EB-2013-0381

ONTARIO ENERGY BOARD

IN THE MATTER OF sections 18 and 19 of the *Electricity Act, 1998;*

AND IN THE MATTER OF a Submission by the Independent Electricity System Operator to the Ontario Energy Board for the review of its proposed expenditure and revenue requirements and the fees which it proposes to charge for the year 2014 in connection with the IESO-controlled grid and IESO-administered markets.

IESO 2014 FEES SUBMISSION FOR REVIEW

November 4, 2013

STIKEMAN ELLIOTT LLP
Barristers & Solicitors
5300 Commerce Court West
199 Bay Street
Toronto, Canada M5L 1B9

Glenn Zacher LSUC#: 43625P
Tel: (416) 869-5688
Fax: (416) 947-0866

Counsel for the IESO

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SUBMISSION FOR REVIEW

1. The Board of Directors of the Independent Electricity System Operator (respectively the "IESO Board" and the "IESO") approved the IESO's business plan for the fiscal year 2014.

2. The IESO submitted its 2014 business plan to the Minister of Energy (the "Minister") for approval pursuant to section 19.1 of the *Electricity Act*, 1998 (the "Act") and the Minister approved the business plan on October 23, 2013.

3. The IESO hereby submits its proposed expenditure and revenue requirements and proposed fees for 2014 to the Ontario Energy Board (the "Board") for review and approval pursuant to section 19(1) of the Act.

Background

4. Section 19 of the Act provides that the IESO shall, at least 60 days before the beginning of each fiscal year, submit its proposed expenditures and revenue requirements for the fiscal year and the fees it proposes to charge during the fiscal year

to the Board for review, but shall not do so until after the Minister approves or is deemed to have approved the IESO's proposed business plan for the fiscal year.

5. On December 11, 2011, the IESO applied to the Board for an interim order to allow the IESO to continue to charge its 2011 usage fee to market participants pending the Minister's approval of the IESO's 2012-14 business plan and the Board's subsequent approval of the IESO's 2012 usage fee.

6. The Board granted the IESO's request by Interim Fee Order dated December 22, 2011, which stated:

> The IESO's current 2011 usage fee of $0.822/MWh and its $1,000 application fee are approved on an interim basis, effective January 1, 2012, pending approval by the Board of its 2012 usage fees. The appropriate treatment of any difference between interim usage fee and the approved final 2012 usage fee will be considered later in the proceeding.
>
> (hereinafter, the "Interim Usage Fee").

7. The Minister did not approve the IESO's 2012-14 Business Plan. Instead, on April 26, 2012, the provincial government introduced Bill 75 which, among other things, proposed the amalgamation of the IESO and the Ontario Power Authority ("OPA").

8. The IESO had not planned on filing a business plan on its own for 2013 given the proposed merger with the OPA. Following the prorogation of the Ontario legislative session on October 15, 2012, the IESO submitted a 2013 Business Plan to the Minister. In the absence of having an approved 2013 Business Plan, the IESO's Interim Usage Fee has remained in effect.

9. The 2014-2016 business plan ("Business Plan") was developed with the assistance of the IESO's Stakeholder Advisory Committee. Since its inception in 2005, this Committee has provided the IESO with valuable guidance for the future direction of the IESO and its efforts to improve the market. The Business Plan sets out the IESO's strategic objectives and priorities for 2014, including:

- *Facilitating and Managing Sector Change* — The IESO will continue to facilitate and manage Ontario's transition from what was a highly centralized system with heavy reliance on fossil fuels. Ontario is moving to more sustainable and complex arrangements requiring increased operational information, adaptability and coordination with an increasing number of participants. The IESO will anticipate and drive change — promoting market efficiencies, strengthening relationships with an increasingly complex and interdependent system of participants on both the supply and demand side.

- *Policy and Market Development* — The IESO will continue to broaden its participation and involvement in the development of Ontario electricity policy through initiatives such as the integrated regional energy planning process and the development of Ontario's new Long-Term Energy Plan. The IESO is responding to stakeholders' requests to move forward with market development work such as improving price signals, reducing barriers for increased participation in the electricity market, enhancing intertie scheduling, and better aligning demand response and conservation and demand management programs with system needs. The IESO will pursue these initiatives within the context of the creation of a longer-term market development plan, including the prioritization of market initiatives in support of this plan.

- *Reliability Standards Compliance* — The IESO will continue to prioritize and focus on compliance with new North American Electric Reliability Corporation ("NERC") reliability standards. The IESO specifically plans to add new resources — including staff and tools — to manage the evolving challenges posed by cybersecurity.

- *Increasing Contribution from Demand Side and Other Market Efficiencies* — The IESO will build on its foundational work and analysis to enable the more effective and efficient participation and contribution from the demand side of the market. Significant demand response potential exists in Ontario that can help reduce peak demand, complement the variable nature of renewable resources and enable customers to manage their electricity use and minimize their costs.

- *Efficiently Managing Our Business* - The IESO will continue with its multi-year program to refresh or replace aging information technology infrastructure (systems that are now at or nearing end of life) and training and developing new employees (almost one third of the IESO's current employees will be eligible for retirement by the end of the planning period) while prudently managing costs that are ultimately passed on to customers.

10. The Business Plan also proposes a change to the methodology by which the IESO levies its usage fee. The IESO is proposing to change its fee structure to also include energy volumes equal to the output for generation embedded in local distribution networks. Currently, those volumes are not included in the determination of the IESO fee because the fee is based on withdrawals net of embedded generations. This change will treat customers more equitably by charging them the same effective IESO fee irrespective of the proportion of embedded generation within their local distribution company ("LDC") service territory; the change in methodology is revenue neutral for both the IESO and LDCs; and, the cost to implement this change will be negligible.

Approvals Requested

11. Under section 19(2) of the Act, the IESO is seeking the following approvals from the Board:

(a) Approval of its proposed 2014 revenue requirement of $129.9 million;

(b) Approval of its proposed 2014 capital expenditure envelope of $24 million for capital plans;

(c) Approval for the continuation of the $1,000 application fee;

(d) Approval of a usage fee of $0.803/MWh to be paid commencing January 1, 2014 by all market participants based on energy withdrawn from the IESO-controlled grid (including scheduled exports) and embedded generation. The IESO proposes to continue to charge the Interim Usage Fee ($0.822/MWh) to market participants from January 1, 2014 until the end of the month in which Board approval is received for the 2014 usage fee, and seeks authorization to charge (or rebate to) market participants the difference between the 2014 and Interim Usage Fee, if any, based on their proportionate quantity of energy withdrawn (including scheduled exports) for the year 2013. Any such charges (or rebates) will be provided to market participants in the next billing cycle following the month in which approval is received;

(e) Approval to rely on and use the information provided to the IESO by LDCs on the amount of embedded generation in their service territory under O.Reg 429/04 in calculating the total usage fee to be billed to each LDC each billing period.

(f) Approval of Interim Usage Fee as the final usage fee for each of the 2012 and 2013 fiscal years; and

(g) Approval to retain $5 million of the accumulated surplus from the 2011, 2012 and 2013 fiscal years. The IESO will rebate the balance of the accumulated surplus, based on the IESO's audited 2013 financial statements as approved by the IESO Board, to market participants based on each market participant's proportionate quantity of energy withdrawn from the IESO controlled grid (including scheduled exports) for 2013.

12. Supporting this Submission is the IESO's pre-filed evidence which includes:

(a) The 2014 – 2016 Business Plan;

(b) The IESO's 2011 and 2012 audited financial statements;

(c) Methodology for calculating the 2014 usage fee and proposal for treatment of accumulated surpluses;

(d) Review of IESO Fees Billing Determinant, Evidence of John Todd, President, Elenchus Research Associates Inc.

13. The IESO intends to file supplementary evidence containing Audited Financial Statements for 2013 by February 21, 2014.

14. The IESO may amend its pre-filed evidence from time to time, prior to and during the course of the Board's proceeding. In particular, should the IESO identify a material change to its 2014 Fees Submission the IESO will update its pre-filed evidence and may also amend its Submission to update the requested usage fee. Furthermore, the IESO may seek to have additional meetings with Board Staff and intervenors in order to identify and address any further issues arising from this Submission, with a view to an early settlement and disposition of this proceeding.

15. The IESO proposes the following title for this proceeding: *Independent Electricity System Operator Fiscal Year 2014 Fees Submission for Review.*

16. The persons affected by this Submission are all market participants as defined in Chapter 2, section 2.1.1 of the *Market Rules for the Ontario Electricity Market,* who participate in the electricity markets administered by the IESO. The IESO communicates regularly with its participants by way of the IESO's website and e-mail. Consistent with the means of notification requested and approved by the Board for the IESO's 2008 to 2011 fee Submissions, the IESO proposes that notice of this application be given by the following means:

(a) Posting this submission and the Notice of Application issued by the Board, including the pre-filed evidence, on the IESO's website on the "Regulatory Affairs" pages;

(b) Posting an announcement, in English and French, on the "Participant News" page, which will be e-mailed to all market participants and interested parties who are registered to receive IESO news and other communiqués; and

(c) The IESO shall deliver an electronic copy of this Submission, including the pre-filed evidence, and an electronic copy of the Notice of Application issued by the Board, to all registered observers and intervenors in the IESO's 2010 and 2011 Fees Submission for Review.

17. The IESO requests that a copy of all documents filed with the Board by each party to this proceeding be served on the IESO and the IESO's counsel in this proceeding, as follows:

(a)	The IESO	Mr. Adrian Pye Senior Regulatory Analyst, Regulatory Affairs Independent Electricity System Operator
	Address for personal service:	655 Bay Street, Suite 410 Toronto, Ontario M5G 2K4
	Mailing address:	655 Bay Street, Suite 410 P.O. Box 1 Toronto, Ontario M5G 2K4
	Telephone: Fax: E-mail:	(416) 506-2858 (416) 506-2843 regulatoryaffairs@ieso.ca
(b)	The IESO:	Jessica Savage Supervisor, Regulatory Affairs Independent Electricity System Operator

	Address for personal service:	655 Bay Street, Suite 410 Toronto, Ontario M5G 2K4
	Mailing address:	655 Bay Street, Suite 410 P.O. Box 1 Toronto, Ontario M5G 2K4
	Telephone: Fax: E-mail:	(416) 506-2851 (416) 506-2843 regulatoryaffairs@ieso.ca
(c)	The IESO's counsel:	Mr. Glenn Zacher Stikeman Elliott LLP Address for personal service: 5300 Commerce Court West 199 Bay Street Toronto, Ontario M5L 1B9
	Mailing address:	5300 Commerce Court West 199 Bay Street, Toronto, Ontario M5L 1B9
	Telephone: Fax: E-mail:	(416) 869-5688 (416) 947-0866 gzacher@stikeman.com

DATED at Toronto, Ontario, this 4th day of November, 2013.

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

By its counsel in this proceeding
Glenn Zacher

EXHIBIT LIST

Exhibit	Tab	Schedule	Description
A – ADMINISTRATION			
A	**1**	**1**	Fees Submission for Review
A	**2**	**1**	Exhibit List
B – PRE-FILED EVIDENCE			
B	**1**	**1**	2013-2016 Business Plan
B	**2**	**1**	October 22, 2013 Letter from the Minister
B	**3**	**1**	Methodology for Calculating the 2014 Usage Fee
B	**4**	**1**	Elenchus Review of IESO Fees Billing Determinant

Independent Electricity System Operator

BUSINESS PLAN

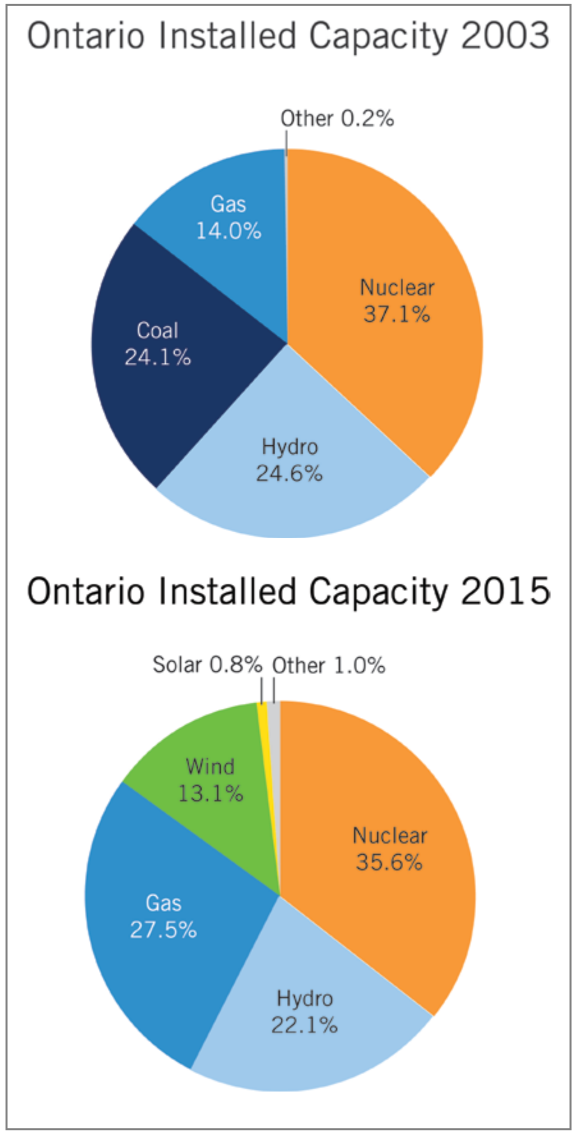
2014-2016

Power to Ontario. On Demand.

Contents

Overview

The ongoing transformation of Ontario's electricity system, increasing operational complexity and evolving North American reliability standards are now converging and helping to define actions the Independent Electricity System Operator (IESO) needs to take over the next three years. The IESO's 2014-16 Business Plan outlines what is needed to address these challenges while balancing a number of stakeholder and customer priorities, including the need to move forward with changes in the Ontario electricity market while prudently managing costs that are passed on to customers.



The next three years represent a turning point for the electricity sector – from what was a highly centralized system with a heavy reliance on fossil fuels to more sustainable and complex arrangements requiring increased operational information, adaptability and co-ordination with an increasing number of participants.

