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Nuclear Staffing Benchmarking Analysis

A Report For:

ONTARIO POWER GENERATION

February 3, 2012

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FINAL REPORT

Report Agenda – *Executive Summary*

- *Executive Summary*
- Objectives
- Approach
- Establishing Benchmarks
- Findings
- Appendices

Tasking And OPG Employee Counts

- **Goodnight Consulting was tasked with:**
  - **Benchmarking OPG nuclear staffing levels against other North American nuclear operators**
  - **Identifying significant differences in staffing levels from the benchmarks**
  - **Analyzing the nature of the differences**
  - **Reviewing and commenting on the direction of the current business plan as it relates to nuclear staffing levels**
- **5,574 OPG employees were included in the study (as of July 2011) consisting of: 2,176 at Pickering, 1,352 at Darlington, and 1,858 Nuclear Support and 188 Dedicated Corporate Support**
- **2,101 OPG Employees in the following groups were excluded from benchmarking (see pgs. 14-16 for more detail)**

Group	Total FTEs
CANDU-Specific	1,031
OPG-Specific	285
Generic	732
Other	53
Total	**2101**

Contractor And Benchmark Counts

- **OPG's total contractor spend was assessed, and 382 additional FTEs were identified for a total functional staffing count of 5,956**
- **OPG's employee staffing and contractor support for the nuclear program were analyzed and adjusted to align with available benchmark data**
- **An OPG CANDU benchmark was developed totaling 5,090 FTES based on large (>800 Mwe) Pressurized Water Reactors**
- **CANDU vs. PWR differences are also addressed in derivation of OPG Nuclear Staffing to be benchmarked (see slides 14-16)**
- **OPG staffing levels were compared to the industry benchmark data on a functional and process area basis, and gaps were identified**

Benchmarking Summary: Total OPG Nuclear Benchmark is 5,090

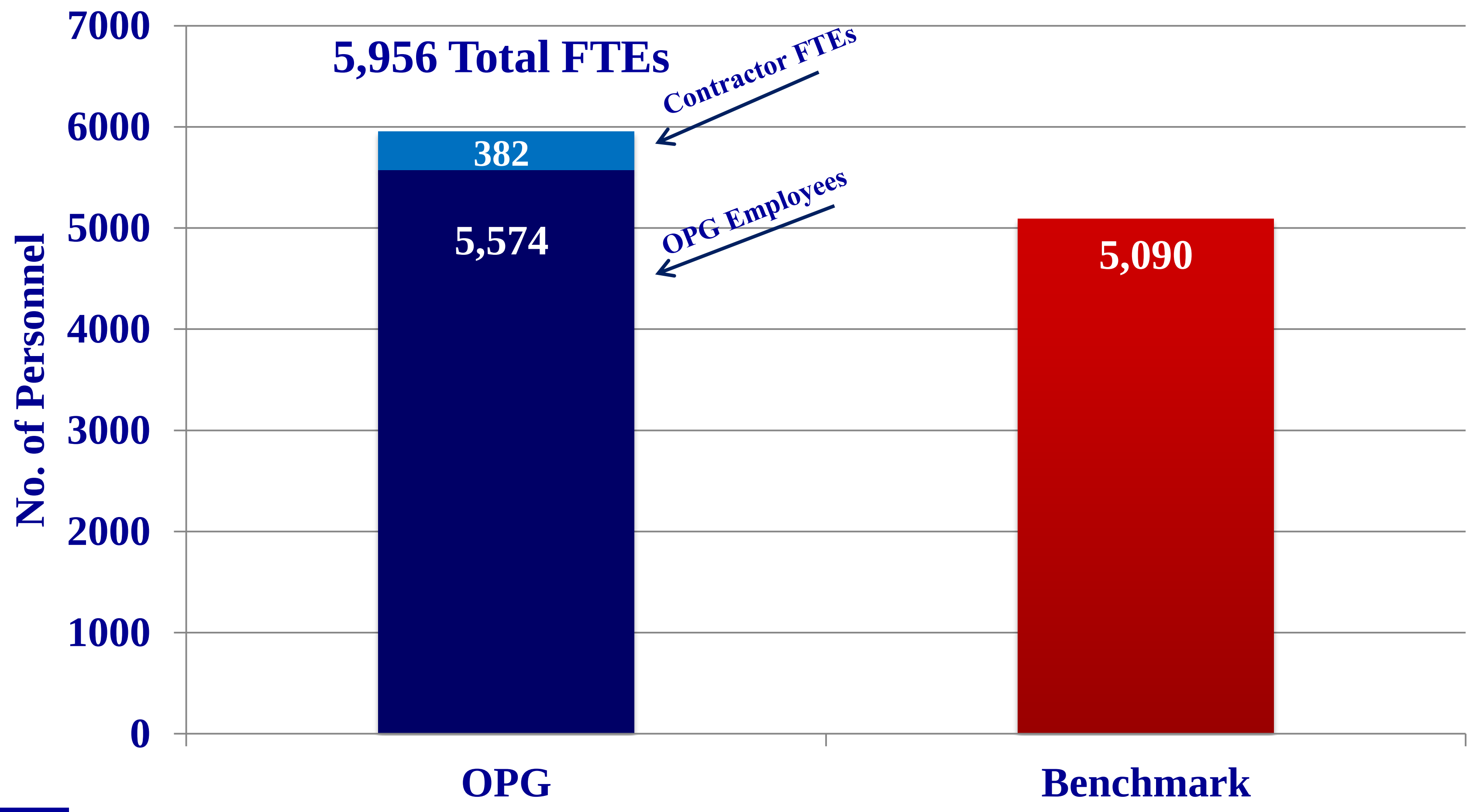
- A benchmark of 965 was derived from Large 2-Unit US PWR staffing
- Adjustments were applied for:
  - Net differences in CANDU vs. PWR technologies[1]
  - OPG work week differences
  - Workload requirements for Units 2 & 3 at Pickering A[2]
- Scaling factors were applied to identify 4-Unit CANDU benchmarks
- These benchmarks include contractor FTEs and corporate nuclear support

	2-Unit PWR	PA	PB	DN	Total
2-Unit U.S. PWR Benchmarks	965				
Adjustment for 2-Unit CANDU	82				
Preliminary 2-Unit CANDU Benchmark	1,047	1,047	1,047	1,047	
Adjustment for 35 Hour Week		58	58	58	
Adjustment for Pickering A Units 2 & 3		17			
Adjustment for Scaling 2 to 4-Units			879	879	
Total		1,122	1,984	1,984	5,090

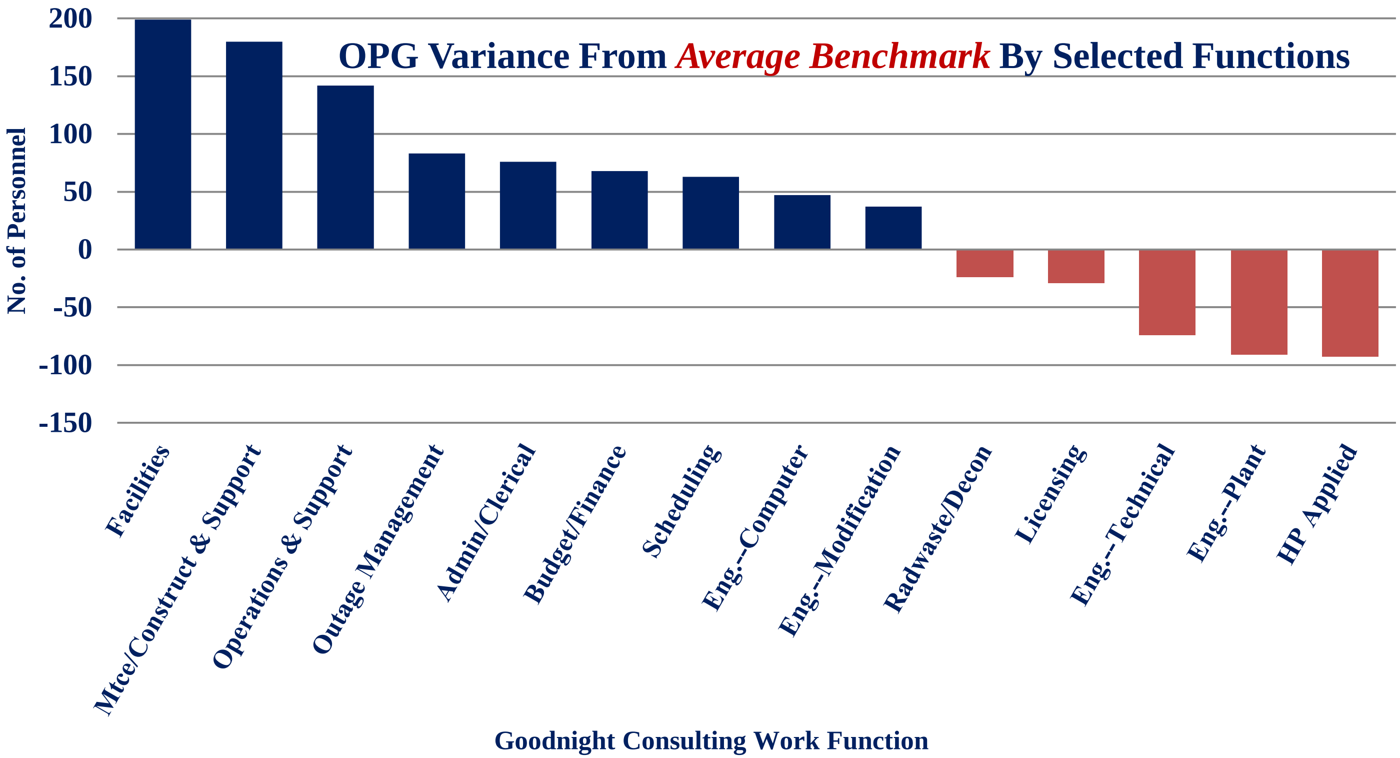
[1]CANDU vs. PWR differences also addressed in derivation of OPG Nuclear Staffing to be benchmarked (see slides 14-16)
[2]Maintenance of common facilities with the two shutdown units

FINAL REPORT February 3, 2012

OPG Staffing, Including Contractor FTEs Is 866 Above the Benchmark



Total Staffing: 23 Functional Areas Are Staffed Above the *Average Benchmark*, 14 are Below



All Functions by Variance	
Maint/Construct Support	251
Facilities	199
Operations Support	189
Outage Management	83
Admin/Clerical	76
Budget/Finance	68
Scheduling	63
Contracts/Purchasing	60
Warehouse	51
Project Management	50
Eng.--Computer	47
Management	41
Eng.--Modification	39
Training	28
Human Resources	23
Materials Management	21
Eng.--Procurement	19
QC/NDE	17
Management Assist	13
Safety/Health	12
QA	7
Document Control	3
Eng.--Reactor	1
Design/Drafting	0
Communications	0
Chemistry	0
Fire Protection	-1
Environmental	-6
Nuclear Fuels	-15
Nuclear Safety Review	-17
ALARA	-19
Emergency Planning	-20
HP Support	-21
Radwaste/Decon	-24
Licensing	-29
Maintenance/Construction	-34
Operations	-47
Eng.--Technical	-76
HP Applied	-93
Eng.--Plant	-93
Grand Total	**866**

OPG Staffing Analysis Conclusions

- **Benchmark analysis indicates OPG exceeds benchmark by 866 FTEs**
- **OPG is generally headed in the right direction by taking action to reduce their headcount; more than half of the staffing above the benchmark will be reduced by end of 2014 based on OPG's business plan**
- **A comprehensive workforce plan will be necessary to ensure staff reductions are appropriately pursued by functional area, and to direct backfilling after attrition to the appropriate areas**

Report Agenda – *Objectives*

- **Executive Summary**
- ***Objectives***
- **Approach**
- **Establishing Benchmarks**
- **Findings**
- **Appendices**

Objectives of the Study

- **Benchmark OPG nuclear staffing levels against other North American nuclear operators**
- **Identify the source of any significant differences in staffing levels**
- **Analyze the nature of the differences**
- **By referencing the OPG 2012 business plan, analyze OPG's planned 2014 staffing levels and compare them with the benchmarks**
  - ***Note: Major project staffing, (e.g. the Darlington Refurbishment project and the Darlington New Nuclear Project) was excluded from this study***

Report Agenda – *Approach*

- **Executive Summary**
- **Objectives**
- ***Approach***
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Approach To Nuclear Staffing Benchmarking

- **Count OPG nuclear staffing supporting steady-state operations**
  - Identify applicable OPG personnel supporting steady-state operations
    - Outage planning/scheduling and preparation are included, outage workforce are excluded
  - Exclude non-nuclear and/or non-benchmarkable OPG personnel (examples provided on slides 14-16)
  - Identify applicable contractors (those providing baseline support) as Full-Time Equivalents (FTEs)
  - Assign OPG and contractor personnel/FTEs to standardized nuclear work functions to allow for comparisons that are not driven by job or organization titles
- **Develop staffing benchmarks reflecting steady-state operations**
  - Identify applicable nuclear plants/nuclear organizations as the benchmarking source
  - Identify staffing benchmarks from functional staffing data using selected nuclear plants/organizations for comparison
  - Adjust for technical/design differences (i.e. PWR vs. CANDU)
  - Adjust for regulatory and/or work rule differences (i.e. 35 vs. 40 hour work week)
  - Apply adjustments and develop final functional staffing benchmarks
  - From functional benchmarks, identify organizational benchmarks (site vs. corporate)
- **Compare OPG and industry benchmark staffing levels**

We Apply Several Key Assumptions In Our Staffing Benchmarking Methodology

Benchmarks Are From Steady State, On-Power Activities

Plants are considered to be in steady state operation:

- **Short-term & outage contractors *excluded***
- **Baseline contractors are *included***
- **Major initiatives (i.e. Darlington Refurbishment, PWR Steam Generator Replacement, PWR Vessel Head replacements, etc.) are *excluded***

Average Productivity Is Assumed

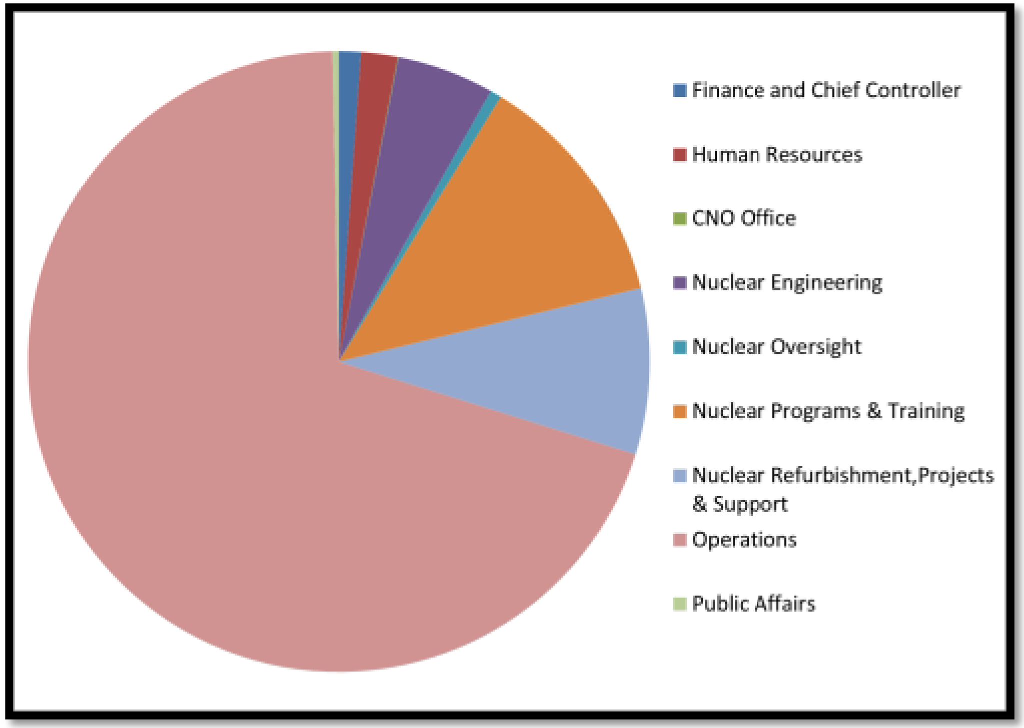
No productivity adjustments are applied to the benchmarks or OPG staffing; *however the benchmarks were adjusted for 35 vs. 40 hr work weeks where applicable*

Current Vacancies Excluded

Benchmark staffing levels do not include permanent vacancies, i.e. vacancies not expected to be filled in the next 30 days are not counted. Regular staff absences (e.g. maternity leave or long term disability leave) are not counted as "regular staff", but may be captured as non-regular staff i.e. temporary backfills

5,574 OPG Employees Were Analyzed For Benchmarking

	Employees
Finance and Chief Controller	64
Human Resources	106
CNO Office	2
Nuclear Engineering	282
Nuclear Oversight	33
Nuclear Programs & Training	694
Nuclear Refurbishment,Projects & Support	481
Operations	3,894
Public Affairs	18
Grand Total	**5,574**



CANDU-Unique, Refurbishment, New Build, & OPG-Unique Activities Were Excluded (1 of 2)

- **CANDU-Specific (i.e. unique to CANDU design) Exclusions [1,031 FTEs]:**
  - **Fuel Handling - On-line fuel handling is unique to CANDU design; comparable function in PWR reactors occurs during outages - hence excluded**
  - **Heavy Water Handling - Unique to CANDU design and has no comparable light water reactor activity**
  - **Tritium Removal Facility - Unique to CANDU design and has no comparable light water reactor activity**
  - **Feeder and Fuel Channel Support - Unique to CANDU design and has no comparable light water reactor activity**
  - **Other CANDU-Specific - support to excluded functions**
- **OPG Specific Exclusions [285 FTEs]:**
  - **Units 2 & 3 Safe Store Support - Out of Scope**
  - **Major Projects/ One time initiatives (e.g. Darlington Refurbishment, New Build, Pickering B Continued Operations) - Out of Scope**

CANDU-Unique, Refurbishment, New Build, & OPG-Unique Activities Were Excluded (2 of 2)

- **Generic Exclusions (Both CANDU & PWR activities but excluded as non baseline/non steady state) [732 FTEs]:**
  - **<u>Nuclear waste and used fuel</u> - These functions are not performed by the nuclear operators in the industry benchmark database**
  - **<u>Outage execution activities</u> - Most work is performed during outages, which are not in our benchmark data; remaining portion (less than 10%) were applied as "on-line“ support to various functions (Quality Control/Non Destructive Examination and Maintenance/Construction Support)**
  - **<u>Water treatment</u> - These functions are not performed by the nuclear operators in the industry benchmark database**

Other Personnel Were Excluded Based On A Lack Of Comparable Benchmarks

- **Other [53 FTEs]:**
  - **Security - excluded consistent with OPG Security policy**
  - **Information Management - that provides direct support to Nuclear was also excluded as a majority of this service is provided via an outsourced contract that cannot be readily translated into an accurate number of baseline FTEs**
  - **Legal - no benchmark data is available for this function**
  - **Long Term Leave - personnel are not included in the benchmark data**
- **Total Exclusions: 1,031 + 285 + 732 + 53 = 2,101 FTEs**
  - ***NOTE: Corporate Support i.e. Treasury, Tax, etc. that are not direct support to the nuclear program are not included except for dedicated Corporate Support (e.g. "Nuclear" Finance; "Nuclear" HR that directly supports nuclear operations, etc.)***

Contractor & Overtime Data Were Reviewed And Selected Portions Were Applied

- **To accurately portray contractor FTE assignments to functional areas, relevant contractor information was analyzed:**
  - **Non-regular staff: temporary OPG staff backfilling for regular staff absences, e.g. maternity leave, or regular staff assigned to outage work**
  - **Staff augmentation contractors: professional staff providing specialized skills, including authorized training contractors or peak work support**
  - **Other purchased services: specialized contractors, such as nuclear safety analysis, and maintenance/construction trades**
  - **Outage contractors and outage overtime were excluded**
  - **Only those contractors that supported steady-state operations (“baseline contractors”) were selected and assigned to applicable nuclear staffing functions**
- **OPG overtime data was also analyzed to determine if overtime was being used as a replacement for additional personnel**

Contractor Information Was Converted From Hours or Costs Into FTEs

- **OPG provided (July-August 2011 YTD) contractor data in either contractor billed YTD costs, or cumulative contractor YTD hours**
- **Cumulative contractor billed YTD dollar values were first divided by an average hourly cost that include wages plus benefits, and then by a value to pro-rate the YTD data into annual hours**
- **Cumulative contractor YTD hours were also divided by the same value to prorate the YTD data into annual hours**
- **The YTD data was assessed to determine an appropriate annual level of baseline contractor utilization, which resulted in the establishment of 382 baseline contractor FTEs**

Applicable Baseline Contractors Includes 382 FTEs

Function	DN	PA	PB	Other	Total
Admin/Clerical	0	0	0	12	12
Chemistry	1	0	0	0	1
Document Control	0	0	0	9	9
Eng. --Computer	0	0	0	2	2
Eng. --Plant	1	0	0	0	1
Eng. --Reactor	0	1	1	10	12
Eng. --Technical	0	0	0	27	27
Eng.--Modification	0	2	0	20	22
Environmental	0	0	0	2	2
Facilities	0	0	0	40	40
Fire Protection	0	0	0	1	1
HP Support	0	0	0	1	1
Maintenance/Construction	9	27	10	122	168
Maintenance/Construction Support	5	0	0	20	25
Management	0	0	0	1	1
Materials Management	0	0	0	1	1
Nuclear Fuels	0	0	0	10	10
Nuclear Safety Review	2	0	0	0	2
Project Management	0	0	0	10	10
Training	0	0	0	21	21
Warehouse	0	0	0	14	14
Total	**18**	**30**	**11**	**323**	**382**

Note: Some of these staff may be used to fill long-term vacancies

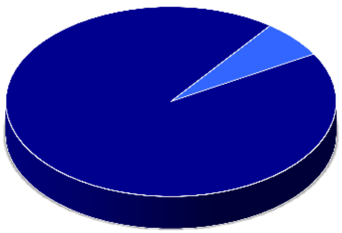
OPG Overtime Does Not Appear Unusual, And Did Not Impact Our FTE Count

- **Overtime calculations are used to determine which functions are consistently recording above average levels of overtime**
- **Typically, we have observed an average level of 5% to 6% at plants**
- **The average overtime levels for OPG are 7% in 2010, and 6% in 2011 YTD (Outage overtime was excluded), so no FTE adjustment was made**

	2010	2011
Darlington	8%	7%
Inspection & Maintenance Svcs.	5%	4%
Nuc Programs and Training	4%	2%
Nuclear Engineering	1%	1%
Nuclear Oversight	1%	1%
Nuclear Supply Chain	4%	4%
Pickering A	10%	9%
Pickering B	6%	6%
Projects & Modifications	5%	5%

OPG Nuclear Staffing of 5,956* Was Categorized Into 40 Work Functions

382 Contractors



5,574 OPG Employees

TOTAL STAFF: 5,956

CNO

- Site VP
- Engineering
- Operations
- Etc.

Functional Staff

- Operations
- Engineering - Plant
- HP Applied
- Management
- Budget/Finance
- Others . . . . .

** Security, IMS, Fuel Handling, Heavy Water, Waste Mgt., TRF, Darlington Refurb, Info Management, Legal and Non-Nuclear Corporate were excluded*

OPG Staffing Was Analyzed By 40 Functions Which Are Arranged in 7 Process Areas

Operate the Plant

- Chemistry
- Environmental
- Operations
- Operations Support

Equipment Reliability

- Engineering - Computer
- Engineering - Plant
- Engineering - Technical
- QC/NDE

Materials & Services

- Contracts/Purchasing[1]
- Materials Mgt
- Warehouse

Support Svcs & Training

- Admin/Clerical
- Budget/Finance
- Communications
- Document Control
- Facilities
- Human Resources
- *Information Mgmt (Excluded)*[3]
- Management
- Management Assist
- Training

Work Management

- ALARA
- HP Applied
- HP Support
- Maint/Construction
- Maint/Constr Support
- Outage Management
- Project Management
- Radwaste/Decon
- Scheduling

Configuration Management

- Design/Drafting
- Engineering - Mods
- Engineering - Procurement
- Engineering - Reactor
- Nuclear Fuels

Loss Prevention

- Emergency Prep
- Fire Protection
- Licensing
- Nuclear Safety Review
- QA
- Safety/Health
- *Security (Excluded)*[2]

[1] Contracts and Purchasing functions were combined due to overlap within the benchmark plant set

[2] The Security function was excluded consistent with OPG Security Policy

[3] Information Mgmt. was excluded due to OPG's inability to derive an accurate contractor FTE headcount for this function

Report Agenda – *Establishing Benchmarks*

- **Executive Summary**
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Our Approach Begins With Current Staffing Data From Large PWRs (Complex Designs)

NUCLEAR PLANT STAFFING BENCHMARKING

GOODNIGHT CONSULTING STAFFING DATABASE

73 OPERATING UNITS

44 NUCLEAR PLANTS
28 Dual-Unit Plants
16 Single-Unit Plants

STAFFING DATA INDEPENDENT OF ORGANIZATION STRUCTURE

ELIMINATE SIGNFICANTLY DIFFERENT PLANTS

	# Units 1	2
Large > 800 MWe	X	✔
Small <=800 MWe	X	X

Apply Functional Staffing Data From U.S. Large (>800 MWe) PWRs[1]

DETERMINE BENCHMARK FUNCTIONAL STAFFING

BENCHMARK STAFFING

40 FUNCTIONS

Apply Adjustments For PWR to CANDU Design Differences

Apply Adjustments For OPG Conditions

FUNCTIONAL STAFFING

FUNCTIONAL STAFFING COMPARISON

ORG STAFFING

ORGANIZATIONAL STAFFING COMPARISON

[1]See Slide 25 for more detail

Large 2-Unit PWRs Provide The Closest Comparison to CANDUs For Benchmarking

- Goodnight Consulting's approach to benchmarking is to apply current information from plants that are the most similar in design to the client's operating plants
- CANDU plants are similar to PWRs in that there are steam generators with similar primary and secondary loops
- Larger capacity PWRS are later model designs, i.e. post TMI. These are more complex designs than either early model PWRs
- This increased complexity in design is closer to the CANDU design than smaller PWRs of an earlier vintage
- Thus, the "most similar" plants in our staffing database are large (over 800 MWe) 2-Unit PWRs
- Using these as the basis for the benchmarks, we were able to:
  - a) identify technology differences between these plants and CANDUs (which are relatively less different than small, older PWRs and all BWRs)
  - b) develop scaling factors for 2 up to 4 units to develop modeled 4-Unit CANDU staffing levels

To Determine Adjustments For CANDU Design Differences, We Reviewed Many Technical Areas

Design & Operational Consideration Areas – PWR to CANDU Benchmark Conversion

- Vacuum Building
- Gadolinium Nitrate Injection
- Liquid Zone Control System
- Health Physics / ALARA / Environmental
- Annulus Gas Systems
- Inspection and Testing
- In Service Inspection / Non-Destructive Examination
- Surveillance Testing
- Materials
- Carbon Steel Primary Heat Transport System
- Fuel Channels (Zr Alloy)
- Systems and Major Components
- 12 steam generators & 16 Main HTS Pumps/unit at Pickering
- Engineering and Maintenance Programs
- PM Program Tasks / Activities
- Mechanical Components
- Electrical Components
- Instrumentation and Controls /Computers
- Reactivity Management in Calandria design, Fuels
- Corrective / Elective / Preventive Maintenance Backlogs
- Radioactive Source Term
- Building and Support Systems Maintenance
- Canadian Nuclear Safety Commission (CNSC)
- OPG as initial point of contact for CANDU Generic Issues
- Nominal 5-year License Interval
- Supply Chain
- Demineralized Water Consumption
- Design Philosophy Differences
- Separation of Control and Safety Channels
- PWR Systems, Programs, and Issues
- Turbine Driven Auxiliary Feedwater
- Condensate Polishing
- Boric Acid Corrosion
- Etc.

