	101	79
Net realized gains [2]	**71**	129
Net unrealized (losses) gains	**(39)**	290
Investment income	**$ 133**	$ 498

[1] Consists of amounts incurred for investments in public markets that are paid directly by PSP Investments. This excludes investments fees related to certain pooled fund investments classified under alternative investments primarily related to performance, in the amount of $4 million for the year ended March 31, 2012 (2011 – $6 million). This also excludes management fees related to investments in private markets and other fixed income securities that are not paid directly by PSP Investments.

Such fees, which generally vary between 0.1% and 2.0% of the total invested and/or committed amount, totalled $8 million for the year ended March 31, 2012 (2011 – $10 million).

[2] Includes foreign currency losses of $3 million for the year ended March 31, 2012 (2011 – gains of $8 million).

7. EXPENSES

(A) ALLOCATION OF EXPENSES

The Act requires that the costs of operation of PSP Investments be charged to the Plan Accounts for which it provides investment services. Under section 4(3) of the Act, the President of the Treasury Board shall determine to which Plan Account these costs will be charged, in consultation with the Minister of National Defence and the Minister of Public Safety. An allocation policy was developed which allocates the direct costs of investment activities, such as external investment management fees and custodial fees, to each Plan Account, based upon the asset value of each Plan Account at the time the expense was incurred.

All other operating expenses, excluding the direct cost of investment activities listed above, for the years ended March 31, were allocated in proportion to the annual amount of net assets in each Plan Account as follows:

	2012	2011
Public Service Pension Plan Account	**72.9 %**	72.7 %
Canadian Forces Pension Plan Account	**19.4**	19.7
Royal Canadian Mounted Police Pension Plan Account	**7.1**	7.1
Reserve Force Pension Plan Account	**0.6**	0.5
Total	**100.0 %**	100.0 %

Expenses are paid by PSP Investments by way of advances from the Public Service Pension Plan Account, which are reimbursed by the other Plan Accounts on a quarterly basis.

(B) OPERATING EXPENSES

Operating expenses allocated to this Plan Account, for the years ended March 31, consisted of the following:

($ thousands)	2012	2011
Salaries and benefits	**$ 6,836**	$ 4,958
Professional and consulting fees	**764**	571
Office supplies and equipment	**1,064**	891
Other operating expenses	**455**	346
Depreciation of fixed assets	**655**	695
Occupancy costs	**391**	339
Custodial fees	**216**	168
Remuneration earned by Directors	**57**	54
Travel and related expenses for Directors	**19**	13
Communication expenses	**15**	14
Total	**$ 10,472**	$ 8,049

8. CAPITAL MARKET DEBT FINANCING

PSP Investments' capital market debt program consists of the private placement of short-term promissory notes as well as medium-term notes issued by PSP Capital Inc., a wholly-owned subsidiary of PSP Investments. The capital raised is primarily used to finance investments in real estate, infrastructure and renewable resources. It is unconditionally and irrevocably guaranteed by PSP Investments in accordance with its corporate leverage policy.

The maximum amount authorized by the Board of Directors for the capital market debt program is 7.5% of the net investments plus all recourse debt outstanding of PSP Investments. Under this limit, the short-term promissory note component cannot exceed $3 billion.

The following outlines the terms as well as the fair value of the notes issued under the capital market debt program allocated to the Plan Account as at March 31:

		2012	2011
($ millions)	**Capital amounts to be paid at maturity**	**Fair Value**	Fair Value
Short-term promissory notes, bearing interest between 1% and 1.42% and maturing within 31 and 364 days of issuance (March 31, 2011 – 29 and 363 days)	**$ 64**	**$ 64**	$ 49
Medium-term notes Series 1, bearing interest of 4.57% per annum and maturing on December 9, 2013	**$ 71**	**$ 74**	$ 75
Medium-term notes Series 2, bearing interest of 2.94% per annum and maturing on December 3, 2015	**$ 49**	**$ 51**	$ 49
Medium-term notes Series 3, bearing variable interest of 3-month CDOR + 39 basis points and maturing on February 16, 2015	**$ 25**	**$ 25**	$ –
Medium-term notes Series 4, bearing interest of 2.26% per annum and maturing on February 16, 2017	**$ 63**	**$ 64**	$ –
Total	**$ 272**	**$ 278**	$ 173

The operating expenses incurred by PSP Capital Inc. were allocated to each Plan Account as described in Note 7 (A).

Interest expense, for the years ended March 31, was as follows:

($ thousands)	**2012**	2011
Short-term promissory notes	**$ 896**	$ 631
Medium-term notes	**4,920**	3,699
Total	**$ 5,816**	$ 4,330

9. CAPITAL MANAGEMENT

As an investment company, PSP Investments' objectives in managing its capital are:

- To invest fund transfers, outlined in Note 5, in the best interests of the beneficiaries and contributors under the *Superannuation Acts*. The funds received are invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the Plans established under the *Superannuation Acts* and the ability of the Plans to meet their financial obligations. The funds are also invested in accordance with the Investment Risk Management policies which are outlined in Note 4.
- To maintain an appropriate credit rating to achieve access to the capital markets at the lowest cost of capital. Through PSP Capital Inc. and its leverage policies, PSP Investments has the ability to raise capital by issuing short-term promissory notes and medium-term notes. Note 8 provides information on the capital market debt financing and Note 4 (C) provides information on PSP Investments' liquidity.

The capital structure of PSP Investments consists of fund transfers and capital market debt financing. PSP Investments has no externally imposed restrictions on capital.

10. GUARANTEES AND INDEMNITIES

PSP Investments provides indemnification to its Directors, its Officers, its vice-presidents and to certain PSP Investments representatives who are asked to serve on boards of directors (or like bodies) or investment advisory boards (or like bodies) of entities in which PSP Investments or its wholly-owned subsidiaries have made an investment or have a financial interest. As a result, but subject to the Act, PSP Investments may be required to indemnify these representatives for costs incurred, such as claims, actions or litigations in connection with the exercise of their duties, unless the liability of such a representative relates to a failure to act honestly and in good faith. To date, PSP Investments has not received any claims or made any payment for such indemnity.

In certain cases, PSP Investments also provides indemnification to third parties in the normal course of business. As a result, PSP Investments may be required to indemnify such third parties in connection with the performance of their contractual obligations. To date, PSP Investments has not received any claims nor made any payments for such indemnities.

PSP Investments unconditionally and irrevocably guarantees all credit facilities, short-term promissory notes and medium-term notes issued by PSP Capital Inc.

PSP Capital Inc. provided funding facilities of a maximum amount of $969 million to support potential margin calls on the ABTNs, of which $69 million has been allocated to the Plan Account. As at March 31, 2012, the margin funding facilities have not been drawn upon since inception.

In certain investment transactions, PSP Investments provided guarantees or indemnifications to third parties, the most significant of which are as follows:

As at March 31, 2012, PSP Investments agreed to guarantee, as part of an investment transaction, a non-revolving term loan. In the event of a default, the Plan Account could assume the obligation up to $29 million (2011 – $29 million) plus interest and other related costs. The loan matures in March 2015.

As at March 31, 2012, a wholly-owned subsidiary of PSP Investments has agreed to provide indemnification with respect to the contractual obligations and commitments of a third-party. In the event of a default by such third-party, the subsidiary may be required to assume an obligation of up to $195 million (2011 – $195 million), of which $14 million (2011 – $14 million) may be allocated to the Plan Account, as estimated at the time of the completion of the investment transaction. The subsidiary would also have direct recourse against the defaulting third party in all circumstances. The guarantee expires in April 2012.

11. COMMITMENTS

PSP Investments and its subsidiaries have committed to enter into investment transactions, which will be funded over the next several years in accordance with agreed terms and conditions. The portion of PSP Investments' commitments that would be assumed by the Plan Account was as follows as at March 31, 2012:

($ millions)		
Real estate	$	107
Private equity		288
Infrastructure		61
Other fixed income securities		41
Total	**$**	**497**

RESERVE FORCE PENSION PLAN ACCOUNT

INDEPENDENT AUDITORS' REPORT

To the Minister of National Defence

REPORT ON THE FINANCIAL STATEMENTS

We have audited the accompanying financial statements of the Public Sector Pension Investment Board – Reserve Force Pension Plan Account (the Reserve Force Pension Plan Account), which comprise the balance sheet as at March 31, 2012, and the statement of net income from operations and comprehensive income and statement of changes in net assets for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

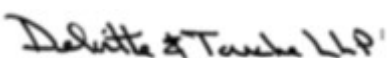
Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Reserve Force Pension Plan Account as at March 31, 2012, and the results of its operations and changes in its net assets for the year then ended in accordance with Canadian generally accepted accounting principles.

REPORT ON OTHER LEGAL AND REGULATORY REQUIREMENTS

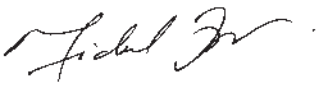
As required by the *Financial Administration Act,* we report that, in our opinion, Canadian generally accepted accounting principles have been applied on a basis consistent with that of the preceding year.

Further, in our opinion, the transactions of the Reserve Force Pension Plan Account that have come to our notice during our audit of the financial statements have, in all significant respects, been in accordance with the applicable provisions of Part X of the *Financial Administration Act* and regulations, the *Public Sector Pension Investment Board Act* and regulations and the by-laws of the Public Sector Pension Investment Board and its wholly-owned subsidiaries.



[1] Chartered accountant auditor permit No. 18527

May 14, 2012
Montréal, Canada



Michael Ferguson, FCA
Auditor General of Canada

May 14, 2012
Ottawa, Canada

BALANCE SHEET

As at March 31

($ thousands)	2012	2011
ASSETS		
Investments (Note 3 (A))	**$397,229**	$339,327
Investment-related assets (Note 3 (A))	**7,107**	8,223
Other assets	**180**	85
	$404,516	$347,635
LIABILITIES		
Investment-related liabilities (Note 3 (A))	**$ 39,585**	$ 24,008
Accounts payable and other liabilities	**437**	139
Due to the Public Service Pension Plan Account	**221**	241
	$ 40,243	$ 24,388
NET ASSETS	**$364,273**	$323,247
Accumulated net income from operations and comprehensive income	**$ 53,701**	$ 43,730
Accumulated fund transfers	**310,572**	279,517
NET ASSETS	**$364,273**	$323,247

Commitments (Note 11)

The accompanying notes are an integral part of the financial statements.

On behalf of the Board of Directors:

Cheryl Barker
Interim Chair of the Board

William A. Mackinnon
Chair of the Audit Committee

STATEMENT OF NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME

For the years ended March 31

($ thousands)	2012	2011
INVESTMENT INCOME (Note 6)	**$ 10,801**	$ 38,759
OPERATING EXPENSES (Note 7)	**$ 830**	$ 570
NET INCOME FROM OPERATIONS AND COMPREHENSIVE INCOME	**$ 9,971**	$ 38,189

The accompanying notes are an integral part of the financial statements.

STATEMENT OF CHANGES IN NET ASSETS

For the years ended March 31

($ thousands)	2012	2011
NET ASSETS, BEGINNING OF YEAR	**$323,247**	$231,013
Fund transfers (Note 5)	**31,055**	54,045
Net income from operations and comprehensive income	**9,971**	38,189
Increase in net assets for the year	**41,026**	92,234
NET ASSETS, END OF YEAR	**$364,273**	$323,247

The accompanying notes are an integral part of the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the year ended March 31, 2012

ORGANIZATION

The Public Sector Pension Investment Board (PSP Investments) is a Crown corporation created under the *Public Sector Pension Investment Board Act* (the "Act") to manage and invest amounts that are transferred to it, under the *Superannuation Acts*, by the funds (as defined in the Act) of the pension plans established under the *Public Service Superannuation Act*, the *Canadian Forces Superannuation Act* (CFSA), the *Royal Canadian Mounted Police Superannuation Act* (collectively the "*Superannuation Acts*"), and certain regulations under the CFSA (the "CFSA Regulations"). The pension plans established under the *Superannuation Acts* consist of the Public Service pension plan, the Canadian Forces pension plan, and the Royal Canadian Mounted Police pension plan, whereas the pension plan established under the CFSA Regulations is the Reserve Force pension plan. They are herein referred to individually as the "Plan" and collectively as the "Plans".

The fund from which amounts are currently transferred to PSP Investments (the "Fund") relates to pension obligations under the Reserve Force pension plan for service on or after March 1, 2007. The account managed by PSP Investments for the Fund is herein referred to as the "Plan Account". PSP Investments maintains records of the Fund's net contributions, as well as the allocation of its investments and the results of its operations in the Plan Account.

PSP Investments is responsible for managing amounts that are transferred to it from the Fund in the best interests of the beneficiaries and contributors under the *Canadian Forces Superannuation Act*. The amounts are to be invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the *Canadian Forces Superannuation Act* and the Reserve Force pension plan's ability to meet its financial obligations.

Pursuant to the CFSA and the CFSA Regulations, the Government of Canada, which administers the Fund, may call upon PSP Investments for amounts required for the purpose of paying benefits under the Plan in respect of service on or after March 1, 2007. Amounts remitted by PSP Investments for such purpose cannot exceed, at any time, the net assets of PSP Investments allocated to the Plan Account.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These financial statements present the financial position and operations of PSP Investments and its wholly-owned subsidiaries as they pertain to the investment of the net contributions transferred to it from the Fund in respect of member service after March 1, 2007. Accordingly, they do not reflect all of the assets or the details of the pension contributions, payments and liabilities of the Fund. The financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). PSP Investments qualifies as an Investment Company and therefore reports its investments at fair value, in accordance with Accounting Guideline 18, "Investment Companies" (AcG-18). All changes in fair value are included in investment income (loss) as net unrealized gains (losses).

Comparative figures have been reclassified to conform to the current year's presentation.

VALUATION OF INVESTMENTS

Investments, investment-related assets and investment-related liabilities are recorded at the date upon which PSP Investments becomes a party to the associated contractual provisions, and are carried at fair value. Purchases and sales are recorded as of the trade date. Fair value is an estimate of the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

At trade date, the best evidence of fair value is the transaction price. At each subsequent reporting year-end, market prices are used to determine fair value where an active market exists (such as a recognized securities exchange), as they reflect actual and regularly occurring market transactions on an arm's length basis. If quoted market prices are not available, then fair values are estimated using present value or other valuation techniques, using inputs existing at the end of the reporting year that are derived from observable market data.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

VALUATION OF INVESTMENTS (continued)

Valuation techniques are generally applied to investments in real estate, private equity, infrastructure and renewable resources, over-the-counter (OTC) derivatives and certain fixed income securities. The values derived from applying these techniques are impacted by the choice of valuation model and the underlying assumptions made concerning factors such as the amounts and timing of future cash flows, discount rates, volatility and credit risk. In certain cases, such assumptions are not supported by market observable data.

The valuation methods of the investments are described in Notes 3 (A) and (B).

TRANSACTION COSTS

Transaction costs are incremental costs directly attributable to the acquisition, due diligence, issue, or disposal of a financial asset or financial liability. Transaction costs are expensed as incurred and recorded as a component of investment income (loss).

INVESTMENT MANAGEMENT FEES

Investment management fees are directly attributable to the external management of assets on behalf of PSP Investments. Management fees incurred for investments in private markets and certain private debt portfolios are paid by the investment directly, through capital contributions by PSP Investments or offset against distributions received from the investment. Management fees are also incurred for certain public markets and alternative investments and are paid either directly by PSP Investments or offset against distributions received from pooled fund investments. In both cases, they are recorded against investment income (loss).

INCOME RECOGNITION

The investment income (loss) has been allocated proportionately based on the asset value held by the Plan Account.

Investment income (loss) is made up of interest income, dividends, realized gains (losses) on the disposal of investments and unrealized gains (losses) which reflect the change in unrealized appreciation (depreciation) of investments held at the end of the year. Interest income is recognized as earned. Dividends are recognized on the ex-dividend date and are reflected as dividend income. Dividends paid or payable on securities sold short are reflected as dividend expense. Other income includes securities lending income (net of fees on securities borrowed), as well as private markets distributions from pooled funds, limited partnerships or from direct investments and co-investments. Co-investments are investments in private entities where the investment is made in conjunction with an external manager with whom PSP Investments already has committed and delegated funds.

TRANSLATION OF FOREIGN CURRENCIES

Investment transactions in foreign currencies are recorded at exchange rates prevailing on the transaction date. Investments denominated in foreign currencies and held at the end of the year are translated at exchange rates in effect at the year-end date. Any realized and unrealized gains (losses) on foreign exchange are included in investment income (loss).

FUND TRANSFERS

Amounts received from the Fund are recorded in the Plan Account.

INCOME TAXES

PSP Investments and the majority of its subsidiaries are exempt from Part I tax under paragraphs 149(1)*(d)* and 149(1)*(d.2)* of the *Income Tax Act* (Canada), respectively.

USE OF ESTIMATES

In preparing these financial statements, management makes certain estimates and assumptions which can affect the reported values of assets and liabilities. This is principally reflected in the valuation of private markets investments, certain fixed income securities, related income and expenses as well as note disclosures. Although estimates and assumptions reflect management's best judgment, actual results may differ from these estimates.

2. FUTURE CHANGES IN ACCOUNTING POLICIES

In February 2008, the Accounting Standards Board of Canada (AcSB) confirmed that Canadian GAAP for publicly accountable enterprises would converge with International Financial Reporting Standards (IFRS) effective January 1, 2011.

In 2011, the AcSB decided to defer the adoption of IFRS by investment companies, currently applying AcG-18 to annual periods starting on or after January 1, 2014. This deferral delays PSP Investments' transition to IFRS until the March 31, 2015 annual consolidated financial statements.

The AcSB's decision was in response to an announcement by the International Accounting Standards Board (IASB) in 2010, regarding an Exposure Draft (ED) being developed. The IASB proposed to define an investment entity and exempt it from consolidation by requiring it to measure all controlled investments at fair value, with changes recognized in profit or loss. The ED, *Investment Entities*, was published in August 2011 and is expected to be finalized in the second half of 2012. PSP Investments will complete the assessment of the impact of its transition to IFRS once the ED is finalized and a standard is issued.

The AcSB also announced in 2011 that it will evaluate whether entities like PSP Investments, which are separate from a pension plan and without a pension obligation, and whose sole purpose is to hold and invest assets received from one or more pension plans, would qualify as investment entities under the IASB's ED. Based on the result of this evaluation, the AcSB will then decide whether these entities would need to be included within the scope of Section 4600, "Pension Plans", where investments are accounted for at fair value.

3. INVESTMENTS

(A) INVESTMENT PORTFOLIO

The investment portfolio is organized according to the nature and common characteristics associated with the investments held. The following table presents the investment portfolio as at March 31:

	2012		2011	
($ thousands)	**Fair Value**	**Cost**	Fair Value	Cost
Public markets				
Canadian equity	**$ 51,632**	**$ 52,862**	$ 78,794	$ 67,062
Foreign equity	**91,648**	**82,727**	72,337	63,941
Private markets				
Real estate	**42,091**	**40,083**	30,390	31,511
Private equity	**34,909**	**28,534**	28,925	23,779
Infrastructure	**24,109**	**25,436**	15,086	16,513
Renewable resources	**2,122**	**2,122**	–	–
Fixed income				
Cash and money market securities	**13,787**	**13,787**	14,287	14,287
Government and corporate bonds	**72,005**	**70,080**	45,013	44,994
Inflation-linked bonds	**22,309**	**20,094**	16,616	16,881
Other fixed income securities	**35,982**	**32,419**	31,669	30,474
Alternative investments	**6,635**	**759**	6,210	478
INVESTMENTS	**$397,229**	**$368,903**	$339,327	$309,920
Investment-related assets				
Amounts receivable from pending trades	**$ 3,554**	**$ 3,554**	$ 3,886	$ 3,886
Interest receivable	**902**	**902**	780	780
Dividends receivable	**336**	**336**	279	279
Derivative-related receivables	**2,315**	**458**	3,278	156
	$ 7,107	**$ 5,250**	$ 8,223	$ 5,101
Investment-related liabilities				
Amounts payable from pending trades	**$ (5,584)**	**$ (5,584)**	$ (6,043)	$ (6,043)
Interest payable	**(137)**	**(137)**	(117)	(117)
Securities sold short	**(2,425)**	**(2,345)**	(240)	(207)
Securities sold under repurchase agreements	**(7,186)**	**(7,160)**	(2,847)	(2,847)
Derivative-related payables	**(2,090)**	**(464)**	(1,101)	(133)
Capital market debt financing:				
Short-term	**(5,088)**	**(5,088)**	(3,916)	(3,916)
Long-term	**(17,075)**	**(16,728)**	(9,744)	(9,542)
	$ (39,585)	**$ (37,506)**	$ (24,008)	$ (22,805)
NET INVESTMENTS	**$364,751**	**$336,647**	$323,542	$292,216

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(i) Public Markets

Public markets consist of Canadian and foreign investments in the following securities: common shares, American depository receipts, global depository receipts, participation notes, preferred shares, income trust units, exchange traded funds units, pooled funds units, and securities convertible into common shares of publicly listed issuers.

Valuation Techniques

Direct investments in Canadian and foreign equities are measured at fair value using quoted market prices, namely, the bid price.

In the case of investments in pooled funds, fair value is measured using unit values obtained from each of the funds' administrators, which are derived from the fair value of the underlying investments in each pooled fund. Where necessary, the impact of restrictions on the sale or redemption of such investments is taken into consideration in determining fair value.