When the electricity market opened in 2002, only 20 generation companies were operating in the market – that has now grown to more than 70. The trading community has grown by 50 per cent while the number of Meter Service Providers with which the IESO coordinates operations has climbed from two to 14. By early 2014, the number of facilities that require direction from the IESO will have also risen from 93 in 2002 to 179, and will continue to grow. This has added to the complexity of managing system and market operations and significantly increased the demand for day-to-day IESO services such as training, outage management and data production.

Yet the full impact of change within the sector has yet to be felt.

All coal-fired generating stations in southern Ontario are to shut down by the end of 2013, leaving the Thunder Bay Generating Station as the lone remaining coal facility. Then, by early 2015, approximately 5,000 megawatts (MW) of renewable wind and solar generation are expected to be connected to Ontario's bulk power system, an increase of more than 3000 MW from the current amount. And, as the end of the three-year business planning cycle approaches, attention will turn to refurbishing existing nuclear units.

Contributing to Ontario's Long-Term Energy Plan

The Ministry of Energy launched a review of the Long-Term Energy Plan (LTEP) in summer 2013, which included province-wide consultations on a variety of topics including the province's mix of energy sources such as wind, solar, nuclear, and conservation.

The IESO supported Ministry staff in the development of the preliminary consultation document and dedicated senior IESO staff to regional consultation meetings. As the consultations concluded, the IESO provided input and staff support to the Ministry in the development of the final plan. The IESO will also provide necessary support to ensure the reliable integration of recommendations arising from the LTEP.

With the contributions of both wind and solar generation continuing to climb and with wind energy output surpassing that of coal in 2012, the variability of the output from these resources also increases and can change quickly over short periods of time. For example, over the summer week when demand for electricity was at its highest for 2013, wind's contribution ranged from an hourly low of 14 MW to a high of 1,544 MW.

Contribution from these renewable resources, and increased output from refurbished nuclear units combined with reduced or flat growth in electricity demand, has also contributed to increased incidents of surplus baseload generation (SBG). SBG occurs when baseload resources like nuclear, certain types of hydro generation, wind and solar, exceed Ontario's domestic electricity demand. In the first seven months of the year, SBG conditions occurred in almost 3,900 hours of the year or over 66 per cent of the time. While much of this surplus electricity was accommodated by exports, there were also a number of occasions when the output of nuclear units was reduced to manage these conditions and on six separate occasions, a nuclear unit was shut down or kept offline because of the surplus.

Over the past few years the IESO anticipated and responded to these changes and invested in development and implementation of new tools and procedures to reliably integrate variable generation resources and more efficiently manage surplus in baseload generation. A new centralized forecasting model has been implemented, resulting in both day ahead and hourly ahead forecasts that are extremely reliable. In September 2013, the IESO also implemented new tools and market rules which allow for the five minute dispatch of wind and solar grid connected resources, reducing the output of these facilities for defined periods when surplus conditions exist or grid conditions warrant. Analysis done in support of this approach indicated potential annual savings to customers in excess of $200 million.

The IESO has also invested in a number of other areas to manage the changing supply mix including developing energy modelling capability and a simulator to assist in operator training. Online limit capability is another area that required additional resources in the past few years but will now allow the IESO, transmitters and other participants to leverage maximum use of the transmission assets in the province resulting in projected annual savings of more than $2 million for consumers. Most recently, the IESO used this capability during the July 2013 blackout in the Greater Toronto Area,

Stakeholder Advisory Committee

Since its inception in 2005, the IESO Stakeholder Advisory Committee (SAC) has provided the IESO with valuable guidance for the future direction of the IESO and its efforts to improve the market. In 2013, representation on the SAC was realigned to fall into four broad sectors -- Generators, Consumers, Conveyors and Electricity Service Providers – reflecting the changing needs of the electricity sector.

Over the next three years, the SAC will continue to assist the IESO by identifying and providing insights on key priorities – such as improving price signals, reducing barriers for increased participation in the electricity market and better aligning demand response and conservation and demand management (CDM) programs with system needs. Specifically, stakeholder input will be sought in the creation of a longer-term market development plan, including the prioritization of market initiatives in support of that plan. This effort will include an increased focus on demand response in the wholesale market, to not only understand the opportunities and barriers to DR, but also explore what mechanisms are needed to better integrate it.

In addition, the IESO Stakeholder Summit, which was first held in March 2013 will become an annual event. The feedback from this inaugural event was highly positive, pointing to a clear need for a broader venue to launch the year's advisory efforts and start the dialogue that will continue across the many different stakeholder engagement platforms.

significantly shortening restoration times as it had a more accurate and real-time view of transmission capabilities as the system was re-energized.

The increased variable nature of Ontario's supply mix along with the increase in volume, frequency and duration of SBG conditions will contribute to the complexity of operating the power system as system patterns, trends and flows vary away from historical norms. But the transformation of the sector will continue – broadening to new players, innovations, influences and priorities. Given its leadership position in the sector, the IESO will need to anticipate and drive change – promoting market efficiencies, strengthening relationships with an increasingly complex and interdependent network of participants on both the supply and demand side.

Reliability standards compliance

The 10th anniversary of the 2003 blackout that affected more than 50 million people in Ontario and the northeastern part of the United States was a reminder of the investment in strengthened reliability standards made over the past decade. New reliability standards continue to be introduced, standards that the IESO must adhere to - including the need to expand network modelling capability to meet new North American Electric Reliability Corporation (NERC) requirements for visibility over a wider area.

Cybersecurity concerns are also emerging, requiring the IESO to increase its focus on this area in order to raise its preparedness level and that of market participants to address these threats.

While the IESO has long used information technologies to monitor and operate the bulk power system, broader digitization throughout the sector is creating the potential for new vulnerabilities. As such, cybersecurity has rapidly developed into an essential component of power system reliability.

In its role as Reliability Co-ordinator for Ontario, the IESO is responsible for enforcing Critical Infrastructure Protection Standards set by the NERC and works closely with industry peers and government agencies to share information on cyber events and best practices. Cybersecurity is, however, an evolving issue. Both the nature of attacks and the defences used to stop cyberthreats change frequently, requiring a sustained and proactive cybersecurity effort.

Over the 2014-16 period, the IESO will need to add new resources – including staff and tools – to manage the evolving challenges posed by cybersecurity. New staff will deal with additional technical work, including threat and data analysis. The IESO will also invest more resources in advanced cybersecurity tools, including new vulnerability identification software.

Increased contribution from the demand side and other market efficiencies

New opportunities in Ontario's electricity market

The IESO is taking a major step forward to bring new technologies such as aggregated loads, flywheels and battery storage into the electricity market by integrating new suppliers of regulation service, a grid-balancing function traditionally provided by generators. By the end of 2014, three new participants will have joined the market and provide up to 10 megawatts of regulation service, allowing the IESO to gain experience with a broader range of technologies.

Ontario has made a significant investment in renewable generation and, as discussed, the IESO has been putting in place new tools, techniques and procedures to best capture the value of that investment. Over the past few years, the IESO has also been doing foundational work and analysis that will support the development of new initiatives that can more effectively and efficiently support Ontario's future supply mix. Over the next three years, the IESO intends to move forward with these initiatives including enabling increased participation and contribution from the demand side of the market.

In preparing the 2014-16 Business Plan, the IESO actively sought out the input of stakeholders. A number of stakeholder priorities were identified through the Stakeholder Advisory Committee, including reducing the barriers to increased participation in Ontario's electricity market and better alignment of system needs with demand-side management programs. In a number of surrounding jurisdictions, demand-side resources are already making important contributions. In the PJM market in central and northeast U.S, more than 12,000 MW of demand response (DR) capability has already been introduced into the market. Similar potential exists in Ontario.

Demand response can help reduce peak demands, complement the variable nature of renewable resources like wind and solar while enabling customers to manage their electricity use and minimize their costs. Closer integration of this resource in Ontario's electricity market has the potential to result in significant benefits to system planning, operational reliability and market efficiency while maximizing the benefit to ratepayers.

Capacity needs on Ontario's power system will fluctuate continually over the next few years as supply and demand conditions ebb and flow. This will become particularly apparent during the nuclear refurbishment period, expected later in the decade. At the same time, greater market integration of DR and other technologies offer transparent and cost-effective opportunities to provide greater flexibility for the system and meet capacity needs. As such, enabling the increased contribution from DR and other technologies through a market-based platform is a priority for the IESO.

The IESO is also responding to stakeholders' requests to clarify and move forward with future market development work. Following up on the recommendations from the Electricity Market Forum which comprised a number of stakeholders across the sector, the IESO is proceeding with analysis and review in a number of areas including the Hourly Ontario Energy Price, Global Adjustment, two-schedule pricing system and more frequent intertie scheduling. Once these various reviews are complete, the IESO will work with stakeholders to seek alignment on the broader goals for improving the market, review potential changes to understand the merits of each change, prioritize the initiatives over a five-year time period and establish a longer-term market development plan of initiatives for the Ontario electricity market.

Maintaining its focus on excellence in reliable and efficient operations will be a continued priority for the IESO over the next three years, as will the need to address recommendations arising from the government's Long-Term Energy Plan. At the same time, momentum must be maintained on the multi-year program to refresh or replace aging information technology infrastructure, systems that are at or nearing the end of their life cycles. An increased investment in training and development for new employees will also be essential given that almost a third of the current employees will be eligible for retirement by the end of 2016.

OPA-IESO Coordination

The IESO continues to work with the Ontario Power Authority to help ensure a reliable and efficient supply of electricity now and in the future.

In partnership with the OPA, the IESO recently developed joint recommendations for a new integrated regional energy planning process, specifically looking at improving the way large energy projects are sited in the province. After a month of consultations and careful consideration of the feedback received from more than 1200 Ontarians, both agencies developed a set of 18 recommendations that will ensure that local communities are engaged in Ontario's electricity planning continuum.

The IESO and OPA worked closely together to address contract considerations associated with the dispatch of wind in Ontario's electricity market The two agencies are also working together to ensure the most effective use of Demand Response resources in meeting Ontario's future electricity needs.

Beyond the resource integration initiatives that are already in place, the IESO is now working with stakeholders to make changes to optimize Ontario's considerable investments in the electricity sector, investments in renewable generation, conservation and demand management and in the electricity delivery system. These initiatives will provide cost-effective flexibility to manage constantly changing demand supply conditions.

Fee Proposal

Prudent financial management is a key priority for the IESO and it recognizes the need to effectively manage costs that are ultimately passed on to customers. The proposed fee for 2014 reflects that commitment, including a proposed $1 million reduction from last year's OM&A budget of $112.1 million.

The IESO's proposed revenue requirement to carry out the above work and continue to manage its ongoing day-to-day responsibilities in market and system operations is $130 million or about $2 million higher than the 2013 budget reflecting increased amortization costs associated with the investment in IT infrastructure.

The 2014 proposed budget is significantly lower than previous forecasts. Overall, the proposed total budget is $11.8 million less than what was forecast in the 2012-14 Business Plan (which was the last multi-year plan developed by the IESO) with the proposed OM&A portion of the budget $5.5 million lower.

The IESO is proposing to change its fee structure to also include energy volumes equal to the output from generation embedded in local distribution networks. Currently, those volumes are not included in the determination of the IESO fee because the fee is based on energy withdrawals net of embedded generation.

With the proposed move to a fee based on gross energy, which is a fairer method of allocation, the IESO is recommending a reduction in its fee from the current $0.822 per megawatt hour (MWh) to $0.803 per MWh. This would result in a fee that would be approximately 16 per cent less than the fee charged 12 years ago.

The change is consistent with the original intent that the IESO fee should be charged to all Ontario load, rather than just a portion.

Financial Overview

The IESO's fiscal management continues to be based on a simple objective – to demonstrate the continued attention to costs, recognizing its fees form part of the overall cost of electricity to the consumer.

The IESO operates two separately funded aspects of the business – wholesale operations and smart meter entity. The financial outlook related to the IESO usage fee is included below and the financial outlook related to the smart meter entity is included later in the document.

Financial Outlook Related to the IESO Usage Fee:

Projected 2013 Financial Results

The following table outlines the 2013 financial projections compared to the approved budgets for the year:

($ millions)	2013 Projected	2013 Budget	Projected Variance
Usage Fees	126.0	123.9	2.1
Market-related Investment Income	1.2	1.2	-
Cost Recovery for Services	2.0	2.7	(0.7)
Total Revenues	**129.2**	**127.8**	**1.4**
OM&A Costs	109.1	112.1	3.0
Amortization	14.7	14.7	-
Net Interest	0.6	1.0	0.4
Total Costs	**124.4**	**127.8**	**3.4**
Operating Surplus	**4.8**	**-**	**4.8**
Rebate to Market Participants	**(4.8)**	**-**	**(4.8)**
Accumulated Operating Surplus	**5.0**	**5.0**	**-**

The most recent projected 2013 financial results demonstrate the continued strong cost controls on the part of IESO management.

The usage fee revenues are a direct result of energy volumes within the province and exported to neighbouring jurisdictions. Due to higher than expected provincial volumes and exports, the energy volumes for 2013 are projected at 153.3 terawatt hour (TWh), some 1.1 TWh above the budgeted volumes of 152.2 TWh and do not include generation embedded within distribution systems.

The market-related investment income is interest earned on funds held by the IESO through the market settlement cycle and the projection of $1.2 million is consistent with the budgeted amount. The reduced projection for cost recovery revenue for services reflects lower than planned Connection Assessment work and the expected slowdown in the feasibility study requests submitted by the Ontario Power Authority (OPA) for supply and transmission assessments, while the Regional Planning process is under review. These are somewhat offset by higher volume of work for the OPA related to demand response programs and higher than planned Technical Feasibility Exemption work.

On the cost side, the IESO has been effective in managing its work programs with operating costs projected to be $3.0 million below the approved budget, largely the result of the higher than planned position vacancies as it has taken management longer than anticipated to fill all vacant positions in 2013. Amortization costs at $14.7 million are projected to be on budget in 2013, as is the projected capital spending, at $22.0 million.

Financial Outlook 2014-2016

The financial outlook for 2014 and beyond extends the message from 2013 – prudent cost management on the part of the IESO. Financial statements related to the IESO Usage Fee are included in Appendix 1.