Further detail provided in Appendix D

Some Functional Staffing Is Independent Of Nuclear Plant Design/Technology Type

- **Several functional staffing areas are support activities where the staffing level is a ratio of other total staff:**
  - ***Admin/Clerical***
  - ***Budget/Finance***
  - ***Human Resources***
  - ***Information Management***
  - ***Management***
  - ***Safety/Health***
- **Other functional staffing benchmarks are determined first, then the respective ratios for these functional areas are applied to identify total staffing requirements**

2-Unit CANDU Staffing Benchmark Is 1,047 Personnel (Includes Corp & Contractors)

Staffing Function	2-Unit U.S. PWR Bmk	Raw Adjustments	Benchmark Ratio %	Ratio Adjustments	Total Adjustments	Total Bmk
Admin/Clerical	37	Ratio	3.76%	3	3	40
ALARA	6	2			2	8
Budget/Finance	11	Ratio	1.12%	1	1	12
Chemistry	28	0			0	28
Communications	3	0			0	3
Contracts/Purchasing	10	0			0	10
Design/Drafting	7	1			1	8
Document Control	16	2			2	18
Emergency Planning	7	0			0	7
Engineering - Computer	5	0			0	5
Engineering - Mods	28	3			3	31
Engineering - Plant	51	8			8	59
Engineering - Procurement	7	2			2	9
Engineering - Reactor	8	2			2	10
Engineering - Technical	36	5			5	41
Environmental	5	2			2	7
Facilities	25	0			0	25
Fire Protection	23	0			0	23
HP Applied	28	3			3	31
HP Support	12	1			1	13
Human Resources	4	Ratio	0.41%	0	0	4
Licensing	9	1			1	10
Mtce/Construct	194	22			22	216
Mtce/Construct Suppt	47	4			4	51
Management	37	Ratio	3.76%	3	3	40
Management Assist	3	0			0	3
Materials Management	6	0			0	6
Nuclear Fuels	6	2			2	8
Nuclear Safety Review	11	0			0	11
Operations	126	0			0	126
Operations Support	30	0			0	30
Outage Management	8	3			3	11
Project Management	13	1			1	14
QA	14	0			0	14
QC/NDE	8	1			1	9
Radwaste/Decon	12	3			3	15
Safety/Health	5	Ratio	0.51%	0	0	5
Scheduling	17	2			2	19
Training	46	3			3	49
Warehouse	16	2			2	18
Total	965	75		7	82	1047

- Refer to Appendix D for additional information on the technical adjustments applied

Technical Adjustments Were Utilized To Derive The 2-Unit CANDU Staffing Benchmark

Staffing Function	2-Unit U.S. PWR Bmk	Total Bmk	Rationale
Admin/Clerical	37	40	Ratio of these functiional staff is related to the total final staffing level
ALARA	6	8	"Hotter shop" tritium, alpha radation pervasive, more opportunities for ALARA-more equipment, bigger source of radiation and more space.
Budget/Finance	11	12	Ratio of these functiional staff is related to the total final staffing level
Chemistry	28	28	No basis for adjustment
Communications	3	3	No basis for adjustment
Contracts/Purchasing	10	10	No basis for adjustment
Design/Drafting	7	8	Higher number of systems
Document Control	16	18	Higher number of systems, more control documents to manage
Emergency Planning	7	7	No basis for adjustment
Engineering - Computer	5	5	No basis for adjustment
Engineering - Mods	28	31	Higher number of systems
Engineering - Plant	51	59	Higher number of systems
Engineering - Procurement	7	9	Higher number of commercial parts dedications due to a smaller vendor market, lower availability of conforming parts
Engineering - Reactor	8	10	Adjusted to 2-unit equivalent of OPG CANDU stated requirements
Engineering - Technical	36	41	Higher number of systems, diversity instead of redundancy design philosphy
Environmental	5	7	Tritium monitoring, Canadian regulatory requirements
Facilities	25	25	No basis for adjustment
Fire Protection	23	23	No basis for adjustment
HP Applied	28	31	Additional radiation sources, differences in staffing are due to choices in program structures
HP Support	12	13	Additional radiation sources, differences in staffing are due to choices in program structures
Human Resources	4	4	Ratio of these functiional staff is related to the total final staffing level
Licensing	9	10	Different regulatory scheme, greater number of saftey systems, design philosophy of diversity over redundancy
Mtce/Construct	194	216	Higher number of systems, diversity instead of redundancy design philosphy-track IMS impacts on numbers
Mtce/Construct Suppt	47	51	Higher number of systems, diversity instead of redundancy design philosphy
Management	37	40	Ratio of these functiional staff is related to the total final staffing level
Management Assist	3	3	No basis for adjustment
Materials Management	6	6	No basis for adjustment
Nuclear Fuels	6	8	Adjusted to 2-unit equivalent of OPG CANDU stated requirements
Nuclear Safety Review	11	11	No basis for adjustment
Operations	126	126	Additional systems to monitor= increases, common systems = decreases
Operations Support	30	30	Additional systems to monitor= increases, common systems = decreases
Outage Management	8	11	Non fueling outages=decreases, more systems to deal with during an outage=increase
Project Management	13	14	Higher number of systems, diversity instead of redundancy design philosphy
QA	14	14	No basis for adjustment
QC/NDE	8	9	Due to additional maintenance work, additional QC/NDE work is required, "Innage" IMS counted here,
Radwaste/Decon	12	15	"Hotter shop" tritium, alpha radation pervasive, more opportunities for deconning-more equipment, bigger source of radiation and more space. Larger volumes of I&LLW generated and packaged.
Safety/Health	5	5	Ratio of these functiional staff is related to the total final staffing level
Scheduling	17	19	Greater number of systems resulting in more scheduling work
Training	46	49	Additional trainers required to handle additional maintenance training requirements
Warehouse	16	18	Additional parts and components needed for more systems and to overcome more materials kept on hand due to a smaller vendor base
Total	965	1047	

- Refer to Appendix D for additional information on the technical adjustments applied

2-Unit *OPG* CANDU Benchmark Is 1,105
4-Unit *OPG* CANDU Benchmark Is 1,984

2-unit to 4-unit Scaling Factors, by Functional Area

Staffing Function	2-Unit CANDU Benchmark	35 hour week	Adjustment for 35 hour week	Scaling Factor From 2 to 4-Units	Initial 4-Unit CANDU Benchmark	Benchmark Ratio %	Ratio Staffing	4-Unit CANDU Benchmark
Admin/Clerical	40	1	46	Ratio		3.76%	68	68
ALARA	8		8	1.8	14			14
Budget/Finance	12	1	14	Ratio		1.12%	20	20
Chemistry	28		28	1.8	50			50
Communications	3		3	1.8	5			5
Contracts/Purchasing	10	1	11	1.8	20			20
Design/Drafting	8	1	9	1.8	16			16
Document Control	18	1	21	1.9	40			40
Emergency Planning	7	1	8	1.5	12			12
Engineering - Computer	5	1	6	2	12			12
Engineering - Mods	31	1	35	1.8	63			63
Engineering - Plant	59	1	67	1.8	121			121
Engineering - Procurement	9	1	10	1.8	18			18
Engineering - Reactor	10	1	11	2	22			22
Engineering - Technical	41	1	47	1.8	85			85
Environmental	7	1	8	1.8	14			14
Facilities	25		25	1.8	45			45
Fire Protection	23		23	1.8	41			41
HP Applied	31		31	1.8	56			56
HP Support	13	1	15	1.8	27			27
Human Resources	4	1	5	Ratio		0.41%	7	7
Licensing	10	1	11	1.8	20			20
Maintenance/Construction	216		216	1.8	389			389
Maintenance/Construction Suppor	51		51	1.8	92			92
Management	40	1	46	Ratio		3.76%	68	68
Management Assist	3	1	3	1.8	5			5
Materials Management	6	1	7	1.8	13			13
Nuclear Fuels	8	1	9	1.8	16			16
Nuclear Safety Review	11	1	13	1.8	23			23
Operations	126		126	2	252			252
Operations Support	30		30	2	60			60
Outage Management	11		11	1.8	20			20
Project Management	14	1	16	1.8	29			29
QA	14	1	16	1.8	29			29
QC/NDE	9		9	1.8	16			16
Radwaste/Decon	15		15	1.8	27			27
Safety/Health	5	1	6	Ratio		0.51%	9	9
Scheduling	19		19	1.8	34			34
Training	49		49	1.8	88			88
Warehouse	18	1	21	1.8	38			38
Total	**1047**		**1105**		**1812**			**1984**

- Where applicable, adjustments were made for OPG's 35 Hour Work work week vs. 40 hours at U.S. plants
- The net increase in the 2-Unit benchmarks is 58 FTEs (5.5%)
- CANDU 2-Unit was then scaled up to a 4-Unit model
- Additional scaling information is provided in Appendix D

Adjustments For Pickering Units 2 & 3 Increase The OPG 2-Unit CANDU Benchmark To 1,122

Adjustments to 2-Unit OPG CANDU for Pickering A						
Staffing Function	2-Unit CANDU Benchmark	35 hour week	Adjustment for 35 hour week	Adjustments for Units 2 & 3	Pickering A Benchmark	Rationale
Admin/Clerical	40	1	46		46	
ALARA	8		8		8	
Budget/Finance	12	1	14		14	
Chemistry	28		28		28	
Communications	3		3		3	
Contracts/Purchasing	10	1	11		11	
Design/Drafting	8	1	9		9	
Document Control	18	1	21		21	
Emergency Planning	7	1	8		8	
Engineering - Computer	5	1	6		6	
Engineering - Mods	31	1	35		35	
Engineering - Plant	59	1	67	4	71	One additional System Engineer per discipine (M, E, I&C, Civil)
Engineering - Procurement	9	1	10		10	
Engineering - Reactor	10	1	11		11	
Engineering - Technical	41	1	47		47	
Environmental	7	1	8		8	
Facilities	25		25		25	
Fire Protection	23		23		23	
HP Applied	31		31	1	32	One additional Rad Pro technican to conduct surveillances
HP Support	13	1	15		15	
Human Resources	4	1	5		5	
Licensing	10	1	11		11	
Maintenance/Construction	216		216	5	221	Estimated Additional staff (FIN-like)
Maintenance/Construction Suppor	51		51	1	52	Ratio of support to additional Maintenance/Construction
Management	40	1	46	1	47	1 Additional Management person to oversee units 2 & 3 Activities
Management Assist	3	1	3		3	
Materials Management	6	1	7		7	
Nuclear Fuels	8	1	9		9	
Nuclear Safety Review	11	1	13		13	
Operations	126		126	5	131	1 Additional Ops person per shift crew for rounds
Operations Support	30		30		30	
Outage Management	11		11		11	
Project Management	14	1	16		16	
QA	14	1	16		16	
QC/NDE	9		9		9	
Radwaste/Decon	15		15		15	
Safety/Health	5	1	6		6	
Scheduling	19		19		19	
Training	49		49		49	
Warehouse	18	1	21		21	
Total	1047		1105	17	1122	

- FTEs assigned to SAFESTORE activities at Pickering 2 & 3 were also removed from the count of OPG staff
- The SAFESTORE activities and the adjustments shown here are both applicable, thus increasing the benchmark and reducing the number of benchmarked OPG personnel

Benchmarking Summary: Total OPG Nuclear Benchmark Is 5,090

- A benchmark of 965 was derived from Large 2-Unit US PWR staffing
- Adjustments were applied for:
  - Net differences in CANDU vs. PWR technologies[1]
  - OPG work week differences
  - Workload requirements for Units 2 & 3 at Pickering A[2]
- Scaling factors were applied to identify 4-Unit CANDU benchmarks
- These benchmarks include contractor FTEs and corporate nuclear support

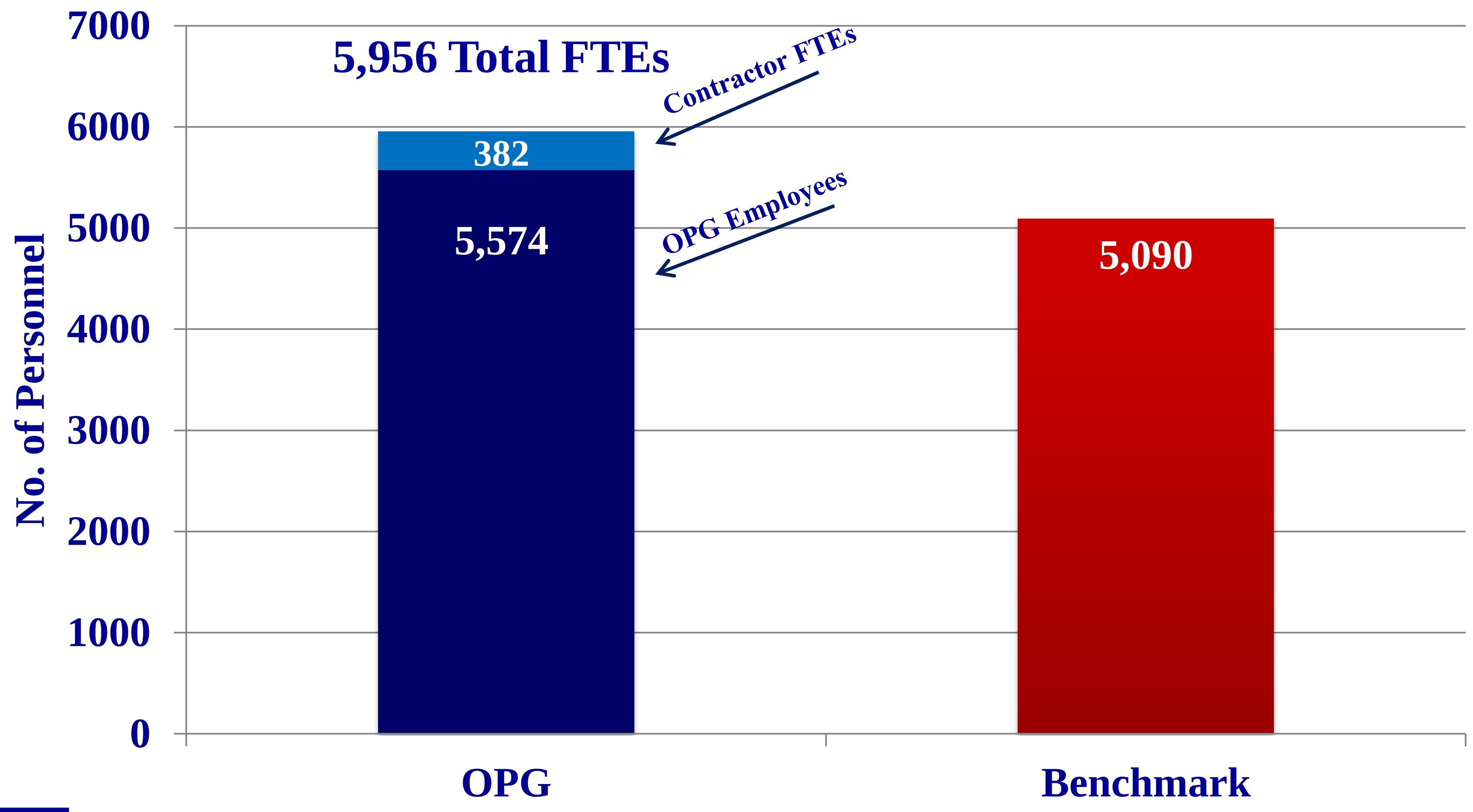
	2-Unit PWR	PA	PB	DN	Total
2-Unit U.S. PWR Benchmarks	965				
Adjustment for 2-Unit CANDU	82				
Preliminary 2-Unit CANDU Benchmark	1,047	1,047	1,047	1,047	
Adjustment for 35 Hour Week		58	58	58	
Adjustment for Pickering A Units 2 & 3		17			
Adjustment for Scaling 2 to 4-Units			879	879	
Total		1,122	1,984	1,984	5,090

[1]CANDU vs. PWR differences also addressed in derivation of OPG Nuclear Staffing to be benchmarked (see slides 14-16)
[2]Maintenance of common facilities with the two shutdown units

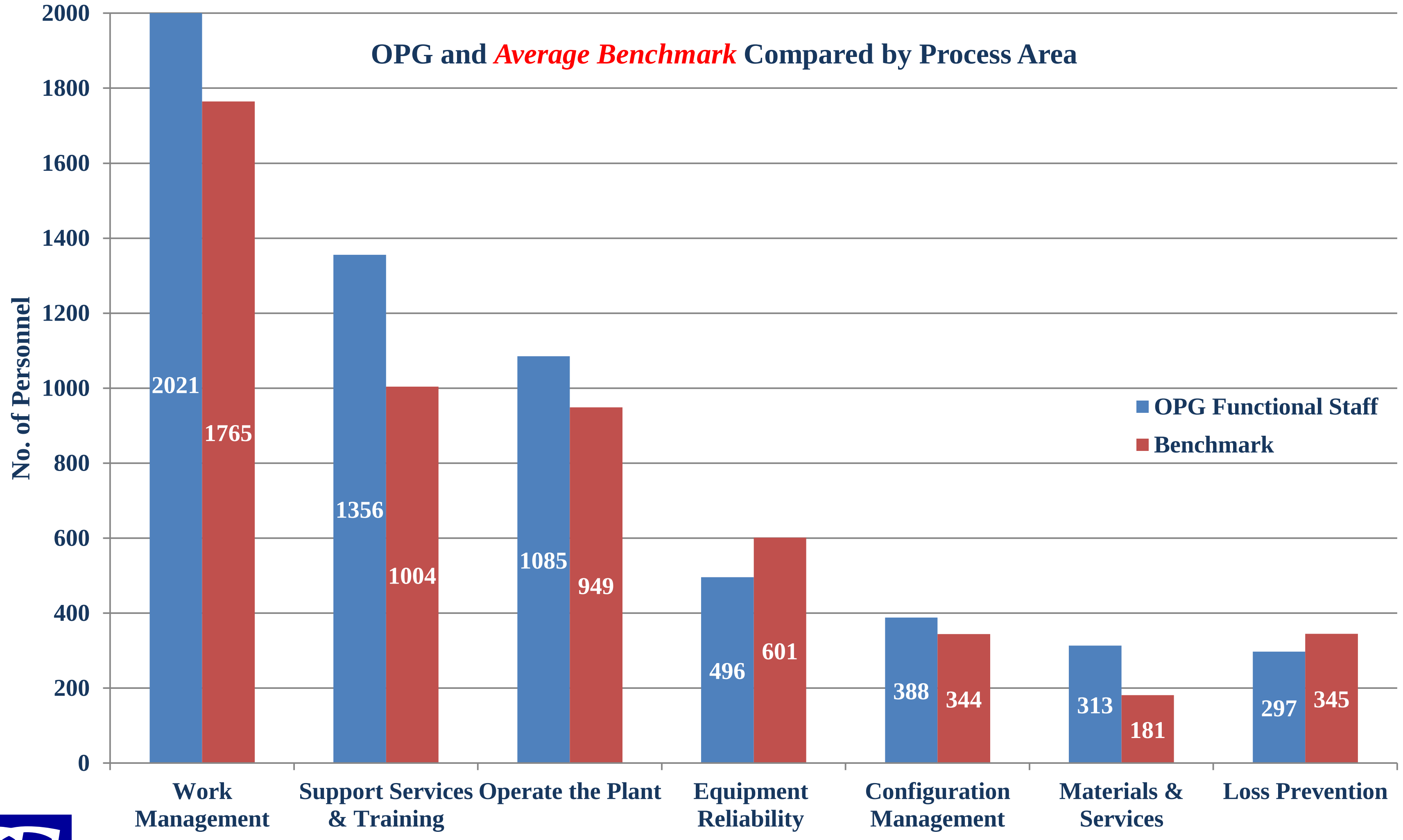
Report Agenda – *Findings*

- **Executive Summary**
- **Objectives**
- **Approach**
- **Establishing Benchmarks**
- **Findings**
  - ***OPG Staffing Benchmark Comparisons***
  - ***OPG Organizational Structure Benchmark Comparisons***
  - ***OPG 2012 Business Plan Review***
- **Appendices**

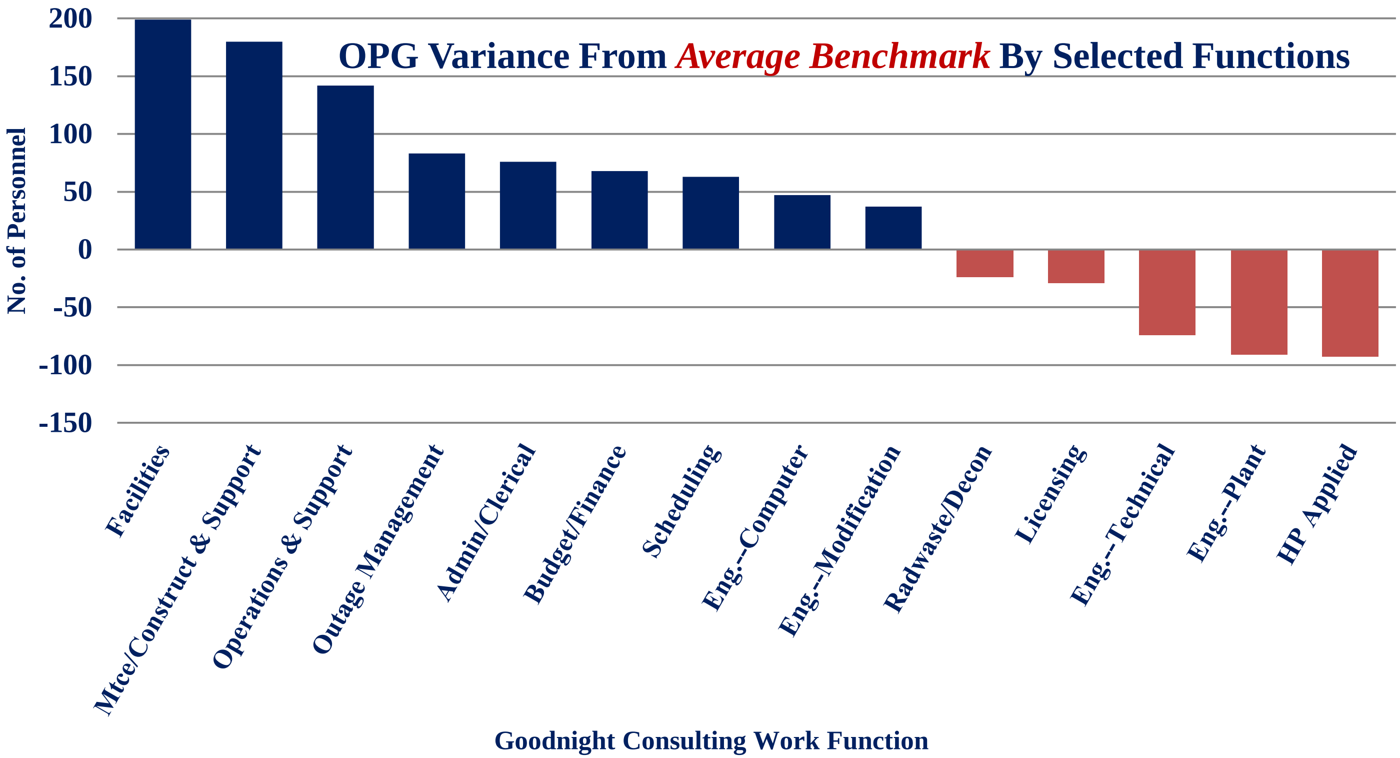
OPG Staffing, Including Contractor FTEs Is 866 (17%) Above the Benchmark