(ii) Private Markets

Private markets consist of investments in real estate, private equity, infrastructure and renewable resources.

Real estate investments are comprised of direct equity positions in various private entities, properties, as well as fund investments in the real estate sector. Real estate investments focus on properties, partnerships and companies operating in the office, retail, industrial, hospitality and residential sectors, as well as private funds invested in real estate assets. Real estate investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of real estate contracted by direct investments controlled by PSP Investments for the Plan Account was $15,037 thousand (2011 – $11,778 thousand).

Private equity investments are comprised of direct equity positions and co-investments in private entities as well as fund investments with similar objectives.

Infrastructure investments are comprised of direct equity positions and co-investments in various private entities and fund investments. Infrastructure investments focus on entities engaged in the management, ownership or operation of assets in energy, transportation and other regulated businesses. Infrastructure investments are accounted for net of all third-party financings. As at March 31, 2012, the total amount of third-party financing included as part of infrastructure contracted by direct investments controlled by PSP Investments for the Plan Account was $1,612 thousand (2011 – $285 thousand).

Renewable resources investments are comprised of properties involving the production and harvesting of replenishable resources. As at March 31, 2012, renewable resources included one investment in timberlands.

Valuation Techniques

The fair value of private markets investments is determined at least annually, using acceptable industry valuation methods. During the year, the fair value is reviewed and adjusted, as appropriate, to reflect the impact of any significant market or investment-specific events or circumstances. For each investment, the relevant methodology is applied consistently over time as appropriate in the prevailing circumstances.

In cases where the services of third-party appraisers are used, management ensures their independence and that valuation methods used are consistent with professional appraisal standards. Such standards include the *International Private Equity and Venture Capital Valuation Guidelines*, the *Canadian Uniform Standards of Professional Appraisal Practice* and the *Uniform Standards of Professional Appraisal Practice* in the United States of America. In validating the work performed by appraisers, management ensures that the assumptions used correspond to financial information and forecasts of the underlying investment.

For direct investments in real estate, valuation methods used include discounted cash flows, prices of recent comparable transactions and the direct capitalization approach. Assumptions used in such valuations include discount rates, capitalization rates, projected cash flows and/or net operating income, which are not fully supported by prices from market observable transactions.

For direct investments in private equity, direct investments and co-investments in infrastructure and in renewable resources, valuation methods used include discounted cash flows, earnings multiples, prices of recent comparable transactions and publicly traded comparables. Assumptions used in such valuations include discount rates and projected cash flows, which are not fully supported by prices from market observable transactions.

In the case of private equity, real estate and infrastructure fund investments as well as private equity co-investments, the annual fair value is generally determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(iii) Fixed Income

Fixed income consists of cash and money market securities, government and corporate bonds, inflation-linked bonds and other fixed income securities.

Cash and money market securities include instruments having a maximum term to maturity of one year, such as treasury bills, certificates of deposit and bankers' acceptances.

Government and corporate bonds include Canadian and foreign, federal, provincial, territorial and municipal bonds. Inflation-linked bonds are fixed income securities that earn inflation adjusted returns.

Other fixed income securities consist of asset-backed securities, floating rate notes as well as private debt portfolios.

Asset-backed securities consist mainly of asset-backed term notes (ABTNs) and mortgage-backed securities. The ABTNs were received in exchange for third-party or non-bank sponsored asset-backed commercial paper (ABCP) that suffered a liquidity disruption in mid-August 2007 and were subsequently restructured in January 2009. Potential margin calls on the ABTNs are supported by funding facilities, as described in Note 10.

Private debt portfolios consist mainly of investments in the real estate sector in the form of third-party loans such as junior and senior debts, construction loans, bridge loans, income-participating loans, as well as other structured finance products. They also include real estate debt funds where significant portions of the value are attributed to the underlying real estate assets.

Private debt portfolios also include debt securities of private companies or other entities such as venture capital organizations, held mainly through private funds. Such debt securities take the form of senior debt, mezzanine and distressed debt.

Valuation Techniques

Cash and money market securities include short-term instruments that are recorded at cost plus accrued interest, which approximates fair value.

Fair values of government and corporate bonds, inflation-linked bonds, floating rate notes and mortgage-backed securities are based on prices obtained from third-party pricing sources. Such prices are determined using either an appropriate interest rate curve with a spread associated with the credit quality of the issuer or other generally accepted pricing methodologies.

ABTNs are measured at fair value whereby management relies on the valuation work performed by a recognized third-party expert. Management ensures that the valuation conducted by such expert uses acceptable industry methods. Financial information used in the valuation of ABTNs includes interest rates, credit spreads and the underlying investments' terms to maturity. In addition to the values determined by the expert, management integrated certain assumptions in the fair value of ABTNs that are not fully supported by market observable data, such as liquidity estimates and the impact of the funding facilities described in Note 10.

The fair value of private debt portfolios in the real estate sector is determined using either a yield-based or collateral-based valuation technique. The yield-based valuation technique involves discounting expected future cash flows that incorporate assumptions with respect to interest rates offered for similar loans to borrowers with similar credit ratings. The collateral-based valuation technique involves assessing the recoverable value of the collateral in question, net of disposal fees.

The fair value of fund investments included as part of private debt portfolios is determined based on the audited fair values reported by the fund's general partner using acceptable industry valuation methods.

(iv) Alternative Investments

Alternative investments consist mainly of units of funds that hold a mix of equity, fixed income and derivative instruments as well as hedge funds.

Valuation Techniques

The fair value of these investments is obtained from the investment's external manager and reflects the fair value of the underlying equity, fixed income or derivative instruments, as applicable.

3. INVESTMENTS (continued)

(A) INVESTMENT PORTFOLIO (continued)

(v) Amounts Receivable and Payable from Pending Trades

Amounts receivable from pending trades consist of proceeds on sales of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Amounts payable from pending trades consist of the cost of purchases of investments, excluding derivative financial instruments, which have been traded but remain unsettled at the end of the reporting year.

Valuation Techniques

The fair value of amounts receivable and payable from pending trades reflects the value at which their underlying original sale or purchase transactions were undertaken.

(vi) Interest and Dividends Receivable

Interest and dividends are recorded at the amounts expected to be received as at the reporting date, which approximates fair value.

(vii) Interest Payable

Interest is accrued at the amount expected to be paid as at the reporting date, which approximates fair value.

(viii) Securities Sold Short

Securities sold short reflect PSP Investments' obligation to purchase securities pursuant to short selling transactions. In such transactions, PSP Investments sells securities it does not own with an obligation to purchase similar securities on the market to cover its position.

Valuation Techniques

Using ask prices as inputs, the fair value of securities sold short is measured using the same method as the similar long positions presented within public markets and fixed income.

(ix) Securities Sold under Repurchase Agreements

PSP Investments is party to agreements which involve the sale of securities with a simultaneous agreement to repurchase such securities at a specified price and at a specified future date.

Securities sold under the repurchase agreements are not derecognized as PSP Investments retains all related risks and rewards of ownership. As such, all related income (loss) continues to be reported in investment income (loss).

Obligations to repurchase the securities sold are accounted for as investment-related liabilities. Interest expense related to such obligations is reported in investment income (loss).

Valuation Techniques

Obligations to repurchase the securities sold under repurchase agreements are recorded at cost plus accrued interest, which approximates fair value.

(x) Derivative-Related Receivables and Payables

The description and valuation of derivative-related receivables and payables are described in Note 3 (B).

(xi) Capital Market Debt Financing

PSP Investments' capital market debt program is described in Note 8. Short-term promissory notes are recorded at cost plus accrued interest, which approximates fair value. The fair value of PSP Investments' medium-term notes is based on prices that are obtained from third-party pricing sources. Such prices are determined using an interest rate curve with a spread consistent with PSP Investments' credit quality.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS

Derivative financial instruments are financial contracts that are settled at a future date. The value of such instruments is derived from changes in underlying assets, interest or exchange rates. Derivative financial instruments do not, typically, require an initial net investment. In certain cases, they require an initial net investment that is less than what would be required to hold the underlying position directly. PSP Investments uses derivative financial instruments to enhance returns or to replicate investments synthetically. Derivatives are also used to reduce the risk associated with existing investments.

PSP Investments uses the following types of derivative financial instruments:

(i) Swaps

Swaps are transactions whereby two counterparties exchange cash flow streams with each other based on predetermined conditions that include a notional amount and a term. Swaps are used to increase returns or to adjust exposures of certain assets without directly purchasing or selling the underlying assets.

(ii) Futures

Futures are standardized contracts to take or make delivery of an asset (buy or sell) at a predefined price and predefined future date. Futures are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iii) Forwards

Forwards are contracts involving the sale by one party and the purchase by another party of a predefined amount of an underlying instrument, at a predefined price and at a predefined date in the future. Forwards are used to adjust exposures to specified assets without directly purchasing or selling the underlying assets.

(iv) Options

Options are the right, but not the obligation, to buy or sell a given amount of an underlying security, index, or commodity, at an agreed-upon price stipulated in advance, either at a determined date or at any time before the predefined maturity date.

(v) Warrants and Rights

Warrants are options to purchase an underlying asset which is in the form of a transferable security and which can be listed on an exchange.

Rights are securities giving shareholders entitlement to purchase new shares issued by a corporation at a predetermined price (normally less than the current market price) in proportion to the number of shares already owned. Rights are issued only for a short period of time, after which they expire.

(vi) Collateralized Debt Obligations

Collateralized debt obligations are a type of asset-backed security that is constructed from a portfolio of credit-related assets. Collateralized debt obligations are usually divided into several tranches with different credit risk levels and corresponding interest payments. Any losses are applied first to the more junior tranches (lowest risk rating) before moving up in seniority.

Valuation Techniques

All listed derivative financial instruments are recorded at fair value using quoted market prices with the bid price for long positions and the ask price for short positions. OTC derivatives are valued using appropriate valuation techniques, such as discounted cash flows using current market yields. The assumptions used include the statistical behaviour of the underlying instruments and the ability of the model to correlate with observed market transactions. Although pricing models used are widely accepted and used by other market participants, in the case of collaterized debt obligations, the nature of such instruments requires more significant assumptions about the behaviour of the default correlation. Such assumptions are not observable in the market.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

Notional values of derivative financial instruments are not recorded as assets or liabilities as they represent the face amount of the contract. Except for credit derivatives[1], notional values do not represent the potential gain or loss associated with the market or credit risk of such transactions disclosed below. Rather, they serve as the basis upon which the cash flows and the fair value of the contracts are determined.

The following table summarizes the derivatives portfolio as at March 31:

	2012				2011			
		Fair Value				Fair Value		
($ thousands)	Notional Value	Assets	Liabilities	Net	Notional Value	Assets	Liabilities	Net
Equity and commodity derivatives								
Futures	**$ 5,718**	**$ –**	**$ –**	**$ –**	$ 2,398	$ –	$ –	$ –
Total return swaps	**46,073**	**737**	**(244)**	**493**	30,891	1,064	(1)	1,063
Warrants and rights	**6**	**3**	**–**	**3**	12	11	–	11
Options:								
Listed-purchased	**6,371**	**84**	**–**	**84**	2,466	69	–	69
Listed-written	**5,453**	**–**	**(59)**	**(59)**	2,204	–	(106)	(106)
OTC-purchased	**3,040**	**33**	**–**	**33**	–	–	–	–
OTC-written	**2,797**	**–**	**(52)**	**(52)**	–	–	–	–
Currency derivatives								
Forwards	**130,411**	**880**	**(1,047)**	**(167)**	95,329	1,762	(675)	1,087
Futures	**856**	**–**	**–**	**–**	–	–	–	–
Swaps	**5,310**	**19**	**(100)**	**(81)**	9,323	135	(61)	74
Options:								
OTC-purchased	**2,770**	**29**	**–**	**29**	5,628	32	–	32
OTC-written	**4,627**	**–**	**(36)**	**(36)**	1,019	–	(10)	(10)
Interest rate derivatives								
Bond forwards	**10,167**	**21**	**(19)**	**2**	5,536	29	(15)	14
Futures	**8,836**	**–**	**–**	**–**	9,867	–	–	–
Interest rate swaps	**42,802**	**150**	**(169)**	**(19)**	97,808	78	(92)	(14)
Total return swaps	**–**	**–**	**–**	**–**	3,599	–	(1)	(1)
Swaptions	**4,561**	**85**	**(33)**	**52**	19,635	35	(17)	18
Options:								
Listed-purchased	**46,619**	**19**	**–**	**19**	29,805	36	–	36
Listed-written	**47,059**	**–**	**(26)**	**(26)**	41,876	–	(39)	(39)
OTC-purchased	**4,511**	**87**	**–**	**87**	–	–	–	–
OTC-written	**21,764**	**–**	**(134)**	**(134)**	–	–	–	–
Credit derivatives[1]:								
Purchased	**6,815**	**157**	**(51)**	**106**	2,331	17	(21)	(4)
Sold	**3,297**	**11**	**(120)**	**(109)**	2,278	10	(63)	(53)
Total	**$ 409,863**	**$ 2,315**	**$ (2,090)**	**$ 225**	$ 362,005	$ 3,278	$ (1,101)	$ 2,177

[1] Credit derivatives include credit default swaps and collateralized debt obligations. PSP Investments, through sold credit derivatives, indirectly guarantees the underlying reference obligations. The maximum potential exposure is the notional amount of the sold credit derivatives as shown in the table above.

3. INVESTMENTS (continued)

(B) DERIVATIVE FINANCIAL INSTRUMENTS (continued)

The term to maturity based on notional value for the derivatives was as follows as at March 31, 2012:

($ thousands)

Less than 3 months	**$234,853**
3 to 12 months	**100,260**
Over 1 year	**74,750**
Total	**$409,863**

(C) FAIR VALUE MEASUREMENT

Investments, investment-related assets and investment-related liabilities are classified according to the following hierarchy based on the significant inputs used in measuring their fair value.

Level 1: Valuation is based on quoted prices in active markets for identical assets or liabilities.

Level 2: Valuation is based on quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active. Level 2 also includes model-based valuation techniques for which all significant assumptions are observable in the market.

Level 3: Valuation is based on model-based techniques for which significant assumptions are not observable in the market. They reflect management's assessment of the assumptions that market participants would use in pricing the assets or liabilities.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2012:

($ thousands)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 51,632	$ –	$ –	$ –	$ 51,632
Foreign equity	86,098	4,590	960	–	91,648
Private markets					
Real estate	–	–	42,091	–	42,091
Private equity	–	–	34,909	–	34,909
Infrastructure	–	–	24,109	–	24,109
Renewable resources	–	–	2,122	–	2,122
Fixed income					
Cash and money market securities	4,599	9,188	–	–	13,787
Government and corporate bonds	–	72,005	–	–	72,005
Inflation-linked bonds	–	22,309	–	–	22,309
Other fixed income securities	–	13,465	22,517	–	35,982
Alternative investments	–	4,921	1,714	–	6,635
INVESTMENTS	$142,329	$126,478	$128,422	$ –	$397,229
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 3,554	$ 3,554
Interest receivable[1]	–	–	–	902	902
Dividends receivable[1]	–	–	–	336	336
Derivative-related receivables	103	2,212	–	–	2,315
	$ 103	$ 2,212	$ –	$ 4,792	$ 7,107
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (5,584)	$ (5,584)
Interest payable[1]	–	–	–	(137)	(137)
Securities sold short	(2,425)	–	–	–	(2,425)
Securities sold under repurchase agreements	–	(7,186)	–	–	(7,186)
Derivative-related payables	(85)	(1,945)	(60)	–	(2,090)
Capital market debt financing:					
Short-term	–	(5,088)	–	–	(5,088)
Long-term	–	(17,075)	–	–	(17,075)
	$ (2,510)	$ (31,294)	$ (60)	$ (5,721)	$ (39,585)
NET INVESTMENTS	$139,922	$ 97,396	$128,362	$ (929)	$364,751

[1] No fair value hierarchy classification is required for these items.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

The following table shows the fair value of investments, investment-related assets and investment-related liabilities, based on the methods previously described, as at March 31, 2011:

($ thousands)	Level 1	Level 2	Level 3	No Level	Total Fair Value
Public markets					
Canadian equity	$ 78,477	$ 317	$ –	$ –	$ 78,794
Foreign equity	60,736	11,601	–	–	72,337
Private markets					
Real estate	–	–	30,390	–	30,390
Private equity	–	–	28,925	–	28,925
Infrastructure	–	–	15,086	–	15,086
Fixed income					
Cash and money market securities	3,250	11,037	–	–	14,287
Government and corporate bonds	–	45,013	–	–	45,013
Inflation-linked bonds	–	16,616	–	–	16,616
Other fixed income securities	–	11,172	20,497	–	31,669
Alternative investments	–	6,210	–	–	6,210
INVESTMENTS	$142,463	$101,966	$ 94,898	$ –	$339,327
Investment-related assets					
Amounts receivable from pending trades[1]	$ –	$ –	$ –	$ 3,886	$ 3,886
Interest receivable[1]	–	–	–	780	780
Dividends receivable[1]	–	–	–	279	279
Derivative-related receivables	108	3,155	15	–	3,278
	$ 108	$ 3,155	$ 15	$ 4,945	$ 8,223
Investment-related liabilities					
Amounts payable from pending trades[1]	$ –	$ –	$ –	$ (6,043)	$ (6,043)
Interest payable[1]	–	–	–	(117)	(117)
Securities sold short	(240)	–	–	–	(240)
Securities sold under repurchase agreements	–	(2,847)	–	–	(2,847)
Derivative-related payables	(145)	(898)	(58)	–	(1,101)
Capital market debt financing:					
Short-term	–	(3,916)	–	–	(3,916)
Long-term	–	(9,744)	–	–	(9,744)
	$ (385)	$ (17,405)	$ (58)	$ (6,160)	$ (24,008)
NET INVESTMENTS	$142,186	$ 87,716	$ 94,855	$ (1,215)	$323,542

[1] No fair value hierarchy classification is required for these items.

The classification within the levels of the hierarchy is established at the time of the initial valuation of the asset or liability and reviewed on each subsequent reporting year-end.

There were no significant transfers between Level 1 and Level 2 during the year ended March 31, 2012 (no significant transfers during the year ended March 31, 2011).

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Reconciliation

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2012:

($ thousands)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Gains	Unrealized Gains (Losses)	Transfer out of Level 3	Closing Balance
Public markets	$ –	$ 880	$ (92)	$ –	$ 12	$ 160	$ –	$ 960
Private markets	74,401	36,134	(12,948)	–	1,176	4,596	(128)	103,231
Fixed income	20,497	6,066	(5,630)	(1,271)	255	2,600	–	22,517
Alternative investments	–	1,672	–	–	–	42	–	1,714
Derivative-related receivables/payables (net)	(43)	–	–	(18)	17	(16)	–	(60)
Total	**$ 94,855**	**$ 44,752**	**$ (18,670)**	**$ (1,289)**	**$ 1,460**	**$ 7,382**	**$ (128)**	**$ 128,362**

The following table shows a reconciliation of all movements related to investments, investment-related assets and investment-related liabilities categorized within Level 3 for the year ended March 31, 2011:

($ thousands)	Opening Balance	Purchases	Sales	Settlements[1]	Realized Losses	Unrealized Gains	Transfer out of Level 3	Closing Balance
Private markets	$ 60,906	$ 34,026	$ (28,598)	$ –	$ (425)	$ 8,800	$ (308)	$ 74,401
Fixed income	19,793	7,045	(8,765)	(2,489)	(399)	5,312	–	20,497
Derivative-related receivables/payables (net)	(1,627)	2,400	(70)	–	(1,270)	524	–	(43)
Total	$ 79,072	$ 43,471	$ (37,433)	$ (2,489)	$ (2,094)	$ 14,636	$ (308)	$ 94,855

[1] Includes Plan Account allocation adjustments.

3. INVESTMENTS (continued)

(C) FAIR VALUE MEASUREMENT (continued)

Level 3 Sensitivity Analysis

In the course of measuring fair value of financial instruments classified as Level 3, valuation techniques used incorporate assumptions that are based on non-observable data. Significant assumptions used for each asset class are described in Notes 3 (A) and (B). Although such assumptions reflect management's best judgment, the use of reasonably possible alternative assumptions could yield different fair value measures representing, at a minimum, a 2% increase/decrease (2011 - 2% increase/decrease) in the fair value of financial instruments categorized as Level 3. This excludes private debt portfolios in the real estate sector and certain fund investments, where a sensitivity analysis is not possible given the underlying assumptions used are not available to PSP Investments. In the case of fund investments, the fair value is determined based on the audited financial statements of the fund's general partner as indicated in Note 3 (A). With respect to private debt portfolios in the real estate sector, the fair value is obtained from third-party appraisers as described in Note 3 (A).

(D) SECURITIES LENDING AND BORROWING PROGRAMS

PSP Investments participates in securities lending and borrowing programs whereby it lends and borrows securities in order to enhance portfolio returns. Lending and borrowing transactions under such programs do not transfer the risks or rewards of ownership of the securities to the counterparty. Consequently, PSP Investments does not derecognize securities lent or recognize securities borrowed.