The following table outlines the planned operating results over the planning period:

($ millions)	2013 Projected	2014 Budget	2015 Plan	2016 Plan
Usage Fees	126.0	126.6	127.1	130.9
Cost Recovery for Services	2.0	2.0	2.1	2.1
Market-related Interest Income	1.2	1.3	2.7	3.8
Total Revenues	**129.2**	**129.9**	**131.9**	**136.8**
OM&A Costs	109.1	111.1	110.0	111.2
Amortization	14.7	17.7	20.1	23.2
Net Interest	0.6	1.1	1.8	2.4
Total Costs	**124.4**	**129.9**	**131.9**	**136.8**
Operating Surplus	**4.8**	**-**	**-**	**-**
Rebate to Market Participant	**(4.8)**	**-**	**-**	**-**
Accumulated Operating Surplus	**5.0**	**5.0**	**5.0**	**5.0**

Total Revenues

As noted earlier, the revenues IESO generates from usage fees are a factor of both energy volumes in terawatt hours (TWh) and the fee per megawatt hour (MWh).

In 2014, the IESO is proposing to change the methodology on which it levies its fee, such that the IESO charges its fee based on the gross load in the province plus exports, thereby adjusting for the growing amount of embedded generation within the province. This methodology does not result in the payment of additional IESO usage fees by consumers, rather it ensures all of the existing payments are paid to the IESO. Currently, Local Distribution Companies (LDCs) collect IESO usage fees from all of their customers[1] based on their total loads – but then only remit to the IESO based on the LDC net load which is reduced by embedded generation. The amount of embedded generation is expected to

[1] The IESO usage fee forms part of the Wholesale Service Charge paid by distribution customers based on their individual load.

continue to increase in materiality. The IESO believes the proposed change in methodology more fairly reflects the changing nature of the grid, including the need for the IESO to establish and maintain visibility of embedded generation and to forecast its impact on bulk system requirements. The IESO's proposed usage fee for 2014 of $0.803 per MWh represents a 2.3% reduction from our current fee of $0.822/MWh.

	2013 Projected	**2014 Budget**	**2015 Plan**	**2016 Plan**
Outlook Demand Forecast (TWh)	141.4	141.0	137.3	134.4
Less: Transmission Line Losses (TWh)	(3.1)	(3.1)	(3.0)	(3.0)
Exports (TWh)	15.0	14.0	14.4	14.3
Total Energy Volumes (net TWh) [2]	**153.3**	**151.9**	**148.7**	**145.7**
Embedded Generation (TWh)	n/a	5.7	7.0	7.6
Total Energy Volumes (gross TWh)[3]	**153.3**	**157.6**	**155.7**	**153.3**
IESO Usage Fee ($/MWh)	**$0.822**	**$0.803**	**$0.816**	**$0.854**
Total Usage Fee Revenue (million)	**$126.0**	**$126.6**	**$127.1**	**$130.9**

The above usage fees reflect a reduction from the 2013 fee for both 2014 and 2015, with an increase of 3.9% in 2016.

Cost recovery revenues are budgeted to remain relatively flat over the three year planning period. These revenues represent services that are provided at cost and there are corresponding costs within the operating costs for these services.

The interest income earned on other real-time market investments is projected to increase over the planning period primarily as a consequence of assumed increases in interest rates.

[2] Energy volume forecasts used in calculating the usage fee over the planning period are based on the 18-Month Outlook released May 2013.

[3] Beginning in 2014 usage fees are based on total energy volumes inclusive of embedded generation

Total Costs

	2013 Projected	2014 Budget	2015 Plan	2016 Plan
OM&A Costs	109.1	111.1	110.0	111.2
Amortization	14.7	17.7	20.1	23.2
Interest (net)	0.6	1.1	1.8	2.4
Total Costs	**124.4**	**129.9**	**131.9**	**136.8**

Over the planning period, it is expected that total costs are expected to change annually by $5.5 million, $2.0 million and $4.9 million respectively.

OM&A Costs

OM&A costs are budgeted to increase by $2.0 million in 2014 and then remain largely flat in 2015 and 2016. These cost increases are largely the result of the lower projected staff costs in 2013 due to delays in hiring to budgeted levels in the first half of the year. In the second half of 2013, IESO management is committed to fill staff positions while recognizing that a consistent, ongoing level of vacancies will occur across the corporation. In addition, the IESO will continue to employ focused vendor management and competitive procurement processes to limit inflationary and other increases in computer support, maintenance and equipment costs and in telecommunication costs.

Staffing

In 2012, IESO management significantly limited hiring in order to provide flexibility for the anticipated merger with the OPA. However, the merger did not proceed, and IESO management is now hiring to 2013 budgeted levels in key areas including: support of renewable integration and market development, compliance activities and increased effort focused on refreshing/replacing existing information technology systems.

The total 2013 budgeted staff level for wholesale operations, including capital labour, is 467 and will decrease to 459 for 2014, with further slight decreases to 458 for 2015 and 456 for 2016. Changes in staffing levels over the planning period result from a reallocation of effort across the different business functions with the recognition of efficiencies being achieved in some of the ongoing processes. These staffing levels include regular and temporary staff for wholesale operations.

	2013		**2014**		**2015**		**2016**	
	Regular	**Temp**	**Regular**	**Temp**	**Regular**	**Temp**	**Regular**	**Temp**
Wholesale Operations	459	8	451	8	451	7	449	7
Total	**459**	**8**	**451**	**8**	**451**	**7**	**449**	**7**

Amortization

Amortization expense, driven by reinvestment in IT systems and infrastructure, continues to be the key driver in the year over year increases in total costs. Increases of $2.7 million in 2015 and $3.1 million in 2016 will bring amortization expense to $23.2 million, reflecting the cost of renewing aging IT infrastructure. For comparison, this is less than half of the amortization cost ten years ago.

($ millions)	2013 Projected	2014 Budget	2015 Plan	2016 Plan
Amortization	14.7	17.7	20.1	23.2

A summary of the capital spending over the 2013 – 2016 period is contained in the table below:

Project ($ millions)	2013 Projected	2014 Budget	2015 Plan	2016 Plan
Renewable Integration Initiative	3.3	-	-	-
Revenue Metering System Replacement	3.0	3.6	-	-
Energy Management System (EMS) Refresh	2.0	5.0	2.0	-
IESO Simulator	1.7	-	-	-
Registration Automation	1.0	0.6	-	-
Oracle 11g RAC Technical Refresh	0.8	0.6	-	-
Market Information Management Refresh	0.5	1.5	-	-
Tier 1 Storage Refresh	0.5	1.5		
Interchange Automation	-	2.0	1.0	-
Market Interface System Refresh	-	1.5	5.0	-
Outage Management Replacement	-	0.5	0.6	
Electrical System Upgrades	-	-	3.0	-
Market Improvements	-	-	4.0	7.0
Reliability Improvements	-	-	3.0	5.0
Information Security Enhancements	-	-	1.0	2.0
Settlements Replacement	-	-	-	6.0
Enterprise Cybersecurity Management Enhancements	-	-	-	1.0
NERC Tools Replacement	-	-	-	1.0
Total Capital Projects (totaling $1M & above)	**12.8**	**16.8**	**19.6**	**22.0**
Other Capital Projects	**9.2**	**7.2**	**4.4**	**1.7**
Total Capital Projects	**22.0**	**24.0**	**24.0**	**23.7**

The IESO continues to have an ongoing need for reprioritization of initiatives it undertakes, and accordingly, the business planning process is not used as the mechanism for capital project approval. Rather, through business planning, an appropriate capital envelope is established for future years, with capital commitments approved individually on an ongoing basis. This practice is consistent with prior years. In addition, the IESO recognizes the need for robust disclosure and information about the projects for which this capital funding is currently intended to be utilized.

Detailed project descriptions are included in Appendix 2.

Interest Expense (net)

($ millions)	2013 Projected	2014 Budget	2015 Plan	2016 Plan
Interest Expense (net)	0.6	1.1	1.8	2.4

Net interest expense is comprised of the following components:

($ millions)	2013 Projected	2014 Budget	2015 Plan	2016 Plan
Interest on Debt	0.5	0.9	1.6	2.2
Financing Charges	0.3	0.3	0.3	0.4
Investment/Other Income	(0.1)	(0.1)	(0.1)	(0.1)
Capitalized Interest	(0.1)	-	-	(0.1)
Net Interest Expense	**0.6**	**1.1**	**1.8**	**2.4**

In May 2013, the IESO entered into a one-year note payable with Ontario Electricity Financial Corporation (OEFC) for $78.2 million at a fixed interest rate of 1.62%. On April 30, 2013, the IESO entered into an unsecured $110 million credit facility with OEFC. Advances under the credit facility are payable at a variable interest rate equal to Province of Ontario's cost of borrowing for a 30 day term plus 0.50% per annum. The facility expires April 30, 2014.

The interest on debt also reflects the following assumptions:

($ millions)	2013 Projected	2014 Budget	2015 Plan	2016 Plan
Debt at end of year	$33.0	$52.6	$64.3	$71.1
Average Interest Rate	1.65%	1.87%	2.57%	2.80%

Increases in debt are shown on the Statement of Cash Flows in Appendix 1 and in 2014 are largely the result of increased capital spending in excess of amortization expense, as well as the expected payment of market participant rebates. In 2015 and 2016 the increase in debt is largely the result of pension contributions in excess of pension costs during those years.

Financial Outlook Related to the Smart Metering Entity:

The Meter Data Management/Repository (MDM/R) was placed in-service in February 2008. Further development and updates have continued and new functionality was released in 2009, 2011, and April 2012. The MDM/R system is actively processing smart meter data and producing time-of-use (TOU) and other billing quantities for customer invoices. The transition of customers to TOU rates is substantially completed with 4.47 million of 4.7 million customers on TOU rates. Most of the remaining customers are targeted to be transitioned in early 2014. By the end of June 2013, 69 LDCs have transitioned to the MDM/R interface, enabling them to receive register reads for billing and support with their compliance with Measurement Canada requirements. The IESO remains actively engaged with the remaining distributors to support their compliance with Measurement Canada requirements.

On March 28, 2013, the Ontario Energy Board issued its Decision and Order in the Smart Metering Charge proceeding (EB-2012-0100 and EB-2012-0211). The Board ordered that beginning May 1, 2013, the Smart Metering Entity (SME) will levy and collect from all Distributors identified in the Ontario Energy Board's annual Yearbook of Electricity Distributors, a monthly Smart Meter Charge in the amount of $0.788, for each Residential and General Service <50kW Customer.

The SME costs incurred to date and projected costs are within the IESO Board authorized budget for Smart Metering and within the Revenue Requirement for the Smart Metering Charge. These are shown in the following table and reflected in the consolidated financial statements provided in Appendix 4.

All direct and/or incremental costs associated with MDM/R are charged separately from all other IESO costs that form part of the revenue requirements for the IESO usage fee.

($ millions)	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
SME Fees	-	30.1	45.2	45.2	45.2
Total Revenues	-	30.1	45.2	45.2	45.2
SME Program Costs	18.6	24.5	27.6	27.3	27.0
Amortization	3.6	3.7	3.9	3.9	3.9
Net Interest	1.5	1.8	1.8	3.0	3.1
Total Costs	23.7	30.0	33.3	34.2	34.0
Operating Surplus/(Deficit)	(23.7)	0.1	11.9	11.0	11.2
Accumulated (Deficit)	(82.4)	(82.3)	(70.4)	(59.4)	(48.2)

The revenue requirement assumptions and resulting Smart Metering Entity balance sheet are included in Appendix 3.

Market Enforcement Activities

The IESO's Market Assessment and Compliance Division has implemented a risk-based framework to assess the areas of market rules and conduct in need of an increased compliance and enforcement focus. Enforcement can result in financial penalties and payment adjustments which are held in the IESO Adjustment Account. The amounts that might be received pursuant to prospective actions cannot be estimated in advance of any given year, as it is difficult to project what enforcement activities may be required. Those enforcement costs that are reimbursed from the Adjustment Account are not included in the IESO's proposed usage fee.

Overall Financial Outlook:

The overall financial outlook of the IESO, including both wholesale operations and Smart Metering Entity activities, are presented in the consolidated financial statements in Appendix 4.

Appendix 1: IESO Usage Fee Financial Statements

Actual and Pro Forma Statement of Operations and Accumulated Surplus
For the Year Ended December 31
(in Millions of Canadian Dollars)

	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
REVENUES					
Usage fees	125.8	126.0	126.6	127.1	130.9
Market-related interest income	1.3	1.2	1.3	2.7	3.8
Cost recovery for services	2.7	2.0	2.0	2.1	2.1
Total Revenues	**129.8**	**129.2**	**129.9**	**131.9**	**136.8**
EXPENSES					
OM&A Costs	106.5	109.1	111.1	110.0	111.2
Amortization	13.0	14.7	17.7	20.1	23.2
Net Interest	0.8	0.6	1.1	1.8	2.4
Total Expenses	**120.3**	**124.4**	**129.9**	**131.9**	**136.8**
Operating Surplus/(Deficit)	**9.5**	**4.8**	**-**	**-**	**-**
Rebates to Market Participants	(9.5)	(4.8)	-	-	-
Accumulated Surplus - Usage fees	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
Market Sanctions & Payment Adjustments	1.1	2.5	-	-	-
Customer Education & Market Enforcement Expenses	(0.7)	(4.1)	-	-	-
Accumulated Market Sanctions & Payment Adjustments	**1.4**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**

Actual and Pro Forma Statement of Financial Position
For the Year Ended December 31
(in Millions of Canadian Dollars)

	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
ASSETS					
Current Assets					
Cash & cash equivalents	6.9	2.0	2.0	2.0	2.0
Accounts receivable	16.8	15.5	15.1	16.7	18.3
Short-term prepaid expenses	3.7	3.5	3.5	3.5	3.5
	27.4	**21.0**	**20.6**	**22.2**	**23.8**
Property & Equipment					
Property & equipment in service	344.1	359.0	382.8	404.8	426.8
Less: accumulated amortization	(279.0)	(293.7)	(311.4)	(331.5)	(354.7)
Net Book Value	65.1	65.3	71.4	73.3	72.1
Construction-in-progress	4.7	11.8	12.0	14.0	15.7
	69.8	**77.1**	**83.4**	**87.3**	**87.8**
Other Assets					
Long-term investments	27.7	29.9	31.8	33.8	36.0
TOTAL ASSETS	**124.9**	**128.0**	**135.8**	**143.3**	**147.6**
LIABILITIES					
Current Liabilities					
Accounts payable & accrued liabilities	17.6	17.7	17.7	17.8	17.8
Accrued interest	0.3	0.3	0.3	0.3	0.3
Rebates to market participants	13.1	17.9	-	-	-
	31.0	**35.9**	**18.0**	**18.1**	**18.1**
Debt	36.7	33.0	52.6	64.3	71.1
Accrued pension liability	41.6	35.6	32.3	18.7	6.9
Accrual for employee future benefits other than pension	69.3	74.2	79.4	84.8	90.5
TOTAL LIABILITIES	**178.6**	**178.7**	**182.3**	**185.9**	**186.6**
Accumulated Surplus - Usage Fees	5.0	5.0	5.0	5.0	5.0
Accumulated Pension Actuarial Losses	(60.1)	(55.5)	(51.3)	(47.4)	(43.8)
Accumulated Fines and Penalties	1.4	(0.2)	(0.2)	(0.2)	(0.2)
TOTAL LIABILITIES & ACCUMULATED SURPLUS	**124.9**	**128.0**	**135.8**	**143.3**	**147.6**