Greatest Process Area Variances Are In Work Management And Support Services/Training

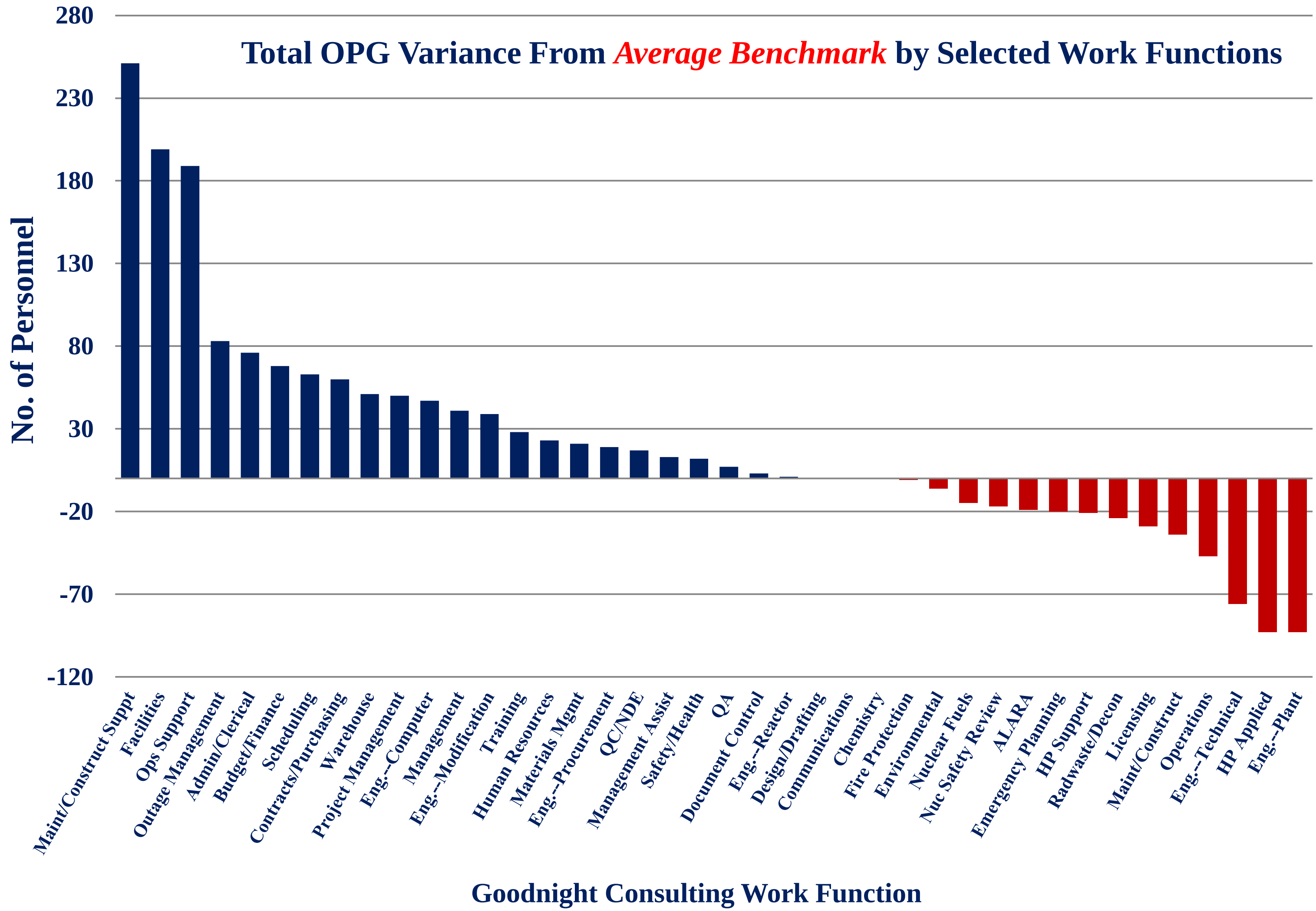


Total Staffing: 23 Functional Areas Are Staffed Above the *Average Benchmark*, 14 are Below



All Functions by Variance	
Maint/Construct Support	251
Facilities	199
Operations Support	189
Outage Management	83
Admin/Clerical	76
Budget/Finance	68
Scheduling	63
Contracts/Purchasing	60
Warehouse	51
Project Management	50
Eng.--Computer	47
Management	41
Eng.--Modification	39
Training	28
Human Resources	23
Materials Management	21
Eng.--Procurement	19
QC/NDE	17
Management Assist	13
Safety/Health	12
QA	7
Document Control	3
Eng.--Reactor	1
Design/Drafting	0
Communications	0
Chemistry	0
Fire Protection	-1
Environmental	-6
Nuclear Fuels	-15
Nuclear Safety Review	-17
ALARA	-19
Emergency Planning	-20
HP Support	-21
Radwaste/Decon	-24
Licensing	-29
Maintenance/Construction	-34
Operations	-47
Eng.--Technical	-76
HP Applied	-93
Eng.--Plant	-93
Grand Total	866

Total Staffing: 23 Functional Areas Are Staffed Above the *Average Benchmark*, 14 are Below



5,956 OPG Employees And Contractor FTEs Were Compared To A Benchmark Of 5,090

	OPG Employees	Baseline Contractors	Functional Staff	Benchmark	Total Variance
Mtce/Construct Suppt	462	25	487	236	251
Facilities	274	40	314	115	199
Operations Support	339	0	339	150	189
Outage Management	134	0	134	51	83
Admin/Clerical	246	12	258	182	76
Budget/Finance	122	0	122	54	68
Scheduling	150	0	150	87	63
Contracts/Purchasing	111	0	111	51	60
Warehouse	134	14	148	97	51
Project Management	114	10	124	74	50
Eng.--Computer	75	2	77	30	47
Management	223	1	224	183	41
Eng.--Modification	178	22	200	161	39
Training	232	21	253	225	28
Human Resources	42	0	42	19	23
Materials Management	53	1	54	33	21
Eng.--Procurement	65	0	65	46	19
QC/NDE	58	0	58	41	17
Management Assist	26	0	26	13	13
Safety/Health	36	0	36	24	12
QA	81	0	81	74	7
Document Control	95	9	104	101	3
Eng.--Reactor	44	12	56	55	1
Design/Drafting	41	0	41	41	0
Communications	13	0	13	13	0
Chemistry	127	1	128	128	0
Fire Protection	103	1	104	105	-1
Environmental	28	2	30	36	-6
Nuclear Fuels	16	10	26	41	-15
Nuclear Safety Review	40	2	42	59	-17
ALARA	17	0	17	36	-19
Emergency Planning	12	0	12	32	-20
HP Support	47	1	48	69	-21
Radwaste/Decon	45	0	45	69	-24
Licensing	22	0	22	51	-29
Maintenance/Construction	797	168	965	999	-34
Operations	588	0	588	635	-47
Eng.--Technical	114	27	141	217	-76
HP Applied	51	0	51	144	-93
Eng.--Plant	219	1	220	313	-93
Grand Total	5574	382	5956	5090	866

Process Areas Can Help Management Decide Where To Place Their Focus

A	B	C	D	E
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark

A - Function being analyzed (e.g. operations, training, etc.)

B - Total OPG Employees performing the function

C- Baseline contractor FTEs (more than 6 months or providing recurring non-outage services)

D - Functional staff is the sum of B plus C

E - Benchmark is the average benchmark for the applicable function

- *NOTE: Where applicable, comments follow each table with function-specific observations made during on-site interviews with OPG personnel and from Goodnight Consulting nuclear industry experience. These comments are not intended to serve as recommendations to OPG as to any actions it should or should not take.*

Total *Operate The Plant* Staffing Is Above The Average Benchmark Level

Process Area	Operate the Plant			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
Chemistry	127	1	128	128
Environmental	28	2	30	36
Operations	588	0	588	635
Operations Support	339	0	339	150
Grand Total	1082	3	1085	949

- **Operations: The number of personnel in Operations training who graduate will reduce the current shortfall in the Operations function; however, when combined, current Operations and Operations Support aggregate staffing is 142 above the combined Operations and Operations Support benchmark level**

Total *Work Management* Staffing Is Above The Average Benchmark Level

Process Area	Work Management			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
ALARA	17	0	17	36
HP Applied	51	0	51	144
HP Support	47	1	48	69
Maintenance/Construction	797	168	965	999
Mtce/Construct Suppt	462	25	487	236
Outage Management	134	0	134	51
Project Management	114	10	124	74
Radwaste/Decon	45	0	45	69
Scheduling	150	0	150	87
Grand Total	1817	204	2021	1765

- **Maintenance/Construction: We typically observe higher levels of contractor participation in this function than currently counted at OPG-typical contractor support for this function is 25-30 FTEs per reactor; equating 250-300 at OPG.**

- **Without these typical levels of contractor support, OPG maintenance/construction staffing (including I&C Technicians, Electricians, Mechanics, and Construction craft) is 3.5% below the benchmark level**

Total *Work Management* Staffing Is Above The Average Benchmark Level (cont.)

- **Maintenance/Construction Support: Some of the overage in the M/C Support function can be attributed to current planning activities, including the use of Legacy tools- maintenance planners spend 74% of their time planning for outages instead of in online operations due to current outage programs; M/C Support personnel also expend more time characterizing conventional waste using outdated/handheld technology: available technologies used at benchmarked plants could reduce this workload; when combined, the M/C and M/C Support functions are 180 above their combined benchmark levels**

- **Project Management: Staffing above the benchmark reflects OPG's current capital equipment replacement program, this condition is also reflected in the Modification Engineering Function**

- **HP Applied: Low staffing is offset by line personnel qualified to provide self monitoring and also, if certified, to monitor the activities of groups**

Total *Work Management* Staffing Is Above The Average Benchmark Level (cont.)

- **Outage Management: Staffing above the benchmark reflects that Pickering A units are subject to long outages to address material conditions following their return to service and Pickering B units are subject to long outages due to enhanced life cycle management maintenance and inspections to support Pickering B Continued Operations. These long outages likely have an impact on steady state staffing levels at Pickering (i.e., system and design engineering, task planners, and supply chain) in addition to outage management staffing**
- **A similar condition existed in the US nuclear power industry in the past. The US nuclear industry average outage duration from 2005-2010 was 26 days per reactor per year (39.3 days per 18 month reactor cycle*) which is down from 43 days per reactor per year (65.6 days per 18 month reactor cycle) during the period 1990-2004, reflecting intensive focus on outage scope and duration in the US nuclear industry.**
- **By comparison, average current and near term outage duration (2009-2014) at Pickering A is 37 days per reactor per year and at Pickering B is 43 days per reactor per year. Darlington is currently operating better than the US industry at 21 days per reactor per year, reflecting the implementation of a three year outage cycle.**

***Per the Nuclear Energy Institute (NEI)**

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EB-2013-0321
Ex. F5-1-1 Part a

Total *Equipment Reliability* Staffing Is Below The Average Benchmark Level

Process Area	Equipment Reliability			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
Eng.--Computer	75	2	77	30
Eng.--Plant	219	1	220	313
Eng.--Technical	114	27	141	217
QC/NDE	58	0	58	41
Grand Total	466	30	496	601

- **Eng.--Computer: Lack of OEM support forces OPG into development of replacements for obsolete computers, software, and programmable logic controllers: this condition helps explain the variance above the benchmark**

- **Eng.--Technical: Below the benchmark staffing may reflect technical analyses being performed by Modification Engineers**

Total *Configuration Management* Staffing Is Above The Average Benchmark Level

Process Area	Configuration Management			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
Design/Drafting	41	0	41	41
Eng.--Modification	178	22	200	161
Eng.--Procurement	65	0	65	46
Eng.--Reactor	44	12	56	55
Nuclear Fuels	16	10	26	41
Grand Total	**344**	**44**	**388**	**344**

- **Eng.--Modification: Staffing above the benchmark reflects OPG's current capital equipment replacement program, this condition is also reflected in the Project Management Function—it also appears that Modification Engineers are performing technical analyses typically performed by Technical Engineers**

- **Eng.--Procurement: Equipment obsolescence and OPG's capital equipment replacement program increased the workload of Procurement Engineers which helps explain the variance above the benchmark**

Total *Materials & Services* Staffing Is Above The Benchmark Levels

Process Area	Materials & Services			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
Contracts/Purchasing	111	0	111	51
Materials Management	53	1	54	33
Warehouse	134	14	148	97
Grand Total	298	15	313	181

- **Contracts/Purchasing:** OPG Supply Chain processes appear significantly more complex for procurement of parts and services than those at benchmark plants; Recent initiatives are aimed at reducing complexity and becoming more efficient
- **Materials Management:** Obsolescence of necessary parts requires long lead time and planning cycles. For example, 25% of the parts are obsolete and can no longer be ordered to fit into the system; 5 – 10% of valves and computer boards take approximately 2 years notice to fill an order; 15% of replenishment items can be obtained after only 6 to 8 months; OPG does not utilize automated picking technology

Total *Loss Prevention* Staffing Is Below The Average Benchmark Level

Process Area	Loss Prevention			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
Emergency Planning	12	0	12	32
Fire Protection	103	1	104	105
Licensing	22	0	22	51
Nuclear Safety Review	40	2	42	59
QA	81	0	81	74
Safety/Health	36	0	36	24
Grand Total	**294**	**3**	**297**	**345**

- **Emergency Planning: Resource requirements are often driven by the number of jurisdictions within the plant's emergency planning zone (EPZ) and the local requirements for emergency response plans required by those jurisdictions—Darlington's relative isolation helps explain the staffing below the benchmark**

- **Licensing: Benchmarked plants have higher staffing due to regulatory requirement differences– In the US many plant modifications require license amendment requests—the size and variety of the US nuclear fleet creates events that drives the regulator to create a broader regulatory scheme affecting all US plants**

Total *Loss Prevention* Staffing Is Below The Average Benchmark Level (cont.)

- **QA: Requirements apply to most installations within the plant, not only nuclear safety, and requires more personnel**

- **Safety/Health: Conventional Safety function reports to HR only to maintain separation and independence from operating decisions. All Worker's Comp claims handled internally by Safety/Health personnel--Safety/Health also handles contractor safety management oversight and oversight of hazardous materials—MSDS, etc.**

Total *Support Services & Training* Staffing Is Above The Average Benchmark Level

Process Area	Support Services & Training			
	OPG Employees	Baseline Contractors	Functional Staff	Benchmark
Admin/Clerical	246	12	258	182
Budget/Finance	122	0	122	54
Communications	13	0	13	13
Document Control	95	9	104	101
Facilities	274	40	314	115
Human Resources	42	0	42	19
Management	223	1	224	183
Management Assist	26	0	26	13
Training	232	21	253	225
Grand Total	1273	83	1356	905

- **Admin/Clerical: Higher staffing in the Management function drives higher admin staffing; Admin/clerical staff at OPG operate three separate printing shops-this activity normally does not occur at nuclear plant sites, and is also reflected in the staffing level above the benchmark**

- **Management Assist: OPG uses more technical specialists to support managers than we normally find**

Total *Support Services & Training* Staffing Is Above The Average Benchmark Level (cont.)

- **Budget/Finance: A variety of conditions help explain the variance above the benchmark:**
  - **OPG has Budget/Finance staff centralized and in line organizations, which is different from benchmark companies**
  - **OPG has a larger number of individual contracts than the benchmarked plants, which require additional budgetary tracking**
  - **OPG nuclear staffing is 17% above the benchmarks in the aggregate, which requires additional support personnel, including Budget/Finance**
  - **OPG has more contracts, more contractor companies to manage, and contracts of a larger value to manage, also requiring more Budget/Finance personnel**
  - **Benchmarked staffing reflects mature fleet efficiencies that have applied many years of effort to centralize personnel, standardize processes, and reduce the number and variety of contracts**

- **Human Resources: HR has representatives scattered throughout the business functions; HR staff are both centralized and decentralized**

Total *Support Services & Training* Staffing Is Above The Average Benchmark Level (cont.)

- **Facilities: OPG has employees located at more than 20 different facilities (see table below) throughout the area. Benchmarked fleets typically have 1-2 non-plant sites, which increases staffing efficiency as compared to distributing over many sites. It should be noted that some of these facilities are leased, and no additional OPG facilities staff are required for those areas. The new Energy Center on the Darlington Campus will house about 450 OPG employees which will help reduce the current Facilities staffing requirement.**

700 University (Corp HQ)	Kipling Ave Toronto
777 Brock Road (Projects & Constr)	L&ILW (Bruce)
889 Brock Road (Corp Nuclear)	NPT-1480 Bailey Road Pickering
Annadale (IMS)	Nuclear Waste and Projects Pickering Town Center -Pickering
Bell Building- Oshawa	Pickering
Clements road	Pickering Training Center -Pickering
Contract Management & Security office-1600 Champlain Whitby	Radiation Safety & IMS Divers-Victoria Street Whitby
Darlington	TMB
GM Building Sub-Lease	TRF
IMS -1610 Clements Pickering	Westlyville
IMS Warehouse	Whitby Warehouse
IMS Whitby	

The Current OPG Business Plan Will Bring Staffing Within ~350 of the Benchmark by 2014

- **The OPG Business Plan is generally headed in the right direction, reducing more than half of the benchmark variance by the end of 2014**
  - **Staffing is 866 above the benchmark.**
  - **Potential reasons for staffing above the benchmarking include material condition issues at Pickering A, and life cycle management and inspection initiatives to support continued operations at Pickering B.**
  - **Planned reductions are 498 for benchmarked staff out of 625 total planned reductions (127 are in non-benchmarked areas such refurbishment, IMS, etc.). OPG claims an additional 25 planned reductions in dedicated corporate support.**
  - **Staffing above the benchmark (866) minus planned reductions (498), minus additional planned corporate support reductions (25), results in 343 positions remaining above the benchmark at the end of 2014.**
  - **Assuming these reductions occur, OPG will be 6.7% above the 2011 benchmark at the end of 2014.**

Report Agenda – *Appendices*

- **Executive Summary**
- **Objectives**
- **Approach**
- **Establishing Benchmarks**
- **Findings**
- ***Appendices***

Report Agenda – *Appendices*

- **Appendix A: OPG Staffing by OPG Business Group**
- **Appendix B: OPG Staffing by Work Function**
- **Appendix C: Staffing Benchmarks and Comparisons with OPG**
- **Appendix D: Benchmark Development Details**

Note: Appendices A, B and C are electronic data files (spreadsheets) which are provided under separate cover

Appendix D – Benchmark Development Details

Factors In Adjusting Staffing From 2-Unit PWRs To A 2-Unit CANDU (1 of 5)

Topics, Programs, and Activities	Related Function(s)	Justification	Staffing Adjustments for 2-Units
Canadian Nuclear Safety Commission (CNSC)			
OPG as IPOC for CANDU Generic Issues			
Nominal 5-year License Interval	Licensing	More frequent licensing interval compared to US increases workload, but most licensing work is driven by changes to the design basis (or proof of lack of change). Total adjustment to increase nominally 10%	1
Supply Chain	Warehouse	More parts, components, and systems in CANDU design, increases workload of warehouse. Nominal adjustment of between 10-15%, settled at 12.5%	2
Demineralized Water Consumption	N/A	No basic difference with comparable systems in PWRs	0
Design Philosophy Differences			
Separation of Control and Safety Channels	Maintenance, Plant Engineering, Technical Engineering, Mods Engineering, etc.	See notes in Mechanical, Electrical, I&C components sections above impacts are included in those sections's adjustments	0

Factors In Adjusting Staffing From 2-Unit PWRs To A 2-Unit CANDU (2 of 5)

Inspection and Testing			
ISI / NDE	N/A	Discussed above in IMS Non-Destructive Examination	0
Surveillance Testing	N/A	Discussed above in IMS Non-Destructive Examination	0
Materials			
Carbon Steel Primary Heat Transport System	N/A	No basic difference with comparable systems in PWRs	0
Fuel Channels (Zr Alloy)	N/A	Excluded as part of the Non-Benchmarked Fuel Handling activities, which exludes FH operations, maintenance, and engineering	0
Systems and Major Components			
12 steam generators & 16 Main HTS Pumps/unit @ Pickering	Maintenance, Plant Engineering, Technical Engineering, Mods Engineering, etc.	See notes in Mechanical, Electrical, I&C components sections below, impacts are included in those sections's adjustments	0

Factors In Adjusting Staffing From 2-Unit PWRs To A 2-Unit CANDU (3 of 5)

Engineering and Maintenance Programs			
PM Program Tasks / Activities	Maintenance, Plant Engineering, Technical Engineering, Mods Engineering, etc.	See notes in Mechanical, Electrical, I&C components sections below, impacts are included in those sections's adjustments	0
Mechanical Components	Maintenance/Construction, Maintenance/Construction Support, Mods Engineering, Desig/Drafting, Plant Engineering, Procurement Engineering, and Technical Engineering	Additional parts, systems, and components at CANDUs estimated to be between 10-15% higher in quantity than PWRs. Additionally, more interconnections between units in contiguous 4-unit CANDU layout than compared to most 2-unit PWRs	43
Electrical Components	Maintenance/Construction, Maintenance/Construction Support, Mods Engineering, Desig/Drafting, Plant Engineering, Procurement Engineering, and Technical Engineering		
I&C / Computers	Maintenance/Construction, Maintenance/Construction Support, Mods Engineering, Desig/Drafting, Plant Engineering, Procurement Engineering, and Technical Engineering		
Reactivity Management in Calandria design, Fuels	Reactor Engineering, Nuclear Fuels		4
Corrective / Elective / Preventive Maintenance Backlogs	Maintenance/Construction, Maintenance/Construction Support, Plant Engineering	No significant difference identified. End of life issues driving PM programs at Pickering are similar to US plants facing end of life in the next decade	0
Radioactive Source Term	N/A - Covered Under ALARA above	N/A - Covered Under ALARA above	0
Building and Support Systems	Facilities	No significant difference identified. Non-Power block building maintenance for two units appears similar	0

Factors In Adjusting Staffing From 2-Unit PWRs To A 2-Unit CANDU (4 of 5)

Canadian Nuclear Safety Commission (CNSC)			
OPG as IPOC for CANDU Generic Issues		E - Not mentioned. D - Not mentioned in my interviews.	
Nominal 5-year License Interval	Licensing	More frequental licensing interval compared to US increases workload, but most licensing work is driven by changes to the design basis (or proof of lack of change). Total adjustment to increase nominally 10%	1
Supply Chain	Warehouse	More parts, components, and systems in CANDU design, increases workload of warehouse. Nominal adjustment of between 10-15%, settled at 12.5%	2
Demineralized Water Consumption	N/A	No basic difference with comparable systems in PWRs	0
Design Philosophy Differences			
Separation of Control and Safety Channels	Maintenance, Plant Engineering, Technical Engineering, Mods Engineering, etc.	See notes in Mechanical, Electrical, I&C components sections above impacts are included in those sections's adjustments	0

Factors In Adjusting Staffing From 2-Unit PWRs To A 2-Unit CANDU (5 of 5)

PWR Systems, Programs, and Issues			
Condensate Polishing	Maintenance, Plant Engineering, Technical Engineering, Mods Engineering, etc.	See notes in Mechanical, Electrical, I&C components sections above impacts are included in those sections's adjustments	0
TDAFW	Maintenance, Plant Engineering, Technical Engineering, Mods Engineering, etc.	See notes in Mechanical, Electrical, I&C components sections above impacts are included in those sections's adjustments	0
Boric Acid Corrosion	N/A	No basic difference with comparable systems in PWRs	0
Other: Support functions driven by core line organizational activities	Document control	Increase due to larger support requirements for more mods and maintenance activities identified above	2
	Project Management	Increase due to larger support requirements for more mods and maintenance activities identified above	1
	Scheduling	Increase due to larger support requirements for more mods and maintenance activities identified above	2
	Training	Additional maintenance technical training and overall GET training due to staff increases shown in all functions	3
	Outage Management	Additional preparation required for outage scope development and refinement driven by larger number of components and systems	3
Total FTE Adjustments for 2-Units from PWR to CANDU			**75**

Factors In Scaling From 2-Units to 4-Units

- To scale up 2-Units to 4-Units, we examined current functional staffing at 1-Unit, 2-Unit, and 3-Unit U.S. reactors
- We expected to identify functionally-based scaling factors going from 1 to 2, and from 2 to 3 units, that could be applicable; the analysis results showed inconsistent relationships for individual functions, including some cases where staffing levels were lower at a 2-Unit plant for the same function at a 1-Unit plant (this is an example of a "less efficient" Stand-Alone plant with no fleet economies of scale compared to a "very efficient" 2-Unit fleet plant that had optimized through centralization and standardization)
- These analysis results were too inconsistent to apply to scaling
- As a consulting team, which included experienced nuclear plant engineers and operators, we developed the scaling factors based on our experience and best estimates – for most functions, we applied a scaling factor of 1.8 times the 2-unit level for a 4-unit plant, which was based on staffing levels we have observed at several international 4-unit sites relative to our benchmark 2-unit sites
- Several exceptions from the 1.8x scaling factor were applied, and are shown in the body of this report (Operations, for example, requires fully staffed shift crews for each reactor or 2-unit set of reactors from our international observations)

2013 Nuclear Staffing Benchmarking Update

An Addendum To The 2011 Nuclear Staffing Benchmarking Analysis

A Report For:

ONTARIO POWER GENERATION

May 10, 2013

GOODNIGHT CONSULTING

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Report Agenda-
Introduction

- Introduction & Executive Summary
- Current Nuclear Staffing Benchmarks
- Comparison of Current & Previous Benchmarks
- Analysis of Change in Benchmarks
- Comparison of Current Benchmarks to OPG
- Appendix A

Goodnight Consulting Was Tasked To Update Key Portions Of The 2011 Benchmarking Report

Our tasking:

Identify 2013 Pressurized Water Reactor (PWR) benchmarks in a manner similar to the one utilized in the 2011 study

Compare the 2011 PWR benchmarks to the 2013 benchmarks on a functional basis

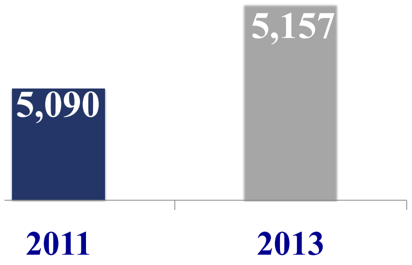
Provide explanations for differences between the 2011 and 2013 PWR benchmarks, where available

Compare OPG's current staffing plan to the 2013 PWR benchmarks to identify variances

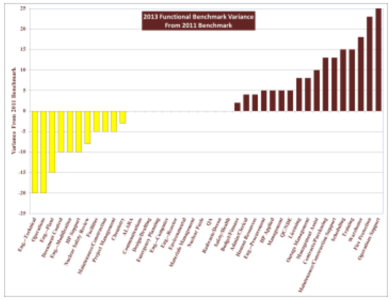
OPG Is Closer To The PWR Benchmarks In 2013 Than It Was In 2011

The 2013 PWR benchmark is 5,157, a 1.3% rise since the 2011 benchmark of 5,090

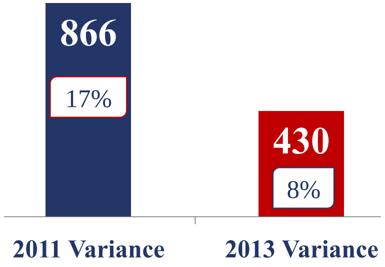
Scale starts at 5000



More job functions in the 2013 PWR *benchmarks* increased since 2011 than decreased, supporting an overall rise



In 2011 OPG was 17% (866 FTEs) above the PWR benchmark, in 2013 OPG is 8% (430 FTEs) above the PWR benchmark



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Report Agenda-
Current Nuclear Staffing Benchmarks

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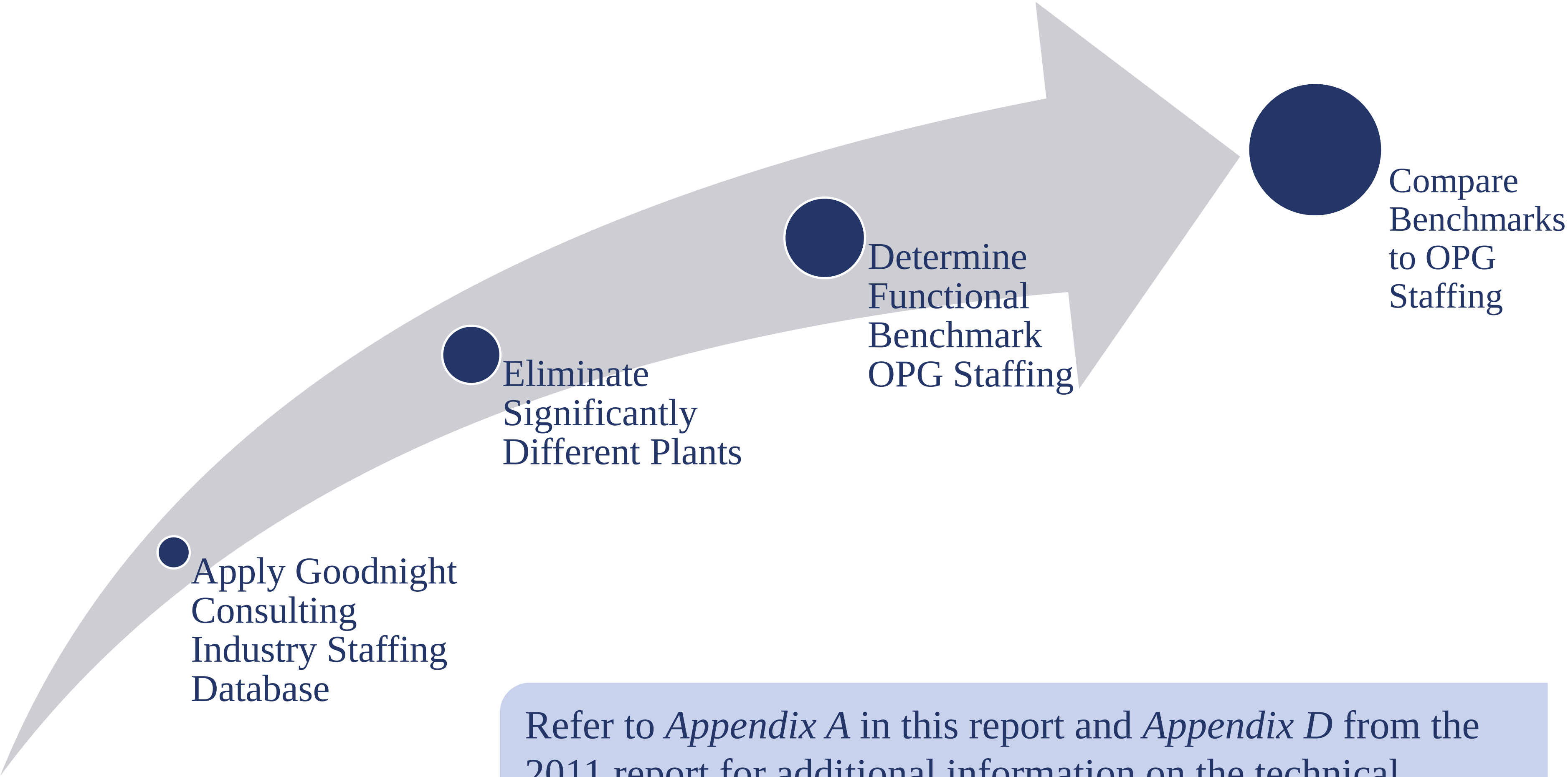
The Benchmarking Methodology Applied For This Report Was The Same As The One Utilized In The 2011 Report



Refer to *Appendix A* in this report and *Appendix D* from the 2011 report for additional information on the technical adjustments applied in identifying the benchmarks

Benchmarking Summary: Total 2013 OPG Nuclear Benchmark is 5,157

- A PWR benchmark of 987 was derived from Large 2-Unit US PWR staffing
- Adjustments were applied for:
  - Net differences in CANDU vs. PWR technologies
  - OPG work week differences
  - Workload requirements for Units 2 & 3 at Pickering A
- Scaling factors were applied to identify 4-Unit CANDU benchmarks
  - These benchmarks include contractor FTEs and corporate nuclear support

Refer to *Appendix A* for a detailed overview of the application of the benchmarking methodology

Benchmarking Summary: Total 2013 OPG Nuclear Benchmark is 5,157

	2-Unit PWR	PA**	PB**	DN	Total
Large 2-Unit US PWR benchmarks	987 *(965)**				
Adjust for 2-Unit CANDU	83 *(82)**				
Preliminary 2-Unit CANDU benchmark	1,070 *(1,047)**	1,070 *(1,047)**	1,070 *(1,047)**	1,070 *(1,047)**	
Adjust for 35 Hour Work Week		58 *(58)**	58 *(58)**	58 *(58)**	
Adjust for PA Units 2 & 3		17 *(17)**			
Adjust for Scaling from 2 to 4 Units			878 *(879)**	878 *(879)**	
		1,145 *(1,122)**	2,006 *(1,984)**	2,006 *(1,984)**	5,157 *(5,090)**

**2011 Number*

**We did not analyze the impacts of the amalgamation of Pickering A & Pickering B as it was outside the scope of this study-we estimate it would slightly decrease the need for senior management and admin/clerical personnel by ~10 FTEs

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Report Agenda-
Comparison of Current & Previous Benchmarks

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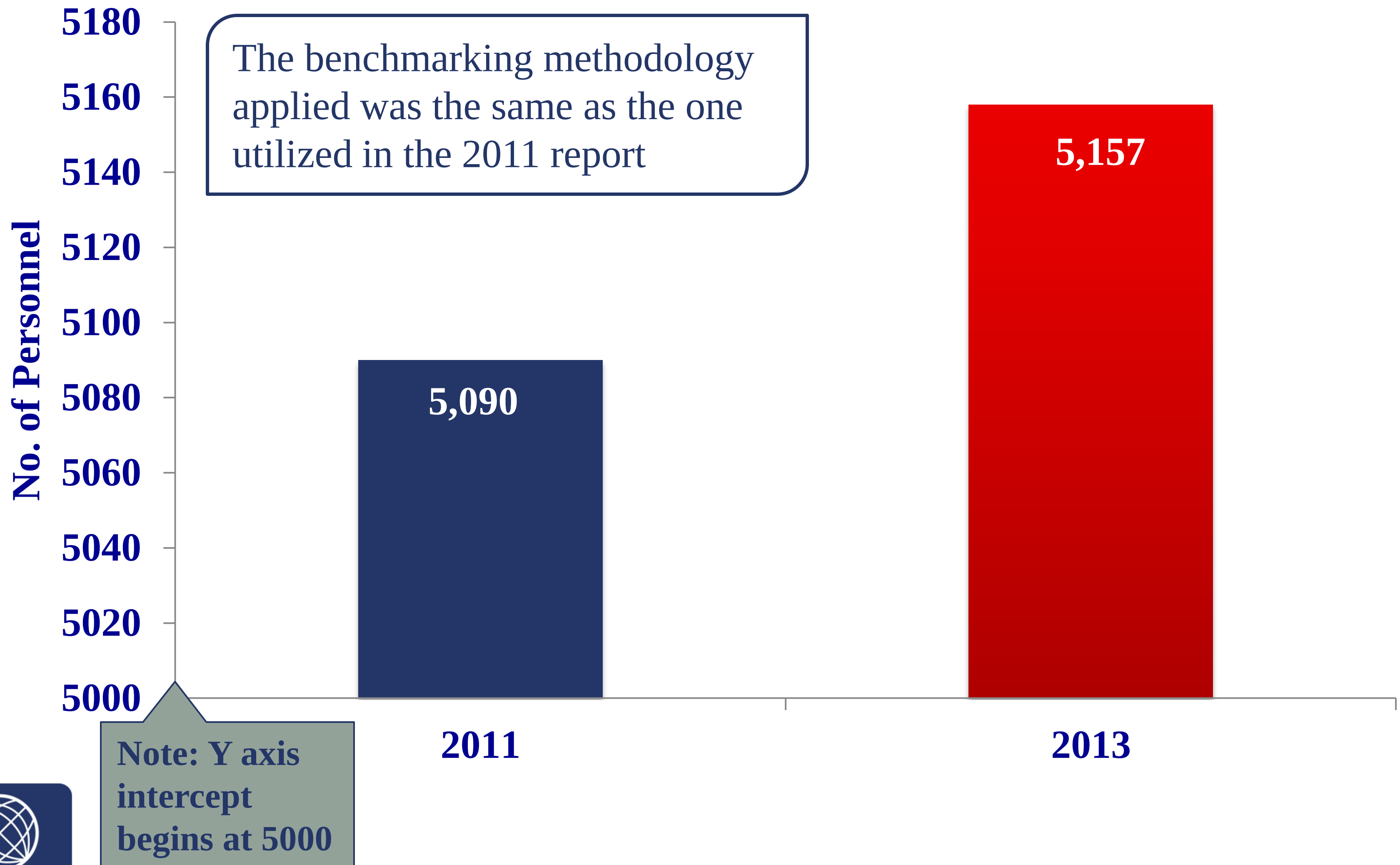
The 2013 OPG *Staffing Benchmark* Has Increased By 67 FTEs (1.3%) Since 2011



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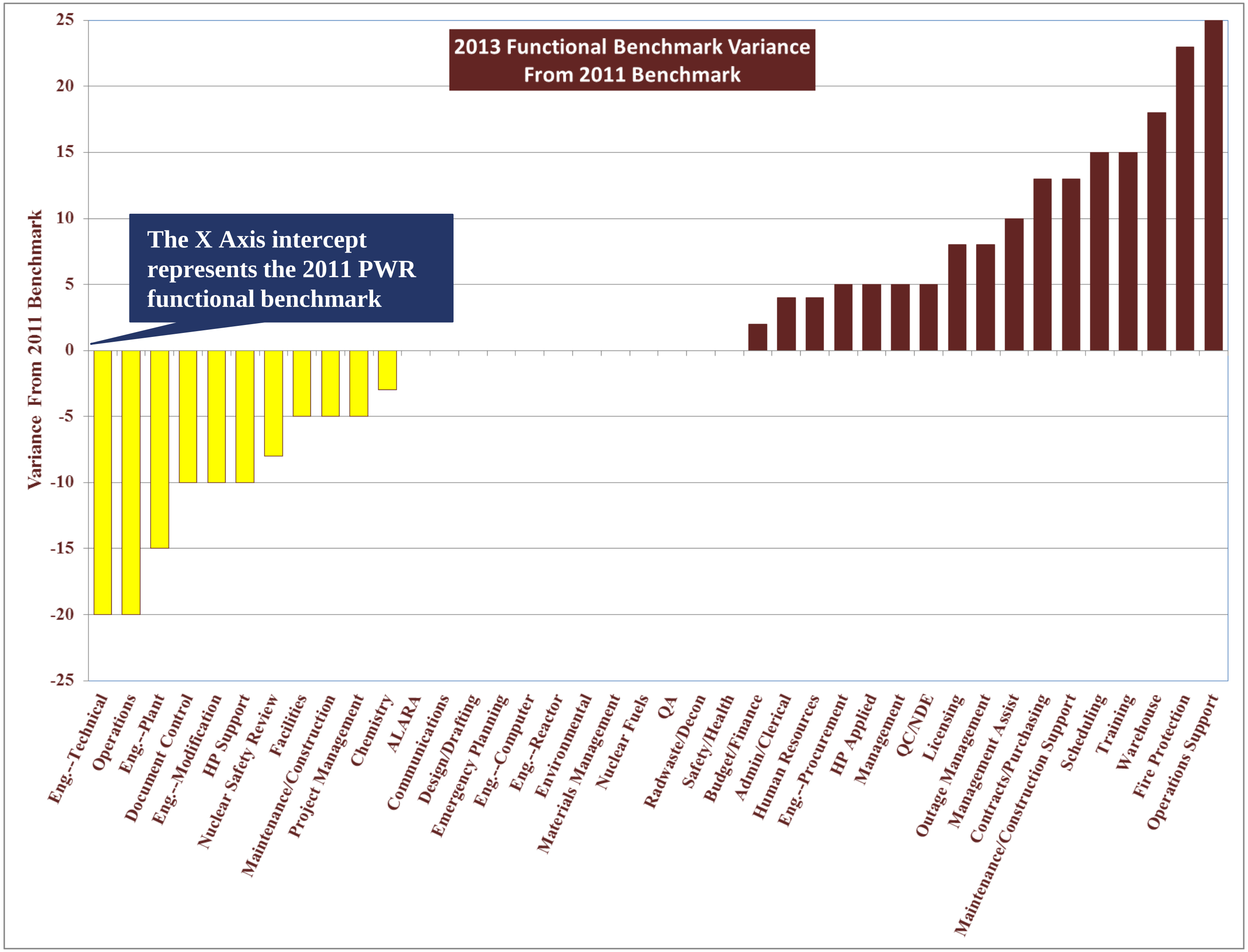
Most Job Functions In The 2013 PWR Benchmarks Increased Since 2011, Resulting In An Overall Rise



Report Agenda-
Analysis of Change in Benchmarks

- Introduction & Executive Summary
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The Following Section Provides An Analysis Of The Changes In The PWR Benchmarks Since 2011

This format will be utilized throughout the following section

2011 PWR Staffing Benchmark

2013 PWR Staffing Benchmark

Applicable Staffing Function (in bold)

Goodnight Consulting analysis of change

	2011 PWR B'Mark	2013 PWR B'Mark
Chemistry		
Attrition without full replacement, Chemistry has become less challenging with replacement of steam generators	28	27
Environmental		
No program/functional change	5	5
Operations		
Downside of cyclical staffing associated with ongoing Operations staffing	126	122
Operations Support		
Increase in Operations training candidates to adjust for the down cycle in qualified Operators	30	35
Grand Total	**189**	**189**

Security and Information Management were both excluded, as in the 2011 study

Just as in 2011, US PWR benchmarks provide the baseline for the 2013 OPG benchmarks

The Total *Operate The Plant* PWR Benchmark Is The Same As It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
Chemistry		
Attrition without full replacement, Chemistry has become less challenging with replacement of steam generators	28	27
Environmental		
No program/functional change	5	5
Operations		
Downside of cyclical staffing associated with ongoing Operations staffing	126	122
Operations Support		
Increase in Operations training candidates to adjust for the down cycle in qualified Operators	30	35
Grand Total	**189**	**189**

The *Work Management* PWR Benchmark Is Higher Than It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
ALARA		
No program/functional change	6	6
HP Applied		
"Hotspots" within the plant increasing due to age and contamination	28	29
HP Support		
Technology improvements in TLDs (Dosimeters)	12	10
Maintenance/Construction		
In spite of overall maintenance requirements increasing, function decreased due to aging workforce	194	193
Maintenance/Construction Support		
More maintenance required due to aging plants	47	50
Outage Management		
Research changes in outage management in trade publications	8	10
Project Management		
Threshold for projects sent to PMs has increased	13	12
Safety/Health		
Industrial safety programs did not change	5	5
Scheduling		
Less efficient due to training requirements for younger staff	17	20
Grand Total	**330**	**335**

The *Equipment Reliability* PWR Benchmark Is Lower Than It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
Engineering - Computer		
No program/functional change	5	5
Engineering - Plant		
Pipeline of candidates is shrinking and attrition has made finding replacements more difficult	51	48
Engineering - Technical		
Attrition	36	33
QC/NDE		
Increase in inspections due to aging equipment	8	9
Grand Total	**100**	**95**

The *Configuration Management* PWR Benchmark Is Slightly Lower Than It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
Design/Drafting		
Increase in modifications offset by improvements in technology/digitization	7	7
Engineering - Mods		
More selective approvals for design changes	28	26
Engineering - Procurement		
Deemed as a less desirable position by senior staff and has become a "training ground" staffed with less-experienced, and therefore less efficient, personnel	7	8
Engineering - Reactor		
Result of significant digital upgrades across the industry-Plants have switched from analog to digital control systems	8	5
Nuclear Fuels		
Several utilities have taken their fuels procurement process in house	6	9
Grand Total	**56**	**55**

The *Materials & Services* PWR Benchmark Is Higher Than It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
Contracts/Purchasing		
Aging plants and equipment obsolescence require additional contracts	10	12
Materials Management		
No program/functional change	6	6
Warehouse		
More parts and components require more support personnel for coordination	16	20
Grand Total	**32**	**38**

The *Loss Prevention* PWR Benchmark Is Higher Than It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
Emergency Planning		
No program/functional change	7	7
Fire Protection		
Operators no longer qualified to provide fire brigade support requiring more fire brigade	23	28
Licensing		
Increase in requirements post-Fukushima	9	10
Nuclear Safety Review		
No available information	11	10
QA		
No program/functional change	14	14
Radwaste/Decon		
Pay per volume to ship waste out provides an incentive to keep volume low	12	12
Grand Total	**76**	**81**

The *Support Services & Training* PWR Benchmark Is Higher Than It Was In 2011

	2011 PWR B'Mark	2013 PWR B'Mark
Admin/Clerical		
Ratio function; a few more nuclear utilities admin personnel organized	37	39
Budget/Finance		
Reporting requirements have become more stringent (ie Sarbanes Oxley)	11	13
Communications		
No program/functional change	3	3
Document Control		
Reduction in labor cost; leveraging newer technologies	16	15
Facilities		
Reduction in labor cost; installation of facilities with lower maintenance	25	24
Human Resources		
Utilities are facing a more challenging regulatory environment in addition to more workforce planning and attrition issues	4	7
Management		
Ratio Function; Aging workforce and attrition-driven organizational changes (ie more "Deputy" 1 over 1 leadership positions)	37	40
Management Assist		
More senior technical personnel that plants want to retain	3	4
Training		
Aging plants and obsolete equipment replacements requires more training	46	49
Grand Total	**182**	**194**

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Report Agenda-
Comparison of Current Benchmarks to OPG

- Introduction & Executive Summary
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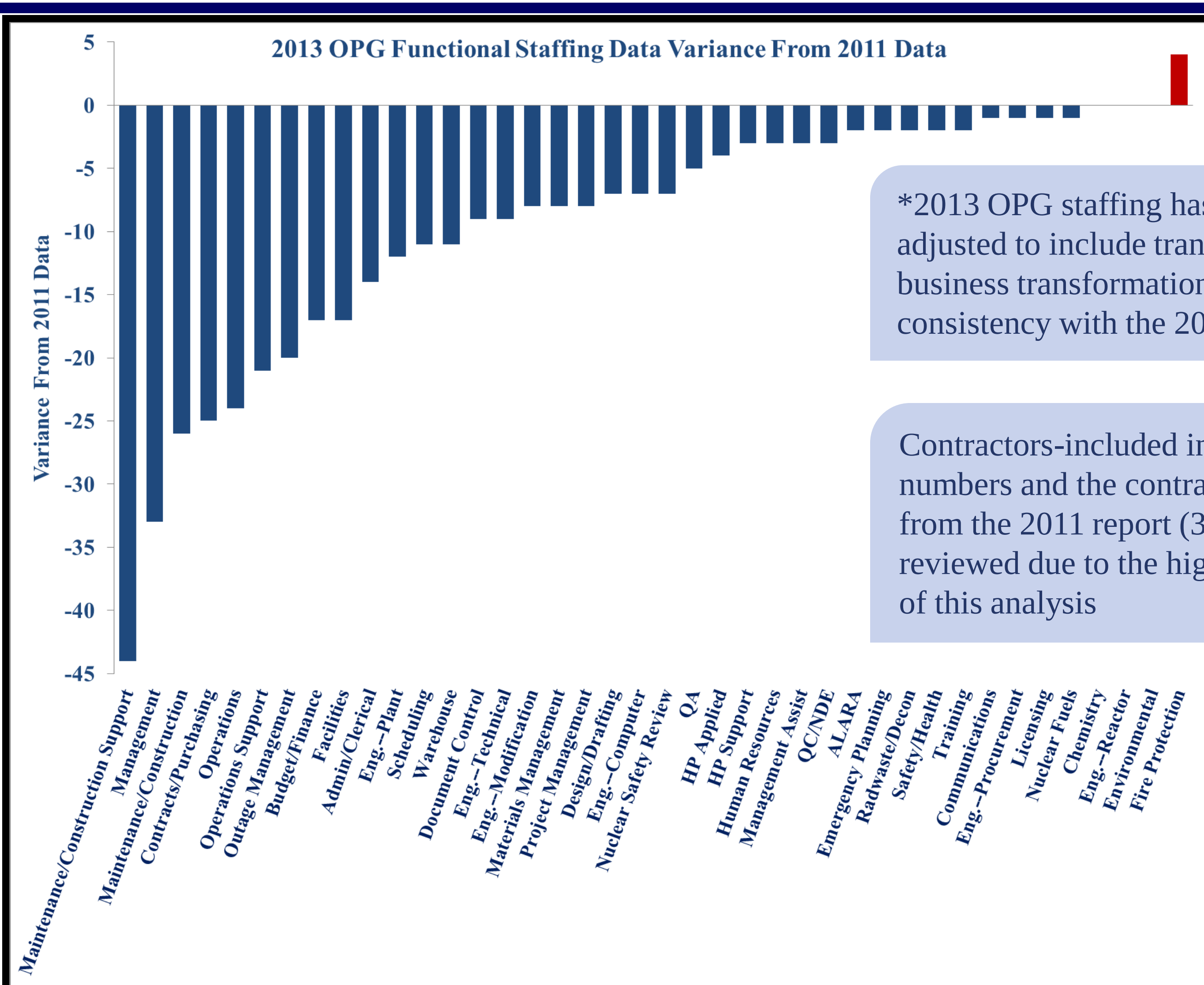
Since 2011, OPG Staffing Has Decreased Or Remained The Same In All But One Job Function*



*2013 OPG staffing has been adjusted to include transfers due to business transformation to ensure consistency with the 2011 study

Contractors-included in these numbers and the contractor count from the 2011 report (382) were not reviewed due to the high-level scope of this analysis