The securities lending and borrowing programs require collateral in cash, high-quality debt instruments or securities. Collateral transactions are conducted under terms that are usual and customary in standard securities lending and borrowing programs. PSP Investments and its counterparties are authorized to sell, repledge or otherwise use collateral held. The same securities or equivalent securities must be returned to the counterparty at the end of the contract, unless an event of default occurs. As at March 31, 2012, PSP Investments, on behalf of the Plan Account, has re-invested $9,803 thousand of collateral held (2011 – $8,348 thousand).

The following table illustrates the fair values of the Plan Account's allocated securities and collateral associated with the lending and borrowing programs as at March 31:

($ thousands)	2012	2011
Securities lending		
Securities lent	**$ 39,490**	$ 32,192
Collateral contractually receivable[1]	**41,621**	33,676
Securities borrowing		
Securities borrowed	**2,425**	240
Collateral contractually payable[2]	**2,700**	254

[1] The minimum fair value of collateral required is equal to 102% of the fair value of the securities lent.

[2] The minimum fair value of collateral required is equal to 100% of the fair value of the securities borrowed.

(E) SECURITIES SOLD AND COLLATERAL PLEDGED UNDER REPURCHASE AGREEMENTS

Securities sold under repurchase agreements are described in Note 3 (A) (ix) and involve pledging collateral consisting of cash or securities deemed acceptable by the counterparties. Collateral transactions are conducted under terms that are usual and customary in standard repurchase arrangements. Such terms require the relevant counterparty to pledge additional collateral based on the changes in the fair value of the existing collateral pledged. The counterparties are authorized to sell, repledge or otherwise use collateral held. The securities pledged as collateral must be returned to the relevant counterparty at the end of the contract, unless an event of default occurs. PSP Investments does not sell, repledge or otherwise use collateral held.

On behalf of the Plan Account, PSP Investments pledged collateral under the repurchase agreements with a fair value of $7,186 thousand at March 31, 2012 (2011 – $2,847 thousand).

4. INVESTMENT RISK MANAGEMENT

Risk Management is a central part of PSP Investments' operations. Included in the overall risk management framework is a continuous process whereby PSP Investments systematically addresses the investment risks related to its various investment activities with the goal of achieving a maximum rate of return without undue risk of loss.

A risk governance framework that includes required reporting on risk to all levels of the organization ensures that appropriate investment objectives are pursued and achieved in line with the fulfillment of PSP Investments' legislated mandate. The Board of Directors and its committees oversee all risk matters and receive assurances from senior management, including the Chief Risk Officer, as well as PSP Investments' independent internal auditor reporting directly to the Audit Committee.

PSP Investments has adopted an Investment Risk Management Policy which is an integral part of its risk control system and supplements the Statement of Investment Policies, Standards and Procedures (SIP&P). The objective of this policy is to provide a framework to manage the risks that PSP Investments is exposed to, namely, market, credit and liquidity risks.

(A) MARKET RISK

Market risk is the risk that the value of an investment will fluctuate as a result of changes in market prices, whether those changes are caused by factors specific to the individual investment, volatility in share and commodity prices, interest rate, foreign exchange or other factors affecting similar securities traded in the market.

Market risk management focuses on the following two key components:

– Policy Portfolio
The Policy Portfolio (long-term asset mix), as defined in the SIP&P, determines a diversification strategy to mitigate risk whereby PSP Investments invests in a diversified portfolio expected to achieve a return at least equal to the Actuarial Rate of Return (ARR); defined as the rate of return assumption used by the Chief Actuary of Canada in the latest actuarial valuation reports of the Plans. In the absence of other factors affecting the funding of the Plans or changes to pension benefits under the Plans, the ARR is the rate of return required to maintain funding requirements and pension benefits at their current levels.

– Active Management
Active management is defined as the sum of investment strategies that deviate from the approved Policy Portfolio. It is designed to supplement the returns of the Policy Portfolio within an active risk budget.

The risks associated with these components are the Policy Portfolio market risk and the active risk. The Policy Portfolio market risk represents the investment risk arising from the exposure to approved asset classes in the approved weightings. In establishing its Policy Portfolio, PSP Investments also takes into consideration the impact of the Policy Portfolio market risk on funding risk. Funding risk is the risk that the assets under management will be insufficient to meet the relevant pension liabilities of the Plans, which may require the contributions to the Funds of the Plans to be increased. The Policy Portfolio is reviewed at least annually as part of the review of the SIP&P, and this review includes changes, if any, to PSP Investments' long-term expectations of market conditions and other factors that may affect the funding levels of the Plans.

Active risk refers to all market risk arising from active management activities. It is managed in accordance with the Investment Risk Management Policy.

Measurement of Market Risk

The Value-at-Risk (VaR) is one of the methods used to measure market risk and is reported on a quarterly basis. It is not the maximum potential loss, but rather the maximum loss not exceeded with a given confidence level, over a given period of time. PSP Investments uses a Historical VaR model incorporating ten years' worth of market returns scaled to a twelve-month holding period at a 95% confidence level. For investments that are not actively traded, the calculation of VaR uses securities with similar risk attributes as proxy.

In measuring Policy Portfolio risk, VaR represents the absolute loss expected from the Policy Portfolio (Policy Portfolio VaR). Whereas in terms of measuring the active risk, VaR reflects the loss relative to the Policy Portfolio benchmark (Active VaR).

VaR is statistically valid under normal market conditions and does not specifically consider losses from severe market events. It also assumes that the future will behave in a pattern similar to the past. Consequently, if future market conditions differ significantly from those of the past, potential losses may differ from those originally estimated.

The following table shows the Total VaR consisting of the Policy Portfolio VaR, the Active VaR and the diversification effect, calculated as a percentage of net investments, as at March 31. The diversification effect captures the impact of holding different types of assets which may react differently in various types of situations and thus reduces the Total VaR.

	2012	2011
Policy Portfolio VaR	**21.7 %**	22.4 %
Active VaR	**2.6**	2.2
Total VaR (undiversified)	**24.3**	24.6
Diversification effect	**(1.6)**	(2.9)
Total VaR	**22.7 %**	21.7 %

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

Stress Testing

Although VaR is a widely accepted risk measure, it is complemented by other risk measurement methodologies that provide greater insight on market risk. PSP Investments uses stress testing and scenario analysis to examine the impact on financial results of abnormally large movements in risk factors. Stress testing and scenario analysis are used to test a portfolio's sensitivity to various risk factors and key model assumptions. These methods also use historically stressed periods to evaluate how a current portfolio reacts under such circumstances. Stress testing and scenario analysis are also deployed to assess new product performance.

(i) Interest Rate Risk

Interest rate risk refers to the risk that fluctuations in interest rates will directly affect the fair value of the Plan Account's net asset values.

The terms to maturity of the investments with the most significant exposure to interest rate risk were as follows as at March 31, 2012:

($ thousands)	Less than 1 Year	1 to 5 Years	5 to 10 Years	Over 10 Years	Other	Total
Government bonds	$ 7,595	$ 26,837	$ 9,656	$ 10,246	$ –	$ 54,334
Corporate bonds	3,523	7,506	4,915	1,727	–	17,671
Inflation-linked bonds	1	5,882	5,534	10,892	–	22,309
Asset-backed securities	2	10,160	172	15	–	10,349
Private debt portfolios:						
Directly held	296	2,284	35	–	–	2,615
Held through funds[1]	–	–	–	–	10,376	10,376
Total investments with significant exposure to interest rate risk	$ 11,417	$ 52,669	$ 20,312	$ 22,880	$ 10,376	$117,654
Other investments[2]	$ –	$ –	$ –	$ –	$ 26,429	$ 26,429
Total fixed income	$ 11,417	$ 52,669	$ 20,312	$ 22,880	$ 36,805	$144,083

[1] Due to their nature, information in connection with the terms to maturity of fund investments included in the private debt portfolios is not available.

[2] Consists of $13,787 thousand in cash and money market securities and $12,642 thousand in floating rate notes, which, due to their nature, are not significantly exposed to interest rate risk.

The terms to maturity of PSP Investments' capital market debt financing are disclosed in Note 8.

Alternative investments as well as derivative contracts described in Notes 3 (A) (iv) and (B), respectively, are also subject to interest rate risk exposures. These exposures are reflected in the VaR calculation described in Note 4 (A).

4. INVESTMENT RISK MANAGEMENT (continued)

(A) MARKET RISK (continued)

(ii) Foreign Currency Risk

PSP Investments and its subsidiaries are exposed to currency risk through holdings of securities, units in pooled funds and units in limited partnerships of non-Canadian assets. Fluctuations in the relative value of the Canadian dollar against these foreign currencies can result in a positive or a negative effect on the fair value of the investments. To mitigate this risk, PSP Investments may take, through foreign forward contracts or cross currency swaps, positions in foreign currencies. PSP Investments' policy is to hedge a target of 50% of its foreign currency investments in non-emerging countries. Additional factors are considered when implementing the hedging target for investments in emerging countries, namely, total relative exposure and cost effectiveness.

The underlying net foreign currency exposures for the Plan Account, after allocating the effect of derivative contracts and investment-related assets and liabilities for both monetary and non-monetary items were as follows as at March 31:

(in thousands of Canadian $)	2012		2011	
Currency	**Fair Value**	**% of Total**	Fair Value	% of Total
US Dollar	**$ 73,305**	**57.9 %**	$ 52,917	54.0 %
Euro	**15,025**	**11.9**	13,297	13.6
British Pound	**9,919**	**7.8**	7,422	7.6
Japanese Yen	**5,720**	**4.5**	3,948	4.0
Brazilian Real	**5,133**	**4.0**	4,909	5.0
Hong Kong Dollar	**3,812**	**3.0**	3,702	3.8
Korean Won	**2,768**	**2.2**	2,618	2.7
Australian Dollar	**2,282**	**1.8**	1,704	1.7
Norwegian Krone	**1,941**	**1.5**	582	0.6
Indian Rupee	**1,083**	**0.9**	785	0.8
Others	**5,714**	**4.5**	6,011	6.2
Total	**$126,702**	**100.0 %**	$ 97,895	100.0 %

PSP Investments and its subsidiaries also had commitments, denominated in foreign currencies of $36,553 thousand (US$32,007 thousand, €2,930 thousand, R682 thousand South African Rands and R1,050 thousand Brazilian Reals) for the Plan Account which were not included in the foreign currency exposure table.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK

PSP Investments is exposed to credit risk, that is, the risk that the issuer of a debt security or that the counterparty to a derivative contract, to a securities lending and borrowing transaction or to securities sold under repurchase agreements, is unable to meet its financial obligations.

Credit risk encompasses the risk of a deterioration of creditworthiness and the relevant concentration risk. Credit risk monitoring entails an evaluation of the credit quality of each issuer and counterparty that transacts with PSP Investments. To perform this evaluation, PSP Investments relies on four recognized credit rating agencies. A minimum of two credit ratings are used to classify each security. Except for ABTNs, securities rated by only one agency are classified as "not rated". If the agencies disagree as to a security's credit quality, PSP Investments uses the lowest of the available ratings.

As at March 31, 2012, the Plan Account's maximum exposure to credit risk amounted to approximately $125 million (2011 – approximately $89 million). This amount excludes investments in distressed debt in the amount of approximately $7.9 million as at March 31, 2012 (2011 – approximately $8.4 million). The maximum exposure to credit risk also excludes collateralized debt obligations, collateral held as disclosed in Notes 3 (D), 3 (E) and 4 (B) and the impact of guarantees and indemnities disclosed in Note 10.

As at March 31, 2012, the Plan Account had a net notional exposure of $948 thousand (2011 – $1,453 thousand) to various tranches of collateralized debt obligations, of which approximately 61% (2011 – approximately 44%) of the underlying dollar exposure was rated "Investment grade", as well as funding facilities, as described in Note 10, to support potential margin calls on the ABTNs.

To monitor the evolution of credit risk, PSP Investments periodically produces a concentration report by credit rating of all credit-sensitive financial securities with the exception of securities held in pooled funds or for private markets investments.

PSP Investments' concentration of credit risk by credit rating, excluding the items described above and any other credit enhancement, for the Plan Account was as follows as at March 31:

	2012	2011
Investment grade (AAA to BBB–)	**98.2 %**	97.9 %
Below investment grade (BB+ and below)	**0.7**	0.4
Not rated:		
Rated by a single credit rating agency	**0.1**	0.1
Not rated by credit rating agencies	**1.0**	1.6
Total	**100.0 %**	100.0 %

Counterparty Risk

Counterparty risk represents the credit risk from current and potential exposure related to transactions involving derivative contracts, securities lending and borrowing as well as securities sold under repurchase agreements. In order to minimize counterparty risk, PSP Investments requires that counterparties provide adequate collateral and meet its credit rating requirements. PSP Investments frequently monitors the credit rating of its counterparties as determined by recognized credit rating agencies. With respect to derivative contracts, PSP Investments has the ability to terminate all trades with most counterparties whose credit rating is downgraded below its requirements.

PSP Investments' policy also requires the use of the International Swaps and Derivative Association (ISDA) Master Agreement with all counterparties to derivative contracts. The ISDA Master Agreement provides the contractual framework within which dealing activities across a full range of OTC products are conducted.

4. INVESTMENT RISK MANAGEMENT (continued)

(B) CREDIT RISK (continued)

Counterparty Risk (continued)

As a credit mitigation technique, the ISDA Master Agreement contractually binds both parties to use master-netting arrangements and, in the case of default of the counterparty, close-out netting. Additionally, the Credit Support Annex (CSA) to the ISDA Master Agreement enables PSP Investments to realize any collateral placed with it in the case of default of the counterparty. The CSA also requires PSP Investments to contribute further collateral when requested. All collateral transactions are in high-quality debt instruments or securities. The CSA also regulates the exchange of collateral when the credit exposure to a counterparty exceeds a predetermined threshold. In certain cases, counterparties are authorized to sell, repledge or otherwise use collateral held. On behalf of the Plan Account, PSP Investments pledged securities with a fair value of $15 thousand as collateral with respect to derivative contracts at March 31, 2012 (2011 – nil). Securities with a fair value of $589 thousand were received from counterparties as collateral at March 31, 2012 (2011 – $762 thousand). PSP Investments does not sell, repledge or otherwise use any collateral held with respect to derivative contracts.

With respect to transactions involving securities lending and borrowing as well as securities sold under repurchase agreements, collateral requirements are in place to mitigate counterparty risk. Notes 3 (D) and 3 (E) describe collateral requirements in securities lending and borrowing programs as well as securities sold under repurchase agreements, respectively.

In the case of the securities lending program, PSP Investments' exposure to counterparty risk is further mitigated as the custodian of the securities lent assumes the risk that a counterparty will be unable to meet its obligations associated with the collateral requirements.

Management is responsible for counterparty risk monitoring and mitigation as well as maintaining a comprehensive, disciplined, and enterprise-wide process for tracking and managing counterparty risk. As such, Management measures counterparty risk on an ongoing basis, evaluates and tracks the creditworthiness of current counterparties and mitigates counterparty risk through collateral management.

(C) LIQUIDITY RISK

Liquidity risk corresponds to PSP Investments' ability to meet its financial obligations when they come due with sufficient and readily available cash resources. PSP Investments' cash position is monitored on a daily basis. In general, investments in cash, cash equivalents, floating rate notes, bonds and public equities are expected to be highly liquid as they will be invested in securities that are actively traded. Management utilizes appropriate measures and controls to monitor liquidity risk in order to ensure that there is sufficient liquidity to meet financial obligations as they come due. A liquidity report taking into consideration future forecasted cash flows is prepared and presented to senior management on a weekly basis. This ensures that sufficient cash reserves are available to meet forecasted cash outflows. Additionally, sufficient sources of liquidity are maintained for deployment in case of market disruption.

PSP Investments has the ability to raise additional capital through the use of its capital market debt program. This program allows PSP Investments to issue short-term promissory notes and medium-term notes. Note 8 provides additional information on the usage of the capital market debt program.

The terms to maturity of the notional amount of derivatives are disclosed in Note 3 (B).

4. INVESTMENT RISK MANAGEMENT (continued)

(C) LIQUIDITY RISK (continued)

Financial Liabilities

The following tables present the fair value of non-derivative-related financial liabilities as well as derivative-related financial instruments, aggregated according to their maturities as at March 31, 2012:

($ thousands)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Non-derivative-related financial liabilities[1]				
Amounts payable from pending trades	$ (5,584)	$ –	$ –	$ (5,584)
Interest payable	(119)	(18)	–	(137)
Securities sold short	(2,425)	–	–	(2,425)
Securities sold under repurchase agreements	(7,186)	–	–	(7,186)
Capital market debt financing	(4,699)	(389)	(17,075)	(22,163)
Accounts payable and other liabilities	(313)	–	(124)	(437)
Total	$ (20,326)	$ (407)	$ (17,199)	$ (37,932)

($ thousands)	Less than 3 Months	3 to 12 Months	Over 1 Year	Total
Derivative-related financial instruments				
Derivative-related receivables	$ 848	$ 961	$ 506	$ 2,315
Derivative-related payables[1]	(895)	(582)	(613)	(2,090)
Total	$ (47)	$ 379	$ (107)	$ 225

[1] Liabilities are presented in the earliest period in which the counterparty can request payment.

5. FUND TRANSFERS

On behalf of the Plan Account, PSP Investments received fund transfers of $31,055 thousand for the year ended March 31, 2012 (2011 – $54,045 thousand) from the Fund.

6. INVESTMENT INCOME

Investment income, for the years ended March 31, was as follows:

($ thousands)	2012	2011
Interest income	**$ 3,835**	$ 2,770
Dividend income	**4,461**	3,239
Other income	**1,144**	968
Dividend expense	**(139)**	(106)
Interest expense (Note 8)	**(472)**	(335)
Transaction costs	**(363)**	(295)
External investment management fees [1]	**(186)**	(210)
	8,280	6,031
Net realized gains [2]	**5,743**	9,959
Net unrealized (losses) gains	**(3,222)**	22,769
Investment income	**$ 10,801**	$ 38,759

[1] Consists of amounts incurred for investments in public markets that are paid directly by PSP Investments. This excludes investments fees related to certain pooled fund investments classified under alternative investments primarily related to performance, in the amount of $314 thousand for the year ended March 31, 2012 (2011 – $470 thousand). This also excludes management fees related to investments in private markets and other fixed income securities that are not paid directly by PSP Investments.

Such fees, which generally vary between 0.1% and 2.0% of the total invested and/or committed amount, totalled $672 thousand for the year ended March 31, 2012 (2011 – $781 thousand).

[2] Includes foreign currency losses of $281 thousand for the year ended March 31, 2012 (2011 – gains of $577 thousand).

7. EXPENSES

(A) ALLOCATION OF EXPENSES

The Act requires that the costs of operation of PSP Investments be charged to the Plan Accounts for which it provides investment services. Under section 4(3) of the Act, the President of the Treasury Board shall determine to which Plan Account these costs will be charged, in consultation with the Minister of National Defence and the Minister of Public Safety. An allocation policy was developed which allocates the direct costs of investment activities, such as external investment management fees and custodial fees, to each Plan Account, based upon the asset value of each Plan Account at the time the expense was incurred.

All other operating expenses, excluding the direct cost of investment activities listed above, for the years ended March 31, were allocated in proportion to the annual amount of net assets in each Plan Account as follows:

	2012	2011
Public Service Pension Plan Account	**72.9 %**	72.7 %
Canadian Forces Pension Plan Account	**19.4**	19.7
Royal Canadian Mounted Police Pension Plan Account	**7.1**	7.1
Reserve Force Pension Plan Account	**0.6**	0.5
Total	**100.0 %**	100.0 %

Expenses are paid by PSP Investments by way of advances from the Public Service Pension Plan Account, which are reimbursed by the other Plan Accounts on a quarterly basis.

(B) OPERATING EXPENSES

Operating expenses allocated to this Plan Account, for the years ended March 31, consisted of the following:

($ thousands)	2012	2011
Salaries and benefits	**$ 541**	$ 351
Professional and consulting fees	**61**	40
Office supplies and equipment	**85**	63
Other operating expenses	**36**	25
Depreciation of fixed assets	**52**	50
Occupancy costs	**31**	24
Custodial fees	**17**	12
Remuneration earned by Directors	**4**	3
Travel and related expenses for Directors	**2**	1
Communication expenses	**1**	1
Total	**$ 830**	$ 570

8. CAPITAL MARKET DEBT FINANCING

PSP Investments' capital market debt program consists of the private placement of short-term promissory notes as well as medium-term notes issued by PSP Capital Inc., a wholly-owned subsidiary of PSP Investments. The capital raised is primarily used to finance investments in real estate, infrastructure and renewable resources. It is unconditionally and irrevocably guaranteed by PSP Investments in accordance with its corporate leverage policy.

The maximum amount authorized by the Board of Directors for the capital market debt program is 7.5% of the net investments plus all recourse debt outstanding of PSP Investments. Under this limit, the short-term promissory note component cannot exceed $3 billion.