Actual and Pro Forma Statement of Cash Flows
For the Year Ended December 31
(in Millions of Canadian Dollars)

	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
OPERATING ACTIVITIES					
Change in rebates to market participants	9.6	4.8	(17.9)	-	-
PSAB transition items	5.8	4.6	4.2	3.9	3.6
Market sanctions and payment adjustments	1.1	2.5	-	-	-
Customer education & market enforcement costs	(1.1)	(4.1)	-	-	-
Amortization	13.0	14.7	17.7	20.1	23.2
Change in fair value long-term investment	(1.1)	(2.2)	(1.9)	(2.0)	(2.2)
Pension cost	12.0	10.8	10.7	10.4	9.8
Increase in accrual for employee future benefits	6.5	6.9	7.3	7.6	8.0
Pension plan contributions	(25.3)	(16.8)	(14.0)	(24.0)	(21.6)
Payment of employee future benefits	(1.7)	(2.0)	(2.1)	(2.2)	(2.3)
Other non-cash items related to operations	(3.4)	1.6	0.4	(1.5)	(1.6)
Cash Provided from Operations	**15.8**	**20.8**	**4.4**	**12.3**	**16.9**
INVESTING ACTIVITIES					
Purchase of long-term investments	(2.3)	-	-	-	-
Investment in property & equipment	(10.1)	(22.0)	(24.0)	(24.0)	(23.7)
Cash Used in Investing Activities	**(12.4)**	**(22.0)**	**(24.0)**	**(24.0)**	**(23.7)**
FINANCING ACTIVITIES					
Issue/(retirement) of debt	(2.1)	(3.7)	19.6	11.7	6.8
Cash Provided from Financing Activities	**(2.1)**	**(3.7)**	**19.6**	**11.7**	**6.8**
Net Change in Cash Flow	**1.3**	**(4.9)**	**-**	**-**	**-**
Cash and Cash Equivalents - Beginning of Year	5.6	6.9	2.0	2.0	2.0
Cash and Cash Equivalents - End of Year	**6.9**	**2.0**	**2.0**	**2.0**	**2.0**

Appendix 2: IESO Capital Projects

(in thousands of Canadian Dollars)

Project	**2013 Projected**	**2014 Budget**	**2015 Plan**	**2016 Plan**
Renewable Integration Initiative	3,268			
Revenue Metering System Replacement	2,950	3,600		
Energy Management System (EMS) Refresh	2,000	5,000	2,000	
IESO Simulator	1,736	20		
Registration Automation	1,033	600		
Oracle 11g RAC Technical Refresh	800	600		
Market Information Management Refresh	500	1,500		
Tier 1 Storage Refresh	500	1,500		
Interchange Automation		2,000	1,000	
Market Interface System Refresh		1,500	5,000	
Outage Management Replacement		500	600	
Electrical System Upgrades			3,000	
Market Improvements			4,000	7,000
Reliability Improvements			3,000	5,000
Information Security Enhancements			1,000	2,000
Settlements Replacement				6,000
Enterprise Cybersecurity Management Enhancements				1,000
NERC Tools Replacement				1,000
Total Capital Projects (totaling $1M & above)	**12,787**	**16,820**	**19,600**	**22,000**
Other Capital Projects	**9,213**	**7,135**	**4,350**	**1,650**
Capital Funding Total	**22,000**	**23,955**	**23,950**	**23,650**

Capital Projects – Descriptions

Project	Description
Renewable Integration Initiative	Additional tools and services are required by the IESO to improve the forecasting of available energy from renewable sources and the impacts that those embedded resources will have on demand. This project includes new systems and changes to existing systems to implement the Renewable Integration design.
Revenue Metering System Replacement	The Revenue Metering Repository systems have not been upgraded from a technology perspective since market opening and are overdue for an upgrade or replacement. Major changes of this type also provide an opportunity to review the business processes that these systems support, and take advantage of tool changes that vendors have implemented to improve efficiency. This initiative encompasses: 1) Meter Registration 2) Meter Polling – MV90 3) Meter Calculation and Archiving – MVSTAR 4) Participant access to Meter Information – MVWEB 5) Meter Trouble Reporting – MTR 6) Meter Data Provisioning – interfaces with other IESO systems.
Energy Management System (EMS) Refresh	The Energy Management System (EMS) is a key system for managing and monitoring the IESO Controlled Grid (ICG). This system collects real-time information from the field, monitors that the system is being operated within defined limits and presents the information to the operators in the form of displays and messages. This system requires regular maintenance to ensure adequate vendor support and to remain in compliance with changing NERC standards. The EMS Refresh will also introduce functional improvements that the vendor has included in the latest release, such as visualization enhancements and integration capabilities. The improvements can be used to improve the user's experience and/or meet the business requirements identified in future projects.
IESO Simulator	The IESO Simulator initiative will provide system operators with a training environment that replicates the operational behaviour of the IESO Controlled Grid during normal and emergency conditions and allows a team of control room operators to respond to power system events in a coordinated manner. The use of a power system simulator will allow the IESO to better train its operators through a more effective training experience and ensure our compliance with NERC standard PER-005-1 Requirement 3.1 which comes into effect on April 1, 2014.
Registration Automation	The Registration Automation project will replace the IESO paper forms based solution for registering participants with an electronic forms solution. This project includes a complete review of the registration processes and the introduction of a Business Process Management solution to implement the new registration process.
Oracle 11 g RAC Technical Refresh	The IESO uses an Oracle Real Application Cluster (RAC) database for all its critical databases. The existing solution is at version 10 and runs on older HP Blade servers. The project will upgrade the Oracle RAC infrastructure to version 11, running on higher performance servers.

Capital Projects – Descriptions continued

Market Information Management Refresh	The Market Information Management (MIM) system supports Market Participant transaction submissions, including the submission of bids, offers, non-dispatchable schedules and physical bilateral contracts. MIM validates and stores these transactions and makes them available for downstream processing in the day-ahead, real-time and settlements timeframes. The MIM system technology has not been upgraded since market opening and the ability to maintain required service levels is becoming more challenging. It is necessary to undertake an upgrade or a replacement before its reliability is impacted.
Tier 1 Storage Refresh	The Tier 1 Storage Refresh initiative will refresh the primary storage arrays the IESO uses for both file systems and databases. This project will refresh the EMC DMX4 array to achieve improved performance and additional capacity to meet the needs of the business for the next four years.
Interchange Automation	This project will review processes and tools associated with managing interchange transactions. It will implement changes to allow us to better integrate with the evolving processes in neighbouring jurisdictions and allow us to continue to be compliant with evolving NERC standards.
Market Interface System Refresh	The Market Interface System (MIS) is a key system for managing the IESO Administered Markets (IAM). This system determines the dispatch schedules for the IAM. A refresh of the system is required to maintain reliability of the MIS and provision a solution that will support the recommended enhancements to the IAM.
Outage Management Replacement	The Outage Management solution is responsible for collecting and presenting outages that may impact the operation of the ICG or IAM. This solution provides interfaces that support both participant requirements and internal user requirements. This solution is nearing end of life and is due for replacement. In addition, discussions with other Independent System Operators and with our participants have identified opportunities for improving the processes and tools associated with managing outages.
Electrical System Upgrades	This initiative involves the replacement, upgrading, or refurbishment of various aspects of the Clarkson System Control Centre electrical system which has been in service for a number of years. The exact nature and extent of the replacement, upgrades, or refurbishment will be determined after an in-depth review.
Market Improvements	There are a number of market design reviews underway in areas such as capacity markets, real-time dispatch models (two-schedule system and HOEP review), generation cost guarantees, increasing the frequency of intertie transaction scheduling and demand side integration projects. The IESO will commence a stakeholder review in the fall of 2013 that will result in the selection, prioritization and sequencing of specific design implementation projects over a five year period. It is expected that implementation of one of the above initiatives could commence near the end of 2014 that may result in the need for capital projects.
Reliability Improvements	This is funding allocated for yet to be identified projects related improving the processes and solutions for managing reliability of the IESO Controlled Grid.
Information Security Enhancements	This is funding allocated for projects to improving the security posture of the IESO based on the changing threats and measures available to counteract those threats.
Settlements Replacement	Analysis activities related to reviewing the existing settlements process and replacing the supporting systems will begin in 2014 with implementation activities being initiated in 2016 for a 2017 delivery.
Enterprise Cybersecurity Management Enhancements	This project will replace the software and hardware currently used to monitor system logs for security events and perform security testing.
NERC Tools Replacement	This funding is allocated for yet to be identified projects related to NERC's change in policy with respect to the provisioning of tools that are used by NERC entities.

Appendix 3: Smart Metering Entity

Smart Metering Entity – Projected Balance Sheet

($ millions)	**2012 Actual**	**2013 Projected**	**2014 Budget**	**2015 Plan**	**2016 Plan**
ASSETS					
Property & Equipment	17.8	15.6	11.7	7.8	3.9
TOTAL ASSETS	**17.8**	**15.6**	**11.7**	**7.8**	**3.9**
LIABILITIES					
Accounts Payable & Accrued Liabilities	3.7	3.0	3.0	3.0	3.0
Debt	96.5	94.9	79.1	64.2	49.1
TOTAL LIABILITIES	**100.2**	**97.9**	**82.1**	**67.2**	**52.1**
Accumulated Deficit	(82.4)	(82.3)	(70.4)	(59.4)	(48.2)
TOTAL LIABILITIES & ACCUMULATED DEFICIT	**17.8**	**15.6**	**11.7**	**7.8**	**3.9**

Smart Metering Entity – Principle Assumptions Underpinning SME Revenue Requirement

- The period over which the costs were or will be incurred is from inception of the Smart Metering Initiative (July 2006) to December 31, 2017.
- The period of cost recovery is from May 1, 2003 to October 31, 2018 as per the Ontario Energy Board Decision and Order issued on March 28, 2013 in connection with the Smart Metering Charge proceeding (EB-2012-0100 and EB-2012-0211).
- The MDM/R asset is being amortized over a ten year period from when it went into operation, from March 1, 2008 to December 31, 2017.
- The service life is based on industry practice and is consistent with service lives used for comparable meter processing and database systems.
- There is no provision for costs associated with providing services for General Service >=50kW Customers.
- There is no provision for a rate of return in the revenue requirement.

Appendix 4: Consolidated Financial Statements

Actual and Pro Forma Consolidated Statement of Operations and Accumulated Surplus
For the Year Ended December 31
(in Millions of Canadian Dollars)

	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
REVENUES					
Usage fees	125.8	126.0	126.6	127.1	130.9
SME fees	-	30.1	45.2	45.2	45.2
Market-related interest income	1.3	1.2	1.3	2.7	3.8
Cost recovery for services	2.7	2.0	2.0	2.1	2.1
Total Revenues	**129.8**	**159.3**	**175.1**	**177.1**	**182.0**
EXPENSES					
OM&A costs	125.1	133.6	138.7	137.3	138.2
Amortization	16.6	18.4	21.6	24.0	27.1
Net Interest	2.3	2.4	2.9	4.8	5.5
Total Expenses	**144.0**	**154.4**	**163.2**	**166.1**	**170.8**
Operating Surplus/(Deficit)	**(14.2)**	**4.9**	**11.9**	**11.0**	**11.2**
Rebates to Market Participants	(9.5)	(4.8)	-	-	-
Accumulated Surplus - Usage fees	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
Accumulated Deficit - SME fees	**(82.4)**	**(82.3)**	**(70.4)**	**(59.4)**	**(48.2)**
Accumulated Market Sanctions & Payment Adjustments	**1.4**	**(0.2)**	**(0.2)**	**(0.2)**	**(0.2)**

Actual and Pro Forma Consolidated Statement of Financial Position
For the Year Ended December 31
(in Millions of Canadian Dollars)

	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
ASSETS					
Current Assets					
Cash & cash equivalents	6.9	2.0	2.0	2.0	2.0
Accounts receivable	16.8	15.5	15.1	16.7	18.3
Short-term prepaid expenses	3.7	3.5	3.5	3.5	3.5
	27.4	**21.0**	**20.6**	**22.2**	**23.8**
Property & Equipment					
Property & equipment in service	375.3	391.8	415.6	437.6	459.6
Less: accumulated amortization	(292.4)	(310.9)	(332.5)	(356.5)	(383.6)
Net Book Value	82.9	80.9	83.1	81.1	76.0
Construction-in-progress	4.7	11.8	12.0	14.0	15.7
	87.6	**92.7**	**95.1**	**95.1**	**91.7**
Other Assets					
Long-term investments	27.7	29.9	31.8	33.8	36.0
	27.7	**29.9**	**31.8**	**33.8**	**36.0**
TOTAL ASSETS	**142.7**	**143.6**	**147.5**	**151.1**	**151.5**
LIABILITIES					
Current Liabilities					
Accounts payable & accrued liabilities	21.3	20.7	20.7	20.8	20.8
Accrued interest	0.3	0.3	0.3	0.3	0.3
Rebates to market participants	13.1	17.9	-	-	-
	34.7	**38.9**	**21.0**	**21.1**	**21.1**
Debt	133.2	127.9	131.7	128.5	120.2
Accrued pension liability	41.6	35.6	32.3	18.7	6.9
Accrual for employee future benefits other than pension	69.3	74.2	79.4	84.8	90.5
TOTAL LIABILITIES	**278.8**	**276.6**	**264.4**	**253.1**	**238.7**
Accumulated Surplus - Usage Fees	5.0	5.0	5.0	5.0	5.0
Accumulated PSAB transition items	(60.1)	(55.5)	(51.3)	(47.4)	(43.8)
Accumulated Deficit - SME Fees	(82.4)	(82.3)	(70.4)	(59.4)	(48.2)
Accumulated Market Sanctions & Payment Adjustments	1.4	(0.2)	(0.2)	(0.2)	(0.2)
TOTAL LIABILITIES & ACCUM. SURPLUS	**142.7**	**143.6**	**147.5**	**151.1**	**151.5**