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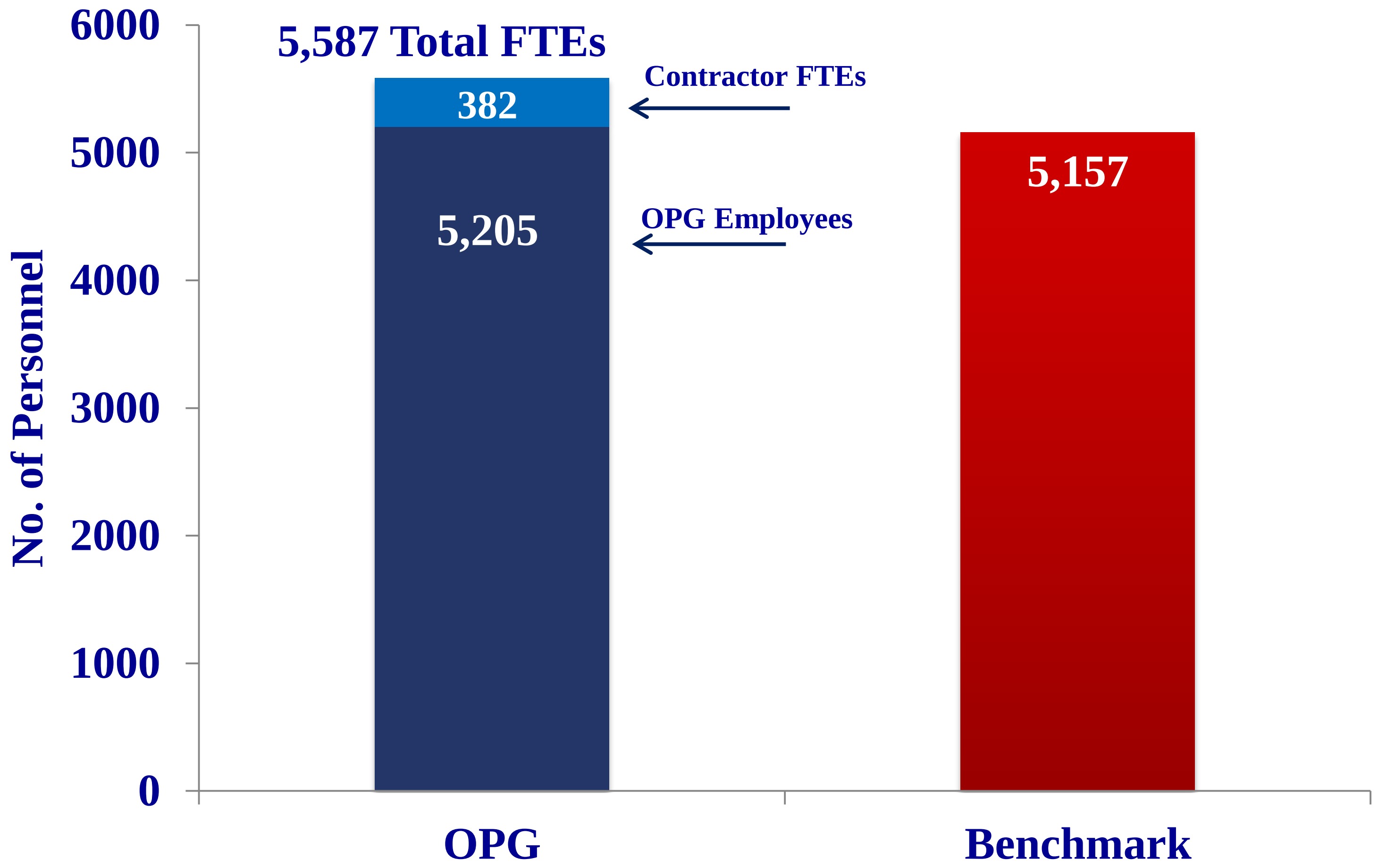
The Variance Between OPG 2013 Staffing & 2013 Benchmark Is 430 FTEs (8%)



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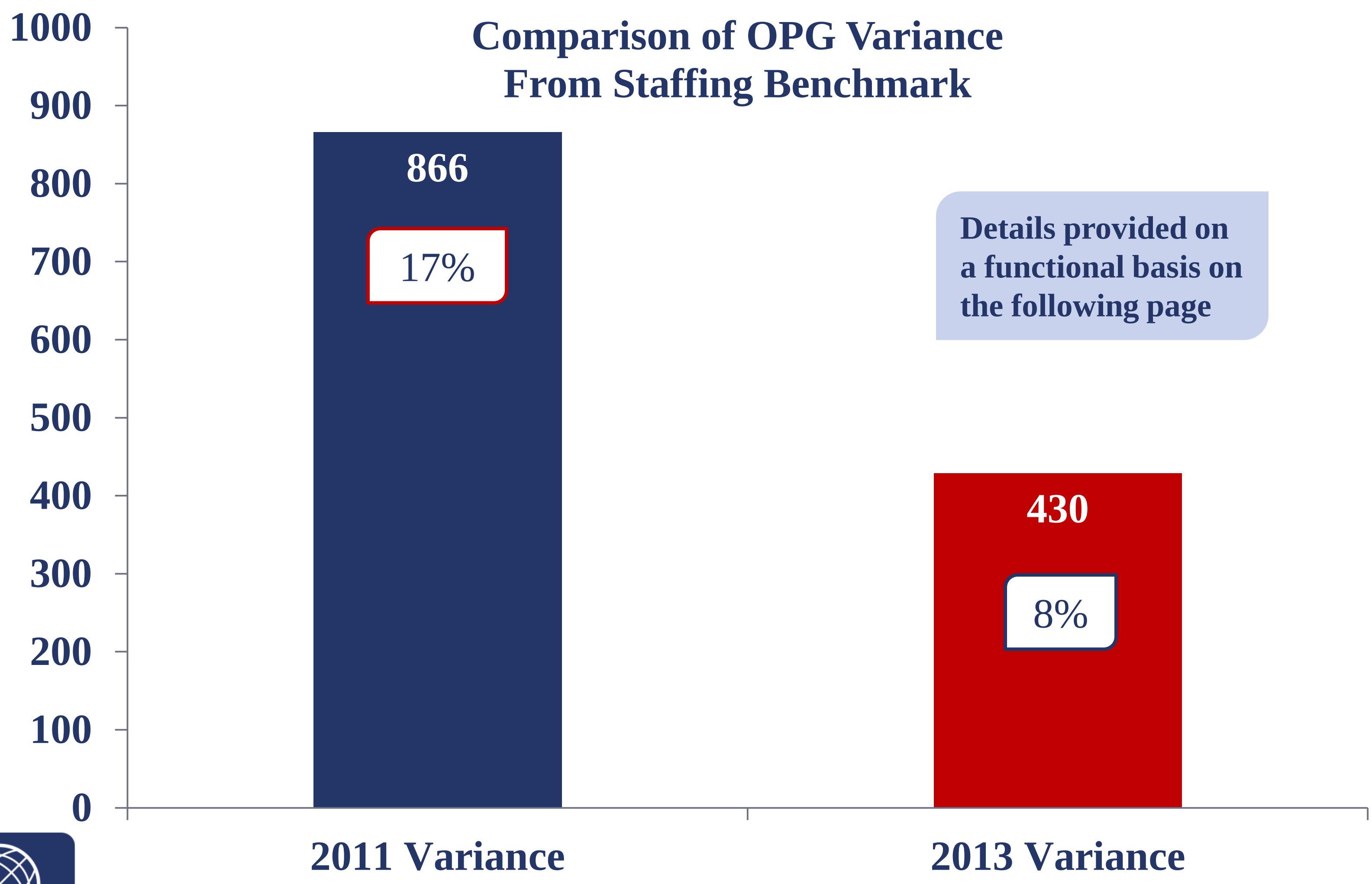
EB-2013-0321
Ex. F5-1-1 Part b

The Gap Between OPG & The Benchmark Is 436 FTEs Smaller In 2013 Than It Was In 2011



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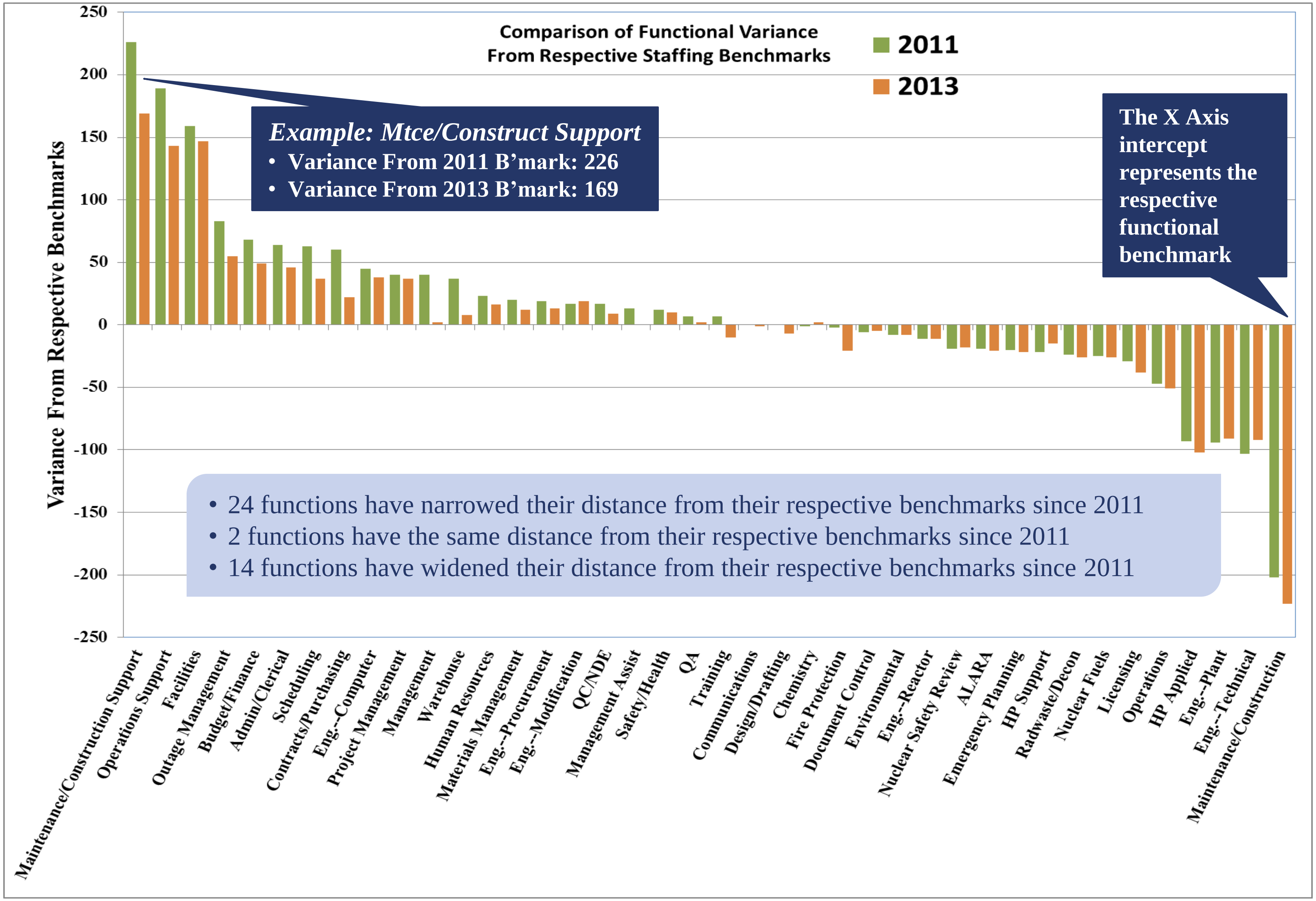
OPG's Variance From The Applicable Benchmark Has Narrowed In 24 Functions Since 2011



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Report Agenda-
Comparison of Current Benchmarks to OPG

2013 2-Unit CANDU *Staffing Benchmark* Is 1,070 Personnel (Includes Corporate & Contractors)

Staffing Function	2013 2-Unit U.S. PWR Bmk	Raw Adjustments 2013	Benchmark Ratio %	Ratio Adjustments	Total Adjustments	Total Bmk (2013)
Admin/Clerical	39	Ratio	3.95%	3	3	42
ALARA	6	2			2	8
Budget/Finance	13	Ratio	1.32%	1	1	14
Chemistry	27	0			0	27
Communications	3	0			0	3
Contracts/Purchasing	12	0			0	12
Design/Drafting	7	1			1	8
Document Control	15	2			2	17
Emergency Planning	7	0			0	7
Engineering - Computer	5	0			0	5
Engineering - Mods	26	3			3	29
Engineering - Plant	48	8			8	56
Engineering - Procurement	8	2			2	10
Engineering - Reactor	5	5			5	10
Engineering - Technical	33	5			5	38
Environmental	5	2			2	7
Facilities	24	0			0	24
Fire Protection	28	0			0	28
HP Applied	29	3			3	32
HP Support	10	1			1	11
Human Resources	7	Ratio	0.71%	1	1	8
Licensing	10	1			1	11
Maintenance/Construction	193	22			22	215
Maintenance/Construction Support	50	4			4	54
Management	40	Ratio	4.05%	3	3	43
Management Assist	4	0			0	4
Materials Management	6	0			0	6
Nuclear Fuels	9	-1			-1	8
Nuclear Safety Review	10	0			0	10
Operations	122	0			0	122
Operations Support	35	0			0	35
Outage Management	10	3			3	13
Project Management	12	1			1	13
QA	14	0			0	14
QC/NDE	9	1			1	10
Radwaste/Decon	12	3			3	15
Safety/Health	5	Ratio	0.51%	0	0	5
Scheduling	20	2			2	22
Training	49	3			3	52
Warehouse	20	2			2	22
Total	**987**	**75**		**8**	**83**	**1070**

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Similar Technical Adjustments From 2011 Were Used To Identify The 2013 *Staffing Benchmark*

Staffing Function	Rationale
Admin/Clerical	Ratio of these functional staff is related to the total final staffing level
ALARA	"Hotter shop" tritium, alpha radiation pervasive, more opportunities for ALARA-more equipment, bigger source of radiation and more space.
Budget/Finance	Ratio of these functional staff is related to the total final staffing level
Chemistry	No basis for adjustment
Communications	No basis for adjustment
Contracts/Purchasing	No basis for adjustment
Design/Drafting	Higher number of systems
Document Control	Higher number of systems, more control documents to manage
Emergency Planning	No basis for adjustment
Engineering - Computer	No basis for adjustment
Engineering - Mods	Higher number of systems
Engineering - Plant	Higher number of systems
Engineering - Procurement	Higher number of commercial parts dedications due to a smaller vendor market, lower availability of conforming parts
Engineering - Reactor	Adjusted to 2-unit equivalent of OPG CANDU stated requirements
Engineering - Technical	Higher number of systems, diversity instead of redundancy design philosophy
Environmental	Tritium monitoring, Canadian regulatory requirements
Facilities	No basis for adjustment
Fire Protection	No basis for adjustment
HP Applied	Additional radiation sources, differences in staffing are due to choices in program structures
HP Support	Additional radiation sources, differences in staffing are due to choices in program structures
Human Resources	Ratio of these functional staff is related to the total final staffing level
Licensing	Different regulatory scheme, greater number of safety systems, design philosophy of diversity over redundancy
Maintenance/Construction	Higher number of systems, diversity instead of redundancy design philosophy-track IMS impacts on numbers
Maintenance/Construction Support	Higher number of systems, diversity instead of redundancy design philosophy
Management	Ratio of these functional staff is related to the total final staffing level
Management Assist	No basis for adjustment
Materials Management	No basis for adjustment
Nuclear Fuels	Adjusted to 2-unit equivalent of OPG CANDU stated requirements
Nuclear Safety Review	No basis for adjustment
Operations	Additional systems to monitor= increases, common systems = decreases
Operations Support	Additional systems to monitor= increases, common systems = decreases
Outage Management	Non fueling outages=decreases, more systems to deal with during an outage=increase
Project Management	Higher number of systems, diversity instead of redundancy design philosophy
QA	No basis for adjustment
QC/NDE	Due to additional maintenance work, additional QC/NDE work is required, "Innate" IMS counted here,
Radwaste/Decon	"Hotter shop" tritium, alpha radiation pervasive, more opportunities for deconning-more equipment, bigger source of radiation and more space. Larger volumes of I&LLW generated and packaged.
Safety/Health	Ratio of these functional staff is related to the total final staffing level
Scheduling	Greater number of systems resulting in more scheduling work
Training	Additional trainers required to handle additional maintenance training requirements
Warehouse	Additional parts and components needed for more systems and to overcome more materials kept on hand due to a smaller vendor base

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2013 2-Unit *OPG* CANDU *Staffing Benchmark* Is 1,128 (vs. 1,105); 4-Unit *OPG* CANDU *Staffing Benchmark* Is 2,006 (vs. 1984)

2-unit to 4-unit Scaling Factors, by Functional Area								
Staffing Function	2-Unit CANDU Benchmark	35 hour week	Adjustment for 35 hour week	Scaling Factor From 2 to 4-Units	Initial 4-Unit CANDU Benchmark	Benchmark Ratio %	Ratio Staffing	4-Unit CANDU Benchmark
Admin/Clerical	42	1	48	Ratio		3.76%	69	69
ALARA	8		8	1.8	14			14
Budget/Finance	14	1	16	Ratio		1.12%	20	20
Chemistry	27		27	1.8	49			49
Communications	3		3	1.8	5			5
Contracts/Purchasing	12	1	14	1.8	25			25
Design/Drafting	8	1	9	1.8	16			16
Document Control	17	1	19	1.9	36			36
Emergency Planning	7	1	8	1.5	12			12
Engineering - Computer	5	1	6	2	12			12
Engineering - Mods	29	1	33	1.8	59			59
Engineering - Plant	56	1	64	1.8	115			115
Engineering - Procurement	10	1	11	1.8	20			20
Engineering - Reactor	10	1	11	2	22			22
Engineering - Technical	38	1	43	1.8	77			77
Environmental	7	1	8	1.8	14			14
Facilities	24		24	1.8	43			43
Fire Protection	28		28	1.8	50			50
HP Applied	32		32	1.8	58			58
HP Support	11	1	13	1.8	23			23
Human Resources	8	1	9	Ratio		0.41%	7	7
Licensing	11	1	13	1.8	23			23
Maintenance/Construction	215		215	1.8	387			387
Maintenance/Construction Support	54		54	1.8	97			97
Management	43	1	49	Ratio		3.76%	69	69
Management Assist	4	1	5	1.8	9			9
Materials Management	6	1	7	1.8	13			13
Nuclear Fuels	8	1	9	1.8	16			16
Nuclear Safety Review	10	1	11	1.8	20			20
Operations	122		122	2	244			244
Operations Support	35		35	2	70			70
Outage Management	13		13	1.8	23			23
Project Management	13	1	15	1.8	27			27
QA	14	1	16	1.8	29			29
QC/NDE	10		10	1.8	18			18
Radwaste/Decon	15		15	1.8	27			27
Safety/Health	5	1	6	Ratio		0.51%	9	9
Scheduling	22		22	1.8	40			40
Training	52		52	1.8	94			94
Warehouse	22	1	25	1.8	45			45
Total	**1070**		**1128**		**1832**		**174**	**2006**

- Where applicable, adjustments were made for OPG's 35 Hour Work work week vs. 40 hour weeks at U.S. plants(same approach as 2011); the net increase in 2-Unit benchmarks is 62 FTEs (5.8%)
- CANDU 2-Unit was then scaled up to a 4-Unit model

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Adjustments For Pickering Units 2 & 3 Increase The 2-Unit CANDU Benchmark From 1,070 To 1,145

Adjustments to 2-Unit OPG CANDU for Pickering A						
Staffing Function	2-Unit CANDU Benchmark	35 hour week	Adjustment for 35 hour week	Adjustments for Units 2 & 3	Pickering A Benchmark	Rationale
Admin/Clerical	42	1	48		48	
ALARA	8		8		8	
Budget/Finance	14	1	16		16	
Chemistry	27		27		27	
Communications	3		3		3	
Contracts/Purchasing	12	1	14		14	
Design/Drafting	8	1	9		9	
Document Control	17	1	19		19	
Emergency Planning	7	1	8		8	
Engineering - Computer	5	1	6		6	
Engineering - Mods	29	1	33		33	
Engineering - Plant	56	1	64	4	68	One additional System Engineer per discipine (M, E, I&C, Civil)
Engineering - Procurement	10	1	11		11	
Engineering - Reactor	10	1	11		11	
Engineering - Technical	38	1	43		43	
Environmental	7	1	8		8	
Facilities	24		24		24	
Fire Protection	28		28		28	
HP Applied	32		32	1	33	One additional Rad Pro technican to conduct surveillances
HP Support	11	1	13		13	
Human Resources	8	1	9		9	
Licensing	11	1	13		13	
Maintenance/Construction	215		215	5	220	Estimated Additional staff (FIN-like)
Maintenance/Construction Suppor	54		54	1	55	Ratio of support to additional Maintenance/Construction
Management	43	1	49	1	50	1 Additional Management person to oversee units 2 & 3 Activities
Management Assist	4	1	5		5	
Materials Management	6	1	7		7	
Nuclear Fuels	8	1	9		9	
Nuclear Safety Review	10	1	11		11	
Operations	122		122	5	127	1 Additional Ops person per shift crew for rounds
Operations Support	35		35		35	
Outage Management	13		13		13	
Project Management	13	1	15		15	
QA	14	1	16		16	
QC/NDE	10		10		10	
Radwaste/Decon	15		15		15	
Safety/Health	5	1	6		6	
Scheduling	22		22		22	
Training	52		52		52	
Warehouse	22	1	25		25	
Total	**1070**		**1128**	**17**	**1145**	

- Refer to the 2011 report for a detailed explanation of adjustments applied for Pickering Units 2 & 3

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ONTARIO POWER GENERATION

URANIUM PROCUREMENT PROGRAM ASSESSMENT

Prepared for: Ontario Power Generation

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CONTENTS

1. Executive Summary

The Ontario Energy Board (OEB) directed Ontario Power Generation Inc. (OPG) to file an external review of OPG's uranium procurement program as part of its next rate application "to determine whether the company is optimizing its contracting, in order to minimize costs to ratepayers."

In response to this direction, Longenecker & Associates (L&A) was retained by OPG through a competitive procurement process.

In preparation of this Report, L&A has undertaken an extensive assessment of OPG's uranium procurement activities, including reviewing purchasing strategies, contracts, risk limit methodology, and inventory policy.

1.1. Summary Assessment and Recommendation

Longenecker & Associates' summary conclusion and recommendation is as follows:

- We find OPG's procurement program appropriate and fully inclusive of the various factors involved in other utility uranium procurement programs, as further described below.

A complete list of our conclusions and recommendations is found at the end of this assessment.

1.2. OPG's Uranium Procurements

- OPG's uranium procurements have been undertaken in a professional manner, using evaluation criteria that give appropriate consideration to diversity of supply, relative capabilities and risk of performance of suppliers, and an appropriate mix of contracts (spot versus long-term, fixed price versus market-related, etc).
- We find OPG's uranium purchasing activities consistent with those of other utilities surveyed.
- We find OPG's forward uranium contract coverage consistent with the aggregated contract coverage of US utilities, as published by the US Energy Information Administration (EIA).
- We find OPG's target inventory policy consistent with other utilities' inventory policies.
- We recommend that OPG maintain, consistent with the physical coverage limits, a continuing presence in the uranium market by frequent market contracting in order to maximize opportunities to achieve attractive contract terms and encourage potential suppliers to solicit OPG's business.

- We recommend revisiting the Physical and Financial Risk Limits on a more regular basis than has been done, given the dynamics in the market.
- We recommend that OPG ensure that its Financial Coverage Limits continue to enable effective monitoring of the degree of price certainty, as new pricing determinants emerge.
- We recommend that OPG evaluate its inventory levels on an ongoing basis based on an assessment of potential supply risks.
- We recommend that OPG explore "off-market" negotiated transactions that may provide value by lowering its costs and providing terms and conditions that are not offered in open market transactions.

1.3. Structure of Report

This Report is structured to provide (1) a description of the Scope of Work requested by OPG, (2) an overview of the uranium market, L&A's methodology, and the documents and information sources reviewed by L&A, (3) comparisons with other utilities' uranium procurement programs, and inventory policies, and with publically available information from the US and Europe, and (4) Longenecker & Associates Assessments and Recommendations for OPG's future review of inventory levels and uranium procurement activities.

2. OPG's Requested Scope of Work

OPG requested that L&A conduct an independent third party review of OPG's uranium procurement program including reviewing OPG's current uranium procurement portfolio, plans and strategies relative to the program's objectives, and provide recommendations for improvement. The specific scope of work that OPG requested included the following:

2.1. Review of Risk Limits

- Review and assess the appropriateness of OPG's Physical and Financial Coverage Limits for uranium procurement.
- Provide recommendations on alternatives or adjustments to OPG's Physical and Financial Coverage Limits.

2.2. Review supply risk and supply risk mitigation strategies by reference to recent uranium concentrates (U308) supply contracts

- Review and assess items such as the evaluation criteria, proposal evaluations, standard contract terms and conditions, and supplier diversity.
- Assess level of supply risk from OPG's existing contract portfolio versus OPG's risk limits, and versus other utilities.

- Provide recommendations on contract improvements for future uranium procurement.

2.3. Review price risk and price risk mitigation strategies by reference to recent uranium concentrates (U308) supply contracts

- Review and assess factors such as market timing, use of market forecasts, pricing mechanisms.
- Assess level of price risk of existing contract portfolio versus OPG's risk limits and versus other utilities.
- Provide recommendations on price risk and risk mitigation strategies for future uranium procurement.

2.4. Review of current minimum inventory targets

- Review and assess OPG's inventory targets versus other utilities.
- Provide any recommendations on alternative inventory targets.

2.5. Provide an overall assessment of OPG's uranium procurement program

- Assess its ability to achieve low cost while meeting OPG's supply and inventory objectives.
- Include comparisons to other utilities.
- Provide any recommendations for improvement.

3. Overview of Uranium Market

The Uranium Market involves transactions with deliveries categorized in three different time frames, spot contracts call for deliveries within 12 months, mid-term contracts generally involve deliveries beyond 12 months and completed within the next 3 years, and long-term contracts involve deliveries extending longer than 3 years. Long-term contract terms range as long as 10 years, but typically run 3 to 5 years, with the first delivery usually occurring within 24 months of contract award.

Reporting of transactions in the uranium industry continues to be somewhat imprecise and difficult to validate, and has grown more so, given the increased activity of financial entities in the market.

In their December, 2011 ***TradeTech's Nuclear Market Review*** issued in January 2012, reported that in 2011, there were *313* "near-term" transactions representing *45.77* million pounds U3O8 equivalent.

In their January 23, 2012 edition, ***UxC's UxWeekly*** reported 2011 Spot Market volume as *55.4* million lbs U3O8e based on *365* transactions, with the number of small transactions, those below 100,000 pounds, having increased greatly in 2011.

UxC reported "actual" demand, essentially purchases by utility end-users that will enter the pipeline inventory, (versus "discretionary" demand), amounted to 16.2 million pounds U3O8e or only 30% of the overall volume of transactions in 2011.