The following outlines the terms as well as the fair value of the notes issued under the capital market debt program allocated to the Plan Account as at March 31:

		2012	2011
($ thousands)	**Capital amounts to be paid at maturity**	**Fair Value**	Fair Value
Short-term promissory notes, bearing interest between 1% and 1.42% and maturing within 31 and 364 days of issuance (March 31, 2011 – 29 and 363 days)	**$ 5,097**	**$ 5,088**	$ 3,916
Medium-term notes Series 1, bearing interest of 4.57% per annum and maturing on December 9, 2013	**$ 5,648**	**$ 5,941**	$ 5,885
Medium-term notes Series 2, bearing interest of 2.94% per annum and maturing on December 3, 2015	**$ 3,954**	**$ 4,080**	$ 3,859
Medium-term notes Series 3, bearing variable interest of 3–month CDOR + 39 basis points and maturing on February 16, 2015	**$ 1,977**	**$ 1,977**	$ –
Medium-term notes Series 4, bearing interest of 2.26% per annum and maturing on February 16, 2017	**$ 5,084**	**$ 5,077**	$ –
Total	**$ 21,760**	**$ 22,163**	$ 13,660

The operating expenses incurred by PSP Capital Inc. were allocated to each Plan Account as described in Note 7 (A).

Interest expense, for the years ended March 31, was as follows:

($ thousands)	2012	2011
Short-term promissory notes	**$ 73**	$ 49
Medium-term notes	**399**	286
Total	**$ 472**	$ 335

9. CAPITAL MANAGEMENT

As an investment company, PSP Investments' objectives in managing its capital are:

- To invest fund transfers, outlined in Note 5, in the best interests of the beneficiaries and contributors under the *Superannuation Acts*. The funds received are invested with a view of achieving a maximum rate of return, without undue risk of loss, having regard to the funding, policies and requirements of the Plans established under the *Superannuation Acts* and the ability of the Plans to meet their financial obligations. The funds are also invested in accordance with the Investment Risk Management policies which are outlined in Note 4.
- To maintain an appropriate credit rating to achieve access to the capital markets at the lowest cost of capital. Through PSP Capital Inc. and its leverage policies, PSP Investments has the ability to raise capital by issuing short-term promissory notes and medium-term notes. Note 8 provides information on the capital market debt financing and Note 4 (C) provides information on PSP Investments' liquidity.

The capital structure of PSP Investments consists of fund transfers and capital market debt financing. PSP Investments has no externally imposed restrictions on capital.

10. GUARANTEES AND INDEMNITIES

PSP Investments provides indemnification to its Directors, its Officers, its vice-presidents and to certain PSP Investments representatives who are asked to serve on boards of directors (or like bodies) or investment advisory boards (or like bodies) of entities in which PSP Investments or its wholly-owned subsidiaries have made an investment or have a financial interest. As a result, but subject to the Act, PSP Investments may be required to indemnify these representatives for costs incurred, such as claims, actions or litigations in connection with the exercise of their duties, unless the liability of such a representative relates to a failure to act honestly and in good faith. To date, PSP Investments has not received any claims or made any payment for such indemnity.

In certain cases, PSP Investments also provides indemnification to third parties in the normal course of business. As a result, PSP Investments may be required to indemnify such third parties in connection with the performance of their contractual obligations. To date, PSP Investments has not received any claims nor made any payments for such indemnities.

PSP Investments unconditionally and irrevocably guarantees all credit facilities, short-term promissory notes and medium-term notes issued by PSP Capital Inc.

PSP Capital Inc. provided funding facilities of a maximum amount of $969 million to support potential margin calls on the ABTNs, of which $4,840 thousand has been allocated to the Plan Account. As at March 31, 2012, the margin funding facilities have not been drawn upon since inception.

In certain investment transactions, PSP Investments provided guarantees or indemnifications to third parties, the most significant of which are as follows:

As at March 31, 2012, PSP Investments agreed to guarantee, as part of an investment transaction, a non-revolving term loan. In the event of a default, the Plan Account could assume the obligation up to $1,375 thousand (2011 – $1,375 thousand) plus interest and other related costs. The loan matures in March 2015.

As at March 31, 2012, a wholly-owned subsidiary of PSP Investments has agreed to provide indemnification with respect to the contractual obligations and commitments of a third-party. In the event of a default by such third-party, the subsidiary may be required to assume an obligation of up to $195 million (2011 – $195 million), of which $1,088 thousand (2011 – $1,088 thousand) may be allocated to the Plan Account, as estimated at the time of the completion of the investment transaction. The subsidiary would also have direct recourse against the defaulting third party in all circumstances. The guarantee expires in April 2012.

11. COMMITMENTS

PSP Investments and its subsidiaries have committed to enter into investment transactions, which will be funded over the next several years in accordance with agreed terms and conditions. The portion of PSP Investments' commitments that would be assumed by the Plan Account was as follows as at March 31, 2012:

($ thousands)	
Real estate	**$ 8,512**
Private equity	**23,041**
Infrastructure	**4,913**
Other fixed income securities	**3,264**
Total	**$ 39,730**

2012

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“Exhibit K”



TransCanada Corporation

2011 Annual information form
February 13, 2012

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Presentation of information

Unless the context indicates otherwise, a reference in this Annual Information Form ("AIF") to "TransCanada", the "Company", "we", "us" and "our" includes TransCanada Corporation and the subsidiaries of TransCanada Corporation through which its various business operations are conducted. In particular, "TransCanada" includes references to TransCanada PipeLines Limited ("TCPL"). Where TransCanada is referred to with respect to actions that occurred prior to its 2003 plan of arrangement with TCPL, which is described below under the heading *TransCanada Corporation - Corporate Structure*, these actions were taken by TCPL or its subsidiaries. The term "subsidiary", when referred to in this AIF, with reference to TransCanada means direct and indirect wholly owned subsidiaries of, and legal entities controlled by, TransCanada or TCPL, as applicable.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2011 ("Year End"). Amounts are expressed in Canadian dollars unless otherwise indicated. Information in relation to metric conversion can be found at Schedule A to this AIF. Terms defined throughout this AIF are listed in the *Glossary* found at the end of this AIF. Financial information is presented in accordance with Canadian generally accepted accounting principles.

Certain portions of TransCanada's Management's Discussion and Analysis dated February 13, 2012 ("MD&A") are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TransCanada's profile.

Effective January 1, 2012, TransCanada adopted U.S. generally accepted accounting principles ("U.S. GAAP") for reporting purposes. For more information regarding TransCanada's adoption of U.S. GAAP, refer to the MD&A under the headings *Accounting Changes – Future Accounting Changes – U.S. GAAP*.

Forward looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

- anticipated business prospects
- financial performance of TransCanada and its subsidiaries and affiliates
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows
- expected costs
- expected costs for projects under construction
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures
- expected operating and financial results, and
- expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

- inflation rates, commodity prices and capacity prices
- timing of debt issuances and hedging
- regulatory decisions and outcomes
- arbitration decisions and outcomes
- foreign exchange rates
- interest rates
- tax rates
- planned and unplanned outages and utilization of the Company's pipeline and energy assets
- asset reliability and integrity

- access to capital markets
- anticipated construction costs, schedules and completion dates, and
- acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

- the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits
- the operating performance of the Company's pipeline and energy assets
- the availability and price of energy commodities
- amount of capacity payments and revenues from the Company's energy business
- regulatory decisions and outcomes
- outcomes with respect to legal proceedings, including arbitration
- counterparty performance
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- labour, equipment and material costs
- access to capital markets
- interest and currency exchange rates
- weather
- technological developments, and
- economic conditions in North America.

Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission ("SEC").

Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this AIF, or the MD&A disclosure incorporated by reference herein, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this AIF or the MD&A disclosure incorporated by reference herein whether as a result of new information, future events or otherwise, except as required by law.

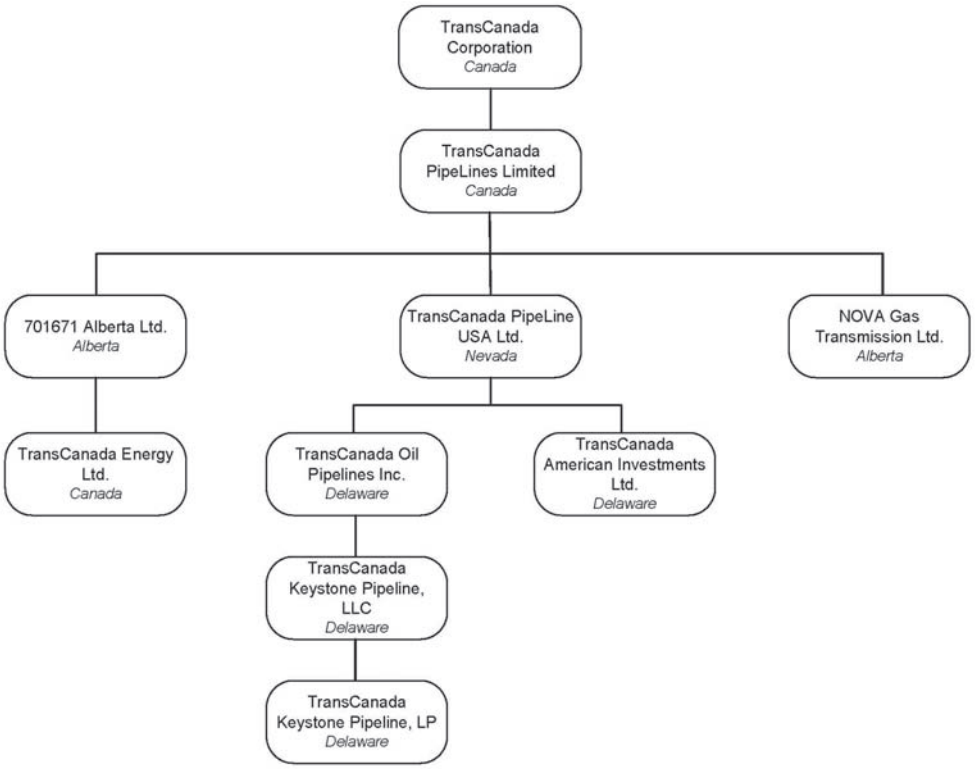
TransCanada Corporation

Corporate structure

Our head office and registered office are located at 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporations Act* ("CBCA") on February 25, 2003 in connection with a plan of arrangement which established TransCanada as the parent company of TCPL. The arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the arrangement became effective May 15, 2003. Pursuant to the arrangement, the common shareholders of TCPL exchanged each of their TCPL common shares for one common share of TransCanada. The debt securities and preferred shares of TCPL remained obligations and securities of TCPL. TCPL continues to carry on business as the principal operating subsidiary of the TransCanada group of entities. TransCanada does not hold any material assets directly, other than the common shares of TCPL and receivables from certain of TransCanada's subsidiaries.

Intercorporate relationships

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TransCanada's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the total consolidated assets of TransCanada or revenues that exceeded 10 per cent of the total consolidated revenues of TransCanada as at Year End. TransCanada beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares in each of these subsidiaries, with the exception of TransCanada Keystone Pipeline, LP in which TransCanada indirectly holds 100 per cent of the partnership interests.



The above diagram does not include all of the subsidiaries of TransCanada. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets or total consolidated revenues of TransCanada as at Year End.

General development of the business

Our reportable business segments are "Natural Gas Pipelines", "Oil Pipelines" and "Energy". Natural Gas Pipelines and Oil Pipelines are principally comprised of the Company's respective natural gas and oil pipelines in Canada, the U.S. and Mexico and our regulated natural gas storage operations in the U.S. Energy includes the Company's power operations and the non-regulated natural gas storage business in Canada. Further information regarding our Natural Gas Pipelines, Oil Pipelines and Energy businesses is available in this AIF under the heading *Business of TransCanada*.

Summarized below are significant developments that have occurred in TransCanada's Natural Gas Pipelines, Oil Pipelines and Energy businesses, respectively, and the significant acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years.

Developments in the Natural Gas Pipelines business

Date	Description of development
Canadian Mainline	
December 2009	The National Energy Board ("NEB") approved TransCanada's application for 2010 final tolls for the Canadian Mainline, effective January 1, 2010. The 2010 calculated return on equity was 8.52 per cent. Reduced throughput and greater use of shorter distance transportation contracts resulted in an increase in tolls for 2010 compared to 2009.
December 2010	TransCanada filed an application with the NEB for approval of the interim 2011 tolls for the Canadian Mainline which contained certain changes to the tolling mechanism to reduce long haul tolls. The NEB decided not to approve the tolls as requested in the interim tolls application and set the then current 2010 tolls as interim commencing January 1, 2011.
January - February 2011	TransCanada received approval for revised interim tolls, effective March 1, 2011 which increased interim tolls to more closely align with tolls calculated in accordance with the 2007-2011 settlement with stakeholders and will more closely reflect the Canadian Mainline's costs and throughput for 2011.
September - October 2011	TransCanada filed with the NEB a 2012 Tolls Application and Restructuring Proposal (the "Restructuring Proposal") designed to enhance the long-term economic viability of the Canadian Mainline. The application also seeks approval of tolls for 2012-2013, including an after tax weighted average cost of capital return of 7.0 percent assuming the Restructuring Proposal is approved. The Restructuring Proposal includes toll design and service and pricing modifications, a depreciation proposal, and geographic extension of the Alberta System service by NOVA Gas Transmission Ltd. ("NGTL") acquiring capacity on the Canadian Mainline and Foothills systems. The application has been set down for hearing (proceeding RH-003-2011) in the second to fourth quarters of 2012, and a decision is expected in late 2012 or early 2013.
November 2011	TransCanada refiled a supplemental application with the NEB to construct $130 million of new pipeline infrastructure on the Canadian Mainline, to receive Marcellus shale natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets. Subject to regulatory approval, deliveries from Niagara Falls are expected to begin at a rate of 230 million cubic feet per day ("MMcf/d") in November 2012 and then increase to 350 MMcf/d by November 2013.
November - December 2011	TransCanada filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as the currently approved 2011 final tolls. The NEB approved TransCanada's application for 2011 final tolls for the Canadian Mainline at the level of the tolls that were being charged on an interim basis. Final 2011 tolls were calculated in accordance with previously approved toll methodologies and were based on the principles contained in the 2007-2011 settlement with stakeholders, with adjustments to reduce toll impacts. Certain aspects of the 2011 revenue requirement were rolled into the RH-003-2011 proceeding referred to above.
Alberta System	
February 2009	The NEB approved TransCanada's June 2008 application for federal regulation of the Alberta System effective April 29, 2009.
February 2009	TransCanada announced the successful completion of a binding open season, securing support for firm transportation contracts of 378 MMcf/d for the Horn River pipeline.
February 2010	TransCanada filed an application with the NEB for approval to construct and operate the Horn River pipeline.
March 2010	The North Central Corridor expansion of the Alberta System was completed.
March 2010	The NEB approved TransCanada's application after a public hearing to construct and operate the Groundbirch pipeline project.
June 2010	TransCanada reached a three year settlement agreement with the Alberta System shippers and other interested parties and filed a 2010-2012 Revenue Requirement Settlement Application with the NEB.
August 2010	The NEB approved TransCanada's November 2009 application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System.
September 2010	The NEB approved the Alberta System's 2010-2012 Revenue Requirement Settlement Application.
October 2010	The NEB approved final 2010 rates for the Alberta System, which reflect the Alberta System 2010-2012 Revenue Requirement Settlement and Rate Design Settlement.
December 2010	The NEB approved the interim 2011 tolls for the Alberta System reflecting the 2010-2012 Revenue Requirement Settlement and continuing to transition to the toll methodology approved in the Rate Design Settlement.
December 2010	Groundbirch pipeline was completed and began transporting natural gas from the Montney shale gas formation into the Alberta System.
January 2011	TransCanada received approval from the NEB to construct the Horn River pipeline.
March 2011	TransCanada commenced construction of the $275 million Horn River project, with a targeted completion date of second quarter 2012. In addition, the Company executed an agreement to extend the Horn River pipeline by approximately 100 kilometer ("km") (62 miles) at an estimated cost of $230 million. An application requesting approval to construct and operate this extension was filed with the NEB in October 2011. The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 MMcf/d by 2020.
August 2011	The NEB approved construction of a 24 km (15 miles) extension of the Groundbirch pipeline and construction commenced in August, with an expected in service date of April 2012.

Date	Description of development
October 2011	Commercial integration of the NGTL and ATCO Pipelines systems commenced. Under an agreement, the facilities of NGTL and ATCO Pipelines are commercially operated as a single transmission system and transportation service is provided to customers by NGTL pursuant to NGTL's tariff and suite of rates and services. The agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of NGTL and ATCO Pipelines.
October 2011	The NEB approved the construction of natural gas pipeline projects for the Alberta System with a capital cost of approximately $910 million. Further pipeline projects with a total capital cost of approximately $810 million are awaiting NEB decision.
November - December 2011	The regulatory decisions by which commercial integration of the NGTL and ATCO Pipelines systems were authorized are the subject of appeals to the Federal Court of Appeal. The timing of the hearing of the appeals is uncertain, but TransCanada expects it to be before the end of 2012.
December 2011	TransCanada filed for interim 2012 tolls on the Alberta System to be effective January 1, 2012. These tolls have been approved on an interim basis pending the outcome of the NEB's decision on the application filed for the Restructuring Proposal.
Mackenzie Gas Project	
December 2009	A Joint Review Panel of the Canadian government released a report on environmental and socio-economic factors in relation to the Mackenzie Gas Project. The report was submitted to the NEB as part of the review process for approval of the project.
December 2010	The NEB approved the proponents' application to construct the Mackenzie Gas Project subject to numerous conditions.
March 2011	The NEB issued a Certificate of Public Convenience and Necessity for the Mackenzie Gas Project.
Alaska Pipeline Project	
June 2009	TransCanada reached an agreement with ExxonMobil Corporation to jointly advance the Alaska Pipeline Project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial work.
April 2010	The Alaska Pipeline open season commenced.
Third Quarter 2010	Interested shippers on the proposed Alaska Pipeline Project submitted conditional commercial bids in the open season that closed in July 2010. The Alaska Pipeline Project team continued to work with shippers to resolve conditional bids received as part of the project's open season in working toward a U.S. Federal Energy Regulatory Commission ("FERC") application deadline of October 2012 for the Alberta option that would extend from Prudhoe Bay to points near Fairbanks and Delta Junction, and then to the Alaska/Canada border where the pipeline would connect with a new pipeline in Canada.
January 2012	TransCanada commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the liquefied natural gas option, that would extend from Prudhoe Bay to liquefied natural gas facilities, to be built by third parties, located in south-central Alaska.
Bison	
December 2010	Construction of Bison pipeline, a 487 km (303 miles) pipeline, was completed.
January 2011	Bison pipeline was placed into commercial service.
May 2011	TransCanada closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC and Bison Pipeline LLC to TC PipeLines, LP for a total transaction value of $605 million, which included U.S. $81 million or 25 percent of Gas Transmission Northwest LLC's debt outstanding.
GTN	
May 2011	TransCanada closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC and Bison Pipeline LLC to TC PipeLines, LP for a total transaction value of $605 million, which included U.S. $81 million or 25 percent of Gas Transmission Northwest LLC's debt outstanding.
November 2011	The FERC approved a settlement agreement between GTN and its shippers for new transportation rates to be effective January 2012 through December 2015. This settlement also requires GTN to file for new rates that are to be effective January 2016.
Great Lakes	
November 2009	The FERC initiated an investigation to determine whether rates on Great Lakes were just and reasonable. In response, Great Lakes Gas Transmission Limited Partnership filed a cost and revenue study with the FERC in February 2010.
July 2010	The FERC approved, without modification, the settlement stipulation agreement reached among Great Lakes Gas Transmission Limited Partnership, active participants and the FERC trial staff. As approved, the stipulation and agreement applies to all current and future shippers on Great Lakes.
North Baja	
July 2009	TransCanada completed the sale of North Baja Pipeline, LLC to TC PipeLines, LP.

Date	Description of development
Guadalajara	
May 2009	TransCanada announced that it was the successful bidder on a contract to build, own and operate the Guadalajara pipeline.
June 2011	The Guadalajara pipeline was completed. TransCanada and the Comisión Federal de Electricidad, Mexico's federal government owned electrical company have agreed to add a US$60 million compressor station to the pipeline that is expected to be operational early in 2013.

Further information about developments in the Natural Gas Pipelines business can be found in the MD&A under the headings *TransCanada's Strategy*, *Natural Gas Pipelines – Highlights*, *Natural Gas Pipelines – Financial Analysis* and *Natural Gas Pipelines – Opportunities and Developments*.

Developments in the Oil Pipelines business

Date	Description of development
Keystone	
August 2009	TransCanada became sole owner of the Keystone project through the purchase of ConocoPhillips' remaining interest for US$553 million and the assumption of US$197 million of short-term debt.
March 2010	The NEB approved TransCanada's application to construct and operate the Canadian portion of the Keystone U.S. Gulf Coast expansion ("Keystone XL").
April 2010	The U.S. Department of State issued a Draft Environmental Impact Statement for Keystone XL.
June 2010	Keystone commenced operating at a reduced maximum operating pressure as the first section of Keystone began delivering oil from Hardisty, Alberta to Wood River and Patoka in Illinois ("Wood River/Patoka").
November 2010	The open seasons for the Bakken Marketlink and Cushing Marketlink projects, which commenced in September 2010, closed successfully.
December 2010	The reduced maximum operating pressure restriction on the Canadian conversion section of the Wood River/Patoka section of Keystone was removed by the NEB following the completion of in-line inspections.
Fourth Quarter 2010	Construction of the second section of Keystone extending the pipeline from Steele City, Nebraska to Cushing, Oklahoma (the "Cushing Extension") was completed, and line fill commenced in late 2010.
January 2011	Required operational modifications were completed on the Canadian conversion section of Keystone. As a result, the system was capable of operating at the approved design pressure.
February 2011	The commercial in service of the Cushing Extension commenced, and the Company also commenced recording earnings for the Wood River/Patoka section.
May 2011	Revised tolls came into effect for the Wood River/Patoka section.
Second Quarter 2011	The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration issued a corrective action order on Keystone as a result of two above-ground incidents at pump stations in North Dakota and Kansas. TransCanada filed a re-start plan with the U.S. Pipeline and Hazardous Material Safety Administration which was approved in June 2011.
August 2011	TransCanada received a Final Environmental Impact Statement regarding the Keystone XL U.S. Presidential Permit application.
November 2011	The U.S Department of State announced that further analysis of route options for Keystone XL would need to be investigated, with a specific focus on the Sandhills area of Nebraska. The review could be completed as early as the first quarter of 2013.
December 2011	TransCanada announced that it received additional binding commitments in support of Keystone XL following the conclusion of the Keystone Houston Lateral open season, which commenced in August 2011.
January 2012	The U.S. Department of State denied TransCanada's application requesting a Presidential Permit to construct Keystone XL. The Company plans to submit a revised Presidential Permit application for Keystone XL.