Actual and Pro Forma Consolidated Statement of Cash Flows
For the Year Ended December 31
(in Millions of Canadian Dollars)

	2012 Actual	2013 Projected	2014 Budget	2015 Plan	2016 Plan
OPERATING ACTIVITIES					
Operating surplus/(deficit) after rebates	(23.7)	0.1	11.9	11.0	11.2
Change in Rebates to Market Participants	9.6	4.8	(17.9)	-	-
PSAB transition items	5.8	4.6	4.2	3.9	3.6
Market sanctions and payment adjustments	1.1	2.5	-	-	-
Customer education & market enforcement costs	(0.7)	(4.1)	-	-	-
Amortization	16.6	18.4	21.6	24.0	27.1
Change in fair value long-term investment	(1.1)	(2.2)	(1.9)	(2.0)	(2.2)
Pension cost	12.0	10.8	10.7	10.4	9.8
Increase in accrual for employee future benefits	6.5	6.9	7.3	7.6	8.0
Pension plan contributions	(25.3)	(16.8)	(14.0)	(24.0)	(21.6)
Payment of employee future benefits	(1.7)	(2.0)	(2.1)	(2.2)	(2.3)
Other non-cash items related to operations	(2.2)	1.0	0.4	(1.5)	(1.6)
Cash Provided from Operations	**(3.1)**	**24.0**	**20.2**	**27.2**	**32.0**
INVESTING ACTIVITIES					
Purchase of long-term investments	(2.3)	-	-	-	-
Investment in property & equipment	(16.3)	(23.6)	(24.0)	(24.0)	(23.7)
Cash Used in Investing Activities	**(18.6)**	**(23.6)**	**(24.0)**	**(24.0)**	**(23.7)**
FINANCING ACTIVITIES					
Issue/(Retirement) of debt	23.0	(5.3)	3.8	(3.2)	(8.3)
Cash Provided from Financing Activities	**23.0**	**(5.3)**	**3.8**	**(3.2)**	**(8.3)**
Net Change in Cash Flow	**1.3**	**(4.9)**	**-**	**-**	**-**
Cash and Cash Equivalents – Beg. of Year	5.6	6.9	2.0	2.0	2.0
Cash and Cash Equivalents - End of Year	**6.9**	**2.0**	**2.0**	**2.0**	**2.0**

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On Demand.

Independent Electricity System Operator
655 Bay Street
Suite 410, PO Box 1
Toronto, Ontario M5G 2K4
t 416 506 2800
www.ieso.ca

October 1, 2013

The Honourable Bob Chiarelli
Minister of Energy
900 Bay Street
Hearst Block, 4th Floor
Toronto, ON M7A 2E1

Dear Minister Chiarelli:

Re: IESO Proposed 2014-16 Business Plan

I am pleased to provide you with the Independent Electricity System Operator's (IESO) proposed 2014-16 Business Plan. Under *The Electricity Act, 1998*, the IESO is required to submit its business plan for Ministerial approval prior to making application to the Ontario Energy Board (OEB) for next year's proposed expenditures, fees and revenue requirements.

The Business Plan reflects the priorities for the IESO over the next three years including the need to effectively manage its costs that are ultimately passed on to Ontario's electricity customers. As our proposed budget demonstrates, the IESO is continuing with its commitment to effective cost management. The resulting revenues would be significantly lower than previous forecasts issued as part of the 2012-14 Business Plan which was the last multi-year Business Plan submitted to the Minster of Energy.

In particular, the 2014 budget included in the Business Plan we are submitting to you today is $11.8 million less than what was forecast for 2014 in our last multi-year submission, including a $5.5 million reduction in proposed Operations, Maintenance and Administration costs. The recommended fee, if approved by the Ontario Energy Board, would be a reduction from the current $0.822 per megawatt hour (MWh) fee to $0.803 per MWh. For the average residential customer, the IESO fee would amount to a monthly cost of about 60 cents.

While the IESO recognizes the need to continue to reduce costs wherever possible, it's worth noting that a small investment by the IESO can result in significant savings across the sector, savings that flow to Ontario electricity customers. For example, the IESO's project to integrate variable resources such as wind and solar into the five-minute dispatch process was completed on time and on budget at a cost of less than $10 million. But starting in 2014 the savings in gas generation costs resulting from the ability to dispatch variable resources are estimated at over $200 million a year. Online limit capability is another area where the IESO allocated modest additional resources to adopt new technology that will now allow the IESO, transmitters and other participants to leverage maximum use of the transmission assets in the province, resulting in projected annual savings of more than $2 million for customers. These annual savings for customers significantly outweigh any associated increase in amortization and operating expenses.

Bruce B. Campbell
President and CEO
bruce.campbell@ieso.ca
t 416 506 2829

While the IESO's total costs are projected to increase by $2.1 million in 2014 as compared to the 2013 budget, this primarily reflects amortization costs associated with necessary re-investments in our IT infrastructure. We need to maintain momentum with our multi-year program to refresh or replace key elements of the aging information technology infrastructure that supports reliable operations. While amortization costs have benefited by extending asset lives, there is a limit and these systems are now at or nearing the end of their life cycles. The required re-investments necessarily result in increased amortization charges.

The IESO has been a sector leader in managing costs and reducing financial impacts on customers. Our proposed budget of $129.9 million for 2014 is $26.4 million less than it was in 2004. This effective cost management is a key factor in a 2014 proposed fee that would be almost 17 per cent less than it was a decade ago.

Our commitment to cost reduction has been realized despite growing demands on the IESO in an increasingly complex operating environment. Ontario is in the final stages of the elimination of coal from its supply mix and implementing significant amounts of variable, renewable generation over the next three years - moving from what was a highly centralized system to a more sustainable decentralized system requiring increased operational information, adaptability and coordination with an increasing number of participants.

Over the past few years the IESO has anticipated and built the necessary capabilities to manage these ongoing changes, developing and implementing the new procedures and tools required to reliably integrate variable resources and more efficiently manage surpluses in baseload generation.

This increased operating complexity, combined with the need to comply with evolving and more stringent North American reliability standards, and address expanding cyber security threats, will require additional effort and investment by the IESO over the next three years. For example, developing and implementing a system simulator for operator training and qualification has now been made a mandatory requirement under the North American reliability standards applicable to the IESO.

Over the next three years, the IESO Business Plan also anticipates moving forward with new initiatives aimed at effectively and efficiently capturing the benefits flowing from the government's electricity policy initiatives. One area of particular focus will be the demand side. Demand side resources are already making significant contributions in neighbouring jurisdictions and similar potential exists in Ontario. Demand response can help reduce peak demands, complement the variability of wind and solar resources while helping customers to manage both their use and cost of electricity. The IESO is working closely with the Ontario Power Authority to transition large scale demand response capability into Ontario's electricity market where it can result in significant benefits to both system reliability and market efficiency.

Our work with the OPA will continue in other areas as well. As you know, the IESO and OPA recently developed joint recommendations for a new integrated regional planning process with a particular focus on improving the siting process of large energy infrastructure projects. We will continue to work closely with the OPA where our efforts are required in implementing the recommendations arising from that project. And we continue to coordinate on new initiatives to ensure that contract provisions are considered in the development of new market rule amendments.

In submitting this Plan for your review, we have also had in mind our ongoing work with your Ministry and other agencies in the development of the government's Long Term Energy Plan (LTEP). I am confident that this Business Plan is well aligned with the government's LTEP objectives.

Finally, as you know, the IESO is a not-for-profit agency and revenues that are not committed are passed back to customers. With approval of this Business Plan by the OEB, the IESO will be in a position to refund almost $18 million to customers, savings we have been able to realize through careful management of our funding since the last Business Plan was approved by the OEB several years ago.

Please do not hesitate to contact me should you wish to discuss any aspect of the IESO's proposed 2014-2016 Business Plan.

Yours Sincerely,

Bruce B. Campbell

c: Deputy Minister Serge Imbrogno

Enc.

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

MC-2013-2728

October 22, 2013

Mr Bruce Campbell
President and CEO
Independent Electricity System Operator (IESO)
655 Bay St, Suite 410
PO Box 1
Toronto, Ontario

Dear Mr. Campbell,

Thank you for submitting the proposed Independent Electricity System Operator's (IESO) 2014-2016 Business Plan for my review, which we received on October 1, 2013. It is my pleasure to inform you that I am satisfied with the overall direction, strategic priorities and the budget proposed for the IESO for its 2014-2016 fiscal years.

I am encouraged that the IESO has proposed a plan that shows a usage fee reduction to ratepayers and am pleased that the IESO is making efforts to maintain or reduce operating expenses and staffing levels.

The 2012-13 Public Accounts of Ontario, audited by the Auditor General of Ontario, outline that for the first year in more than a decade, the government's total spending fell from the previous year. These savings have not been easy to achieve, however, Ontario remains committed to controlling the growth in spending while protecting key public services. We expect our agencies to make the same effort.

As you are aware, the government has made commitments to ensure that there are expenditure and staffing restraints across the Ontario Public Service as well as at the various agencies across the Province. The government is leading by example and has implemented many measures to operate more efficiently, control expenses and reduce staffing levels, for example, the 2009 Ontario Budget committed to a five per cent reduction in the size of the OPS over three years.

I am asking that you continue to demonstrate prudence and realize savings that will ultimately benefit ratepayers. As you can appreciate, the interest of rate payers is the key priority for the government in the electricity sector.

...cont'd

It is my expectation that the IESO will continue to play an important role in the modernization of the power system, through delivering market efficiencies, exploring demand side management and new technology, contributing to the development and implementation of government policy, while maintaining its focus on excellence in reliable operation of the electricity grid in Ontario.

I am aware that the IESO has been making important and needed capital investments in recent years to enable renewable integration, improve market signals and renew IT infrastructure. I look forward to hearing from you the benefits that these recent capital initiatives have begun to deliver. In making future capital investments, I urge you to be mindful of the cost impacts of your activities on electricity consumers.
Also, given the importance of these investments, I would request that the IESO provide me with quarterly updates on the implementation of its key IT projects.

Therefore, in accordance with the authority granted to me under section 19.1 (2) of the *Electricity Act, 1998,* this letter constitutes my approval of the IESO 2014-2016 Business Plan.

I would like to thank you and your staff for the work that you have accomplished in the past year, and the commitment you have made in this business plan for 2014-2016.

I look forward to working with you to meet the challenges and opportunities that lie ahead.

Sincerely,

Bob Chiarelli
Minister

c: Tim O'Neill, Chair, IESO
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Serge Imbrogno, Deputy Minister, M

Methodology for Calculating the 2014 Usage Fee and Proposal for Treatment of Accumulated Surplus

Year 2014 Regulatory Approvals - IESO Usage Fee

This document explains how the IESO calculated the proposed 2014 usage fee and the forecast usage fees for 2015 and 2016. It also explains how the IESO proposes to treat the accumulated surplus.

Revenue Sources

There are three sources of revenue for 2014:

- Cost recovery for services
- Market-related Interest income
- Revenue from IESO fees

Cost Recovery for Services

The IESO will continue in its plan to recover the cost of services that are directly attributed to specific participants or clients, such as training, assessments, and services to the Ontario Power Authority on a cost recovery basis. The estimated total revenues from cost recovery in 2014 are $2.0 million.

Market-related Interest Income

According to the market rules, at the end of each year, monies which have been earned from interest on market settlement funds are applied to offset the IESO administration charge. The projected market-related interest income is $1.3 million for 2014.

Revenue from IESO Fees

The OEB-approved fee structure, which has been in effect since market opening, includes an application fee of $1,000 per application, plus a $/MWh usage fee. The revenue from application fees is expected to be negligible in 2014.

Usage Fee

This section explains how the proposed usage fee for the year 2014 is derived and it provides a projection of the anticipated usage fees for 2015 and 2016.

There are three basic steps to calculating the usage fee:

The first step is to calculate the revenues required.

Revenue Requirement Calculation for IESO Usage Fee			
($ millions)	**2014**	**2015**	**2015**
Total Costs	129.9	131.9	136.8
Less: Other Revenues			
• Cost recovery for services	2.0	2.1	2.1
• Market-related interest income	1.3	2.7	3.8
Revenue Requirement to be recovered by IESO Usage Fee	**126.6**	**127.1**	**130.9**

The second step is to estimate the charge determinant for the usage fee. The charge determinant is the total forecast AQEW (Allocated Quantity of Energy Withdrawn) plus SQEW (Scheduled Quantity of Energy Withdrawn (i.e. exports) plus generation embedded in local distribution networks, less transmission line losses:

Charge Determinant Calculation for IESO Usage Fee			
(TWh)	**2014**	**2015**	**2015**
18 Mth Outlook Demand Forecast	141.0	137.3	134.4
Less: Transmission Line Losses	(3.1)	(3.0)	(3.0)

Charge Determinant Calculation for IESO Usage Fee			
(TWh)	**2014**	**2015**	**2015**
Exports	14.0	14.4	14.3
Total Energy Volumes (net TWh)	**151.9**	**148.7**	**145.7**
Embedded Generation	5.7	7.0	7.6
Total Energy Volumes (gross TWh)	**157.6**	**155.7**	**153.3**

The third step is the rate calculation:

Year	Revenue Requirement To Be Recovered ($ million)	÷	Total Energy Volumes (gross TWh)	=	Usage Fee ($/MWh)
2014	126.6	÷	157.6	=	0.803
2015	127.1	÷	155.7	=	0.816
2016	130.9	÷	153.3	=	0.854

Implementation of 2014 usage fee

The requested usage fee for 2014 is a decrease from the Interim Usage Fee approved by the Board in EB-2011-0374. The IESO proposes to continue to charge the Interim Usage Fee ($0.822/MWh) to market participants from January 1, 2014 until the end of the month in which Board approval is received for the 2014 usage fee, and seeks authorization to charge (or rebate to) market participants the difference between the 2014 and Interim Usage Fee, if any, based on their proportionate quantity of energy withdrawn (including scheduled exports) for the year 2013. Any such charges (or rebates) will be provided to market participants in the next billing cycle following the month in which approval is received

Utilization of Deferral Account Balance

The IESO projects an accumulated surplus at the end of 2013 of $17.9 million, in excess to the $5.0 million approved for retention in past fees cases. The IESO will calculate the exact 2013 surplus and total accumulated surplus when it files supplementary information with the Board in February 2014. The IESO proposes that any funds in excess of $5 million be rebated to market participants based on their proportionate amount of energy withdrawn from the IESO controlled grid during 2013, following approval of the audited 2013 financial statements by the IESO Board of Directors.