Spot Market--As indicated, spot transactions, those involving immediate or near term deliveries represent a relatively small portion of the total amount of uranium traded annually, and much of the volume traded in spot transactions does not involve utility end-users.

Mid-Term Market--The "mid-term" market is a relatively recent delineation in uranium transaction reporting. TradeTech initiated monthly postings of a Mid-Term U3O8 Price indicator beginning in mid-2009. Mid-term market transactions often involve arbitrage transactions by brokers and financial entities with access to financing at lower costs than utility end-users. Mid-term prices are driven by the comparative levels of spot prices versus long-term prices and the cost and availability of financing.

Mid-term market transactions are often structured on a back-to-back basis with aggregated purchases on the spot market being resold to utility end-users. Therefore on an annual basis, mid-term market transactions may involve double reporting of volumes previously sold in spot transactions.

Long Term Market--Deliveries under long-term contracts represent the vast majority of contracted supplies. Total uranium consumed worldwide in 2010 was about 174 million lbs U3O8, and about 177 million lbs U3O8 in 2011. It was estimated that 87% of uranium delivered worldwide in 2010 was sold under long-term, multi-year contracts.

Historically, long-term contracts have been priced using an escalated base price or tied to the spot market price at time of delivery. Recently a significant volume of long-term contracts contain what is termed "hybrid pricing" or pricing based on a combination of spot market at time of delivery and an escalated base price, generally with escalating floor and ceiling prices. TradeTech estimates that 85% of long-term contracts awarded in the last 18 months involved "hybrid pricing". Obviously, the level of floor and ceiling prices vary with market conditions and a discount from the future spot market also may be achievable depending upon market conditions.

TradeTech reported that there were 16 new sales agreements under term contracts in 2011 covering 19.27 million lbs U3O8e, down significantly from 19 contracts covering 74.4 million lbs U3O8e in 2010, when the Chinese were more active in the long term market. TradeTech data also shows that prior to 2007 Long Term Prices and Spot Prices tended to track closely , but since then there has been a divergence between Spot and Long Term Prices, with a more gradual change in the trend of Long Term Prices. Since 2008, Long Term Prices have been an average of 35% higher than Spot Prices.

4. Methodology

4.1. Process for Assessing OPG's Uranium Procurement Strategy

L&A initiated its assessment by reviewing OPG's recent procurement activities in a chronological manner, and surveyed other utilities regarding their uranium procurement programs. Additional information was gathered from the US Department of Energy, Energy Information Administration (EIA) on US utility inventory and procurement patterns, and from the World Nuclear Association (WNA) and European Atomic Energy Community (EURATOM) on inventory levels.

Conference calls involving discussions with various OPG Fuel Working Group personnel, in addition to an in-person meeting with OPG's fuel specialists, were undertaken as L&A assessed OPG's uranium procurement program and its risk limits methodology. L&A also evaluated the prices OPG paid to uranium suppliers on an annual basis.

L&A's conclusions and recommendations about OPG's uranium procurement program were based on its review and discussions, and on the authors' extensive personal utility experience in uranium markets and their understanding of other utility uranium procurement programs.

4.2. OPG's Filing with the OEB

L&A reviewed OPG's May 26, 2010 Nuclear Fuel Cost filing with the OEB, (EB-2010-0008 Exhibit F2, Tab 5, Schedule 1).

4.3. Review of OPG's Objectives and Methods

L&A reviewed the stated objectives and methods of OPG's Uranium Procurement Program. OPG's objectives are as follows:

- Ensure adequate supplies of uranium are available to meet the operational requirements of OPG's nuclear units, a combined 6,600 MW of generating capability at the Pickering and Darlington Nuclear Power Stations.
- Manage the risks, particularly the price, market and credit risks, associated with the supply of uranium.
- Minimize cost consistent with the other objectives.

OPG identified that these objectives are met through the following methods:

- Purchase within physical limits:
  - Forces regular entry into markets, which reduces significant fluctuations in the average price paid by OPG;
  - Encourages diversity of supply, which reduces the impact of individual supply disruptions.
- Purchase within financial limits (relating to that portion of supply under “fixed” price arrangements):
  - Mitigates near term market uncertainty;
  - Encourages diversity of price mechanisms.
- Operate within credit limits:
  - Mitigates exposure to the financial impact of default risk;
  - Encourages diversity of supply.
- Maintain a strategic inventory of uranium:
  - Mitigates the impact of supply disruptions and ensures continuous reactor operations.
- Employ competitive and fair procurement practices:
  - Provides the opportunity to achieve the best value for money.

4.4. Review of OPG’s Risk Limits

Risk management is a widely used quantitative technique applied in many areas of business to evaluate comparative risks of various outcomes. Beginning in 2008, OPG began utilizing a risk management methodology to provide quantitative, long-term guidelines for Physical Coverage Limits from inventories, spot purchases and forward contracting, and for financial coverage limits for the appropriate fixed priced portion of OPG’s uranium supply going forward.

L&A reviewed OPG’s Uranium Limits Overview document describing the derivation of and motivation for OPG’s minimum and maximum limits for both physical and financial coverage. These limits are used to optimize the operating range of uranium inventories and reduce both the physical and financial risks in uranium procurement. Discussions also were undertaken with staff from OPG’s Corporate Risk Management Department. OPG staff indicated that the limits are applied in a pragmatic fashion. Senior management can approve exceptions to these limits and did so during 2011.

4.5. Review of OPG's Recent Uranium Procurements

Longenecker & Associates assessment of OPG's uranium procurement involved a review of OPG's recent supply strategies and procurement plans, and OPG's uranium contracting.

These included:

- The 2006 Uranium Supply Strategy upon which the March 20, 2006 Request For Proposals was initiated and the Memorandum of Purchase Approval dated May 2, 2006 covering three contracts – one for the supply of 3 million pounds U3O8 over 2008-2013, the second for 3 million pounds U3O8 over 2010-2015, and the third for the supply of 1 million pounds U3O8 over 2011-2015.
- The Amendment to the Memorandum of Purchase Approval: Uranium Supply Contracts dated May 30, 2006 covering an additional 300,000 lbs in 2007 and 500,000 lbs U3O8 in 2008 for a total of 3.8 million lbs U3O8 over the 2007-2013 period.
- The 2007 Uranium Procurement Plan upon which the June 14, 2007 Request For Proposals was based, resulting in a term contract dated November 15, 2007 for 500,000 lbs U3O8 per year over the period 2009-2011, and 250,000 lbs U3O8 per year from 2012-2017.
- The 2009 Uranium Procurement Plan, authorizing the purchase of 3 million lbs U3O8 (500,000 lbs of Spot Purchases in 2009, 750,000 lbs to be delivered under a term contract between 2010 and 2012, and 1.750 million lbs under a term contract between 2012 and 2018). Based on this Plan, the April 27, 2009 Request For Proposals for 200,000 lbs U3O8 for spot delivery was issued and resulted in two spot contract purchases of 200,000 lbs U3O8 each for delivery in June and July 2009 respectively.
- The March 15, 2010 review of the 2009 Uranium Procurement Plan, which recommended continuation of the long term portion of this Plan and upon which the April 21, 2010 Request For Proposals was based, resulting in two term contracts – one for 250,000-275,000 lbs U3O8 per year over 2012-2014, and a contract for 250,000 lbs U3O8 per year from 2015-2020.
- The May 2011 Uranium Procurement Plan upon which the August 3, 2011 Request For Proposals was based resulting in a spot purchase of 200,000 lbs U3O8 for delivery in September 2011. A November 2011 Request for Proposals was also based on the May 2011 Uranium Procurement Plan and resulted in a spot purchase of 275,000 lbs U3O8 for delivery in the December 2011.
- The June 15, 2011 Information Briefing – Uranium Supply Contracts recommending executing the two term uranium supply contracts (for 2012-

2014 and 2015-2020), which had resulted from the April 21, 2010 Request for Proposals discussed above.

4.6. Review of OPG's Uranium Supply Contracts

L&A reviewed summary information on all of OPG's existing uranium supply contracts as well as requests for proposals, contract templates and contract terms and conditions. Examples of specific uranium contracting documents provided by OPG include:

- The October 6, 2006 Term Contract for total delivery of 3.8 million lbs U3O8 over the 2007-2013 period, which was one of the three contracts resulting from the March 20, 2006 Request For Proposals, and referred to in the May 30 Amendment to the Memorandum of Purchase Approval;
- The January 15, 2007 Term Contract for 200,000 lbs U3O8 per year over the 2011-2015 delivery period with a total delivery of 1 million lbs U308, which was one of the three contracts resulting from the March 20, 2006 Request For Proposals;
- The November 15, 2007 Term Contract for 500,000 lbs U3O8 per year over the period 2009-2011, and 250,000 lbs U3O8 from 2012-2017;
- The April 14, 2010 Draft Agreement sent by OPG with the April 21, 2010 Request for Proposals; and
- The July 8, 2011 Term Contract for 275,000 lbs U3O8 per year over the 2012-2014 period resulting from the April 21, 2010 Request for Proposals.

4.7. Other Information Sources

To compare OPG's procurement program with other utilities, in October, 2011, L&A surveyed fuel managers from 10 US utilities in order to ascertain specific relative comparative parameters, such as annual volumes of uranium required, procurement strategies such as spot versus long term contracting, inventory status, existence of formal protocols or policies for risk management, and inventory levels. Individual company information in these areas generally is held confidential and not available on a published basis, but L&A was able to obtain a reasonable overview, based upon relationships with these fuel managers.

Additional information published by the US Energy Information Agency regarding US utilities' uranium aggregated purchases and inventories held as of 2010 was compared with OPG's inventory position.

Information on European utilities uranium contracting inventory levels published by the EURATOM agency was also compared with OPG.

5. OPG's Risk Limits

The Uranium Limits Overview document describes the inputs for the uranium risk model developed by OPG's Corporate Risk Management Department as including GDP, CPI, reactor efficiency, conversion factors, forward price curves, forced outage rates, planned outage days, fuel inventory levels, and contract information, which are updated regularly to reflect current market and operating conditions.

Financial Coverage Limits

The Financial Coverage Limits provide a formal guideline representing the optimal mix of fixed and variable priced uranium supply contracts.

When OPG buys uranium under fixed or base-escalated priced supply contracts, they are protected against increases in future market prices above the fixed or escalating base pricing, but are subject to the risk that market prices may decline or stabilize at a level below the escalating base price.

In contrast, when OPG buys under market-priced contracts they are subject to potentially dramatic market price swings for that portion of their uranium contract portfolio.

OPG's objective is to maintain an appropriate balance between fixed and variable priced contracts avoiding undue exposure to future uranium prices.

OPG's guidelines provide that the optimal financial coverage limit for the current year is to hold approximately 60% of its overall uranium requirements as fixed-priced or base-escalated contracts, with coverage decreasing progressively in future years, leading to the Financial Coverage Limits expressed as a percentage of overall uranium requirements shown in Table 1.

Table 1 – OPG's Financial Coverage Limits

	Minimum Financial Coverage Limit	Maximum Financial Coverage Limit
Current Year	60%	110%
Year +1	50%	100%
Year +2	40%	90%
Year +3	30%	80%
Year +4	20%	70%
Year +5	15%	60%
Year +6	10%	50%
Year +7	5%	40%
Year +8	0%	30%
Year +9	0%	20%

OPG has indicated that the Financial Coverage Limits are higher in the near term because near term price risk is lower and OPG's objective is to avoid locking in large quantities at fixed prices given the greater uncertainty in future prices. The later years are also impacted by variables such as the level of future plant generation, economic variables, and potential disruption in uranium mine operations. OPG uses these limits in procurement planning to determine how much uranium to purchase under fixed price or base-escalated supply contracts in various future years.

These limits are displayed graphically in the following Figure 1, which shows OPG's current financial coverage from 2011 through 2020, versus the Financial Coverage Limits, and OPG's overall uranium requirements.

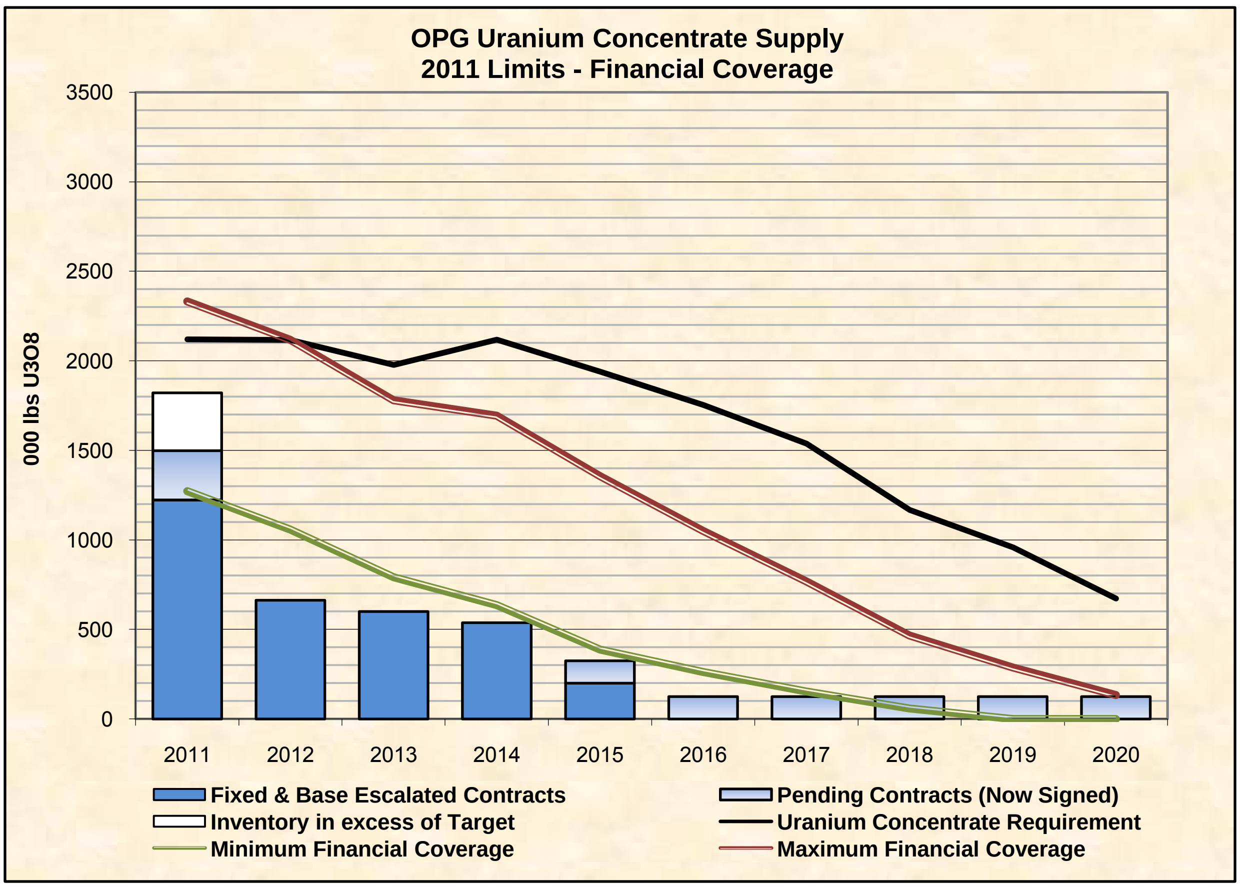


Figure 1 – OPG's Financial Coverage 2011-2020

The graph indicates that as of 2011, forward contracting of uranium supplies under fixed price or base escalated contracts and the associated deliveries in out years, was below the recommended Minimum Financial Coverage limit, suggesting additional contracting utilizing these determinable price mechanisms is warranted. OPG has advised that it has deferred additional contracting while awaiting the outcome of this Uranium Procurement Program Assessment.

In addition, OPG's anticipated Uranium Concentrate Requirements for the out years are significantly higher than the Maximum Financial Coverage limit, indicating that uranium contracts based on future market prices will also be a component of OPG's uranium costs in those years.

Physical Coverage Limits

The Physical Coverage Limits provide guidelines for the total quantity of committed uranium supply under all contracting types (fixed price, market priced, and contract options), including inventory in excess of OPG's minimum inventory targets, expressed as a percentage of the overall requirements.

The physical coverage limits progressively decline for the next ten years as shown in Table 2 below.

Table 2 – OPG's Physical Coverage Limits

	Minimum Physical Coverage Limit	Maximum Physical Coverage Limit
Current Year	100%	160%
Year +1	100%	130%
Year +2	80%	110%
Year +3	70%	100%
Year +4	60%	90%
Year +5	50%	80%
Year +6	40%	70%
Year +7	30%	60%
Year +8	20%	50%
Year +9	10%	40%

These limits are displayed graphically in the following Figure 2, which also shows OPG's actual physical coverage, from 2011 through 2020, versus the Physical Coverage Limits and OPG's overall uranium requirements:

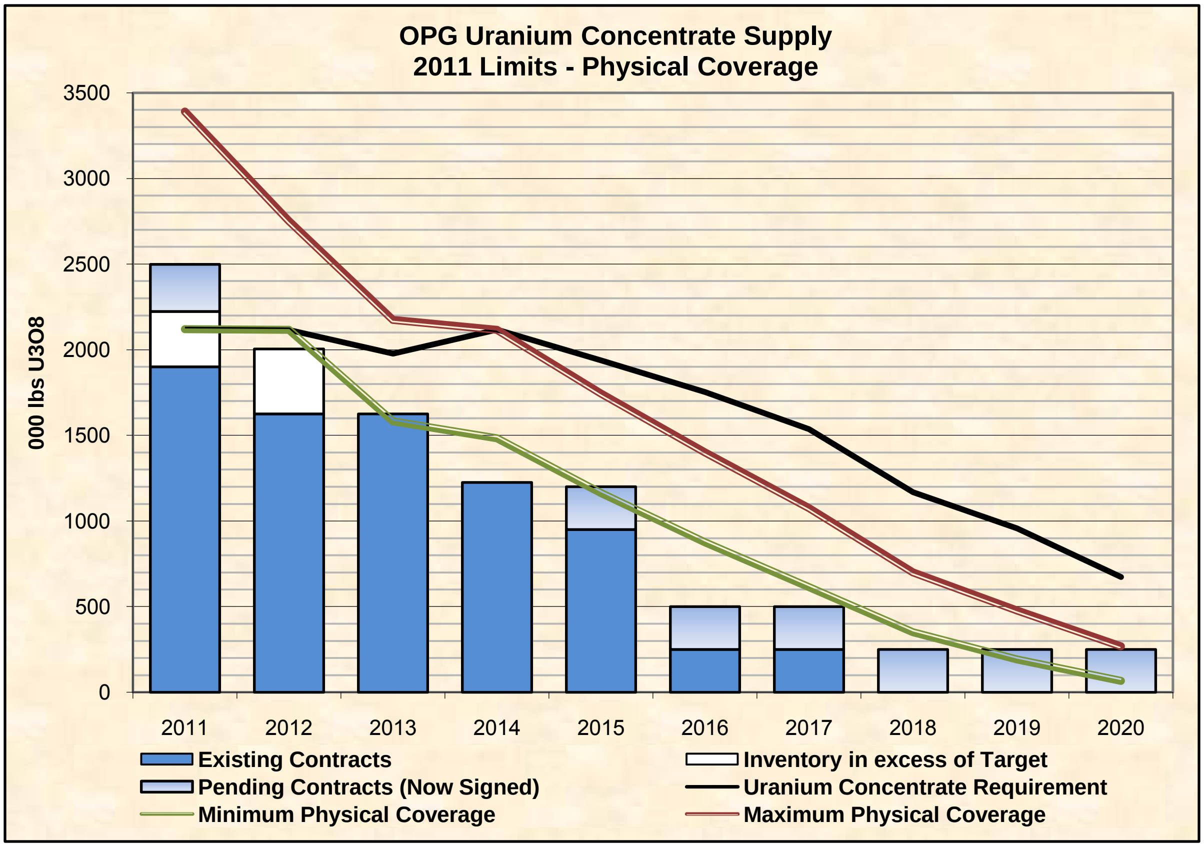


Figure 2 – OPG's Physical Coverage 2011-2020

The graph indicates that as of last year, OPG had aggregate supplies in excess of the actual Uranium Concentrate Requirement for 2011, but substantial uncovered forward requirements in the out years, especially in 2013 and beyond. Uranium Concentrate Supplies were in all years below the projected Maximum Physical Coverage Limit and in several years below the Minimum Physical Coverage Limit. OPG has advised that it has deferred additional contracting while awaiting the outcome of this Uranium Procurement Program Assessment.

OPG uses these guidelines in procurement planning, developing specific uranium procurement strategies, or procurement plans, to determine how much uranium to purchase in various future years.

OPG's procurement plans describe individual contracting actions consistent with the Physical and Financial Coverage Limits, while addressing the current outlook on uranium supply/demand, pricing trends, and other information driving market perceptions.

6. OPG's Uranium Procurement Strategy

OPG's forecast of future uranium requirements, as of September 2011, is as shown in Table 3 below.

Table 3 – OPG's Uranium Requirements

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2119	2116	1976	2117	1938	1752	1536	1167	957	672

(000 lbs U3O8)

6.1. OPG's Contracted Uranium Supplies

OPG's contracted future uranium deliveries, as of December 2011, including Spot purchases, are as shown in Table 4 below.

Table 4 – OPG's Contracted Uranium Deliveries

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2175	1625	1625	1225	1200	500	500	250	250	250

(000 lbs U3O8)

6.2. OPG's Projected Uranium Inventories

In the 2011 Uranium Procurement Plan, OPG's Target Inventory Policy is stated as maintaining a minimum strategic and working inventory of 1 million lbs U3O8.

As of December 2011, absent any further procurement actions, OPG's projected year-end uranium inventories are as shown in Table 5 below.

Table 5 – OPG's Projected Year-end Inventories

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1379	888	537	-355	-1093	-2345	-3381	-4298	-5005	-5427

(000 lbs U3O8)

In addition, OPG maintains individual inventories at each stage of the nuclear fuel supply chain.

- An inventory of finished fuel bundles equivalent to 12 months expected forward usage to allow continued fueling.
- A working inventory of UO2 to feed the manufacturing process, described generally as a 2-3 month UO2 supply.
- The uranium conversion supplier is also contractually required to maintain an inventory of UO2 for OPG's use in the event of a supply interruption.

7. Evaluation of Utility Uranium Procurement Policies

7.1. Utility Procurement Patterns

Uranium procurement patterns vary greatly from utility to utility. L&A surveyed ten utilities to determine their current uranium strategies. Table 6 below reflects the results of an October 2011 survey (Utilities A to J).

- The fuel managers were interviewed regarding their uranium procurement strategies including Spot versus Term buying decisions, extent of contract coverage, the utilization of supply risk assessment protocols, and any uranium inventory guidelines.
- The companies surveyed represent both large and small utilities, and reflect diverse uranium procurement strategies that appear to be independent of the size of the utility or volume of annual uranium consumption. In total, these companies account for approximately 60% of annual uranium purchases by US utilities.
- The regulatory structures of US nuclear utilities vary greatly; many are diversified utilities with unregulated or merchant generating operations, combined with regulated distribution subsidiaries. It can be concluded from the survey data described below that various nuclear fuel procurement organizations operate under widely differing philosophies, with a broad mix of reliance on spot and term contracting.
- There have been two large US utilities that managed to successfully minimize costs for a number of years, with almost total reliance on uranium purchases on the spot market, and just-in-time deliveries to meet fuel processing requirements.
- However, this very aggressive, cost-minimizing strategy exposed the utilities to supply risks once the spot market price began to rise dramatically. Sellers held material off the market, financial entities moved to manipulate market prices by buying small quantities at ever-increasing prices, while the availability of substantial quantities of uranium evaporated in the face of the fly-up in pricing.
- As a result, these utilities were hard pressed to secure uranium requirements for a period of time. And, while they experienced no operational constraints, their experience illustrates the risk of over-reliance on the spot market.

Table 6 – U.S. Utility Information with OPG Comparative Information

Utility	Size[1]	Regulatory Status	Single/ Multi Unit	Annual U3O8 Consumption	Procurement Strategy and Risk Management	Inventory Status	Spot Market Approach
OPG	Large	Regulated	Multi	2 million lbs	Ensure adequate uranium supplies to meet the operational requirements for a combined 6,600 MW of generation. Manage price, market and credit risks using Physical and Financial Coverage Limits and credit risk assessment. Minimize cost consistent with the other objectives.	Minimum 1 million lbs. U3O8 inventory. Can be higher, subject to Physical Coverage Limits, if market conditions warrant ("buy and hold").	Use to cover a disruption in supply. Always evaluate "buy and hold" spot purchases vs. contract for future delivery.
A	Large	Deregulated	Multi	3.5 Million lbs	Try to layer term contracts with not more than 20% from each supplier. No risk assessment protocol other than credit risk for counterparties. Credit risk assessment has never resulted in stopping a deal. Monitors credit ratings of intermediaries involved in each transaction.	Working inventories down to a 6 month level from levels built up during the 2007 price rise.	Utilize spot when market conditions attractive.
B	Mid-Size	Deregulated	Multi	1.1 - 1.3 million lbs	Moving more to spot and mid-term contracting, evaluating "buy and hold" as internal cost of capital seems less expensive than	"No inventories to speak of"	Consider spot when relatively attractive

[1] "Size" relates to the amount of nuclear generation. "Small" includes companies with a single plant site. "Mid-size" includes companies in the range of 3,000-4,000 MWe of nuclear generation. "Large" includes companies with greater than 4,000 MWe of nuclear generation.