Further information about developments in the Oil Pipelines business can be found in the MD&A under the headings *TransCanada's Strategy*, *Oil Pipelines – Highlights*, *Oil Pipelines – Financial Analysis* and *Oil Pipelines – Opportunities and Developments*.

Developments in the Energy business

Date	Description of development
Ravenswood	
May 2009	Ravenswood's 981 MW Unit 30 returned to service. Subsequent to closing the acquisition of Ravenswood in August 2008, TransCanada experienced a forced outage event related to the unit. TransCanada has filed claims against the insurers to enforce its rights under the insurance policies and litigation proceedings are ongoing.
Third and Fourth Quarters 2011	Since July 2011, spot prices for capacity sales in the New York Zone J market have been negatively impacted by the manner in which the New York Independent System Operator ("NYISO") has applied pricing rules for a new power plant that recently began service in this market. TransCanada believes that this application of pricing rules by the NYISO is in direct contravention of a series of the FERC orders which direct how new entrant capacity is to be treated for the purpose of determining capacity prices. TransCanada and other parties have filed formal complaints with the FERC that are currently pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown. During third quarter 2011, the demand curve reset process was completed following the FERC's acceptance of the NYISO's September 22, 2011 compliance filing. This resulted in increased demand curve rates that apply going forward to 2014. Until the above noted NYISO actions relative to new unit pricing are resolved, capacity prices are expected to remain volatile
Bécancour	
June 2011	Hydro-Québec Distribution ("Hydro-Québec") notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2012. Under the original agreement, Hydro-Québec has the option, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TransCanada continues to receive capacity payments under the agreement similar to those that would have been received under the normal course of operation.
Bruce Power	
November 2011	Bruce Power commenced the approximately six month West Shift Plus outage as part of the life extension strategy for Unit 3. Subject to regulatory approval, Unit 3 is expected to return to service in second quarter 2012.
February 2011	The Bruce Power Refurbishment Implementation Agreement (the "BPRIA") was amended to extend the suspension date for Bruce A contingent support payments from December 31, 2011 to June 1, 2012. Contingent support payments received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A will be subject to spot prices effective June 1, 2012 until the restart of both Units 1 and 2 is complete. Bruce Power and the OPA had amended certain terms and conditions of the BPRIA in July 2009, which included: amendments to the Bruce B floor price mechanism, the removal of a support payment cap for Bruce A, an amendment to the capital cost-sharing mechanism, and addition of a provision for deemed generation payments to Bruce Power at the contracted prices under circumstances where generation from Bruce A and Bruce B is reduced due to system curtailments on the Independent Electricity System Operator controlled grid in Ontario. Under the original BPRIA, which was signed in 2005, Bruce A committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 and replace the steam generators on Unit 4. Fuelling of both Unit 2 and Unit 1 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.
Portlands Energy	
April 2009	The 550 megawatt ("MW") Portlands Energy power plant was fully commissioned.
Oakville Generating Station	
September 2009	The OPA advised TransCanada that it was awarded a 20 year Clean Energy Supply contract to build, own and operate a 900 MW generating station in Oakville, Ontario.
October 2010	The Government of Ontario announced that it would not proceed with the Oakville generating station.
August 2011	TransCanada, the Government of Ontario and the OPA reached a formal agreement to use arbitration to settle a dispute resulting from termination of the 20 year Clean Energy Supply contract with the OPA referred to above.
Cartier Wind	
Third Quarter 2009	Construction activity began on the Cartier Wind's 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms.
November 2011	The Montagne-Sèche project and phase one of the Gros-Morne wind farm were completed.
Coolidge	
August 2009	TransCanada began construction of the 575 MW Coolidge power generating station.
May 2011	Coolidge power generating station was completed and placed in service.
Kibby Wind	
October 2009	The 22 turbine, 66 MW first phase of Kibby Wind was completed and placed in service.
October 2010	The 22 turbine, 66 MW second phase of Kibby Wind was completed and placed in service.

Date	Description of development
Sundance	
February 2011	TransCanada received notice from TransAlta Corporation ("TransAlta") under the Sundance A power purchase arrangement that TransAlta determined that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored and that TransAlta therefore seeks to terminate the power purchase arrangement in respect of those units. In December 2010, the Sundance 1 and 2 generating units were withdrawn from service and were subject to a force majeure claim by TransAlta in January 2011. TransCanada has disputed both claims under the binding dispute resolution process provided in the power purchase arrangement and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims.
Halton Hills	
September 2010	The 683 MW Halton Hills power plant was completed and placed in service.
Ontario Solar	
December 2011	Subject to a number of conditions precedent, TransCanada agreed to purchase nine Ontario solar power projects from Canadian Solar Solutions Inc. with a combined capacity of 86 MW for approximately $470 million.

Further information about developments in the Energy business can be found in the MD&A under the headings *TransCanada's Strategy*, *Energy – Highlights*, *Energy – Financial Analysis* and *Energy – Opportunities and Developments*.

Business of TransCanada

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Oil Pipelines and Energy. At Year End, Natural Gas Pipelines accounted for approximately 49 per cent of revenues and 48 per cent of TransCanada's total assets, Oil Pipelines accounted for approximately 9 per cent of revenues and 19 per cent of TransCanada's total assets and Energy accounted for approximately 42 per cent of revenues and 29 per cent of TransCanada's total assets. The following table shows TransCanada's revenues from operations by segment, classified geographically, for the years ended December 31, 2011 and 2010.

Revenues from operations *(millions of dollars)*	**2011**	**2010**
Natural Gas Pipelines		
Canada - Domestic	$2,187	$2,125
Canada - Export[1]	787	837
United States and other	1,526	1,411
	4,500	4,373
Oil Pipelines		
Canada - Domestic	-	-
Canada - Export[1]	300	-
United States and other	527	-
	827	NIL
Energy[2]		
Canada - Domestic	2,649	2,243
Canada - Export[1]	-	1
United States and other	1,163	1,447
	3,812	3,691
Total revenues[3]	$9,139	$8,064

(1) Exports include pipeline revenues attributable to deliveries to U.S. pipelines and power deliveries to U.S. markets.
(2) Revenues include sales of natural gas.
(3) Revenues are attributed to countries based on country of origin of product or service.

The following is a description of each of TransCanada's three main areas of operations.

Natural Gas Pipelines business

TransCanada has substantial Canadian and U.S. natural gas pipeline and related holdings, including those listed below. The following natural gas pipelines are owned 100 per cent by TransCanada unless otherwise stated.

TransCanada has the following natural gas pipelines and related holdings in Canada:

- The Canadian Mainline is a 14,101 km (8,762 miles) pipeline system in Canada that extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

- The Alberta System is a 24,373 km (15,145 miles) pipeline system in Alberta and northeast British Columbia ("B.C.") which gathers natural gas for use within the province of Alberta and delivers it to provincial boundary points for connection with the Canadian Mainline and Foothills and with third party natural gas pipelines. During the past three completed financial years, TransCanada has enhanced the operating capacity of the Alberta System as follows:

    - the North Central Corridor, which extends the northern section of the Alberta System, was completed in March 2010;

    - the Groundbirch pipeline was completed in December 2010, connecting the Alberta System to natural gas supplies from the Montney shale gas formation in northeast B.C.; and

    - TransCanada continues to advance further pipeline development in B.C. and Alberta to transport unconventional shale gas supply as follows:

        - in January 2011, TransCanada received approval from the NEB to construct the proposed Horn River pipeline, an extension of the Alberta System to serve production from the new shale gas supply in the Horn River basin north of Fort Nelson, B.C. The Horn River pipeline is expected to be operational in the second quarter 2012. The Company has executed an agreement to extend the Horn River pipeline by approximately 100 km (62 miles), and an application requesting approval to construct and operate this extension was filed with the NEB in October 2011. This extension is projected to commence in 2014; and

        - the Company has filed applications with the NEB requesting approval for expansions to the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the Western Canada Sedimentary Basin. These new requests are expected to result in the need for further extensions and expansions of the Alberta System.

- Foothills is a 1,241 km (771 miles) pipeline system in Western Canada which carries natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

- TransCanada Pipeline Ventures LP owns a 161 km (100 miles) pipeline and related facilities that supply natural gas to the oil sands region near Fort McMurray, Alberta as well as a 27 km (17 miles) pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

- TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with the Portland system. TransCanada has a 50 per cent ownership interest in TQM and operates this pipeline.

- The Mackenzie Gas Project is a proposed pipeline extending 1,196 km (743 miles) that would connect northern onshore natural gas fields with North American markets. TransCanada has the right to acquire an equity interest in the project.

TransCanada has the following natural gas pipelines and related holdings in the U.S.:

- ANR is a 16,656 km (10,350 miles) pipeline system which transports natural gas from producing fields located in the Texas and Oklahoma panhandle regions, from the offshore and onshore regions of the Gulf of Mexico, and from the U.S. midcontinent region to markets located mainly in Wisconsin, Michigan, Illinois, Indiana and Ohio. ANR also connects with other natural gas pipelines, providing access to diverse sources of North American supply, including Western Canada, and the mid-continent and Rocky Mountain supply regions, and a variety of markets in the Midwestern and Northeastern U.S.

- Underground gas storage facilities owned and operated by American Natural Resources Company and ANR Storage Company provide regulated gas storage services to customers on the ANR and Great Lakes systems in upper Michigan. The ANR business unit owns and operates natural gas storage facilities throughout the State of Michigan with total natural gas storage capacity of 250 billion cubic feet ("Bcf").

- GTN is TransCanada's 2,178 km (1,353 miles) pipeline system that transports Western Canada Sedimentary Basin and Rocky Mountain sourced natural gas to third party natural gas pipelines and markets in Washington, Oregon and California, and connects with the Tuscarora Gas Transmission Company's pipeline ("Tuscarora"). TransCanada

operates GTN and effectively owns 83.3 per cent of the system through the combination of its direct ownership and its 33.3 per cent interest in TC PipeLines, LP which owns a 25 per cent interest in the pipeline.

- Great Lakes is a 3,404 km (2,115 miles) natural gas pipeline system connecting to the Canadian Mainline and serving markets primarily in Eastern Canada and the Northeastern and Midwestern U.S. TransCanada operates Great Lakes and effectively owns 69.0 per cent of the system through its 53.6 per cent ownership interest and its indirect ownership, which it has through its 33.3 per cent interest in TC PipeLines, LP.

- Bison is a 487 km (303 miles) pipeline from the Powder River Basin in Wyoming connecting to the Northern Border pipeline in Morton County, North Dakota. Bison became operational in January 2011. TransCanada operates Bison and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its indirect ownership, which it has through its 33.3 per cent interest in TC PipeLines, LP.

- Northern Border is 50 per cent owned by TC PipeLines, LP and is a 2,265 km (1,407 miles) natural gas pipeline system, which serves the U.S. Midwest. TransCanada operates Northern Border and effectively owns 16.7 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

- Tuscarora is 100 per cent owned by TC PipeLines, LP. TransCanada operates Tuscarora, a 491 km (305 miles) pipeline system transporting natural gas from GTN at Malin, Oregon to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

- North Baja is 100 per cent owned by TC PipeLines, LP. TransCanada operates North Baja, a pipeline system which extends 138 km (86 miles) from Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border and connects with a third party natural gas pipeline system in Mexico. TransCanada operates North Baja and effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

- Iroquois is a pipeline system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. TransCanada has a 44.5 per cent ownership interest in this 666 km (414 miles) pipeline system.

- Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. TransCanada has a 61.7 per cent ownership interest in Portland and operates this pipeline.

- TransCanada holds a 33.3 per cent interest in TC PipeLines, LP, a publicly held limited partnership of which a subsidiary of TransCanada acts as the general partner. The remaining interest of TC PipeLines, LP is widely held by the public. TC PipeLines, LP owns a 50 per cent interest in Northern Border, 46.4 per cent interest in Great Lakes, 25 per cent interest in GTN, 25 per cent interest in Bison, 100 per cent of Tuscarora and 100 per cent of North Baja.

- The Alaska Pipeline Project is a proposed natural gas pipeline and treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the natural gas treatment plant at Prudhoe Bay, Alaska to Alberta, or an alternative pipeline to Valdez, Alaska. The Alaska Pipeline Project is a joint effort between TransCanada and ExxonMobil Corporation.

TransCanada has the following natural gas pipeline and related holdings in Mexico and South America:

- TransGas is a 344 km (214 miles) natural gas pipeline system which runs from Mariquita in the central region of Colombia to Cali in the southwest of Colombia. TransCanada holds a 46.5 per cent ownership interest in this pipeline.

- Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

- Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico which extends from the facilities of Pemex Gas near Naranjos, Veracruz to an electricity generating station near Tamazunchale, San Luis Potosi.

- The Guadalajara pipeline was completed in June 2011, and extends 310 km (193 miles), transporting natural gas from a liquefied natural gas terminal near Manzanillo on Mexico's Pacific coast to Guadalajara in Mexico.

Further information about the Company's pipeline holdings, developments and opportunities and significant regulatory developments which relate to Natural Gas Pipelines can be found in the MD&A under the headings *Natural Gas Pipelines*, *Natural Gas Pipelines – Opportunities and Developments* and *Natural Gas Pipelines – Financial Analysis*.

Oil Pipelines business

The Company's Keystone pipeline system and other opportunities in TransCanada's Oil Pipelines business are described below.

Keystone is a 3,467 km (2,154 miles) crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Wood River/Patoka and Cushing Extension sections commenced commercial operations in June 2010 and February 2011, respectively. In January 2012, the U.S. Department of State denied TransCanada's application to construct Keystone XL, a 2,673 km (1,661 miles) extension and expansion of the pipeline to the U.S. Gulf Coast. The Company intends to re-apply for a Presidential Permit for Keystone XL.

Further information about the Company's pipeline holdings, developments and opportunities and significant regulatory developments which relate to Oil Pipelines can be found in the MD&A under the headings *Oil Pipelines*, *Oil Pipelines – Opportunities and Developments* and *Oil Pipelines – Financial Analysis*.

Regulation of the Natural Gas and Oil Pipelines businesses

Canada

Natural Gas Pipelines
Under the terms of the *National Energy Board Act* (Canada), the Canadian Mainline, TQM, Foothills, and the Alberta System (collectively, the "Systems") are regulated by the NEB. The NEB sets tolls that provide TransCanada the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for each of the Systems. In addition, new facilities are approved by the NEB before construction begins and the NEB regulates the operations of each of the Systems. Net earnings of the Systems may be affected by changes in investment base, the allowed return on equity, and any incentive earnings.

Oil Pipelines
The NEB regulates the terms and conditions of service, including rates, and the physical operation of the Canadian portion of the Keystone system. NEB approval is also required for facility additions. The rates for transportation service on the Keystone system are calculated in accordance with a methodology agreed to in transportation service agreements between Keystone and its shippers, and approved by the NEB.

United States

Natural Gas Pipelines
TransCanada's wholly owned and partially owned U.S. pipelines, including the ANR, Bison, GTN, Great Lakes, Iroquois, Portland, Northern Border, North Baja and Tuscarora systems, are considered "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938* and the *Natural Gas Policy Act of 1978*, and are subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation and interstate commerce.

Oil Pipelines
The FERC also regulates the terms and conditions of service, including transportation rates, on the U.S. portion of the Keystone system. Certain states in which Keystone has rights of way also regulate construction and siting of Keystone.

Energy business

The Energy segment of our business includes the acquisition, development, construction, ownership and operation of electrical power generation plants, the purchase and marketing of electricity, the provision of electricity account services to energy and industrial customers, and the development, construction, ownership and operation of non-regulated natural gas storage in Alberta.

The electrical power generation plants and power supply that TransCanada has an interest in, including those under development, in the aggregate, represent more than 10,800 MW of power generation capacity. Power plants and power supply in Canadian power account for approximately 65 per cent of this total, and power plants in U.S. power account for the balance, being approximately 35 per cent.

TransCanada owns and operates the following facilities:

- Ravenswood generating station, a 2,480 MW power plant located in Queen's, New York which consists of multiple units employing dual fuel-capable steam turbine, combined-cycle and combustion turbine technology.

- Halton Hills, a 683 MW natural gas-fired combined-cycle power plant in Halton Hills, Ontario which is contracted under a 20 year Clean Energy Supply contract with the OPA.

- Kibby Wind, a 132 MW wind farm located in the Kibby and Skinner Townships in Maine.

- TC Hydro, TransCanada's hydroelectric facilities located in New Hampshire, Vermont and Massachusetts on the Connecticut and Deerfield Rivers, consists of 13 hydroelectric facilities, including stations and associated dams and reservoirs, with a total generating capacity of 583 MW.

- Ocean State Power, a 560 MW natural gas-fired, combined-cycle facility in Burrillville, Rhode Island.

- Bécancour, a 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec. The entire power output is supplied to Hydro-Québec which is contracted under a 20 year power purchase agreement expiring in 2026.

- Natural gas-fired cogeneration plants in Alberta at Carseland (80 MW), Redwater (40 MW), Bear Creek (80 MW) and MacKay River (165 MW).

- Grandview, a 90 MW natural gas-fired cogeneration power plant located on the site of the Irving Oil Limited oil refinery in Saint John, New Brunswick. Irving Oil Limited is under a 20 year tolling arrangement that expires in 2025, to supply fuel for the plant and to contract 100 per cent of the plant's heat and electricity output.

- Cancarb, a 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TransCanada's adjacent thermal carbon black facility.

- Edson, an underground natural gas storage facility connected to the Alberta System near Edson, Alberta.

- Coolidge, a 575 MW simple-cycle, natural gas-fired peaking power generation station in Arizona. Coolidge, which was placed in service in May 2011, operates under a 20 year power purchase agreement with the Salt River Project Agricultural Improvement and Power District.

TransCanada has the following long-term power purchase arrangements in place:

- TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generation facility under a power purchase arrangement that expires in 2017. TransCanada also has a 50 per cent interest in ASTC Power Partnership, which has a power purchase arrangement that expires in 2020, in place for 100 per cent of the production from the 706 MW Sundance B power facility. The Sundance facilities are located in south-central Alberta.

- The Sheerness facility, which consists of two coal-fired thermal power generating units, is located in Southeastern Alberta. TransCanada has the rights to 756 MW of generating capacity from the Sheerness power purchase arrangement that expires in 2020.

TransCanada has interests in the following:

- Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and comprises Bruce A and Bruce B. Bruce A has four 750 MW reactors, two of which are being refurbished. The two units being refurbished are expected to resume commercial operations in first and third quarter 2012, respectively. Bruce B has four operating reactors with a combined capacity of 3,200 MW. Bruce A subleases Units 1 to 4 from Bruce B, and Bruce B consists of Units 5 to 8. TransCanada owns a 48.8 per cent interest in Bruce A and a 31.6 per cent interest in Bruce B.

- A 60 per cent ownership in CrossAlta, which is a 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. The facility's central processing system is capable of maximum injection and withdrawal rates of 550 MMcf/d of natural gas. TransCanada owns 60 per cent of CrossAlta and, through an agreement made effective July 1, 2011, is now the operator of the facility.

- A 62 per cent interest in the Cartier Wind energy project. The Carleton (109 MW), Anse-à-Valleau (101 MW) and Baie-des-Sables (110 MW) commenced commercial operation in November 2008, November 2007 and November 2006, respectively. Montagne-Sèche (58 MW) and the first phase of Gros-Morne (101 MW) commenced commercial operation in November 2011. The second phase of Gros-Morne (111 MW) is expected to be operational in December

2012. All of the power produced by Cartier Wind is sold to Hydro-Québec Distribution under a 20 year power purchase agreement.

- Portlands Energy, a 550 MW, combined-cycle natural gas power plant located in Toronto, Ontario, is 50 per cent owned by TransCanada, and is operated by TransCanada under a 20 year Accelerated Clean Energy Supply contract with the OPA.

Further information about the Company's energy holdings and significant developments and opportunities in relation to Energy can be found in the MD&A under the headings *Energy*, *Energy – Highlights*, *Energy – Financial Analysis* and *Energy – Opportunities and Developments*.