34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

Review of IESO Fees Billing Determinant

Evidence of John Todd

President, Elenchus Research Associates Inc.

On Behalf of IESO

October 2013

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Table of Contents

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1 INTRODUCTION

The current IESO fee structure was implemented as part of the IESO's initial year 2000 fee application[1]. It is a volumetric fee charged to loads and exports in proportion to the amount of energy they withdraw from the IESO-controlled grid.

Since 2000, the Ontario electricity system and market has evolved such that increasing amounts of power are being generated and consumed in Ontario that are not subject to the IESO fee since the IESO fee applies only to energy withdrawn from the transmission grid and it does not apply to the consumption that is offset by embedded generation (i.e., generation that is directly connected to a distributor's network). The scale of embedded generation has increased significantly as a direct result of the Green Energy Act and Green Economy Act, 2009 ("GEA") initiatives which started transforming Ontario's electricity sector a decade after the current IESO fee design was implemented. While reliably managing and balancing all generation and load in the Province the IESO also considers and accounts for this embedded generation.

In light of these changes to the Ontario electricity system, the IESO has asked Elenchus to review the current IESO net-load fee structure and assess whether it continues to be appropriate, or whether the IESO's fee should be charged on the basis of gross-load.

As explained in more detail below, Elenchus recommends[2]that the billing determinant for the IESO fee be changed from net to gross billing. The gross billing approach would be implemented by using as the charge determinant for AQEW+SQEW plus the embedded generation reported by distributors to the IESO on a monthly basis.

In the remaining sections, this evidence addresses the following topics.

- The history and rationale for the current IESO fee design.
- The evolutionary changes in the Ontario electricity system and market that have occurred since 2000.

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1 RP-1999-0049.

2 This evidence has been prepared by John Todd, President of Elenchus Research Associates. His CV is available at the Elenchus website: http://www.elenchus.ca.

- The proposed alternative fee design and an analysis of the pros and cons associated with this alternative.
- Conclusions and recommendation.

2 THE CURRENT IESO FEE DESIGN

The IESO charges a volumetric fee to market participant (“MP”) loads based on the allocated quantity of energy withdrawn (AQEW) plus the scheduled quantity of exports withdrawn (SQEW) from the IESO-controlled grid. The IESO also currently charges a fixed one time application fee of $1,000.

The current fee structure was adopted as part of the IESO’s initial year 2000 fee application to the OEB and has not changed since then. This fee design was based on the recommendation of the Market Design Committee (MDC), which evaluated four fee structures using five principles:

The four fee structures that the MDC considered were:

a) Single fixed fee under which all wholesale market participants would pay a fixed annual fee;

b) Single variable fee based on all energy transacted – i.e., all wholesale market participants, both generators and loads, would pay a volumetric MWh fee on all energy transactions;

c) Single variable fee based on all energy purchased – i.e., all wholesale market participant loads would pay a volumetric MWh fee based on all energy purchases;

d) Individual fixed fee and variable fee – i.e., all wholesale market participants would pay a fixed fee to recover IESO sunk costs (which would decline over time) and a variable volumetric fee based on either all energy transactions or only purchases.

The five principles the MDC used to assess the alternate fee structures were[3]:

1. *Simplicity — The fee structure calculation methodology should be simple to understand and simple to administer. A simple fee would contribute to the smooth start-up and efficient operation of the market…. By being simple to administer, the IMO cost of billing and collecting the fee will be minimized, resulting in lower IMO operating costs.*

2. *Best Industry Practice — Having a fee structure that reflects best industry practice, the IMO operation and costs can be better benchmarked against similar organizations (the IMO in its 2000 fee application referenced the fact that its fee design was similar to other ISOs).*

3. *Fair, Equitable, Neutral and Transparent — The fee structure should be fair and equitable, i.e. not unduly discriminatory among market participants. IMO fees should be neutral in that it not provide incentives for participants to change their market behaviours. The rates and billing determinant should be transparent.*

   …

   The fee structure should be such that no undue burden is placed on one particular group of participants, as this could lead to distortions or disincentives in the market.

   …

   The market place is being established to benefit ultimately end-use customers and therefore they should pay the IMO costs, to the extent possible.

4. *Cost Reflective — The IMO fee should reflect the cost of providing the service and the level of service provided.*

   Matching cost recovery to cost causality is required for economic efficiency, fairness and practicality. Where possible and practical, the users or beneficiaries of an IMO service should pay for the cost of providing that service.

5. *Recovery IMO revenue requirement — The fees should be designed to recover its budgeted annual revenue requirement of capital and OM&A costs.*

The MDC recommended a volumetric fee charged to loads principally on the basis of simplicity, fairness and compatibility with other jurisdictions.

---

[3] IMO Application to the Ontario Energy Board, RP-1999-0049, SCHEDULE E, IMO Fee Structure Recommendation Final Report, CMO/IMO Development Technical Panel December 1998, pg 281

In its evidence in the year 2000 fees case, the IESO referenced the specific recommendations of the MDC:

> *"The reasons for recommending this fee structure are that it best meets the fee structure principles set by the Technical Panel, balanced against the tenets of economic theory as well as traditional regulated rate setting and cost recovery principles. It is simple to understand and administer, it is comparable to the fee structure of other market and system operators, and it is reasonably fair and equitable in that it charges buyers according to their usage of IMO services as measured by energy purchases.*
>
> *…*
>
> *The recommended fee structure is based on balancing all criteria and principles, with emphasis on the principles of simplicity, comparability with neighbouring jurisdictions and reasonable fairness. It is judged that these principles are more important than others, at this point in time, as they would result in a fee structure that would facilitate the market starting."*

The IESO also acknowledged in its year 2000 fees submission evidence that the proposed fee structure was an initial structure to apply during the start-up of the new market and, as recommended by the MDC, it would be reviewed as the market developed.[4]

3 THE EVOLVING ONTARIO ELECTRICITY MARKET

Since the implementation of the current fee design after the IESO's 2000 fees case, there have been fundamental changes in the Ontario electricity system and market, energy policy and IESO functions.

The IESO now is responsible not only for administering the transmission grid and the wholesale market but also for facilitating green energy policy, including incorporating significant amounts of distribution-connected embedded renewable generation[5] into the IESO's reliable operation of the provincial electricity system, which offsets the power drawn from the transmission grid.

---

[4] The MDC had recommended that such a review take place within two years of market opening.

[5] Ontario Regulation 429/04 in Part I, Interpretations and Definitions, states that "'embedded generator means a generator who is not a market participant and whose generation facility is connected to a distribution system of a licensed distributor, but does not include a generator who consumes more electricity than it generates" (section 1.(1)).

The electricity system has and is continuing to evolve from what was a highly centralized system with a heavy reliance on fossil fuels to more sustainable and complex arrangements requiring increased operational information, adaptability and coordination with an increasing number of participants. Ontario's Long Term Energy Plan[6] targets 10,700 MW of renewable generation across the distribution and transmission networks by 2018. The 2013-2015 IESO Business Plan forecasts distribution-connected wind and solar resources will total approximately 5,000 MW by early 2015. The influx of these resources and their variability has introduced significant new challenges to the planning and operation of Ontario's electricity system. The IESO has had to adapt and develop new tools and services to integrate these resources into Ontario's supply mix. For example:

- The IESO has expanded its centralized forecasting to include embedded variable generation facilities larger than 5 MW. All such facilities must now register with the IESO.
- A new centralized forecasting model has been implemented, providing both day-ahead and hour-ahead forecasts. The ability to predict output of renewable resources is required to maintain system reliability and market efficiency.
- The IESO has invested in the development and implementation of new tools and procedures to integrate variable generation resources reliably and to manage more efficiently surplus baseload generation, including new modelling capability and tools to assist operator training. The IESO has also developed and implemented new market rules, market manuals, systems, procedures and reports that will reliably and efficiently integrate variable generation into the IESO-controlled grid and the IESO-administered markets.
- The IESO has broadened its participation and involvement in the development of Ontario electricity policy, including the development of the new integrated

[6] Ontario's Long Term Energy Plan, issued 2010

regional energy planning processes, paying particular focus on operability and reliability considerations.[7]

3.1 OEB POLICY CHANGES

The changes to the Ontario electricity system and market have been accompanied by an evolution in OEB policy towards gross load billing.

In 2009, for example, the OEB amended the Retail Settlement Code ("RSC") and the Distribution System Code ("DSC") regarding the settlement and billing of generation facilities that would qualify under the "feed-in-tariff" ("FIT") program to be administered by the Ontario Power Authority. As a result, "… a load customer associated with a FIT-contracted embedded retail generator will be billed for non-competitive electricity costs and other volume-based charges, including the global adjustment, based on the customer's gross load (all of the energy consumed by the customer, regardless of whether it was provided by the embedded retail generator or withdrawn directly from the distribution system), adjusted for losses as required." The OEB Notice of Amendment includes the following comments.

> *The Board believes that the timely and efficient implementation and administration of the FIT program will be supported by billing and settlement rules that:*
>
> - *are as administratively simple as possible for distributors, generators and load customers;*
> - *provide for the uniform application of charges for all customers, regardless of connection configuration; and*
> - *avoid or defer potentially costly CIS system investments or upgrades.*
>
> *…*
>
> *"While distributors may incur incremental costs in relation to the administration of a second account, the Board anticipates that these costs will be more than off-set by the savings that are expected to result from the proposal to settle "in series" embedded retail generation configurations on a gross load billing basis.*

Notably, the Board expressed the rationale for limiting the application of gross load billing to embedded generators with FIT contracts as follows.

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[7] IESO 2014-2016 Business Plan, page 2.

> *The Board remains of the view that it is appropriate for the current rules to continue to apply to all embedded retail generation other than those that have a FIT contract. While the Board is mindful of the desire to minimize costs and administrative efforts, embedded retail generation projects that were put into place under the RESOP program were developed on the basis that settlement and billing would be effected on a net load basis. The Board does not believe that it is appropriate to change the basis for billing and settlement in mid-contract.*[8]

3.2 Two Anomalies with the Current IESO Fee Design

The evolution of the market has resulted in an increasingly significant mismatch between how the IESO calculates and collects its usage fee from MPs (i.e., based on AQEW+SQEW which is net of embedded generation[9]) and how LDC MPs calculate and collect the IESO usage fee from their customers (i.e., inclusive of embedded generation). The mismatch can be illustrated with the following example.

- If an LDC withdraws 80 MWh from the IESO grid and has 20 MWh of embedded generation, it currently pays a volumetric fee to the IESO based on its AQEW of 80 MWh, not its 100MWh of total load.
- However, the same LDC charges it customers the WMSC (an OEB approved regulatory charge which includes the IESO's usage fee) in respect of its 100 MWh of total load.

Prior to the introduction of the Green Energy Act initiatives, the discrepancy was minor since the amount of embedded generation was minimal. However, as the result of RESOP, FIT, MicroFIT, etc., embedded generation has increased and is expected to increase further.

The effect of this change is that non-LDC market participants and LDCs with comparatively small amounts of embedded generation are increasingly paying a comparatively larger share of the IESO usage fee vis-à-vis the customers of LDCs with comparatively larger amounts of embedded generation.

---

[8] OEB Notice of Amendment to a Code – Amendments to the Retail Settlement Code and the Distribution System Code – Board File No: EB-2009-0303.

[9] AQEW is the Allocated Quantity of Energy Withdrawn. SQEW is the Scheduled Quantity of Energy Withdrawn ("SQEW") for export (i.e., scheduled exports).

This inconsistency gives rise to anomalies and inequities in the effective IESO usage rate paid by customers in different circumstances. Two specific anomalies are illustrated in the following sections.

3.2.1 Embedded Generation Gives Rise to a Discounted IESO Usage Fee

As alluded to above, one anomalous consequence of the continued use of net load billing for the IESO fee is that the effective fee paid by distribution customers depends on the scale of embedded generation within their respective distributor's service territories. A simple example illustrates this anomaly. Consider a hypothetical distributor that has a load in a particular month of 10 GWh and in that month there is embedded generation of 2 GWh; hence, the net load is 8 GWh. The effective IESO volumetric fee can be calculated as follows:

Effective IESO fee = nominal IESO fee x (net load/gross load)

Hence, in this example

Effective IESO fee = $0.822 /MWh x (8/10) = $0.6576 /MWh

The presence of embedded generation reduces the effective IESO volumetric fee that is born the by end-use customers. The larger the proportion of embedded generation relative to a distributor's gross load, the lower the effective fee borne by customers.

This anomaly is a consequence of the method used to collect the IESO usage fee, which involves a charge to the LDC and a pass-through mechanism that is used to recover the charge from each LDC MP's end use customers. The specific steps are as follows.

- First, the distributor pays the volumetric fee to the IESO based on the net load which, in the example above, is 20% less than the gross load.
- Second, in the same period, the distributor collects the IESO fee, which is embedded in the WMSC, from its customers based on the gross load, adjusted for losses. As a result, the amount collected from customers equals the amount

that the LDC would be required to remit to the IESO if it had no embedded generation.[10]

- Third, the amounts paid to the IESO and collected from customers are each recorded in account 1580 ($RVSA_{WMS}$).
- Fourth when overpayments in account 1580 ($RVSA_{WMS}$) are disposed of to the distributor's customers, which is done through a rate rider, this results in an effective IESO usage fee that is less than the nominal fee.