Utility	Size[1]	Regulatory Status	Single/ Multi Unit	Annual U3O8 Consumption	Procurement Strategy and Risk Management	Inventory Status	Spot Market Approach
					mid-term prices. Rejected offers using the long-term price indicator as a price determinant in long-term contracts. No risk assessment protocol other than credit risk for contracting counterparties.		
C	Mid-Size	Deregulated	Multi	2.5 - 3 million lbs	70% coverage with long-term contracts through 2016.	No information provided	Fuel budget constrained, can't buy spot uranium right now. Internal short-term cost of capital approximately 2.5% versus 5% for longer term financing.
D	Small	Regulated (Municipal)	Single (Unit Currently Shut-down)	.2 million lbs	Currently have 3 long-term contracts, pricing based on discount from 1) spot at time of delivery, 2) long-term price, and 3) base escalated.	Inventory policy is to hold 1 year of fuel reload as UF6. Approval of inventory investment took 2 years	Potential for small spot purchases due to flexibility in delivery quantities, once reactor re-starts operation in 2012.
E	Mid-size	Deregulated	Single (Multiple Owners)	2.5 million lbs	Currently have 100% coverage with long- term contracts through 2020 with declining coverage through 2025. Seven utility owners want predetermined future pricing, even if the cost is higher. Use base escalated or fixed prices, with price re-openers	No information provided	Believe that financial players are manipulating the spot market prices.

Utility	Size[1]	Regulatory Status	Single/ Multi Unit	Annual U3O8 Consumption	Procurement Strategy and Risk Management	Inventory Status	Spot Market Approach
					every 3-5 years. Don't like the long-term price Indicator as a price determinant, as there are not many data points for each posting. Hoping to narrow gap between floors and ceilings in next contract.		
F	Large	Deregulated	Multiple Units (Some Merchant Plants)	9-10 million lbs	Layered long-term contracts typically 3-5 years, spot price related, some incorporate long - term price indicator as the price determinant. Staggered contract expiration dates keep them in the long-term market. 100% physical coverage through 2014, declining thereafter.	Target strategic inventory level of about 3 million pounds. Inventory level derived from a risk assessment based on physical upset on supply side. Assessment accounted for inventory in process at the time of market upset.	Anticipate regular purchases on the spot market.
G	Large	Regulated	Multiple Units	3.5 - 4 million lbs	No formal procurement plan or strategic protocol, other than to "Stay in the spot market all the time" and evaluate the price variation (spot vs. long term). Base escalated, fixed price, spot related, with price reopeners every 3-4 years. Diversity of supply, political	No information provided	Constant presence in the spot market

Utility	Size[1]	Regulatory Status	Single/ Multi Unit	Annual U3O8 Consumption	Procurement Strategy and Risk Management	Inventory Status	Spot Market Approach
					risks, geographical diversity, determinants of when to re-enter long-term market. 100% physical coverage through 2015, less thereafter.		
H	Small	Deregulated	Single Site (2 Units) w/shared ownership	1 million lbs.	Long-term contracting extending to end of plant license in 2022, contracted on the “back side” of the 2007 price spike. 100% physical coverage. Management wants to know future costs.] Pricing based on spot indicators, long-term indicators, and base escalated. No price re-openers in their long-term contracts.	No information provided	Spot market purchasing is not part of procurement strategy
I	Large	Deregulated	Multiple Units	3+ million lbs.	Currently have layered long-term contracts, prefer hybrid price indicators (base escalated, combined with discount from spot), prefer not to use long-term price indicator as price determinant. No formal procurement strategy. No risk assessment protocol.	No information provided	Haven’t been in spot market lately, concerned about spot market Indicators.
J	Mid-size	Deregulated	Single Site (2 Units)	1 million lbs.	Uses long-term contracts with escalating fixed	No information provided	

Utility	Size[1]	Regulatory Status	Single/ Multi Unit	Annual U3O8 Consumption	Procurement Strategy and Risk Management	Inventory Status	Spot Market Approach
					price based on spot with re-openers every 5 years. If price exceeds a given percentage above market then open renegotiations. If no agreement, then contract terminates after following year's deliveries. Current physical coverage is 100% through 2016.		

7.2. Utility Goals in Fuel Procurement

First and foremost, utilities seek to assure ongoing availability of nuclear generating capacity and scheduled operation of reactors. Thus, assured fuel supply has a higher priority than minimized costs. Replacement power for unavailable nuclear generating capacity is costly, on the order of $1 million per day for a 1000 MWe reactor.

The majority of US utilities hold a goal of "minimizing costs", consistent with achieving uninterrupted electrical generation, either to benefit ratepayers by avoiding unnecessary expenses or to maximize profits for stockholders.

However, given individual supply uncertainties and speculative market influences, the goal of "minimizing costs" is elusive, and can only be evaluated after the fact. At any point in time, a utility may find that it has not achieved the minimum possible costs, but may have taken a series of progressive actions which were reasonable at the time each decision was made.

As an example, a new supplier just entering the market may offer very attractive, below-market pricing, however, if they are unable to deliver, neither supply assurance nor cost minimization goals have been met. If minimizing costs is the sole goal, then the buyer is likely to take the risks associated with the offer and commit to a substantial quantity. A balanced goal related to supply assurance and minimizing cost would not rule out the supplier entirely, but it would most likely result in a contract for a lower quantity as an initial step to prove the supplier's reliability.

In addition, there are utilities or utility-owner groups that believe that having predictable future costs is a higher goal than "minimizing costs", as an example, the priorities related by surveyed utilities E and H.

7.3. OPG Procurement in Comparison Utilities Surveyed

The utilities surveyed represent a reasonable population of US utilities, with varying annual uranium requirements and a wide spectrum of procurement philosophies, and not directly corresponding to whether the utility's rate structure is regulated or deregulated. While not every fuel manager was willing to respond to every question, the survey information does provide evidence of the diversity of procurement philosophies.

As discussed further in the next section, like OPG, most utilities contract to cover a declining percentage of their needs in the later years. However, the two utilities mentioned earlier, utility E and utility H, involve owner groups that require 100% forward uranium contract coverage for the term of their reactor operating licenses, to assure supplies and predictable pricing.

Given the wide divergence of procurement approaches shown among the utilities above, it is not surprising that OPG's procurement activities are similar to some utilities surveyed and with variations from others.

In terms of its actions during the 2007 price spike, however, OPG was not alone in seeking assured supplies as market price increased. Several utilities, including some of the utilities surveyed were also active purchasers during this period and experienced the rapid fly-up and decline in the spot market, with TradeTech's Exchange Value at \$135 / lb U3O8 on June 30, 2007, declining to \$123 on July 31, 2007, \$85 on August 31, 2007, and \$75 on September 30, 2007.

In comparison, TradeTech's Long Term Price Indicator was at \$95 / lb U3O8 on June 30, 2007, and remained unchanged at the end of July, August, and September.

TradeTech reported five relatively small Spot sales in July, 2007, all involving an Intermediary and no Long Term Contracts.

In August 2007, TradeTech reported a Long-Term Contract "*with a non-US utility selecting a preferred supplier for delivery of a total of 3 million pounds U3O8 over* *the period 2009-2017,* assumed referencing the subject OPG procurement. At month end, nine utilities remained in the market seeking 23 million pounds U3O8 equivalent for delivery between 2007 and 2017. One US utility was evaluating offers for 5 million pounds U3O8 to be delivered over a ten-year period. Another US utility was evaluating offers for 1.7 million pounds U3O8 equivalent. A third US utility was seeking 2 million pounds U3O8 with delivery beginning in 2009. One other US utility was seeking just over 2.4 million pounds U3O8 for delivery between 2010 and 2013.

In September 2007, TradeTech reported a US utility seeking 4.4 million pounds for delivery between 2011 and 2020 had selected preferred suppliers, and eight utilities remained in the market seeking 18 million lbs U3O8 for delivery between 2007 and 2017.

TradeTech's observations that month on continuing the $95/lb U3O8 Long-Term Price were that "*the price was representative for delivery in the near term but prices were softer for delivery in much later years when offers include more speculative production. In the wake of the steep decline in the spot uranium price, buyers are showing strong resistance to higher long-term prices, especially floor and base-escalated prices for deliveries beyond 2010.*"

7.4. US DOE Energy Information Administration (EIA) Data

EIA's Report on Uranium Contract Coverage by US Utilities.

- The US EIA publishes data (Figure 3) regarding committed and unfilled uranium for US utilities as shown below with data reported as of 2010 (Thousands of Lbs U3O8 equivalent, referred to as "U3O8e").
- The data in Figure 3 shows a declining level of committed contract coverage for US utilities, and presents results consistent with those of OPG's coverage limits analysis, with the EIA data reflecting a level of 20% of Maximum Anticipated Market Requirements covered 10 years out, for the year 2020.

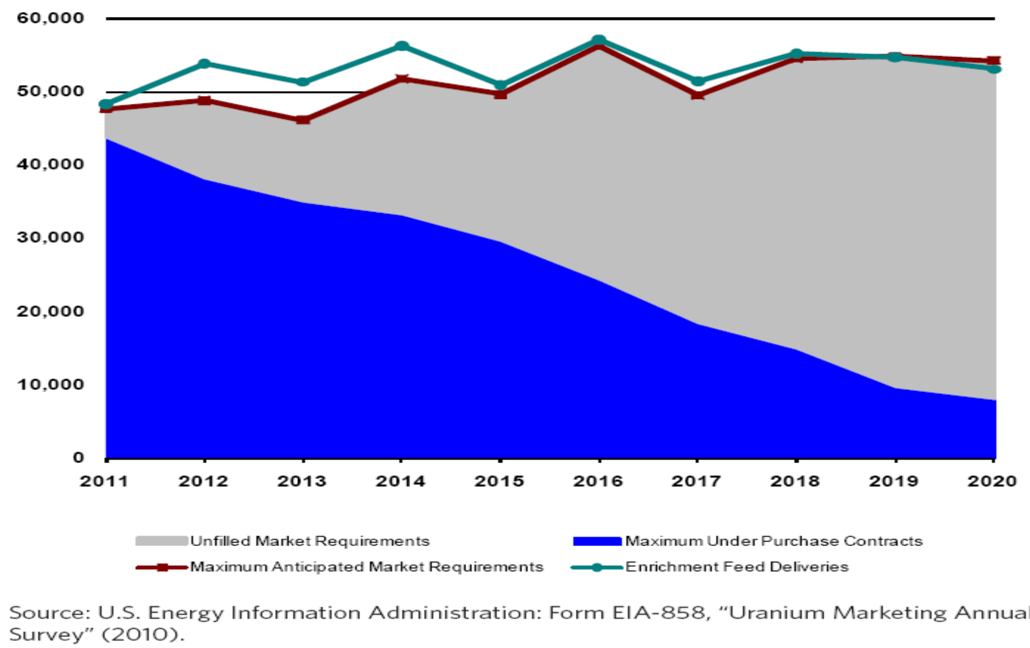


Figure 3 - Committed and Unfilled Uranium Requirements for US Utilities (000 lbs U3O8e)

Figure 3 reflects the relatively short term commitments generally followed by US utility nuclear fuel managers. For example, the line graph titled Maximum Anticipated Market Requirements shows that uranium requirements for US reactors five years forward, in 2015, were forecast to be approximately 50 Million Lbs U3O8. The blue-shaded area, titled Maximum Under Purchase Contrasts, indicates that these requirements were approximately 60% covered, approximately 30 Million Lbs U3O8, when the survey data was reported to EIA in 2010.

In comparison, OPG's Physical Coverage Ratios for 2015 and 2016 are 60 to 90 percent and 50 to 80 percent, at ranges consistent with the aggregate data reported above.

8. Inventory Levels

8.1. EIA Information on US Inventory Levels

The US EIA annually reports on aggregate inventories held by Owners and Operators of US civilian nuclear power reactors in a document entitled Uranium Marketing Annual Report. Their most recent report, dated May 31, 2011, indicates the following inventories (Table 7).

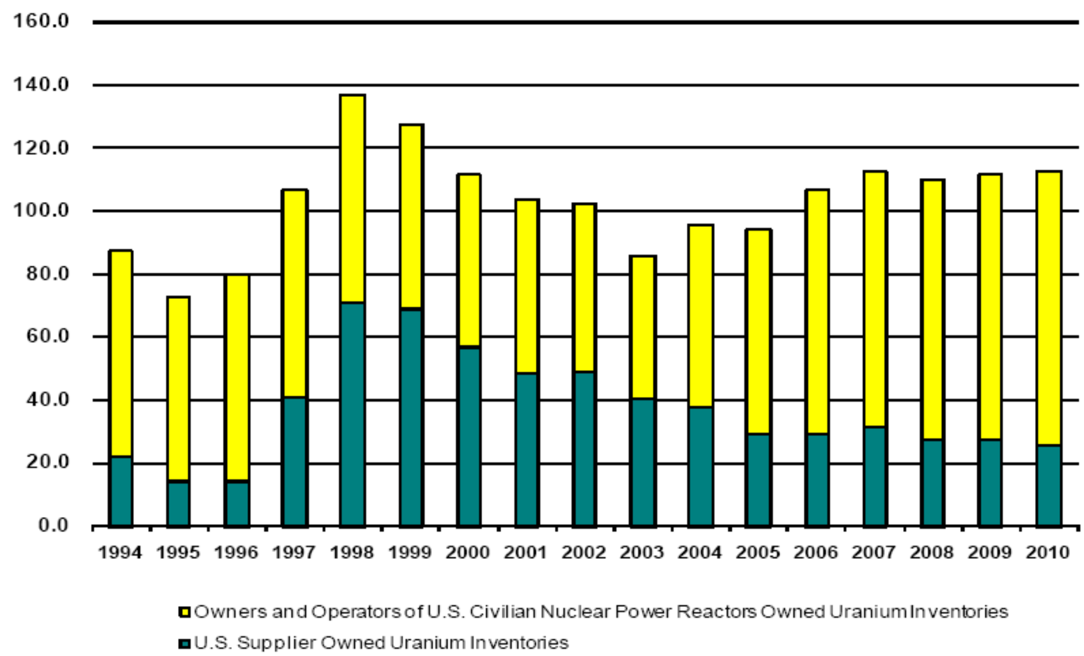
Table 7 – EIA Aggregate Inventories

Owner of Uranium Inventory	2006	2007	2008	2009	2010
Owners and Operators of US Civilian Nuclear Power Reactors	77,484	81,227	82,972	84,757	86,528

(000 lbs U3O8e)

The data reflects a growing level of inventories held by US utilities, likely a result of increased contracting after the 2007 price run-up and more recent expectations of continued high volume of contracting by China.

The US EIA also reports aggregated information on uranium inventories held by nuclear plant owners/operators and by US suppliers. This information is shown below in Figure 4.



Source: U.S. Energy Information Administration: 1994-2002-Uranium Industry Annual reports. 2003-2010-Form EIA-858, "Uranium Marketing Annual Survey".

Figure 4 - US Uranium Inventories (Millions lbs U3O8)

The data for inventories held by utilities combined with those held by suppliers reflects a trend of relatively stable aggregate inventory levels for the last four or five years.

8.2. World Nuclear Association (WNA) Data

The WNA report *The Global Nuclear Fuel Market: Supply and Demand 2011-2030* includes data on worldwide uranium inventories. As of 2010, about 145,000 MtU

(377 Million lbs. U3O8e) is held in commercial inventories worldwide. Utilities held about 120,000 MtU (312 Million lbs. U3O8e) of these inventories, up from 119,000 MtU (309 Million lbs. U3O8e) in 2008. Of the 120,000 MtU, only 32,000 MtU (83 Million lbs. U3O8e) was considered "non-strategic" and required to satisfy reactor requirements in the next several years.

China imported 4,333 MtU (11.26 Million lbs. U3O8e) in 2009 and 14,806 MtU (38.5 Million lbs. U3O8e) in 2010, which likely induced utilities elsewhere to hold onto existing inventories or increase them during this period.

8.3. European Utility Information

Inventory data reported annually by the EURATOM Supply Agency:

- The average annual inventory held by European utilities for the 143 operating reactors and 6 reactors under construction grew at a rate of 3% from 2006 to 2010, before declining slightly in 2010, to a level of approximately 45,272 MtUe, or approximately 117.7 Million Lbs U3O8e. This historical build-up and the current declining trend are due to contracting during the rapid run-up in market prices which culminated in mid-2007. Inventory build-up will accrue as previously contracted deliveries are made.
- This is consistent with the WNA data and with comments from US utilities that they are currently working off inventories built up during the price run-up.

8.4. OPG Inventory Levels in Comparison to Other Utilities

OPG's inventory policy is to maintain a minimum inventory of 1 million lbs. U3O8. Inventory can be higher, subject to Physical Coverage Limits, if market conditions warrant. In contrast, Several US utilities surveyed indicated they maintain a minimal inventory level, or were moving toward reducing uranium inventories built up during the 2007 rapid run-up in prices.

Comparison of OPG inventories to those held by other generators should be made on the basis of percent of requirements represented by the inventory. OPG's annual uranium requirements, as shown in Table 3 are about 2 million pounds per year. Therefore, a one million pound inventory is about 50% of annual requirements. There is, however, additional inventory in the form of finished fuel which contains approximately 2 million pounds. No US utility carries finished fuel as inventory except for the very short time between when it is delivered and when it is placed into the reactor. OPG is carrying about 1.5 years of inventory, including finished fuel, or 150% of annual requirements. Further discussion of OPG's inventories is included in Section 12.

This can be compared to a large generator in the US with annual requirements of nine to ten million pounds per year. This utility carries an inventory of about 3 million pounds or between 30 and 35% of requirements. This utility does not maintain an inventory of finished fuel but due to its number of reactors always has uranium in process for the production of new fuel assemblies.

8.5. Risk Assessment Methodology

Several utilities employ a risk management-based method to determine their desired inventory levels. The method begins by establishing the utility's physical supply risk by reviewing all supply contracts in the context of assurance of supply. For example, a uranium supply contract may have an attractive price but the source is located in an area of political instability. Another concern might be related to the physical conditions at the mine, such as those mines in the Athabasca Basin that have flooded. Each contract must be examined to ascertain its risks.

Once the risks have been identified, they must be quantified. The utility must assign a probability to the event(s) and determine the consequences if the event occurs. Determining the consequences requires the fuel analyst to estimate the duration of the interruption, since it is assumed that there is a temporal component to the event (a flooded mine can be pumped dry and recovered but it takes time; other types of interruptions may be seasonal in nature and last only for 2 or 3 months and have little impact on the overall risk profile). The risk is determined by multiplying the probability by the consequences.

The identified risks must be placed in the context of the utility's contract portfolio. For example, the consequence of a supply disruption will be greater for a utility with a small number of contracts than for a utility with a large number of diversified supply contracts. The context is determined by utilizing some of the information already in place.

The real questions to be answered are: "What are the physical risks"? and "How long can the utility continue to fuel its reactors if there is a supply disruption"? Getting to answers is achieved by looking at material already in process and future deliveries from other sources. The result of the analysis will express forward uninterrupted coverage in months. Once that is known the utility can determine inventory levels and inventory forms that will protect it from a supply disruption.

This method of determining appropriate inventory levels arrives at a specific quantity and form of inventory based on the utility's risk perception. The method is specific to a point in time and the underlying analysis must be repeated as circumstances change. The results should also be periodically reviewed to assure that they are still relevant.

Once the physical risk situation has been assessed, many utilities move on to add Financial Risk to the inventory form and level determination. The process is similar, however, this time it is focused primarily on price risk. The analysis is contextually the same, but the cost of offsetting the Financial Risk come into play. Therefore the utility must factor the capital and carrying costs into the analysis.

If the result of the Financial Risk assessment concludes that the inventory should be larger than the inventory levels derived from the Physical Risk assessment, higher inventory levels can be justified. Our observation is that the duration of price spikes tends to be relatively short and quite often the inventory being held for protection from supply interruption is sufficient to cover a period of price spike.

9. Uranium Prices, Markets and Transactions

9.1. EIA Market Price Information

In the US, the EIA reported that in 2010, 82% of deliveries to US utilities, or about 38.5 million lbs U3O8 were under term contracts at an average price of $50.43 / lb U3O8. The remaining 18% or 8.5 million lbs U3O8 were under spot sales and had an average price of $46.45 / lb U3O8.

The chart below (Figure 5, **Uranium Prices**), reflects the annual average prices paid by OPG compared with US EIA's weighted average price of uranium purchased by owners and operators of US reactors, together with UxC's published indicators for the spot market (Ux U3O8 Price) and prices reported for new long term contracts, the long-term market price (Ux LT U3O8 Price).

The US EIA and OPG ranges were calculated using the US EIA-developed methodology to minimize over-emphasis of outlier data points. The high ends of the US EIA and of the OPG ranges reflect the average price for the highest 1/8th of the total volume purchased. The low ends of the ranges reflect the average price for the lowest 1/8th of the total volume purchased. Therefore, actual prices for the very highest and very lowest priced deliveries will be outside of the identified range shown in the chart below.

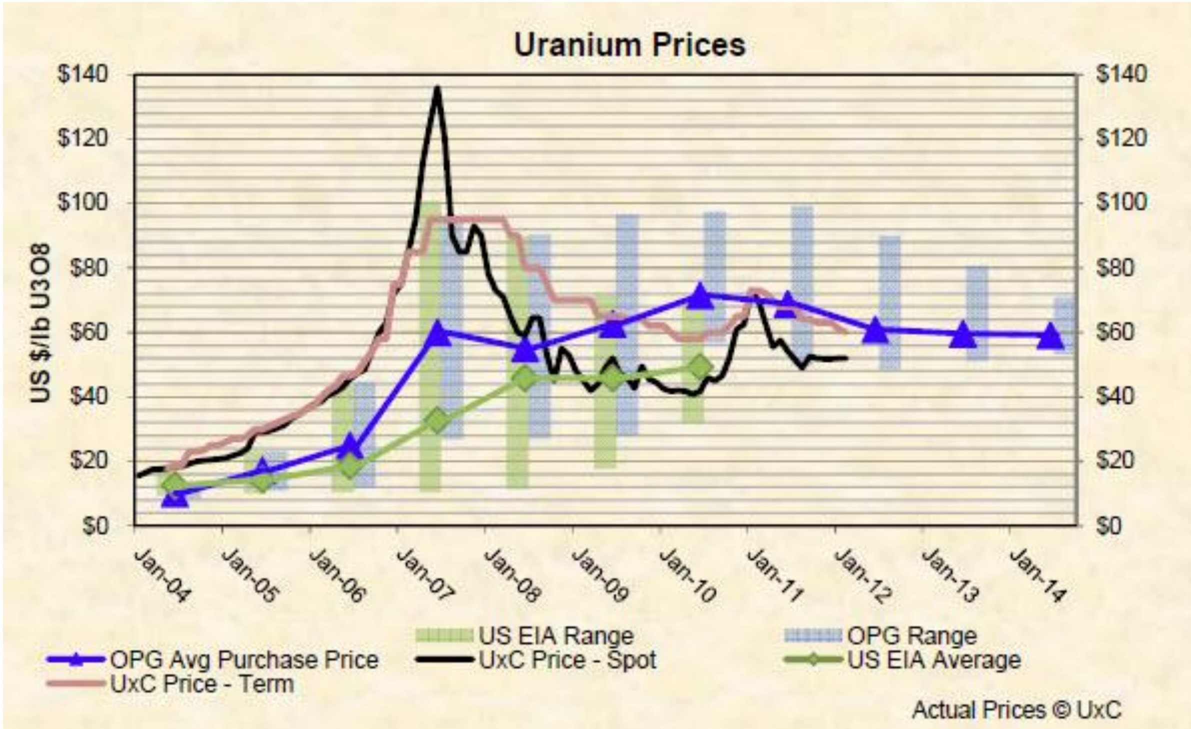


Figure 5 – Uranium Prices

The divergence of the OPG Average Purchase Price with the US EIA data for US utilities reflects the impact of legacy long-term fixed price and base escalated contracts in the US EIA Average prices.

As noted previously, if utilities buy uranium under such contracts, they are protected against fluctuations in the market price, but pay a premium if market prices are subsequently lower at the time of delivery. Conversely, if market prices are above the fixed price at the time of delivery, the utility benefits. The divergence may also reflect reduced buying activity in the spot market by US utilities as prices rose. As discussed, in the 2007 ramp-up of prices there was heavy speculative trading activity in the spot market by financial entities in an effort to extend the price ramp-up. The prices involved in these trading activities by financial entities, are not reflected in the US EIA data in Figure 5.

Another factor to be considered is that utilities with Light Water Reactors (LWRs), in the process of enriching the U235 isotope for their LWR fuel, are able to optimize their input of UF6 feed versus the amount of enrichment required or Separative Work Units (SWU) utilized. For a given enrichment assay required for their fuel design, utilities have a degree of flexibility with their uranium enricher, which depending on their contract terms potentially allows them to reduce uranium requirements by as much as 20% and correspondingly increase SWU purchased. In times of high uranium prices they increase the quantity of SWU purchased and utilize marginally less uranium, as many utilities did as prices rose in 2007. OPG's CANDU reactors do not use enriched uranium and cannot, therefore, make this tradeoff.

9.2. Comparison of Uranium Pricing with Other Markets

In the uranium market, there is no central clearinghouse for transactions, and as recently, there are weeks when relatively few transactions occur. Price reporters such as TradeTech and UxWeekly must make frequent phone or e-mail inquiries of market participants in order to gather transaction information. They are subject to receiving misleading trading information, and many transactions occur "off-market" and are only revealed to the price reporters much later, if at all.

There are a small number of brokers publishing bid and ask quotations for relatively small quantities of uranium. The Uranium Spot Market is not equivalent to the London Metals Exchange. There is no central market location, no "open outcry" of bid and ask by individuals in a trading pit. There is no mandatory reporting of transactions or verification of prices paid as in the London Metals Exchange.