General

Employees

At Year End, TransCanada's principal operating subsidiary, TCPL, had approximately 4,300 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary		1,955
Western Canada (excluding Calgary)		451
Houston		467
U.S. Midwest		440
U.S. Northeast		403
Eastern Canada		253
U.S. Southeast/Gulf Coast		246
U.S. West Coast		79
Mexico and South America		5
	Total	**4,299**

Social and environmental policies

Health, safety and environment ("HSE") are top priorities in all of TransCanada's operations and business activities. These areas are guided by our HSE Commitment Statement, which outlines guiding principles for a safe and healthy environment for TransCanada's employees, contractors and the public, and for our commitment to protect the environment. All employees are responsible for TransCanada's HSE performance. We are committed to being an industry leader in conducting our business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to the public, and the environment. We are committed to continually improving our HSE performance, and to promoting safety on and off the job, in the belief that all occupational injuries and illnesses are preventable. We endeavour to do business with companies and contractors that share our perspective and expectation on HSE performance and influence them to improve their collective performance. We are committed to respecting the diverse environments and cultures in which we operate and to support open communication with our stakeholders.

The Health, Safety and Environment Committee of our Board of Directors (the "Board") monitors compliance with the Company's HSE corporate policy through regular reporting. TransCanada's integrated HSE management system is modeled after the International Organization for Standardization standard for environmental management systems, ISO 14001; and the Occupational Health and Safety Assessment Series (OHSAS 18001) for occupational health and safety. Our HSE management system conforms to external industry consensus standards and voluntary regulatory programs and complies with applicable legislated requirements and various other internal management systems. Resources are focused on the areas of significant risk to the organization's HSE business activities. Management is informed regularly of all important and/or significant HSE operational issues and initiatives through formal reporting and incident management processes. TransCanada's HSE management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in 2009 and did not identify any material issues. The HSE management system is subject to ongoing internal and external review to ensure that it remains effective as circumstances change.

As one of TransCanada's priorities, safety is an integral part of the way our employees work. In 2011, one of our objectives was to sustain health and safety performance year over year. Overall, TransCanada's safety frequency rates in 2011 continued to be better than most industry benchmarks.

The safety and integrity of our existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. We expect to spend approximately $322 million in 2012 for pipeline integrity on pipelines we operate, an increase of approximately $78 million over 2011 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on our NEB-regulated pipelines are treated on a flow-through basis and, as a result, these expenditures have no impact on TransCanada’s earnings. Under the Keystone transportation contracts, pipeline integrity expenditures are recovered through

the tolling mechanism and, as a result, these expenditures have no impact on TransCanada's earnings. Our pipeline safety record in 2011 continued to be better than industry benchmarks. We experienced two pipeline breaks in 2011 on pipelines we operate. The first break occurred in a remote part of Northern Ontario on the Canadian Mainline pipeline system. The second break occurred in a remote part of Wyoming on the Bison pipeline system. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment and is slightly higher than previous years due to increased spending to repair damage from the high flow events of 2011 caused by Hurricane Irene.

Environmental controls including physical design, programs, procedures and processes are in place to effectively manage TransCanada's environmental risk factors. With respect to physical risks arising from climate change, we have in place a set of procedures to manage our response to natural disasters such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes regardless of cause. These procedures are included in TransCanada's Operating Procedures and are part of the Company's Incident Management System. The procedures are in place to protect the health and safety of our employees and to limit the impact to the environment of any operational upsets caused by a natural disaster.

With respect to business opportunities, the Company has well established processes and criteria for assessing new business opportunities including those that may arise as a result of climate change policies. These processes have been and continue to be key contributors to our financial strength and success. Governments in North America are developing long-term plans for limiting greenhouse gas ("GHG") emissions. These plans, combined with a shift in consumer attitude and demand for low-emissions fuels, will require changes in energy supply and infrastructure. With the Company's experience in pipeline transmission and power generation, TransCanada is well-positioned to participate in these opportunities.

Aboriginal, Native American and stakeholder engagement

We recognize that an enhanced level of engagement of a wide variety of stakeholders in our business activities can have a significant impact on the Company's ability to obtain approvals for new assets and to maintain our social licenses to operate. TransCanada has a number of policies, guiding principles and practices in place to help manage stakeholder engagement. TransCanada has adopted a code of business ethics which applies to our employees that is based on the Company's four core values of integrity, collaboration, responsibility and innovation, which guide the interaction between and among the Company's employees and serve as a standard for TransCanada in our dealings with all stakeholders. The code may be viewed on our website (www.transcanada.com).

Our approach to stakeholder engagement is based on building relationships, mutual respect and trust while recognizing the unique values, needs and interests of each community. Key principles that guide TransCanada's engagement include: the Company's respect for the diversity of Aboriginal/Native American communities and recognition of the importance of the land to these communities; and our belief in engaging stakeholders from the earliest stages of our projects, through the project development process and into operations.

Environmental protection

TransCanada's facilities are subject to stringent federal, state, provincial, and local environmental statutes and regulations governing environmental protection, including, but not limited to, air emissions and GHG emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements and/or the issuance of orders respecting future operations. We have ongoing inspection programs designed to keep all of our facilities in compliance with environmental requirements.

At December 31, 2011, TransCanada recorded liabilities of approximately $69 million (2010 - $84 million) for remediation obligations and compliance costs associated with certain environmental regulations. We believe that the Company has considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us to set aside additional amounts.

TransCanada is not aware of any material outstanding orders, claims or lawsuits against it in relation to the release or discharge of any material into the environment or in connection with environmental protection.

The Company owns assets in four regions, Alberta, Québec, B.C., and the Northeastern U.S., where regulations exist to address industrial GHG emissions. We have procedures in place to comply with these regulations. In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHG emissions over an intensity threshold level are required to reduce the intensity of GHG emissions by 12 per cent below an average baseline. Our Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with respect to which TransCanada has certain rights under power purchase arrangements. TransCanada has a program in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls paid by customers. Some of the compliance costs from the Company's power generation facilities in Alberta are recovered through

market pricing and contract flow-through provisions. TransCanada has estimated and recorded GHG emissions related costs of $13 million for 2011 (2010 - $22 million), after contracted cost recovery.

In Québec, the natural gas distributor collects the hydrocarbon royalty on behalf of the provincial government through a green fund contribution charge on gas consumed. In 2011, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility's power generation.

The carbon tax in B.C., which came into effect in mid-2008, applies to carbon dioxide ("CO_2") emissions from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax in 2011 were approximately $3 million (2010 - $4 million). The cost per tonne of CO_2 will be increased in July 2012 to $30.00 from $25.00.

States in the northeastern U.S. that are members of the Regional Greenhouse Gas Initiative ("RGGI") implemented a CO_2 cap-and-trade program for electricity generators effective in January 2009. Under the RGGI, both the Ravenswood and Ocean State Power generation facilities were required to submit allowances following the end of the first compliance period on December 31, 2011. TransCanada participated in the quarterly auctions of allowances for the Ravenswood and Ocean State Power generation facilities and incurred related costs of $4 million in 2011 (2010 - $5 million). These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

Risk factors

Environmental risk factors

Environmental risks

Environmental risks from our operating facilities typically include: air emissions and GHG emissions; potential impacts on land, including land reclamation or restoration following construction; the use, storage and release of hydrocarbons or other chemicals; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge.

TransCanada's assets are located throughout North America and the Company's facility design must deal with different geographical areas. In northern regions, changing permafrost distribution due to warmer temperatures have been experienced, however, very few kilometers of our pipeline systems are currently in permafrost regions. If we build new facilities in northern areas, the Company's facility designs will take into account the potential for changing permafrost distribution.

As mentioned above, our operations are subject to various environmental laws and regulations that establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties. It is not possible for TransCanada to estimate the amount and timing of all future expenditures related to environmental matters due to:

- uncertainties in estimating pollution control and clean up costs, including at sites where only preliminary site investigation or agreements have been completed
- the potential discovery of new contaminated sites or additional information at existing contaminated sites
- the uncertainty in quantifying the Company's liability under environmental laws that impose joint and several liability on all potentially responsible parties
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement of them, and
- the potential for litigation on existing or discontinued assets.

Changing legislation and regulations

The impact of new or proposed federal, state, and/or provincial safety and environmental laws, regulations, guidelines and enforcement in Canada and the U.S. on our business is not yet certain. We make assumptions about possible expenditures for safety and environmental matters based on current laws and regulations and interpretations thereof. If the laws or regulations or the interpretation thereof changes, the Company's assumptions may change. Incremental costs may or may not be recoverable under existing rate structures or commercial agreements. Proposed changes in environmental policy, legislation or regulation are routinely monitored by TransCanada, and where the risks are potentially large or uncertain, the Company works independently or through industry associations to comment on proposals.

In April 2010, the Environmental Protection Agency ("EPA") published an Advanced Notice of Proposed Rulemaking to solicit comments with respect to EPA reassessment of current regulations under the *Toxic Substances Control Act*, governing the authorized use of polychlorinated biphenyls in certain equipment. Following a review of comments, the EPA has indicated that

the use authorization for pipelines will likely remain in place but that requirements to use the authorization may become more strict. These changes would likely result in increased costs for our impacted pipelines. Proposed EPA rules are expected in 2012.

In Canada, development of the major elements of an Air Quality Management System ("AQMS") continued in 2011 following endorsement of the AQMS in October 2010 by the Canadian Council of Ministers of the Environment. Two key aspects of the AQMS are of particular interest to us: the Base Level Industry Emissions Standards, which assumes that all significant industrial sources of emissions in Canada should be expected to meet, base-level of environmental performance; and air zone management, which is intended to address the sources of air pollution and the actions that are required to ensure that a specified level of air quality is improved or maintained in a specified region. While our Canadian based facilities would likely be impacted by AQMS, the potential financial impact of this initiative is currently unknown.

Regulation of air pollutant emissions under the U.S. *Clean Air Act* and state regulations continue to evolve. A number of EPA initiatives could lead to impacts ranging from requirements to install enhanced emissions control equipment, to additional administrative and reporting requirements. At this time, there is insufficient detail to accurately determine the potential impacts of these initiatives. While the majority of the proposals are not expected to be material to TransCanada, we anticipate additional future costs related to the monitoring and control of air emissions.

In addition to those climate change policies already in place, there are also federal, regional, state, and provincial initiatives currently in development. While recent political and economic events may significantly affect the scope and timing of new policies, we anticipate that most of the Company's facilities in Canada and the U.S. are or will be subject to federal and/or regional climate change regulations to manage industrial GHG emissions.

In August 2011, the Canadian government published the first sector specific draft regulation that will impact industrial GHG emissions. This proposed regulation is focused on the coal-fired generation of electricity and requires a natural gas performance standard for all coal-fired facilities reaching the end of their economic life. The draft regulation is expected to come into effect in July 2015. This process is not expected to pose a significant risk or financial impact to our existing facilities and may present opportunities for new power generation investment. Additional sectors, including the natural gas-fired generation of electricity and upstream oil and gas facility sectors, are expected to begin consultations with Environment Canada.

The Western Climate Initiative ("WCI") continues to work toward implementing a regional cap-and-trade program. California and Québec are the only WCI members with cap-and-trade regulations. In December 2011, the Government of Québec adopted the "Regulation respecting the cap-and-trade system for greenhouse gas emission allowances". The initial phase of the cap-and-trade system will begin January 1, 2013. The regulation will have a limited impact on TransCanada's Bécancour power generation facility and natural gas pipeline assets. With respect to California, the Air Resources Board adopted a cap-and-trade regulation in October 2011. The regulation is divided into two phases: the first, beginning in 2013, will include all major industrial sources and electricity utilities; the second, starting in 2015, will cover distributors of transportation fuels, natural gas and other fuels. The regulation may impact the Company's importation of electricity into the state.

TransCanada monitors climate change policy developments and, when warranted, participates in policy discussions in jurisdictions where we have operations. We are also continuing our programs to manage GHG emissions from our facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates. For example, in 2011 TransCanada participated in a number of multi-stakeholder expert groups that were established to develop equipment standards in Canada. TransCanada participated both independently and through industry associations.

Other risk factors

A discussion of the Company's risk factors can be found in the MD&A under the headings N*atural Gas Pipelines – Opportunities and Developments*, *Natural Gas Pipelines – Business Risks, Natural Gas Pipelines – Outlook*, *Oil Pipelines – Opportunities and Developments*, *Oil Pipelines – Business Risks*, *Oil Pipelines – Outlook, Energy – Opportunities* and *Developments, Energy – Business Risks, Energy – Outlook* and *Risk Management and Financial Instruments*.

Dividends

The Board has not adopted a formal dividend policy. The Board reviews the financial performance of TransCanada quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, TransCanada's payment of dividends is primarily funded from dividends it receives as the sole common shareholder of TCPL. Provisions of various trust indentures and credit arrangements to which TCPL is a party restrict TCPL's ability to declare and pay dividends to TransCanada under certain circumstances and, if such restrictions apply, they may, in turn, have an impact on TransCanada's ability to declare and pay dividends. In the opinion of TransCanada's management, such provisions do not currently restrict or alter TransCanada's ability to declare or pay dividends.

Holders of cumulative redeemable first preferred shares, series 1 ("Series 1 Preferred Shares") are entitled to receive fixed cumulative dividends, at an annual rate of $1.15 per share, payable quarterly, as and when declared by the Board, for the initial five year period ending December 31, 2014. For the period from issuance on September 30, 2009 to December 31, 2009, dividends in the amount of $0.29 per share were declared and paid on the Series 1 Preferred Shares. For the period January 1, 2010 to December 31, 2010, dividends in the amount of $1.15 per share were declared and paid on the Series 1 Preferred Shares. For the period January 1, 2011 to December 31, 2011, dividends in the amount of $1.15 per share were declared and paid on the Series 1 Preferred Shares. The dividend on the Series 1 Preferred Shares will reset on December 31, 2014 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.92 per cent. The holders of Series 1 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 2 (the "Series 2 Preferred Shares") as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 3 ("Series 3 Preferred Shares") are entitled to receive fixed cumulative dividends, at an annual rate of $1.00 per share, payable quarterly, as and when declared by the Board, for the initial five year period ending June 30, 2015. For the period from issuance on March 11, 2010 to December 31, 2010, dividends in the amount of $0.80 per share were declared and paid on the Series 3 Preferred Shares. For the period January 1, 2011 to December 31, 2011, dividends in the amount of $1.00 per share were declared and paid on the Series 3 Preferred Shares. The dividend on the Series 3 Preferred Shares will reset on June 30, 2015 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.28 per cent. The holders of Series 3 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 4 (the "Series 4 Preferred Shares") as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 5 ("Series 5 Preferred Shares") are entitled to receive fixed cumulative dividends, at an annual rate of $1.10 per share, payable quarterly, as and when declared by the Board, for the initial five and a half year period ending January 30, 2016. For the period from issuance on June 29, 2010 to December 31, 2010, dividends in the amount of $0.65 per share were declared and dividends in the amount of $0.37 per share were paid, on the Series 5 Preferred Shares. For the period January 1, 2011 to December 31, 2011, dividends in the amount of $1.10 per share were declared and paid on the Series 5 Preferred Shares. The dividend on the Series 5 Preferred Shares will reset on January 30, 2016 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.54 per cent. The holders of Series 5 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 6 (the "Series 6 Preferred Shares") as set out under the heading *First preferred shares* below.

The dividends declared per common share of TransCanada during the past three completed financial years are set forth in the following table:

	2011	2010	2009
Dividends declared on common shares	$1.68	$1.60	$1.52

Description of capital structure

Share capital

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 703,861,065 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which 22,000,000 Series 1 Preferred Shares, 14,000,000 Series 3 Preferred Shares and 14,000,000 Series 5 Preferred Shares are issued and outstanding. The following is a description of the material characteristics of each of these classes of shares.

Common shares

The common shares entitle the holders thereof to one vote per share at all meetings of shareholders, except meetings at which only holders of another specified class of shares are entitled to vote, and, subject to the rights, privileges, restrictions and conditions attaching to the first preferred shares and the second preferred shares, whether as a class or a series, and to any other class or series of shares of TransCanada which rank prior to the common shares, entitle the holders thereof to receive (i) dividends if, as and when declared by the Board out of the assets of TransCanada properly applicable to the payment of the dividends in such amount and payable at such times and at such place or places as the Board may from time to time determine and (ii) the remaining property of TransCanada upon a dissolution.

TransCanada has a Shareholder Rights Plan (the "SR Plan") that is designed to ensure, to the extent possible, that all shareholders of TransCanada are treated fairly in connection with any take-over bid for the Company. The SR Plan creates a right attaching to each Common Share outstanding and to each Common Share subsequently issued. Each right becomes exercisable ten trading days after a person has acquired, or commences a take-over bid to acquire, 20 per cent or more of the common shares, other than by an acquisition pursuant to a take-over bid permitted under the terms of the SR Plan. Prior to a flip-in event (as described below), each right permits registered holders to purchase from the Company common shares of

TransCanada at the exercise price equal to three times the market price of such shares, subject to adjustments and anti-dilution provisions (the "exercise price"). The beneficial acquisition by any person of 20 per cent or more of the common shares, other than by way of a take-over bid permitted under the terms of the SR Plan, is referred to as a "flip-in event". Ten trading days after a flip-in event, each TransCanada right will permit registered holders to receive, upon payment of the exercise price, the number of common shares with an aggregate market price equal to twice the exercise price. The SR Plan was reconfirmed at the 2010 annual and special meeting of shareholders and must be reconfirmed every third annual meeting thereafter.

TransCanada has a Dividend Reinvestment and Share Purchase Plan which permits common and preferred shareholders of TransCanada and preferred shareholders of TCPL, to elect to reinvest their cash dividends in additional common shares of TransCanada. Commencing with dividends declared in April 2011, common shares purchased with reinvested cash dividends were satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares were provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. In February 2012, the Board approved an increase in the quarterly common share dividend payment by 5 per cent to $0.44 per share from $0.42 per share, for the quarter ending March 31, 2012. Participants may also make additional cash payments of up to $10,000 per quarter to purchase additional common shares, which optional purchases are not eligible for any discount on the price of common shares. Participants are not responsible for payment of brokerage commissions or other transaction expenses for purchases made pursuant to the Dividend Reinvestment and Share Purchase Plan.

TransCanada also has stock-based compensation plans (the "SOPs") that allow some employees to purchase common shares of TransCanada. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the SOPs are generally fully exercisable after three years and expire seven years after the date of grant.

First preferred shares

Subject to certain limitations, the Board may, from time to time, issue first preferred shares in one or more series and determine for any such series, its designation, number of shares and respective rights, privileges, restrictions and conditions. The first preferred shares as a class have, among others, the provisions described below.

The first preferred shares of each series rank on a parity with the first preferred shares of every other series, and are entitled to preference over the common shares, the second preferred shares and any other shares ranking junior to the first preferred shares with respect to the payment of dividends, the repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Except as provided by the CBCA or as referred to below, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the directors if TransCanada fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the approval of the holders of the first preferred shares as a class. Any such approval to be given by the holders of the first preferred shares may be given by the affirmative vote of the holders of not less than sixty-six and two-thirds per cent of the first preferred shares represented and voted at a meeting or adjourned meeting of such holders.

The Series 1 Preferred Shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The Series 1 Preferred Shares are redeemable by TransCanada in whole or in part on or after December 31, 2014, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 1 Preferred Shares have the right to convert their shares into cumulative redeemable Series 2 Preferred Shares, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1 Preferred Shares shall be entitled to receive $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 1 Preferred Shares.

The Series 3 Preferred Shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 3 Preferred Shares are substantially identical to those attaching to the Series 1 Preferred Shares, except as outlined below. The Series 3 Preferred Shares are redeemable by TransCanada in whole or in part on or after June 30, 2015, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 3 Preferred Shares have the

right to convert their shares into cumulative redeemable Series 4 Preferred Shares, subject to certain conditions, on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 3 Preferred Shares shall be entitled to receive $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 3 Preferred Shares.

The Series 5 Preferred Shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 5 Preferred Shares are substantially identical to those attaching to the Series 1 Preferred Shares, except as outlined below. The Series 5 Preferred Shares are redeemable by TransCanada in whole or in part on or after January 30, 2016, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 5 Preferred Shares have the right to convert their shares into cumulative redeemable Series 6 Preferred Shares, subject to certain conditions, on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 5 Preferred Shares shall be entitled to receive $25.00 per Series 5 Preferred Share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 5 Preferred Shares.

Except as provided by the CBCA, the respective holders of the Series 1, 2, 3, 4, 5 and 6 Preferred Shares are not entitled to receive notice of, attend at, or vote at any meeting of shareholders unless and until TransCanada shall have failed to pay eight quarterly dividends, whether or not consecutive, in which case the respective holders of Series 1, 2, 3, 4, 5 and 6 Preferred Shares shall have the right to receive notice of and to attend each meeting of shareholders at which directors are to be elected and which take place more than 60 days after the date on which the failure first occurs, and to one vote with respect to resolutions to elect directors for each Series 1, 2, 3, 4, 5 and 6 Preferred Share, respectively, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the Series 1, 2, 3, 4, 5 or 6 Preferred Shares may be amended with the written approval of all the holders of such series of shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Second preferred shares

The rights, privileges, restrictions and conditions attaching to the second preferred shares are substantially identical to those attaching to the first preferred shares, except that the second preferred shares are junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Credit ratings

Although TransCanada has not issued debt to the public, it has been assigned credit ratings by Moody's Investors Service, Inc. ("Moody's") and Standard & Poor's ("S&P"). Moody's has assigned an issuer rating of Baa1 with a stable outlook and S&P has assigned a long-term corporate credit rating of A- with a stable outlook. TransCanada does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL. The following table sets out the current credit ratings assigned to those outstanding classes of securities of TCPL which have been rated by DBRS Limited ("DBRS"), Moody's and S&P:

	DBRS	**Moody's**	**S&P**
Senior unsecured debt			
Debentures	A	A3	A-
Medium-term notes	A	A3	A-
Junior subordinated notes	BBB (high)	Baa1	BBB
Preferred shares	Pfd-2 (low)	Baa2	P-2
Commercial paper	R-1 (low)	-	A-2
Trending/rating outlook	Stable	Stable	Stable

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

The Company paid fees to each of DBRS, Moody's and S&P for the credit ratings rendered on each of the outstanding classes of securities noted above. No additional payments were made to DBRS, Moody's and S&P in respect of any other services provided to the Company during the past two years.