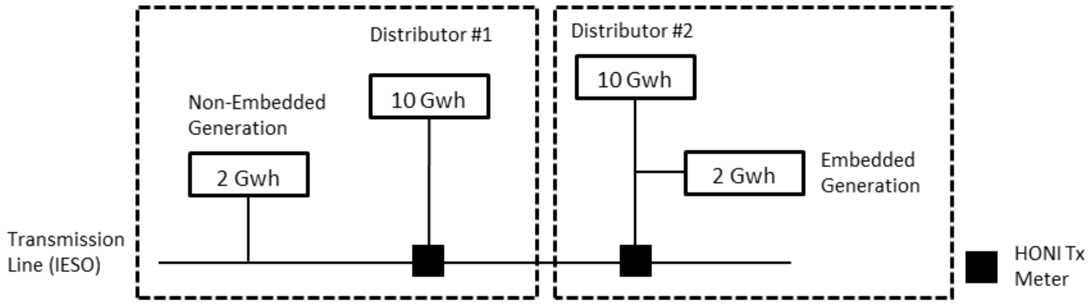
Therefore, the customers of any distributor that does not have embedded generation will pay an effective IESO fee that is equal to the full fee, i.e.,$0.822/kWh, whereas customers of distributors with embedded generation will pay less than that amount. There is no obvious reason why customers being served by distributors with embedded generation should enjoy a discount on the IESO fee, with the discount being proportional to the quantity of embedded generation relative to the gross load.

3.2.2 Only Distribution-Connected Embedded Generation Results in the Discount

The second related anomaly of net load billing for the IESO fee is that renewable generation within a distributor's service territory will reduce the effective fee paid by the distribution customers if it is connected to the distribution system (i.e. embedded), but it will not reduce the effective fee if the same generation facility is directly connected to the transmission grid. The schematic diagram on the next page (Figure 1) illustrates this point.

[10] In fact, there will be a slight variance that arises because the amount of the fee included in the WMSC is adjusted on the basis of the average provincial loss factor, which will not equal the actual loss factors of the individual LDCs.

Figure 1: IESO Fees, Embedded vs. Transmission Connected Generation



Billed Currently (AQEW)	10 Gwh @ $822	10 Gwh – 2 Gwh @ $822

The diagram shows two distributors with identical customer loads equal to 10 GWh. Each distributor has a renewable generation development within its service territory that generates 2 GWh in the month. The renewable generation in the service territory of Distributor #1 is directly connected to the transmission grid (i.e., upstream of the Hydro One Transmission meter) while the equivalent facility in Distributor #2's territory is connected to the distribution network (i.e., downstream of the Hydro One Transmission meter). Hence, the AQEW of Distributor #1 is 10 GWh while the AQEW of Distributor #2 is 8 GWh.

Assuming the current IESO fee of $0.822 per MWh is applicable, the variable IESO charge payable by each of these distributors would be:

Distributor #1 Fees = \$0.822 x 10×10^3 = \$8,220

Distributor #2 Fees = \$0.822 x 8×10^3 = \$6,576

If the IESO fee were based on AQEW plus embedded generation rather than the net load (only AQEW) the fees payable by the two distributors would be identical (i.e., $8,220). Furthermore, it may be noted that each distributor would collect $8,220 from its customers through the WMSC. However, distributor #2 has a net addition to the balance in account 1580 ($RVSA_{WMS}$) of $1,644 that is attributable to this difference between gross and net billing. This amount would be refunded to customers at some time in the future when the account is cleared.

4 UPDATING THE CHARGE DETERMINANT

4.1 PROPOSED CHANGE TO THE CHARGE DETERMINANT

Elenchus proposes, for the reasons set out below, that the current charge determinant for the IESO fee, which is AQEW+SQEW, be replaced by AQEW+SQEW plus embedded generation.

It should be noted that since the change from net to gross billing would be revenue neutral and the recovery of the IESO revenue requirement would be based on a larger quantity (i.e., 20 GWh in total instead of the 18 GWh for the two distributors in the example presented above), the change in the billing determinant will result in a reduction in the nominal IESO usage fee. An estimate of the impact of the proposed change on the rate is presented in Appendix A.

4.2 ASSESSMENT OF STATUS QUO VS. REVISED CHARGE DETERMINANT

The five principles that were originally used by the MDC to assess fee design alternatives can also be used to assess the proposed change in the billing determinant from net to gross:

> 1. *Simplicity — The fee structure calculation methodology should be simple to understand and simple to administer. A simple fee would contribute to the smooth start-up and efficient operation of the market…. By being simple to administer, the IMO cost of billing and collecting the fee will be minimized, resulting in lower IMO operating costs.*
>
> *One important aspect of the IMO fee that drives simplicity is materiality. The future electricity market will be seeking to generate and recover approximately $8 billion in revenues through various charges and payments … The IMO revenue requirement will be in the order of $IOO million/year, i.e. -1.25% of the total market revenue. Recovery of such a small proportion of the total market revenue would not justify a complex fee structure and calculation methodology*

From the perspective of simplicity, a change to gross billing would be an improvement since the above-noted anomalies would be eliminated.

Furthermore, since the information required to implement the change from net to gross billing is currently being provided by LDC MPs to the IESO in accordance with Ontario Regulation 429/04 under the Electricity Act, 1998, s. 20 (2), no incremental effort would be required to implement gross billing for the IESO usage fee. In addition, s. 21 of that regulation directs the IESO to “rely on the information provided to it by licensed distributors.”

> 2. *Best Industry Practice — Having a fee structure that reflects best industry practice, the IMO operation and costs can be better benchmarked against similar organizations (the IMO in its 2000 fee application referenced the fact that its fee design was similar to other ISOs).*

Ontario is at the leading edge of increasing the significance of embedded renewable generation in its electricity system and market. It is premature to identify best practices based on the approaches adopted in other jurisdictions. Rather, it is appropriate to evaluate compliance with best practices based on the approach that is appropriate given the jurisdiction-specific circumstances. For the reasons outlined in this report, it is the view of Elenchus that using gross load as the charge determinant should be considered the “best industry practice” in cases where there is significant embedded generation.

> 3. *Fair, Equitable, Neutral and Transparent — The fee structure should be fair and equitable, i.e. not unduly discriminatory among market participants. IMO fees should be neutral in that it not provide incentives for participants to change their market behaviours. The rates and billing determinant should be transparent.*
>
> …
>
> *The fee structure should be such that no undue burden is placed on one particular group of participants, as this could lead to distortions or disincentives in the market.*
>
> …
>
> *The market place is being established to benefit ultimately end-use customers and therefore they should pay the IMO costs, to the extent possible.*

The IESO is responsible for reliably managing and balancing the total generation and load in the province, taking into account renewable generation that is reported to it, whether it is transmission connected or distribution connected. The proposed approach attributes cost responsibility in a manner that is more reflective of cost causality. This approach is more equitable, neutral and transparent than basing the charge on net load. It does not discriminate amongst customers by charging them a different IESO rate that depends upon the amount of distribution-connected embedded generation in their distributor's service area.

Since the change from net to gross billing is revenue neutral, it will have no impact on the average level of the effective IESO administrative charge. The only effect will be to standardize the charge so that all customers will pay the same effective IESO usage rate regardless of the amount of embedded generation in their LDC's service area. Charging customers the same effective rate will result in more equitable treatment of consumers.

> 4. *Cost Reflective — The IMO fee should reflect the cost of providing the service and the level of service provided. Matching cost recovery to cost causality is required for economic efficiency, fairness and practicality. Where possible and practical, the users or beneficiaries of an IMO service should pay for the cost of providing that service.*

The proposed approach matches cost recovery and cost causality more closely for the reasons noted above since there is no distinguishable difference between the IESO costs caused by customers served by distributors with embedded generation as compared to those without embedded generation.

Looking at this principle from a cost causality perspective, there is no obvious reason that the causal cost associated with loads depend on whether there is embedded generation in the service area of the distributor serving the load. On the contrary, while there are differences in the costs caused by embedded generation, an approach that accommodates effective rates that vary with the relative amount of embedded generation would appear to be inequitable and perhaps discriminatory. Put differently, charging different effective IESO usage rates to different end-use customer amounts to a cross-subsidy of customers in service areas with more than the average proportion of embedded generation, by customers in service areas with less than the average proportion of embedded generation.

5. *Recovery IMO revenue requirement — The fees should be designed to recover its budgeted annual revenue requirement of capital and OM&A costs.*

This principle is not significantly affected by the option used to recover the IESO revenue requirement. There may be a minor benefit, however, in that the lower fee would tend to reduce the impact on the IESO's recovery of its revenue requirement due to variances in demand.

4.3 OTHER CONSIDERATIONS

4.3.1 COST TO IMPLEMENT ADMINISTRATIVE CHANGES

A relevant consideration in evaluating the proposed change to the charge determinant is the cost that will be incurred by the IESO and other parties in implementing the change. There are potential costs for the IESO's billing process, the systems and processes of LDCs and, potentially, costs associated with changes to the market rules. Potential cost implications for each of these administrative process are addressed below

4.3.1.1 COSTS ASSOCIATED WITH CHANGES IN THE IESO BILLING PROCESSES

The IESO has reviewed the changes that will be required to issue bills to market participants based on total load, including embedded generation. Elenchus has been advised that there will be no external costs incurred to adapt the IESO's billing system. The required changes will be implemented by IESO staff and the costs to do this will be minimal.

4.3.1.2 COSTS ASSOCIATED WITH CHANGES IN LDC SYSTEMS AND PROCESSES

From the perspective of distributors, there will be no changes in their administrative or billing processes. A reduction in the IESO Administration Fee will result in a corresponding reduction in the WMSC, but other than the rate change there will be no administrative implications.

Nevertheless, it is worth noting that the proposed change will reduce the over-collection of the IESO Administration Fee by distributors with embedded generation; hence, there will be a reduction in the excess amounts that will have to be rebated to customers on a periodic basis. This will not have an implication for administrative costs since account 1580 ($RVSA_{WMS}$) will likely still have balances to dispose of; however, there will be a positive change that will tend to reduce the balances accumulating in this deferral account, all other things being equal.

4.3.1.3 Costs Related to Market Rule Changes

Elenchus has been advised that the IESO has examined the need for market rule changes if the billing determinant for the IESO fee is changed from net to gross billing and has determined that no market rule changes will be required.

4.3.2 Materiality

LDC-specific impacts will correspond to the amount of embedded generation in their service area and LDCs with above-average embedded generation will experience an increase in the amount of the IESO fee they remit and will no longer over-collect the IESO fee from their customers. Their customers will no longer receive a lower effective IESO fee due to the over-collection being returned through a rate rider.

As an indication of the materiality of the impact of the proposed change, it may be noted that the LDC with the largest proportion of embedded generation will remit $111,493 annually, or 19%, more to the IESO as a result of the change from net to gross billing. This increased payment will increase the LDC's revenue requirement and, as is shown in Appendix A, the resulting average bill impact will be 0.135%. Customers of all other LDCs will be experience bill impacts that are at most about one-half of these impacts. Since the proposed change is revenue neutral across the Province as a whole, the province-wide net bill impact will be zero.

Based on these estimates, it seems reasonable to conclude that the proposed change to the IESO fee design will have an immaterial effect on customer bills.

4.3.3 INTERGENERATIONAL EQUITY

Though relatively immaterial, the change will have a beneficial impact in terms of intergenerational equity. As noted above, one of the effects of net billing is that all LDCs with embedded generation over-collect the IESO Administrative Fee from their customers, with the excess being tracked in account 1580 ($RVSA_{WMS}$). While the over-collection is refunded to customers when the account is cleared the refund could be delayed several years until the balance is large enough to warrant disposition. Given the mismatch between when an LDC's customers overpay the fee and when that LDC pays the corresponding refund to its customers, there is a degree of intergenerational inequity that will result.

Changing to gross billing will eliminate this intergenerational inequity.

4.3.4 NET LOAD BILLING IS USED FOR TRANSMISSION SERVICE

The current IESO fee design corresponds to the basis for charging for transmission service, which utilizes net load billing. As a result, customers with embedded generation do not pay for transmission service they do not use. This approach would appear to be appropriate with respect to transmission service from a cost causality perspective since it is clear that embedded generation does not utilize the transmission grid. In fact, development of embedded generation can serve as a substitute for increasing the capacity of the transmission network. It follows that net load billing is appropriate for transmission service both from a cost causality perspective and from a price signalling perspective.

In contrast, the IESO is responsible for administering all generation connected to either the transmission network or a distributor's network. For example, the IESO's responsibilities in relation to embedded generation are woven through Ontario Regulation 429/04. In addition, the IESO's load balancing responsibilities must take into account embedded generation. For these reasons, it is appropriate and equitable to bill for transmission services on the basis of net load while charging the IESO usage fee on the basis of gross load.

4.3.5 Hydro One Remotes Exemption

Hydro One Remotes does not charge the WMSC or its component parts to its customers. The communities Hydro One Remotes serves are disconnected from the transmission grid and are not part of the IESO administered market. It therefore follows that it would be appropriate to continue to exempt Hydro One Remotes from the IESO fee as it would be inequitable to recover costs from customers that are not connected to the transmission network.

5 Conclusion and Recommendation

It is recommended that the billing determinant for the IESO fee be changed from net to gross billing. The gross billing approach would be implemented by using as the charge determinant for AQEW+SQEW plus the embedded generation reported by distributors to the IESO on a monthly basis.

The recommended approach would be more equitable in that all customers would then pay the same effective rate for the IESO administration fee, regardless of the proportion of embedded generation within the service territory of their distributor. While the dollar value of the existing inequity is relatively small, the cost of correcting the inequity is immaterial; hence, cost is not an impediment to adopting the change.

The proposed change in the billing determinant is independent of the changes in the IESO's revenue requirement and volume forecast; hence it is revenue neutral for both electricity consumers and LDCs. From the perspective of the IESO, the impact of the proposed change in the billing determinant is that there will be a lower charge that is applied to a larger volume with the total revenue being unchanged. From the LDCs perspective, they will recover from customers only the amount remitted for the IESO Administration Fee; hence, the variances between the amount paid to the IESO and the amount collected from customers will be reduced. As a result, the amounts flowing into account 1580 ($RVSA_{WMS}$) related to an over-collection of the fee will be reduced.

The only stakeholders financially impacted by the proposed change will be the end-use customers who will all pay the same effective kWh-based fee if the change is implemented, rather than paying an effective rate that is affected by the amount of embedded generation in their LDC's service area. The average effective fee paid by customers will not change, although customers served by LDCs with above average embedded generation as a percentage of load will experience a slight increase in the effective fee they pay since they currently pay less than the average fee, while those served by LDCs with comparatively less embedded generation will pay a slightly lower effective rate, since they are currently paying an above average effective rate.

APPENDIX A

Table 1

Shows the 2012 reported Embedded Generation; the Net Billed Energy (Withdrawals) and calculates Embedded Generation over Net Billed Energy. LDC's are ranked highest impact to lowest impact to show determine bill impact.