The information concerning the Company's credit ratings relates to the Company's financing costs, liquidity and operations. The availability of TransCanada's funding options may be affected by certain factors, including the global capital market environment and outlook as well as the Company's financial performance. TransCanada's access to capital markets at competitive rates is dependent on its credit rating and rating outlook, as determined by credit rating agencies such as DBRS, Moody's and S&P, and if TransCanada's ratings were downgraded the Company's financing costs and future debt issuances could be unfavorably impacted. A description of the rating agencies' credit ratings listed in the table above is set out below.

DBRS Limited (DBRS)

DBRS has different rating scales for short- and long-term debt and preferred shares. "High" or "low" grades are used to indicate the relative standing within all rating categories other than AAA and D. The absence of either a "high" or "low" designation indicates the rating is in the "middle" of the category. The R-1 (low) rating assigned to TCPL's short-term debt is in the third highest of ten rating categories and indicates good credit quality. The overall strength is not as favourable as higher rating categories, but any qualifying negative factors that exist are considered manageable. The A rating assigned to TCPL's senior unsecured debt is in the third highest of ten categories for long-term debt. Long-term debt rated A is good credit quality. The capacity for the payment of interest and principal is substantial, but of lesser credit quality than that of AA rated securities. Long term debt rated A may be vulnerable to future events but qualifying negative factors are considered manageable. The BBB (high) rating assigned to junior subordinated notes is in the fourth highest of the ten categories for long-term debt. Long- term debt rated BBB is of adequate credit quality. The capacity for the payment of interest and principal is considered acceptable, but it may be vulnerable to future events. The Pfd-2 (low) rating assigned to TCPL's and TransCanada's preferred shares is in the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial; however, earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. In general, Pfd-2 ratings correspond with long-term debt rated in the A category.

Moody's Investors Service, Inc. (Moody's)

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are applied to each rating classification from Aa through Caa, with 1 being the highest and 3 being the lowest. The A3 rating assigned to TCPL's senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are considered upper medium grade and are subject to low credit risk. The Baa1 and Baa2 ratings assigned to TCPL's junior subordinated debt and preferred shares, respectively, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated debt ranking slightly higher within the Baa rating category with a modifier of 1 as opposed to the modifier of 2 on the preferred shares. Obligations rated Baa are subject to moderate credit risk, are considered medium-grade, and as such, may possess certain speculative characteristics.

Standard & Poor's (S&P)

S&P has different rating scales for short- and long-term obligations. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The A- rating assigned to TCPL's senior unsecured debt is in the third highest of ten rating categories for long-term obligations. An A rating indicates the obligor's capacity to meet its financial commitment is strong; however, the obligation is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. As guarantor of a U.S. subsidiary's commercial paper program, TCPL has been assigned a commercial paper rating of A-2 which is the second highest of nine rating categories for short-term debt obligations. A short term debt rated A-2 is somewhat more susceptible to adverse effects of changes in economic conditions than higher rated categories; however, the capacity to meet all financial commitments remains satisfactory. The BBB and P-2 ratings assigned to TCPL's junior subordinated notes and TCPL's and TransCanada's preferred shares exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

Market for securities

TransCanada's common shares are listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the symbol "TRP". TransCanada's Series 1 Preferred Shares, Series 3 Preferred Shares and Series 5 Preferred Shares have been listed for trading on the TSX since September 30, 2009, March 11, 2010 and June 29, 2010, under the symbols "TRP.PR.A", "TRP.PR.B", and "TRP.PR.C", respectively. The following tables set forth the reported

monthly high, low, and month-end closing trading prices and monthly trading volumes of the common shares of TransCanada on the TSX and the NYSE, and the respective Series 1 Preferred Shares, Series 3 Preferred Shares and Series 5 Preferred Shares on the TSX, for the period indicated:

Common shares

	TSX (TRP)				NYSE (TRP)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**	**High (US$)**	**Low (US$)**	**Close (US$)**	**Volume Traded**
December 2011	44.74	42.03	44.53	38,155,545	43.95	40.55	43.67	10,540,577
November 2011	42.90	39.25	42.88	40,551,335	42.54	38.62	41.80	22,065,841
October 2011	44.10	39.81	42.37	41,926,225	44.38	37.58	43.04	15,887,005
September 2011	43.23	40.27	42.54	33,171,287	43.79	39.08	40.49	16,346,869
August 2011	42.36	37.00	42.36	41,333,472	43.20	37.29	43.15	26,402,340
July 2011	42.39	39.42	40.14	32,882,839	44.08	40.66	41.95	8,871,558
June 2011	43.72	41.07	42.35	33,597,026	45.09	41.76	43.84	8,832,316
May 2011	43.48	40.75	43.39	27,895,419	44.97	42.10	44.83	7,444,917
April 2011	40.71	38.95	40.71	24,366,705	43.02	40.37	42.94	7,523,263
March 2011	39.64	37.73	39.31	36,681,641	40.76	37.88	40.53	12,204,704
February 2011	39.19	36.53	39.04	37,966,180	40.32	36.76	40.21	9,750,606
January 2011	38.40	36.10	36.55	32,309,382	38.61	36.12	36.54	8,313,201

Series 1 Preferred Shares

	TSX (TRP.PR.A)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**
December 2011	26.50	25.85	26.21	154,033
November 2011	26.38	25.66	26.02	215,475
October 2011	26.05	25.71	25.97	305,469
September 2011	26.32	25.78	25.85	221,164
August 2011	26.28	25.65	25.85	156,599
July 2011	26.20	25.81	26.07	226,612
June 2011	26.24	25.68	25.94	278,119
May 2011	26.25	25.65	25.66	1,207,022
April 2011	26.00	25.70	25.80	172,341
March 2011	26.00	25.40	25.75	282,270
February 2011	26.36	25.40	25.64	479,357
January 2011	26.25	25.75	26.21	601,031

Series 3 Preferred Shares

	TSX (TRP.PR.B)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**
December 2011	25.89	24.94	25.75	165,577
November 2011	25.45	24.97	25.16	359,674
October 2011	25.39	24.96	25.25	350,993
September 2011	25.38	25.00	25.12	221,672
August 2011	25.67	24.81	25.01	278,636
July 2011	25.92	25.15	25.67	501,178
June 2011	25.54	24.93	25.20	343,637
May 2011	25.44	24.85	24.99	326,765
April 2011	25.39	24.93	25.20	328,708
March 2011	25.20	24.42	24.96	389,964
February 2011	25.35	24.36	24.79	336,606
January 2011	25.48	24.70	25.02	499,120

Series 5 Preferred Shares

Month	TSX (TRP.PR.C)			
	High ($)	Low ($)	Close ($)	Volume Traded
December 2011	26.67	25.58	25.80	175,643
November 2011	25.98	25.45	25.84	388,764
October 2011	25.60	25.00	25.49	696,761
September 2011	26.44	25.27	25.46	281,423
August 2011	26.00	25.45	25.77	308,562
July 2011	26.10	25.50	25.88	199,978
June 2011	26.10	25.33	25.56	170,757
May 2011	25.90	25.45	25.80	450,511
April 2011	25.73	25.27	25.52	154,113
March 2011	25.89	25.19	25.73	724,705
February 2011	25.76	25.12	25.39	378,470
January 2011	26.15	25.28	25.49	541,030

In addition, TransCanada's subsidiary, TCPL, has cumulative redeemable first preferred shares, series U and series Y listed on the TSX under the symbols "TCA.PR.X", and "TCA.PR.Y", respectively.

Directors and officers

As of February 13, 2012, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction, directly or indirectly, over an aggregate of 551,756 common shares of TransCanada. This constitutes less than one per cent of TransCanada's common shares. The Company collects this information from our directors and officers but otherwise we have no direct knowledge of individual holdings of TransCanada's securities.

Directors

The following table sets forth the names of the 14 directors who serve on the Board, as of February 13, 2012, together with their jurisdictions of residence, all positions and offices held by them with TransCanada and the Company's significant affiliates, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Kevin E. Benson Calgary, Alberta Canada	President and Chief Executive Officer, Laidlaw International, Inc. (transportation services) from June 2003 to October 2007. Director, Calgary Airport Authority.	2005
Derek H. Burney [(1)], O.C. Ottawa, Ontario Canada	Senior strategic advisor at Norton Rose Canada LLP (law firm). Chair (not a Director), International Advisory Board for Garda World Consulting and Investigation/Global Risks Group, a division of Garda World Security Corporation since 2008. Chair, Canwest Global Communications Corp. (communications) from August 2006 (director since April 2005) to October 2010 and lead director at Shell Canada Limited (oil and gas) from April 2001 to May 2007.	2005
Wendy K. Dobson Uxbridge, Ontario Canada	Professor, Rotman School of Management. Director, Institute for International Business, University of Toronto and Director, the Toronto-Dominion Bank. Vice Chair, Canadian Public Accountability Board until February 2010 and Chair of the Audit Committee of the same organization from 2003 to 2009.	1992
E. Linn Draper Lampasas, Texas U.S.	Director, Alliance Data Systems Corporation (data processing and services) and Director, Alpha Natural Resources, Inc. (mining). Chair, NorthWestern Corporation (conducting business as NorthWestern Energy) (oil and gas).	2005
The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Stein Monast L.L.P. (law firm). Director, Metro Inc., Royal Bank of Canada, Care Canada and the Fondation du Musée national des beaux-arts du Québec. Director, Institut Québecois des Hautes Études Internationales, Laval University from 2002 until 2009 and RBC Dexia Investors Trust until October 2009.	2002
Russell K. Girling Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 1, 2010. Chief Operating Officer from July 2009 to June 30, 2010 and President, Pipelines from June 2006 to June 30, 2010. Director, Agrium Inc.	2010

Name and place of residence	Principal occupation during the five preceding years	Director since
S. Barry Jackson Calgary, Alberta Canada	Chair of the Board, TransCanada since April 2005. Director, Nexen Inc. (oil and gas) and Director, WestJet Airlines Ltd. Director Cordero Energy Inc. from April 2005 to September 2008.	2002
Paul L. Joskow New York, New York U.S.	Economist and President of the Alfred P. Sloan Foundation. Professor of Economics, Emeritus, Massachusetts Institute of Technology (MIT) where he has been on the faculty since 1972. Director, Exelon Corporation (energy), and a trustee of Putnam Mutual Funds. Director of the MIT Center for Energy and Environmental Policy Research from 1999 to 2007 and Director of National Grid plc from 2000 to 2007.	2004
John A. MacNaughton[(2)], C.M. Toronto, Ontario Canada	Chair of the Business Development Bank of Canada. Chair of the Independent Nominating Committee of the Canada Employment Insurance Financing Board since 2008. Member of the Prime Minister's Advisory Committee on the Public Service. Chair, CNSX Markets Inc. (formerly the Canadian Trading and Quotation System Inc.) (stock exchange) from 2006 to July 2010. Director, Nortel Networks Corporation and Nortel Networks Limited (the principal operating subsidiary of Nortel Networks Corporation) (technology) from 2005 to September 2010.	2006
David P. O'Brien[(4)] Calgary, Alberta Canada	Chair, Encana Corporation (oil and gas) since April 2002 and Chair, Royal Bank of Canada since February 2004. Director, Molson Coors Brewing Company, and Enerplus Corporation. Member of the Science, Technology and Innovation Council of Canada.	2001
Paula Rosput Reynolds Seattle, Washington U.S.	President and Chief Executive Officer of PreferWest, LLC (business advisory group) since October 2009. Director of Anadarko Petroleum Corporation, Delta Air Lines, Inc. and BAE Systems plc. Vice Chairman and Chief Restructuring Officer of American International Group Inc. (insurance and financial services) from October 2008 to September 2009. President and Chief Executive Officer of Safeco Corporation (insurance) from 2006 to 2008.	2011
W. Thomas Stephens[(3)] Greenwood Village, Colorado U.S.	Trustee, Putnam Mutual Funds. Chair and Chief Executive Officer of Boise Cascade, LLC (paper, forest products and timberland assets) from November 2004 to November 2008. Director, Boise Inc. from February 2008 until April 2010.	2007[(3)]
D. Michael G. Stewart Calgary, Alberta Canada	Director, Canadian Energy Services & Technology Corp., Pengrowth Energy Corporation and C&C Energia Ltd. Director, Orleans Energy Ltd. from October 2008 to December 2010. Director, Pengrowth Corporation (the administrator of Pengrowth Energy Trust) from October 2006 to December 2010. Director, Canadian Energy Services Inc. (the general partner of Canadian Energy Services L.P.) from January 2006 to December 2009.	2006
Richard E. Waugh Toronto, Ontario Canada	President and Chief Executive Officer and director of The Bank of Nova Scotia (Scotiabank) since March 2003. Director and President, International Monetary Conference. Vice-Chair, Board of the Institute of International Finance.	2012

(1) Canwest Global Communications Corp. ("Canwest") voluntarily entered into the Companies' Creditors Arrangement Act ("CCAA") and obtained an order from the Ontario Superior Court of Justice (Commercial Division) to start proceedings on October 6, 2009. Although no cease trade orders were issued, Canwest shares were de-listed by the TSX after the filing and started trading on the TSX Venture Exchange. Canwest emerged from CCAA protection, and Postmedia Network acquired its newspaper business on July 13, 2010 while Shaw Communications Inc. acquired its broadcast media business on October 27, 2010. Mr. Burney ceased to be a director of Canwest on October 27, 2010.

(2) Nortel Networks Limited was the principal operating subsidiary of Nortel Networks Corporation (collectively referred to as "Nortel"). Mr. MacNaughton became a director of Nortel on June 29, 2005. Nortel was subject to a management cease trade order on April 10, 2006 issued by the Ontario Securities Commission ("OSC") and other provincial securities regulators. The cease trade order related to a delay in filing some of Nortel's 2005 financial statements. The order was revoked by the OSC on June 8, 2006, and the other provincial securities regulators shortly after. On January 14, 2009, Nortel and some of its Canadian subsidiaries filed for creditor protection under CCAA.

(3) Mr. Stephens previously served on the Board from 2000 to 2005.

(4) Air Canada filed for protection under the CCAA and applicable bankruptcy protection statutes in the U.S. in April 2003. Mr. O'Brien resigned as a director of Air Canada on November 26, 2003.

Board committees

TransCanada has four committees of the Board: the Audit Committee, the Governance Committee, the Health, Safety and Environment Committee and the Human Resources Committee. The voting members of each of these committees, as of February 13, 2012, are identified below:

Director	Audit Committee	Governance Committee	Health, Safety and Environment Committee	Human Resources Committee
Kevin E. Benson	Chair	✓		
Derek H. Burney	✓	✓		
Wendy K. Dobson			✓	✓

Director	Audit Committee	Governance Committee	Health, Safety and Environment Committee	Human Resources Committee
E. Linn Draper	✓		Chair	
Paule Gauthier			✓	✓
S. Barry Jackson		✓		✓
Paul L. Joskow	✓	✓		
John A. MacNaughton	✓	Chair		
David P. O'Brien		✓		✓
Paula Rosput Reynolds			✓	✓
W. Thomas Stephens			✓	Chair
D. Michael G. Stewart	✓		✓	
Richard E. Waugh		✓		

The charters of the Audit Committee, Governance Committee, the Health, Safety and Environment Committee and the Human Resources Committee can be found on our website (www.transcanada.com) under *Corporate Governance – Board Committees*. Information about the Audit Committee can be found in this AIF under the heading *Audit Committee*.

Further information about the Board committees and corporate governance can also be found on TransCanada's website.

Officers

All of the executive officers and corporate officers of TransCanada reside in Calgary, Alberta, Canada, with the exception of Mr. Hobbs who resides in Houston, Texas, U.S. References to positions and offices with TransCanada prior to May 15, 2003 are references to the positions and offices held with TCPL. Current positions and offices held with TransCanada are also held by such person at TCPL. As of the date hereof, the officers of TransCanada, their present positions within TransCanada and their principal occupations during the five preceding years are as follows:

Executive officers

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	Prior to July 2010, Chief Operating Officer since July 2009 and President, Pipelines since June 2006. Prior to June 2006, Executive Vice-President and Chief Financial Officer, Corporate Development, since March 2003 and Chief Financial Officer, since August 1999.
Wendy L. Hanrahan[(1)]	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Gregory A. Lohnes	President, Natural Gas Pipelines	Prior to July 2010, Executive Vice-President and Chief Financial Officer since June 2006.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
Dennis J. McConaghy	Executive Vice-President, Corporate Development	Prior to July 2010, Executive Vice-President, Pipeline Strategy and Development.
Sean McMaster	Executive Vice-President, General Counsel and Chief Compliance Officer, and Executive Vice-President, Stakeholder Relations	Prior to February 2012, Executive Vice-President, Corporate and General Counsel and Chief Compliance Officer. Prior to January 2007, Executive Vice-President and General Counsel and Chief Compliance Officer. Prior to October 2006, General Counsel and Chief Compliance Officer.
Alexander J. Pourbaix	President, Energy and Oil Pipelines	President, Energy from July 2006 to July 2010 and Executive Vice-President, Corporate Development from July 2009 to July 2010.
Donald M. Wishart	Executive Vice-President, Operations and Major Projects	Prior to July 2009, Executive Vice-President, Operations and Engineering since March 2003.

[(1)] Ms. Hanrahan has held the position of Executive Vice-President, Corporate Services since May 1, 2011, upon the retirement of Ms. Sarah Raiss who had held the position since January 2002.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Sean M. Brett	Vice-President and Treasurer	Prior to July 2010, Vice-President, Commercial Operations of TC PipeLines GP, Inc., and Director, LP Operations of TCPL. Prior to December 2009, Director, Joint Venture Management, Keystone Pipeline Project of TCPL. Prior to December 2008, Vice-President and Treasurer of TC PipeLines GP, Inc.

Name	Present position held	Principal occupation during the five preceding years
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation since April 2002.
Donald J. DeGrandis	Vice-President and Corporate Secretary	Prior to February 2009, Corporate Secretary since June 2006.
Lee G. Hobbs	President, U.S. Natural Gas Pipelines	Senior Vice-President and General Manager, U.S. Pipelines, Pipelines Division, TCPL, June 2009 to July 2010. Vice-President and General Manager, U.S. Pipelines Central, Pipelines Division, TCPL, March 2007 to June 2009. President, Great Lakes Gas Transmission Company and Great Lakes Gas Transmission Limited Partnership, September 2006 to March 2007.
Joel E. Hunter	Vice-President, Finance	Director, Corporate Finance, January 2008 to July 2010. Prior to January 2008, Senior Analyst, Corporate Finance. Prior to January 2007 Mr. Hunter held a number of positions of increasing responsibility with TransCanada's Finance and Treasury Group.
Garry E. Lamb	Vice-President, Risk Management	Vice-President, Risk Management since October 2001.
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller since June 2006.

Conflicts of interest

Directors and officers of TransCanada and its subsidiaries are required to disclose the existence of existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the CBCA. Although some of the directors sit on boards or may be otherwise associated with companies that ship natural gas on TransCanada's pipeline systems, TransCanada, as a common carrier in Canada, cannot, under our tariff, deny transportation service to a creditworthy shipper. Further, due to the specialized nature of the industry, TransCanada believes that it is important for our Board to be composed of qualified and knowledgeable directors, so some of them must come from the oil and gas producer and shipper community; the Governance Committee monitors relationships among directors to ensure that business associations do not affect the Board's performance. In a circumstance where a director declares an interest in any material contract or material transaction being considered at a meeting, the director generally absents himself or herself from the meeting during the consideration of the matter, and does not vote on the matter.

Corporate governance

Our Board and management are committed to the highest standards of ethical conduct and corporate governance.

TransCanada is a public company listed on the TSX and the NYSE, and we recognize and respect rules and regulations in both Canada and the U.S.

Our corporate governance practices comply with the Canadian governance guidelines, which include the governance rules of the Canadian Securities Administrators ("CSA"):

- National Instrument 52-110, *Audit Committees* (Canadian audit committee rules)
- National Policy 58-201, *Corporate Governance Guidelines*, and
- National Instrument 58-101, *Disclosure of Corporate Governance Practices*.

We also comply with the governance listing standards of the NYSE and the governance rules of the SEC that apply to foreign private issuers.

Our governance practices comply with the NYSE standards for U.S. companies in all significant respects, except as summarized on our website (www.transcanada.com). As a non-U.S. company, we are not required to comply with most of the governance listing standards of the NYSE. As a foreign private issuer, however, we must disclose how our governance practices differ from those followed by U.S. companies that are subject to the NYSE standards.

We benchmark our policies and procedures against major North American companies to assess our standards and we adopt best practices as appropriate. Some of our best practices are derived from the NYSE rules and comply with applicable rules adopted by the SEC to meet the requirements of the *Sarbanes-Oxley Act of 2002* and the *Dodd-Frank Wall Street Reform and Consumer Protection Act.*

Further information about TransCanada's corporate governance can be found on our website (www.transcanada.com) under the heading *Corporate Governance* and in the *Governance* section of TransCanada's Management Information Circular dated February 13, 2012.

Audit committee

The Audit Committee is responsible for assisting the Board in overseeing the integrity of our financial statements and our compliance with legal and regulatory requirements. It is also responsible for overseeing and monitoring the internal accounting

and reporting process and the process, performance and independence of our internal and external auditors. The Charter of the Audit Committee can be found in Schedule B of this AIF and on our website (www.transcanada.com) under the *Corporate Governance – Board Committees* page.

Relevant education and experience of members

The members of the Audit Committee as of February 13, 2012 are Kevin E. Benson (Chair), Derek H. Burney, E. Linn Draper, Paul L. Joskow, John A. MacNaughton, and D. Michael G. Stewart.

The Board believes that the composition of the Audit Committee reflects a high level of financial literacy and expertise. Each member of the Audit Committee has been determined by the Board to be "independent" and "financially literate" within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Mr. Benson is an "Audit Committee Financial Expert" as that term is defined under U.S. securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit Committee. The following is a description of the education and experience, apart from their respective roles as directors of TransCanada, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Kevin E. Benson

Mr. Benson earned a Bachelor of Accounting from the University of Witwatersrand (South Africa) and was a member of the South African Society of Chartered Accountants. Mr. Benson was the President and Chief Executive Officer of Laidlaw International, Inc. until October 2007. In prior years, he has held several executive positions including one as President and Chief Executive Officer of The Insurance Corporation of British Columbia and has served on other public company boards and on the audit committees of certain of those boards.

Derek H. Burney

Mr. Burney earned a Bachelor of Arts (Honours) and Master of Arts from Queen's University. He is currently a senior strategic advisor at Norton Rose Canada LLP. Mr. Burney previously served as President and Chief Executive Officer of CAE Inc. and as Chair and Chief Executive Officer of Bell Canada International Inc. Mr. Burney was the lead director at Shell Canada Limited until May 2007 and was the Chair of Canwest Global Communications Corp. until October 2010. He has served on one other organization's audit committee, and has participated in Financial Reporting Standards Training offered by KPMG.

E. Linn Draper

Dr. Draper holds a Bachelor of Science in Chemical Engineering from Rice University and a Ph.D. in Nuclear Science and Engineering from Cornell University. Dr. Draper was Chair, President and Chief Executive Officer of American Electric Power Co., Inc. until 2004. He previously served as Chair, President and Chief Executive Officer of Gulf States Utilities Company. Dr. Draper has served and continues to serve on several other public company boards.

Paul L. Joskow

Mr. Joskow earned a Bachelor of Arts with Distinction in Economics from Cornell University, a Masters of Philosophy in Economics from Yale University, and a Ph.D. in Economics from Yale University. He is currently the President of the Alfred P. Sloan Foundation and a Professor of Economics, Emeritus, at MIT. He has served on the boards of several public companies and other organizations and on the audit committees of certain of those boards.

John A. MacNaughton

Mr. MacNaughton earned a Bachelor of Arts in Economics from the University of Western Ontario. Mr. MacNaughton is currently the Chair of the Business Development Bank of Canada, and was Chair of CNSX Markets Inc. (formerly Canadian Trading and Quotation System Inc.) until July 2010. In prior years, he has held several executive positions including founding President and Chief Executive Officer of the Canadian Pension Plan Investment Board and President of Nesbitt Burns Inc. He has served on the audit committee of other public companies.

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science (Honours) in Geological Science from Queen's University. Mr. Stewart has served and continues to serve on the boards of several public companies and other organizations and on the audit committees of

certain of those boards. Mr. Stewart held a number of senior executive positions with Westcoast Energy Inc. including Executive Vice-President, Business Development. He has been active in the Canadian energy industry for over 38 years.

Pre-approval policies and procedures

TransCanada's Audit Committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit Committee has granted pre-approval for specified non-audit services. For engagements of $25,000 or less which are not within the annual pre-approved limit, approval by the Audit Committee is not required, and for engagements between $25,000 and $100,000, approval of the Audit Committee Chair is required, and the Audit Committee is to be informed of the engagement at the next scheduled Audit Committee meeting. For all engagements of $100,000 or more, pre-approval of the Audit Committee is required. In all cases, regardless of the dollar amount involved, where there is a potential for conflict of interest involving the external auditor to arise on an engagement, the Audit Committee Chair must pre-approve the assignment.

To date, TransCanada has not approved any non-audit services on the basis of the de-minimus exemptions. All non-audit services have been pre-approved by the Audit Committee in accordance with the pre-approval policy described above.

External auditor service fees

The following table provides information about the fees paid by the Company to KPMG LLP, the external auditor of the TransCanada group of companies, for professional services rendered for the 2011 and 2010 fiscal years.

($ millions)	2011	2010
Audit fees • audit of the annual consolidated financial statements • services related to statutory and regulatory filings or engagements • reviewing interim consolidated financial statements and information contained in various prospectuses and other offering documents	$ 6.9	$ 6.5
Audit-related fees • services related to the audit of the financial statements of certain TransCanada pension plans	0.2	0.2
Tax fees • Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings	0.4	1.0
All other fees • services related to environmental compliance in 2011 and advice and training related to International Financial Reporting Standards in 2010	0.1	0.2
Total fees	**$ 7.6**	**$ 7.9**

Legal proceedings and regulatory actions

TransCanada and its subsidiaries are subject to various legal proceedings and regulatory actions arising in the normal course of business. While the final outcome of such legal proceedings and regulatory actions cannot be predicted with certainty and there can be no assurance that such matters will be resolved in TransCanada's favour, it is the opinion of TransCanada's management that the resolution of such proceedings and regulatory actions will not have a material impact on TransCanada's consolidated financial position, results of operations or liquidity.

The Company believes that TransAlta's claims with respect to Sundance A do not meet the test of force majeure or destruction as specified in the power purchase arrangement and has therefore recorded revenues and costs throughout 2011 under the power purchase arrangement as though this event was an interruption of supply. While the outcome of any arbitration process is not certain, TransCanada believes the matter will be resolved in its favour.

Further information about the Sundance arbitration can be found in this AIF under the heading *Developments in the Energy Business* and in the MD&A under the heading *Energy – Opportunities and Developments*.

Transfer agent and registrar

TransCanada's transfer agent and registrar is Computershare Trust Company of Canada with its Canadian transfer facilities in the cities of Vancouver, Calgary, Toronto, and Montréal.

Interest of experts

TransCanada's auditors, KPMG LLP, have confirmed that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Additional information

1. Additional information in relation to TransCanada may be found under TransCanada's profile on SEDAR (www.sedar.com).

2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TransCanada's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransCanada's management information circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransCanada.

3. Additional financial information is provided in TransCanada's audited consolidated financial statements and MD&A for its most recently completed financial year.

Glossary

AIF	Annual Information Form of TransCanada Corporation dated February 13, 2012
AQMS	Air Quality Management System
Alaska Pipeline	A proposed natural gas pipeline extending from Prudhoe Bay, Alaska to either Alberta or Valdez, Alaska
Alberta System	A natural gas transmission system in Alberta and B.C.
ANR	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and U.S. midcontinent region to markets located primarily in Wisconsin, Michigan, Illinois, Indiana and Ohio, and regulated underground natural gas storage facilities in Michigan
B.C.	British Columbia
BPRIA	Bruce Power Refurbishment Implementation Agreement
Bcf	Billion cubic feet
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A natural gas pipeline extending from the Powder River Basin in Wyoming to Northern Border in North Dakota
Board	TransCanada's Board of Directors
Bruce A	A partnership interest in a nuclear power generation facility consisting of Units 1 to 4 of Bruce Power (Bruce Power A L.P.)
Bruce B	A partnership interest in a nuclear power generation facility consisting of Units 5 to 8 of Bruce Power (Bruce Power L.P.)
Bruce Power	A nuclear power generating facility located northwest of Toronto, Ontario (Bruce A and Bruce B, collectively)
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Canwest	Canwest Global Communications Corp.
Cartier Wind	Five wind farms in Gaspé, Québec, four plus the first phase of the fifth which are operational and phase two of the fifth under construction.
CBCA	*Canada Business Corporations Act*
CCAA	*Companies' Creditors Arrangement Act*
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station in Coolidge, Arizona
CSA	Canadian Securities Administrators
Cushing Extension	A crude oil pipeline extending from Steele City, Nebraska to Cushing, Oklahoma
DBRS	DBRS Limited
Energy	As defined in this AIF under the heading *General Development of the Business*
EPA	Environmental Protection Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
GHG	Greenhouse gas
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
GTN	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
Guadalajara	A natural gas pipeline in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
Halton Hills	A natural gas-fired, combined-cycle power plant in Halton Hills, Ontario
HSE	Health, safety and environment
Hydro-Québec	Hydro-Québec Distribution
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
Keystone	A crude oil pipeline system which extends from Hardisty, Alberta to the U.S. markets and includes Wood River/Patoka and the Cushing Extension
Keystone XL	Keystone XL includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the expansion of existing facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty to Steele City, Nebraska.
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometer(s)
Mackenzie Gas Project	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
MD&A	TransCanada's Management's Discussion and Analysis dated February 13, 2012
MMcf/d	Million cubic feet per day
Moody's	Moody's Investors Service, Inc.
MW	Megawatt(s)
Natural Gas Pipelines	As defined in this AIF under the heading *General Development of the Business*
NEB	National Energy Board
North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan to the U.S. Midwest
NGTL	Nova Gas Transmission Ltd.
Nortel	Nortel Networks Limited and Nortel Networks Corporation, collectively
NYISO	New York Independent System Operator
NYSE	New York Stock Exchange

Ocean State Power	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Oil Pipelines	As defined in this AIF under the heading *General Development of the Business*
OPA	Ontario Power Authority
OSC	Ontario Securities Commission
Portland	A natural gas transmission system extending from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A natural gas-fired, combined-cycle power plant in Toronto, Ontario
Ravenswood	A natural gas- and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology located in Queens, New York
Restructuring Proposal	Canadian Mainline 2012 Tolls Application and Restructuring Proposal
RGGI	Regional Greenhouse Gas Initiative
S&P	Standard & Poor's
SEC	U.S. Securities and Exchange Commission
Series 1 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 1
Series 2 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 2
Series 3 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 3
Series 4 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 4
Series 5 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 5
Series 6 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 6
Sheerness	A coal-fired power generating facility near Hanna, Alberta
Subsidiary	As defined in this AIF under the heading *Presentation of Information*
Sundance	Two coal-fired power generating facilities near Wabamun, Alberta (Sundance A and Sundance B, collectively)
Systems	As defined in this AIF under the heading *Regulation of the Natural Gas and Oil Pipelines business*es
TCPL	TransCanada PipeLines Limited
TQM	A natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with Portland
TransCanada or the Company	TransCanada Corporation
TransAlta	TransAlta Corporation
TSX	Toronto Stock Exchange
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S. or US	United States
U.S. GAAP	U.S. generally accepted accounting principles
WCI	Western Climate Initiative
Wood River/Patoka	A crude oil pipeline extending from Hardisty, Alberta to U.S. Markets at Wood River and Patoka in Illinois
Year End	December 31, 2011

Schedule A

Metric Conversion Table

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	Imperial	Factor
Kilometres (km)	Miles	0.62
Millimetres	Inches	0.04
Gigajoules	Million British thermal units	0.95
Cubic metres*	Cubic feet	35.3
Kilopascals	Pounds per square inch	0.15
Degrees Celsius	Degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees; to convert to Celsius subtract 32 degrees, then divide by 1.8

* The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15 degrees Celsius.

Schedule B

Charter of the Audit Committee

1. Purpose

The Audit Committee shall assist the Board of Directors (the "Board") in overseeing and monitoring, among other things, the:

- Company's financial accounting and reporting process;
- integrity of the financial statements
- Company's internal control over financial reporting;
- external financial audit process;
- compliance by the Company with legal and regulatory requirements; and
- independence and performance of the Company's internal and external auditors.

To fulfill its purpose, the Audit Committee has been delegated certain authorities by the Board of Directors that it may exercise on behalf of the Board.

2. Roles and Responsibilities

I. Appointment of the Company's External Auditors

Subject to confirmation by the external auditors of their compliance with Canadian and U.S. regulatory registration requirements, the Audit Committee shall recommend to the Board the appointment of the external auditors, such appointment to be confirmed by the Company's shareholders at each annual meeting. The Audit Committee shall also recommend to the Board the compensation to be paid to the external auditors for audit services and shall pre-approve the retention of the external auditors for any permitted non-audit service and the fees for such service. The Audit Committee shall also be directly responsible for the oversight of the work of the external auditor (including resolution of disagreements between management and the external auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The external auditor shall report directly to the Audit Committee.

The Audit Committee shall also receive periodic reports from the external auditors regarding the auditors' independence, discuss such reports with the auditors, consider whether the provision of non-audit services is compatible with maintaining the auditors' independence and the Audit Committee shall take appropriate action to satisfy itself of the independence of the external auditors.

II. Oversight in Respect of Financial Disclosure

The Audit Committee, to the extent it deems it necessary or appropriate, shall:

(a) review, discuss with management and the external auditors and recommend to the Board for approval, the Company's audited annual financial statements, annual information form including management discussion and analysis, all financial statements in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including without limitation, the annual proxy circular, but excluding any pricing supplements issued under a medium term note prospectus supplement of the Company;

(b) review, discuss with management and the external auditors and recommend to the Board for approval the release to the public of the Company's interim reports, including the financial statements, management discussion and analysis and press releases on quarterly financial results;

(c) review and discuss with management and external auditors the use of "pro forma" or "adjusted" non-GAAP information and the applicable reconciliation;

(d) review and discuss with management and external auditors financial information and earnings guidance provided to analysts and rating agencies; provided, however, that such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Audit Committee need not discuss in advance each instance in which the Company may provide earnings guidance or presentations to rating agencies;

(e) review with management and the external auditors major issues regarding accounting and auditing principles and practices, including any significant changes in the Company's selection or application of accounting principles, as well as major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies that could significantly affect the Company's financial statements;

(f) review and discuss quarterly reports from the external auditors on:

(i) all critical accounting policies and practices to be used;

(ii) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor;

(iii) other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences;

(g) review with management and the external auditors the effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Company's financial statements;

(h) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;

(i) review disclosures made to the Audit Committee by the Company's CEO and CFO during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls;

(j) discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies;

III. Oversight in Respect of Legal and Regulatory Matters

(a) review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's compliance policies and any material reports or inquiries received from regulators or governmental agencies.

IV. Oversight in Respect of Internal Audit

(a) review the audit plans of the internal auditors of the Company including the degree of coordination between such plan and that of the external auditors and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;

(b) review the significant findings prepared by the internal auditing department and recommendations issued by the Company or by any external party relating to internal audit issues, together with management's response thereto;

(c) review compliance with the Company's policies and avoidance of conflicts of interest;

(d) review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with associates and affiliates;

(e) ensure the internal auditor has access to the Chair of the Audit Committee and of the Board and to the Chief Executive Officer and meet separately with the internal auditor to review with him any problems or difficulties he may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;

(ii) any changes required in the planned scope of the internal audit; and

(iii) the internal audit department responsibilities, budget and staffing;

and to report to the Board on such meetings;

V. Insight in Respect of the External Auditors

(a) review the annual post-audit or management letter from the external auditors and management's response and follow-up in respect of any identified weakness, inquire regularly of management and the external auditors of any significant issues between them and how they have been resolved, and intervene in the resolution if required;

(b) review the quarterly unaudited financial statements with the external auditors and receive and review the review engagement reports of external auditors on unaudited financial statements of the Company;

(c) receive and review annually the external auditors' formal written statement of independence delineating all relationships between itself and the Company;

(d) meet separately with the external auditors to review with them any problems or difficulties the external auditors may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management; and

(ii) any changes required in the planned scope of the audit;

and to report to the Board on such meetings;

(e) review with the external auditors the adequacy and appropriateness of the accounting policies used in preparation of the financial statements;

(f) meet with the external auditors prior to the audit to review the planning and staffing of the audit;

(g) receive and review annually the external auditors' written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;

(h) review and evaluate the external auditors, including the lead partner of the external auditor team;

(i) ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years;

VI. Oversight in Respect of Audit and Non-Audit Services

(a) pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:

(i) the aggregate amount of all such non-audit services provided to the Company constitutes not more than 5% of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;

(ii) such services were not recognized by the Company at the time of the engagement to be non-audit services; and

(iii) such services are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee;

(b) approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;

(c) the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval;

(d) if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection;

VII. Oversight in Respect of Certain Policies

(a) review and recommend to the Board for approval the implementation and amendments to policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's codes of business ethics and Risk Management and Financial Reporting policies;

(b) obtain reports from management, the Company's senior internal auditing executive and the external auditors and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's codes of business conduct and ethics;

(c) establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;

(d) annually review and assess the adequacy of the Company's public disclosure policy;

(e) review and approve the Company's hiring policies for partners, employees and former partners and employees of the present and former external auditors (recognizing the Sarbanes-Oxley Act of 2002 does not permit the CEO, controller, CFO or chief accounting officer to have participated in the Company's audit as an employee of the external auditors' during the preceding one-year period) and monitor the Company's adherence to the policy;

VIII. Oversight in Respect of Financial Aspects of the Company's Canadian Pension Plans (the "Company's pension plans"), specifically:

(a) provide advice to the Human Resources Committee on any proposed changes in the Company's pension plans in respect of any significant effect such changes may have on pension financial matters;

(b) review and consider financial and investment reports and the funded status relating to the Company's pension plans and recommend to the Board on pension contributions;

(c) receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;

(d) review and approve annually the Statement of Investment Policies and Procedures ("SIP&P");

(e) approve the appointment or termination of auditors and investment managers;

IX. Oversight in Respect of Internal Administration

(a) review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates;

(b) review the succession plans in respect of the Chief Financial Officer, the Vice President, Risk Management and the Director, Internal Audit;

(c) review and approve the policy and guidelines for the Company's hiring of partners, employees and former partners and employees of the external auditors who were engaged on the Company's account;

X. Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external auditors. The Audit Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Audit Committee to provide broad oversight of the financial disclosure, financial risk and control related activities of the Company, and are specifically not accountable nor responsible for the day to day operation of such activities. Although designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Audit Committee, designation as an "audit committee financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board in the absence of such designation. Rather, the role of any audit committee financial expert, like the role of all Audit Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Company's financial information or public disclosure.

3. Composition of Audit Committee

The Audit Committee shall consist of three or more Directors, a majority of whom are resident Canadians (as defined In the Canada Business Corporations Act), and all of whom are unrelated and/or independent for the purposes of applicable Canadian and United States securities law and applicable rules of any stock exchange on which the Company's shares are listed. Each member of the Audit Committee shall be financially literate and at least one member shall have accounting or related financial management expertise (as those terms are defined from time to time under the requirements or guidelines for audit committee service under securities laws and the applicable rules of any stock exchange on which the Company's securities are listed for trading or, if it is not so defined as that term is interpreted by the Board in its business judgment).

4. Appointment of Audit Committee Members

The members of the Audit Committee shall be appointed by the Board from time to time, on the recommendation of the Governance Committee and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be Directors of the Company.

5. Vacancies

Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. Audit Committee Chair

The Board shall appoint a Chair of the Audit Committee who shall:

(a) review and approve the agenda for each meeting of the Audit Committee and as appropriate, consult with members of management;

(b) preside over meetings of the Audit Committee;

(c) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;

(d) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and

(e) meet as necessary with the internal and external auditors.

7. Absence of Audit Committee Chair

If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. Secretary of Audit Committee

The Corporate Secretary shall act as Secretary to the Audit Committee.

9. Meetings

The Chair, or any two members of the Audit Committee, or the internal auditor, or the external auditors, may call a meeting of the Audit Committee. The Audit Committee shall meet at least quarterly. The Audit Committee shall meet periodically with management, the internal auditors and the external auditors in separate executive sessions.

10. Quorum

A majority of the members of the Audit Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. Attendance of Company Officers and Employees at Meeting

At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. Procedure, Records and Reporting

The Audit Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Audit Committee may deem appropriate but not later than the next meeting of the Board.

14. Review of Charter and Evaluation of Audit Committee

The Audit Committee shall review its Charter annually or otherwise, as it deems appropriate, and if necessary propose changes to the Governance Committee and the Board. The Audit Committee shall annually review the Audit Committee's own performance.

15. Outside Experts and Advisors

The Audit Committee is authorized, when deemed necessary or desirable, to retain and set and pay the compensation for independent counsel, outside experts and other advisors, at the Company's expense, to advise the Audit Committee or its members independently on any matter.

16. Reliance

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Audit Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Company from which it receives information, (ii) the accuracy of the financial and other information provided to the Audit Committee by such persons or organizations and (iii) representations made by Management and the external auditors, as to any information technology, internal audit and other non-audit services provided by the external auditors to the Company and its subsidiaries.