Table 2

Compares the 2012 IESO revenue that is generated using the current methodology; Net Billed Energy (Withdrawals) times the current rate of $0.822/MWh versus revenue generated by using the proposed methodology; Gross Billed Energy (Withdrawals plus Embedded Generation) times a calculated revenue neutral rate of $0.800/MWh. This highlights the potential annual impact by LDC.

Table 3

Calculates the potential annual bill impact for the highest ranking LDC. Compares the expected increase over reported 2012 gross revenue reported by the LDC. This indicates that he average customer will experience an increase of $0.13 per $100 billed.

Table 4

Illustrates the potential monthly bill impact for an average Residential Customer consuming 800 kWh. The highest ranking LDC customer may experience an increase of $0.10 per month.

Ranking by Impact	Embedded Generation (MWh) A	Withdrawals (MWh) B	EG % of Withdrawals C = A / B
1	158,811	713,173	22.27%
2	79,625	629,433	12.65%
3	2,334,345	22,600,137	10.33%
4	17,430	175,015	9.96%
5	33,454	419,699	7.97%
6	36,206	467,829	7.74%
7	43,681	805,182	5.42%
8	43,739	942,187	4.64%
9	13,683	364,776	3.75%
10	21,525	942,392	2.28%
11	686	32,573	2.11%
12	37,395	1,850,077	2.02%
13	93,866	4,825,258	1.95%
14	15,177	839,700	1.81%
15	124,576	7,248,379	1.72%
16	1,364	81,718	1.67%
17	46,457	3,289,854	1.41%
18	8,453	739,881	1.14%
19	12,262	1,255,808	0.98%
20	1,401	154,927	0.90%
21	5,877	803,740	0.73%
22	1,220	243,833	0.50%
23	1,098	245,148	0.45%
24	1,722	390,958	0.44%
25	94	24,288	0.39%
26	5,229	1,493,910	0.35%
27	27,203	7,811,899	0.35%
28	1,685	512,071	0.33%
29	619	193,234	0.32%
30	7,768	2,446,680	0.32%
31	912	296,437	0.31%
32	11,371	4,016,035	0.28%
33	215	80,138	0.27%
34	23,409	8,751,038	0.27%
35	806	319,895	0.25%
36	2,751	1,133,461	0.24%
37	3,952	1,728,610	0.23%
38	686	318,346	0.22%
39	1,308	608,687	0.21%
40	2,974	1,492,376	0.20%
41	1,760	914,896	0.19%
42	300	207,865	0.14%
43	251	191,605	0.13%
44	169	129,470	0.13%
45	13	10,347	0.13%
46	135	108,286	0.12%
47	622	521,317	0.12%
48	846	734,583	0.12%
49	115	108,386	0.11%
50	2,312	2,306,269	0.10%
51	115	125,926	0.09%
52	160	187,879	0.09%
53	225	264,234	0.09%
54	20,862	25,443,539	0.08%
55	365	459,816	0.08%
56	171	221,270	0.08%
57	308	420,560	0.07%
58	149	255,447	0.06%
59	65	115,216	0.06%
60	156	300,526	0.05%
61	291	647,567	0.04%
62	33	84,211	0.04%
63	45	118,611	0.04%
64	71	214,270	0.03%
65	188	568,055	0.03%
66	439	1,702,581	0.03%
67	244	1,589,423	0.02%
68		277,908	0.00%
68		81,689	0.00%
68		28,011	0.00%
68		13,733	0.00%
68		12,833	0.00%
68		9,320	0.00%

Table 1

Ranking by Impact	**Current Charge** (Withdrawls * $0.822/MWh) D = B * $0.822	**Proposed Charge** (Embedded + Withdrawls * @ Proposed Rate/MWh) E = (A + B) * $0.800	Change in Charge to LDC from Current to Proposed F = E - D	Change in % collected G = E / D
1	$586,228	$697,722	$111,493	119.0%
2	$517,394	$567,357	$49,962	109.7%
3	$18,577,313	$19,951,442	$1,374,129	107.4%
4	$143,863	$153,986	$10,124	107.0%
5	$344,992	$362,592	$17,600	105.1%
6	$384,555	$403,305	$18,750	104.9%
7	$661,860	$679,222	$17,362	102.6%
8	$774,478	$788,894	$14,416	101.9%
9	$299,846	$302,826	$2,980	101.0%
10	$774,646	$771,282	-$3,364	99.6%
11	$26,775	$26,613	-$162	99.4%
12	$1,520,764	$1,510,270	-$10,494	99.3%
13	$3,966,362	$3,936,060	-$30,302	99.2%
14	$690,234	$684,034	-$6,199	99.1%
15	$5,958,168	$5,899,505	-$58,663	99.0%
16	$67,172	$66,479	-$693	99.0%
17	$2,704,260	$2,669,564	-$34,695	98.7%
18	$608,183	$598,783	-$9,399	98.5%
19	$1,032,274	$1,014,652	-$17,622	98.3%
20	$127,350	$125,086	-$2,264	98.2%
21	$660,674	$647,819	-$12,855	98.1%
22	$200,431	$196,081	-$4,350	97.8%
23	$201,512	$197,035	-$4,477	97.8%
24	$321,368	$314,205	-$7,163	97.8%
25	$19,965	$19,509	-$456	97.7%
26	$1,227,994	$1,199,543	-$28,451	97.7%
27	$6,421,381	$6,272,494	-$148,887	97.7%
28	$420,922	$411,084	-$9,838	97.7%
29	$158,839	$155,113	-$3,726	97.7%
30	$2,011,171	$1,963,938	-$47,233	97.7%
31	$243,671	$237,925	-$5,746	97.6%
32	$3,301,181	$3,222,548	-$78,633	97.6%
33	$65,874	$64,295	-$1,579	97.6%
34	$7,193,353	$7,020,915	-$172,438	97.6%
35	$262,954	$256,610	-$6,344	97.6%
36	$931,705	$909,145	-$22,560	97.6%
37	$1,420,917	$1,386,317	-$34,600	97.6%
38	$261,681	$255,275	-$6,406	97.6%
39	$500,340	$488,090	-$12,250	97.6%
40	$1,226,733	$1,196,511	-$30,222	97.5%
41	$752,045	$733,467	-$18,578	97.5%
42	$170,865	$166,564	-$4,301	97.5%
43	$157,499	$153,515	-$3,985	97.5%
44	$106,424	$103,731	-$2,693	97.5%
45	$8,505	$8,290	-$216	97.5%
46	$89,011	$86,753	-$2,257	97.5%
47	$428,522	$417,631	-$10,891	97.5%
48	$603,827	$588,457	-$15,371	97.5%
49	$89,093	$86,817	-$2,276	97.4%
50	$1,895,753	$1,847,222	-$48,531	97.4%
51	$103,511	$100,852	-$2,659	97.4%
52	$154,437	$150,461	-$3,976	97.4%
53	$217,200	$211,608	-$5,592	97.4%
54	$20,914,589	$20,375,459	-$539,130	97.4%
55	$377,969	$368,216	-$9,753	97.4%
56	$181,884	$177,187	-$4,697	97.4%
57	$345,701	$336,760	-$8,941	97.4%
58	$209,978	$204,517	-$5,461	97.4%
59	$94,708	$92,243	-$2,465	97.4%
60	$247,032	$240,592	-$6,440	97.4%
61	$532,300	$518,387	-$13,913	97.4%
62	$69,222	$67,408	-$1,813	97.4%
63	$97,499	$94,944	-$2,555	97.4%
64	$176,130	$171,506	-$4,624	97.4%
65	$466,941	$454,682	-$12,259	97.4%
66	$1,399,522	$1,362,679	-$36,842	97.4%
67	$1,306,506	$1,271,980	-$34,526	97.4%
68	$228,441	$228,441		
68	$67,148	$67,148		
68	$23,025	$23,025		
68	$11,288	$11,288		
68	$10,549	$10,549		
68	$7,661	$7,661		
	$98,364,165	$98,364,165	$0	

Table 2

Impact OF IESO change in Fee Calculation

Ranking by Impact # 1

2012 Revenue (per OEB 2012 Electricity Year Book)	$82,276,247
Change in IESO Fee	$111,493
Increase in Average Total Bill	0.1353%

Table 3

	Impact on Average Residential Customer Monthly Bill								
Ranking by Impact	Billed kWh H	Current IESO Rate I	Current Billed Amount J = H * I	EG Adjustment K = 1 + C	Effective Rate due to Embed Gen L = I / K	Effective Amount Charged M = H * L	Proposed IESO Rate N	Future Billed Amount O = H * N	Change P = O - M
1	800	$0.000822	$0.66	122.27%	$0.000672	$0.54	$0.000800	$0.64	$0.10
2	800	$0.000822	$0.66	112.65%	$0.000730	$0.58	$0.000800	$0.64	$0.06
3	800	$0.000822	$0.66	110.33%	$0.000745	$0.60	$0.000800	$0.64	$0.04
4	800	$0.000822	$0.66	109.96%	$0.000748	$0.60	$0.000800	$0.64	$0.04
5	800	$0.000822	$0.66	107.97%	$0.000761	$0.61	$0.000800	$0.64	$0.03
6	800	$0.000822	$0.66	107.74%	$0.000763	$0.61	$0.000800	$0.64	$0.03
7	800	$0.000822	$0.66	105.42%	$0.000780	$0.62	$0.000800	$0.64	$0.02
8	800	$0.000822	$0.66	104.64%	$0.000786	$0.63	$0.000800	$0.64	$0.01
9	800	$0.000822	$0.66	103.75%	$0.000792	$0.63	$0.000800	$0.64	$0.01
10	800	$0.000822	$0.66	102.28%	$0.000804	$0.64	$0.000800	$0.64	-$0.00
11	800	$0.000822	$0.66	102.11%	$0.000805	$0.64	$0.000800	$0.64	-$0.00
12	800	$0.000822	$0.66	102.02%	$0.000806	$0.64	$0.000800	$0.64	-$0.00
13	800	$0.000822	$0.66	101.95%	$0.000806	$0.65	$0.000800	$0.64	-$0.00
14	800	$0.000822	$0.66	101.81%	$0.000807	$0.65	$0.000800	$0.64	-$0.01
15	800	$0.000822	$0.66	101.72%	$0.000808	$0.65	$0.000800	$0.64	-$0.01
16	800	$0.000822	$0.66	101.67%	$0.000809	$0.65	$0.000800	$0.64	-$0.01
17	800	$0.000822	$0.66	101.41%	$0.000811	$0.65	$0.000800	$0.64	-$0.01
18	800	$0.000822	$0.66	101.14%	$0.000813	$0.65	$0.000800	$0.64	-$0.01
19	800	$0.000822	$0.66	100.98%	$0.000814	$0.65	$0.000800	$0.64	-$0.01
20	800	$0.000822	$0.66	100.90%	$0.000815	$0.65	$0.000800	$0.64	-$0.01
21	800	$0.000822	$0.66	100.73%	$0.000816	$0.65	$0.000800	$0.64	-$0.01
22	800	$0.000822	$0.66	100.50%	$0.000818	$0.65	$0.000800	$0.64	-$0.01
23	800	$0.000822	$0.66	100.45%	$0.000818	$0.65	$0.000800	$0.64	-$0.01
24	800	$0.000822	$0.66	100.44%	$0.000818	$0.65	$0.000800	$0.64	-$0.01
25	800	$0.000822	$0.66	100.39%	$0.000819	$0.66	$0.000800	$0.64	-$0.01
26	800	$0.000822	$0.66	100.35%	$0.000819	$0.66	$0.000800	$0.64	-$0.02
27	800	$0.000822	$0.66	100.35%	$0.000819	$0.66	$0.000800	$0.64	-$0.02
28	800	$0.000822	$0.66	100.33%	$0.000819	$0.66	$0.000800	$0.64	-$0.02
29	800	$0.000822	$0.66	100.32%	$0.000819	$0.66	$0.000800	$0.64	-$0.02
30	800	$0.000822	$0.66	100.32%	$0.000819	$0.66	$0.000800	$0.64	-$0.02
31	800	$0.000822	$0.66	100.31%	$0.000819	$0.66	$0.000800	$0.64	-$0.02
32	800	$0.000822	$0.66	100.28%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
33	800	$0.000822	$0.66	100.27%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
34	800	$0.000822	$0.66	100.27%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
35	800	$0.000822	$0.66	100.25%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
36	800	$0.000822	$0.66	100.24%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
37	800	$0.000822	$0.66	100.23%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
38	800	$0.000822	$0.66	100.22%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
39	800	$0.000822	$0.66	100.21%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
40	800	$0.000822	$0.66	100.20%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
41	800	$0.000822	$0.66	100.19%	$0.000820	$0.66	$0.000800	$0.64	-$0.02
42	800	$0.000822	$0.66	100.14%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
43	800	$0.000822	$0.66	100.13%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
44	800	$0.000822	$0.66	100.13%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
45	800	$0.000822	$0.66	100.13%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
46	800	$0.000822	$0.66	100.12%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
47	800	$0.000822	$0.66	100.12%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
48	800	$0.000822	$0.66	100.12%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
49	800	$0.000822	$0.66	100.11%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
50	800	$0.000822	$0.66	100.10%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
51	800	$0.000822	$0.66	100.09%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
52	800	$0.000822	$0.66	100.09%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
53	800	$0.000822	$0.66	100.09%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
54	800	$0.000822	$0.66	100.08%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
55	800	$0.000822	$0.66	100.08%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
56	800	$0.000822	$0.66	100.08%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
57	800	$0.000822	$0.66	100.07%	$0.000821	$0.66	$0.000800	$0.64	-$0.02
58	800	$0.000822	$0.66	100.06%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
59	800	$0.000822	$0.66	100.06%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
60	800	$0.000822	$0.66	100.05%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
61	800	$0.000822	$0.66	100.04%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
62	800	$0.000822	$0.66	100.04%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
63	800	$0.000822	$0.66	100.04%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
64	800	$0.000822	$0.66	100.03%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
65	800	$0.000822	$0.66	100.03%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
66	800	$0.000822	$0.66	100.03%	$0.000822	$0.66	$0.000800	$0.64	-$0.02
67	800	$0.000822	$0.66	100.02%	$0.000822	$0.66	$0.000800	$0.64	-$0.02

Table 4