9.3. Contracting Parties Active in the Uranium Market

Over the last several years there have been numerous efforts to improve the transparency of the uranium market by establishing a formal market to trade uranium. The London Metal Exchange investigated the possibility with an international group of producers and utility consumers. After more than a year of trying to establish a trading floor for uranium, the attempt was abandoned. The London Metal Exchange reviewed the business case and concluded that the volume of transactions was too small to allow the Exchange to operate a profitable business.

A subsequent effort was undertaken using the model established by buyers and sellers of steam coal. The WNA established a task force to investigate emulating the steam coal program. Once again, the forecasted volume of uranium trades was determined to be too small to support the overhead related to operating a formal exchange. The relatively small size of the uranium market can be seen by comparison to the natural gas market. The gas market can involve hundreds of thousands of trades per day whereas the uranium market may see only a few hundred transactions in a year.

The lack of a formal exchange for uranium limits the degree of price transparency when compared to that found in formal commodity markets. As a result of the impracticality of establishing a formal exchange for uranium, transactions in the uranium market generally involve direct contact between buyers and sellers. The fact that there is no formal exchange also means that there is not a standard contract, but rather a wide range of contract terms and conditions that are negotiated for each contract.

Spot market contracts are relatively straightforward. The price is tied to the price as published by Ux or Trade Tech for the month of delivery. There may be a small discount offered if there is a buyer's market, but there is no guarantee that that will be the case.

Long-term or term contracts are more complex with several parameters to be negotiated. The price can be a base escalated, often with step-wise increases in various out years, referred to as a fixed price. The price escalation can be based on changes in economic indices published by government entities such as the United States Bureau of Labor Statistics, or it can be tied to a combination of the spot price and the long- term price, (although use of this indicator is no longer in favor). Items such as the date at which the escalation begins (Base Date) and how much of the price is escalated (percentage escalated) are important parameters in a term contract.

Since the term of the contract can be as long as 10 years or more, it is important to have price reopeners in the contract to protect both the buyer and the seller. Another feature of term contracts that can protect both sides is floor and ceiling price limits. These limits constrain the impact of market volatility on the contract price.

In 2011, the ratio of term to spot contracting was about 2 to 1. More than 100 million pounds were sold under term contracts while the spot contract volume was 45-55 million pounds.

There were well over 300 transactions in the spot market versus about 25 in the term market. This is consistent with the split in prior years.

When markets are moving there are predictable behaviors on either side of transactions. Essentially, sellers want to maximize their profit and buyers want to minimize their costs. If prices are moving up, sellers will be reluctant to offer price ceilings that will protect buyers. Conversely, when prices appear to be falling, buyers will be reluctant to accept floor prices that will protect sellers. If prices are falling, utilities may find themselves competing in the market against seller's taking advantage of low spot prices to acquire uranium below their cost of production.

Market prices can also be influenced to some extent by the activities of brokers and traders who may try to move the market to their own advantage. Producers also may buy spot quantities near the end of the year in an effort to increase spot prices, improving revenue generated from their market-priced contract portfolios, a significant portion of which may have year-end deliveries.

Other considerations, aside from floor and ceiling prices, also influence the negotiation of term contracts. These include the proportion of the price to be escalated, the base escalation date, and the index or indices selected for the escalation calculation.

Although sellers' prefer that the entire price be escalated, the reality is that not all of the cost components actually escalate over time. Some components, such as the capital cost of a mine are largely fixed and do not vary with production. As a result, it is appropriate for the Buyer to negotiate a position that escalates only a portion of the price. A fixed component should be based on an analysis of the mine costs for the source of the material. If there is no specific mine identified then the analysis may include reviewing the cost of production at all of the facilities owned by the seller. It is not unreasonable to find that 20% of the costs are fixed which would result in a coefficient such as 0.80 being inserted into the escalation equation, which effectively eliminates the fixed costs from escalating.

In a seller's market, the seller will want to have the escalation begin as early as possible. In this circumstance, it is not unusual for sellers to ask that the price escalation begin at the time of contract signing, as opposed to the timing of the first delivery under the contract. The buyer, naturally, will want the escalation to begin as close to the first delivery date as possible. This difference is usually negotiated to a compromise that balances the interests of both sides.

Uranium producers and utility end-users predominate as buyers and sellers in the long term market. However, pure traders, entities that neither produce nor consume uranium, also are active in the uranium market and acquire positions in uranium. Uranium producers may also act like traders purchasing uranium to meet contract deliveries, or to leverage market prices for their contract portfolio.

Brokers also participate in the uranium market, typically negotiating deals for a small number of counterparties, often financial entities, and generally involving small volume transactions. Their activities impact uranium prices to a greater degree than their size would justify.

Financial entities with a particular price risk exposure seek to influence the price direction especially at month end, in an effort to push prices in a direction that will be beneficial to them.

The lack of a formal exchange to facilitate buying and selling uranium is likely to continue, since the number of participants and transactions is not expected to increase sufficiently to support a formal exchange.

Given this lack of an exchange, the traditional market price risk mitigation mechanisms are not widely utilized for uranium. Uranium futures are not traded in sufficient volume to provide an adequate hedging mechanism for utilities' uranium price exposure. Instead, utility fuel buyers structure their supply portfolios to include contractual pricing terms which protect against market price risk. They achieve this protection by maintaining a portion of their supply arrangements with fixed or base-escalated pricing.

9.4. Alternative Transactions - Off Market Solicitations

A significant number of US utilities initiate "off market" solicitations (i.e. solicitations that are not initiated through a formal Request for Proposals), essentially negotiating with a limited number of suppliers, and "off market" transactions have become the predominant procurement method for private US utilities.

In recent years, nearly 90% of current spot market activity has been classified as "off-market." Utilities either solicit offers or are presented with offers by incumbent suppliers seeking to add-on additional coverage to existing contracts. US utilities also will initiate counter-offers, negotiate simultaneously with multiple suppliers and offer add-on delivery commitments in these negotiations.

Pricing mechanisms are not the only parameters that may be negotiated in an off-market deal. Payment terms and timing are often more favorable in off-market transactions. The terms available can include discounts for a short payment period or changes to the date at which escalation is begun. For example, in a seller's market the escalation may begin at the contract signing date, however, in an off-market transaction the date may be moved closer to the initial delivery date.

Off-market transactions are generally viewed as beneficial to both buyers and sellers since they offer the opportunity to conclude arrangements privately that would have an impact on the market if the transaction or the terms and conditions were made public. All of the terms and conditions of the transaction, not just pricing, can be maintained as confidential by both parties. Sellers are able to offer terms to close the deal in a buyer's market, without the negative impact on published prices that would result if the transaction details were publicly known. Conversely, in a seller's market the confidential nature of the transaction can benefit the buyer.

9.5. Spot Market

Utilities also undertake intermittent opportunistic activity on the spot market. They take advantage of potential opportunities to acquire supplies at spot prices, sometimes reducing existing commitments using flexibility in their existing supply contracts, while continuing reliance on the long-term contracts for assurance of supply in out years.

10. Supply – Demand Overview

Most industry participants rely on the World Nuclear Association's biennial report for projections of uranium supply and demand. The most recent edition, *The Global Nuclear Fuel Market: Supply and Demand 2011-2030,* was released in September, 2011.

Conditions can vary dramatically in a dynamic market such as the uranium market, with situations such as the flooding of Cameco's Cigar Lake mine, and ongoing reaction to the Fukushima accident, impacting the market. Having the ability to recognize attractive timing for entry into the market, albeit within the constraints of mitigating physical supply risks, can have a significant effect on the overall costs incurred by a utility.

10.1. Role of Financial Intermediaries in the 2007 Uranium Price Spike

An important, but challenging aspect of a successful procurement program is the ability to recognize the reasons for price spikes. The spike that occurred in 2007 was initiated by a number of supply disruptions and was amplified by financial intermediaries who seized upon the belief that there would be a shortage of uranium due to the forecasted construction of new power plants and the planned end of the Russian nuclear weapons downblending known as the Megatons-to-Megawatts program.[2] While both were legitimate concerns at the time, the price overshot the level needed to support exploration and development of new mines. It is evident given increased mine development

[2] The results are very similar to the spike in the palladium market that occurred in the late 1990s. The same phenomena occurred there, i.e., a rapid price rise to an irrational level followed by a rapid drop in price to a more appropriate level related to the underlying market fundamentals.

since 2007, that new uranium mines need a long-term price of at least $65/ lb U3O8 in today's dollars, to support the forward production cost of the marginal mine needed to deliver the last pound required to the market. This price does not include the capital cost of exploration and mine development. Adding the capital cost component will likely drive the price into the range of $80 - $85 per pound. The decision on the part of a mining company to proceed with mine development also hinges on their analysis of demand for uranium going forward. The miners want to be sure that demand for their product will be there and utilities want to be sure that uranium supply will be there when they need it.

Examination of the trades being made at the time found that the price was pushed to an irrational peak mainly by trades made between intermediaries, and not by the activities of uranium producers and utilities.

The 2007 price spike was very different from the price spike in the early to mid-1970s. In the 1970s there was a "false" demand created by the US Government's requirements for "Early Feed" deliveries under the DOE's uranium enrichment contracts. This apparent demand, however, was not supported by reality because many of the planned nuclear plants that drove it were cancelled even before the events at Three Mile Island Unit 2.

Keeping a very close eye on the fundamentals of the uranium market is a necessary step to take in order to minimize purchases in an overheated market.

10.2. Current Market Situation

The current uranium market as of early 2012 is relatively in balance; essentially supply and demand are in equilibrium, with spot prices holding around the low $50s. Utility end-user demand is essentially satisfied for the next few years. Few spot transactions are being reported, as financial entities and traders are not active in the market.

Worldwide inventories are building due to reduced utilization of uranium in the aftermath of the Fukushima accident, the shutdown of 8 reactors in Germany with the remainder scheduled for closing by 2022, and 52 of the 54 Japanese reactors currently shut down for annual inspection, with growing public opposition leading to indeterminate delays in restarting the reactors, as well as generally delayed construction schedules for new reactors in China and elsewhere.

There have been expectations in the market that uranium producers with sales contracts with Japanese utilities may now seek alternate consumers, although on February 24, 2012 Kazatomprom stated that their Japanese utility customers would accept contracted deliveries scheduled to begin this year. Japanese trading companies are actively seeking to place excess inventories held by the Japanese utilities with other buyers, while not disturbing the current market price levels.

Although there are no widespread reports of cutbacks in investment, uranium producers see uncertainty in the current uranium market, related to the situations in Japan, Germany, and elsewhere.

10.3. Outlook for the Future

This situation with excess inventories and uncertain demand is anticipated to extend for the next 18-24 months. There are also some expectations that uranium market prices may be soft and even slightly decline over this period as the Japanese plants remain off line and construction of new plants in China gradually resumes.

In spite of the impacts from Fukushima and other factors described above, the longer-term outlook still remains strong for future uranium demand. Last year, TradeTech estimated that the impact of Fukushima would result in a 2-3 year delay in demand and a reduction in uranium requirements of about 9%, or about 263 million lb U3O8, for the period between 2011 and 2025. Given ongoing delays in resumed operation of reactors in Japan and new construction in China, TradeTech is currently updating this outlook.

There is also uncertainty surrounding the 2013 ending of the 24 million lbs U3O8e supplied annually from the Megatons-to-Megawatts program. Some in the uranium industry and the investment community postulate that a supply deficit could occur if new mine capacity, such as Cameco's Cigar Lake, is unable to smoothly ramp up production. Prices may even rise precipitously, leveraged by speculative buying by financial entities and traders active in the market.

The WNA took the accident at Fukushima into account with respect to its mid-2011 forecast of uranium demand in its Market Report dated September 2011. The impact of the accident was reflected in the reactor requirements for Japan and Germany with respect to the number of operating reactors, at that time. The report also reduced projected uranium demand from Switzerland, Belgium and prospective countries such as Italy. While the adjustments are an important reflection of the negative impact of Fukushima, demand from the number of new reactors moving forward overcomes the negative impact. Overall, near-term demand is suppressed, but it is expected that in the longer term that demand will rebound by about 2020.

Financing for new uranium projects will become increasingly difficult in the post-Fukushima environment, making it even more important that utilities contract long term in order to assure supplies.

11. L&A's Assessment of OPG's Uranium Procurement Strategy

11.1. OPG's Procurement Objectives

- Ensure adequate supplies of uranium are available to meet the operational requirements of OPG's nuclear units, a combined 6,600 MWe of generating capability at the Pickering and Darlington Nuclear Power Stations.
  Assessment: OPG has successfully ensured that adequate supplies of uranium have been available to meet reactor operating requirements through forward contracting.

  We find OPG's uranium contract coverage consistent with the aggregated contract coverage of US utilities as published by the US EIA.

- Manage the risks, particularly the price, market and credit risks, associated with the supply of uranium, and
- Minimize costs consistent with the other objectives.
  Assessment: OPG has successfully managed market and credit risks associated with uranium supplies by diversifying its supply portfolio and continued evaluation of the credit risks of individual suppliers.

  In 2007, in the face of dynamic market conditions with rapidly rising prices and predicted supply shortages, OPG experienced some contract portfolio exposure to high uranium prices, as did a number of other utilities. OPG continues to review uranium purchase strategies and inventory holding costs consistent with other objectives.

OPG's procurement objectives are met through the following methods:

- Purchase within physical limits
  - Forces regular entry into markets, which reduces significant fluctuations in the average price paid by OPG
    Assessment: OPG's Physical Coverage Limits provides a band of procurement volumes for each of the next ten years, introducing market opportunities on a regular basis and provide flexibility to manage the timing of procurements if the market is perceived as subject to a short term price spike.

    Recommendation: We recommend that OPG maintain, consistent with the physical coverage limits, a continuing presence in the uranium market by frequent market contracting in order to maximize opportunities to achieve attractive contract terms and encourage potential suppliers to solicit OPG's business.

  - Encourages diversity of supply, which reduces the impact of individual supply disruptions
    Assessment: OPG's current supply portfolio is diverse and its procurement plans and evaluation criteria continue strategies that diversify supply sources, minimizing the risk of delivery default by an individual supplier.

- Purchase within financial limits (portion of supply under "fixed" price arrangements)
  - Mitigates near term market uncertainty
    Assessment: OPG's Financial Coverage Limits provide a band of procurements of fixed price or base escalated contracts, declining in out years, in an effort to mitigate the impact of price fluctuations.

  - Encourages diversity of price mechanisms
    Assessment: OPG's Financial Coverage Limits encourage a balanced procurement of fixed price and base escalated pricing mechanisms, together with market-related pricing mechanisms and spot market purchases.

- Operate within credit limits
  - Mitigates exposure to the financial impact of default risk
    Assessment: OPG's counterparty credit limit constraints limit exposure to potential default by uranium suppliers.

- Encourages diversity of supply
  Assessment: OPG's strategy of operating within counterparty credit limits also encourages diversity of supply by limiting the volume of commitments to any one supplier.

- Maintain a strategic inventory of uranium
  - Mitigates the impact of supply disruptions and ensures continuous reactor operations
    Assessment: OPG's strategic inventory of uranium provides a supply cushion to assure continued reactor operations in the event of specific supplier or industry-wide disruptions in supply. The level of strategic inventory has not been re-assessed at OPG in a number of years.

    Recommendation: Risk evaluations as to the appropriate level of strategic inventory should be undertaken on a more frequent basis and consider significant industry issues such as AREVA's financial retrenchment, Cameco's ability to ramp up Cigar Lake production, the impact of Fukushima on uranium demand and mining expansions, and the ending of Megatons-to-Megawatts program. These developments warrant keeping a close watch on mine development activities. Being aware of progress related to mine development is an appropriate way to strengthen OPG's ability to foresee changes in market conditions before they become generally known.

- Employ competitive and fair procurement practices
  - Provides the opportunity to achieve the best value for money
    Assessment: OPG's procurement practices encourage competition among suppliers.

- Objectives should guide procurement decisions and be reflective of the current operating situation and regulatory environment.
  Assessment: We find OPG's Procurement Objectives appropriate and fully inclusive of the factors which should be considered in a uranium procurement program.

11.2. <u>Supply Risks and Mitigation</u>

Were OPG's contracting decisions appropriate regarding timing, quantity, and supply diversity?

It is our perspective that OPG's uranium procurement activities have been effective and appropriate, with qualified suppliers and geographic diversity, and reasonable prices have been achieved based on the market conditions at the time of each uranium procurement.

In our review of OPG's Uranium Procurement Plans and bid evaluations, we found due consideration was given by OPG as to timing of market entry, quantities sought, description of procurement alternatives, assessment of supplier capabilities, risk of performance, and geographical diversity. OPG has achieved a mix of contracts (spot, short term versus long-term, fixed price versus market-related, etc.) that balance the risks related to security of supply and price. The balance achieved is similar to that of other large uranium consumers. The procurement decisions must balance the physical and price risks rather than focus solely on one or the other and OPG's approach achieves this goal

Assessment: In our view OPG's uranium procurements have been undertaken in a professional manner, with consideration for timing of market entry, quantities purchased, diversity of supply, relative capabilities and risk of performance of suppliers, and an appropriate mix of contracts (e.g., spot, short term versus long-term and fixed price versus market-related). We believe that OPG has optimized its contract portfolio with respect to protecting itself from both supply and market price disruptions.

11.3. <u>Price Risks and Mitigation</u>

In the specific instance in the 2007 Procurement, OPG was faced with a very difficult market during the 2007 price run-up. The long term contract entered into in that procurement was concluded during a period of very high prices in the market associated with a growing perception of potentially insufficient supplies in the future and competition from new build reactor demand. It was a period with strong competition from other buyers and financial intermediaries resulting in a strong sellers' market. We evaluated the pros and cons of the contract as follows:

- Deliveries from the November 15, 2007 contract of 500,000 lbs per year from 2009-2011 and 250,000 lbs U3O8 per year from 2012-2017 do not represent an overly large portion of OPG's future requirements. They also provide security of supply out through 2017, an ongoing period of supply uncertainty regarding new mine development, especially in the post-Fukushima environment.
- This contract's escalated Base Price is high compared to current price levels, but consistent with the market at the time the contract was awarded.

- Over the life of this contract the price provisions are attractive in that they provide a gradual transition to a discount off the spot market price over the 2012-2014 period from the escalating base price in 2009-2011. During the final three years of the contract, 2015-2017, the discount off spot market price is in effect and will be more attractive than reliance on spot market purchases over that period.
- L&A's initial view was that this agreement might present an opportunity for OPG to negotiate near term price concessions with the supplier in exchange for offering to commit additional contract supply coverage. OPG related that it has explored such options and found them to be not economically competitive with alternative supplies.

Assessment: We find that OPG made appropriate uranium contracting decisions regarding price risk in a period of dynamic price volatility and growing uncertainty. We believe that the 2007 long-term contract provides OPG with assurance of supply over a future period of uncertainty, although with a significant price premium for the 2009-2011 deliveries.

11.4. <u>Recommendation on Contract Improvements for Future Uranium Procurement.</u>
Dynamics in the term uranium market can provide or remove attractive terms and conditions. Such terms as contract quantity flexibility, pricing based on a nominal percentage discount from the spot market price at time of delivery, no-cost options for additional quantities, extended payment terms, short notice periods, price re-openers on long-term contracts, and dedicated inventories held by suppliers can often prove very attractive for the buyer.

The reality of the uranium market is that when prices are trending upward and there are fewer suppliers competing, attractive contract terms may no longer be achievable. It is therefore incumbent upon a utility to maintain a presence in the market to determine the currently offered terms and conditions. Aggressive fuel managers will explore these attractive terms in negotiations with a "short list" of potential successful bidders in term contract procurements, or in "off-market" negotiations. By continuing to have an ongoing presence in the uranium market, OPG will recognize opportunities to achieve attractive contract terms.

Recommendation: Exploring "off-market" negotiated transactions may provide value to OPG in terms of lowering costs and providing terms and conditions that are not offered in open market transactions.

11.5. OPG's Risk Limits

11.5.1.1. Physical Risk Limits

OPG's Physical Coverage Limits provide a valuable tool to assess forward commitments and the utilization of inventories. Applying the methodology incorporates critical thinking into the process and establishes parameters for evaluation of various procurement alternatives such as purchasing spot, mid-term, long-term contracting, or buy-and-hold strategies, etc. Looking out into the future to determine an appropriate level of physical coverage is difficult unless parameters are considered on a consistent basis.

OPG's Physical Coverage Limits provide a quantitative range of acceptable uranium supply arrangements, a situation that is generally approached in a less structured manner by other fuel management groups. The range allows for uncertainties in requirements and market conditions and allows for some pragmatism in planning uranium purchases. The procurement strategy also has controls related to the risk limits that ensure the targets are not exceeded without review and approval.

Having the Physical Coverage Limit range also provides a basis for evaluating procurement alternatives or adverse scenarios in light of real supply and demand situations. For example, "what happens to our program if our Supplier A has a mine flooding and declares *Force Majeure* on its commitments?" Firstly, one would expect the supplier to make every effort to secure alternative uranium supplies from other operations or purchase them in the market, as one supplier has done recently. But if OPG's contract delivery price is lower than the current market price that may not be a realistic expectation.

Risk limits methodology can be a valuable tool if it is frequently assessed against current market perspectives, such as changing uranium market dynamics, the impact of financial players in the uranium market, changes in uranium demand and uranium mining developments.

Absent frequent calibration, the potential exists to perpetuate a band of physical coverage, which could understate or overstate the optimal level of forward commitments and inventory utilization. OPG frequently reviews their purchasing plan in light of market conditions and their strategy. They then adjust the plan based on the findings of the review.

This is a good practice. OPG's procedures require a review of the limits at least every 2 years. Their procedures also allow for more frequent reviews. However, OPG's risk limits (Physical and Financial Coverage Limits) were last approved by OPG's Enterprise Risk Committee in August 2008. We agree with the need to review and adjust limits on a regular basis due to changes in the future supply/demand outlook for uranium. Given the current uncertainty in the uranium markets, we encourage OPG to undertake such a review.

We recommend that OPG revisit the Physical and Financial Coverage Limits on a more regular basis.

11.5.1.2. Financial Risk Limits

L&A approached the assessment of OPG's Financial Coverage Limits by evaluating the purpose intended. OPG stated that the purpose of their Financial Coverage Limits methodology was to establish a formal guideline that represents the optimal mix between fixed and variable price supply.

This guideline is used to define the optimal trade-off between fuel cost risk and the forgone opportunity cost. If OPG buys under a fixed price contract, it is protected against fluctuations in the market price, but is potentially subject to paying a premium, if the ultimate delivery price is higher than the spot market price at the time of delivery. Conversely, if the delivery price is lower than the spot price at the time of delivery there would be a discount to market. The point here is that the limits are in place to define a range of acceptable price trade-offs.

When purchasing under a market index priced contract, for example one based on the spot market price at time of delivery, OPG is subject to price risk and uncertainty as to the cost of the forgone opportunity to buy later at a fixed price that may be lower.

It is important to OPG to maintain the appropriate portfolio balance as guided by its Financial Coverage Limits. A Balanced portfolio of contracts in a well managed procurement process eliminates speculative behavior.

Maintaining a balanced mix of fixed price contracts and market-related contracts has proven desirable to both uranium buyers and suppliers. As mentioned previously in this report, this factor has resulted in the growing use of "hybrid pricing" in long term contracts.

OPG's Financial Coverage Limits analysis only applies to fixed price contracts, therefore the large portion of future supply contracts based on market price mechanisms, and any future spot market purchases are not included in the Financial Coverage Limits evaluation.

We anticipate that over time price determinants in long term contracting will continue to evolve. As an example, the nascent effort by some suppliers in marketing multi-year contracts to apply the Long Term Price Indicator to determine the Delivery Price in contracts has been rejected by market participants. Contracting formats can be expected to continue to evolve.

The objective of OPG's Financial Coverage Limits is to provide a degree of price certainty for future deliveries under current Long-term contracts rather than to control the absolute level of price paid.

Recommendation: We recommend that OPG ensure that its Financial Coverage Limits continue to enable effective monitoring of the degree of price certainty as new pricing determinants emerge.

Financial limits should also be reviewed on a periodic basis. Items such as OPG's current weighted average cost of capital should be monitored to assure that the cost to carry inventory is accurately forecast. This may present opportunities to buy and hold if market prices are attractive. This information is important to have readily available when presented with unsolicited offers. Being able to quickly assess and execute offers will give OPG an advantage over most other potential buyers.

Assessment: We find that OPG's Risk Limits provide an appropriate methodology to optimize contracting with regard to forward commitments and the balance of fixed price and market priced contracts.

12. Inventory Levels

12.1. OPG's Strategic Inventories

OPG has a uranium concentrate target inventory level of 1 million lbs U_3O_8 on hand. The Physical Coverage Limits also allow OPG to increase the level of U_3O_8 inventories if market conditions make it prudent to purchase more than is required, to be held for future use.

In addition, OPG maintains individual inventories at each stage of the nuclear fuel supply chain.

- An inventory of finished fuel bundles equivalent to 12 months expected forward usage to allow continued fueling.
- A working inventory of UO2 to feed the manufacturing process, described generally as a 2-3 month UO2 working inventory,
- and the UO2 conversion supplier is also contractually required to maintain and inventory of UO2 for OPG's use in the event of a supply interruption.

With 10 units between Pickering and Darlington, OPG may be able to reduce inventories. The steady stream of incoming uranium under contract, combined with material in process, either at the conversion or fabrication stage, is a significant hedge in itself.

L&A estimates the value of the uranium contained in inventories carried by OPG to be on the order of $170 million based on the following:

- $50 million for the Target Inventory (1 million Lbs U3O8 @ $50/lb U3O8)
- $100 million for U3O8 contained in 12 months of Finished Fuel Bundles (2 million Lbs U3O8@ $50/ lb U3O8)
- $20 million for the 2-3 months of UO2 working inventory (400 thousand Lbs U3O8 @ $50/lb U3O8)

It is our view is that these multiple inventories provide an opportunity for reduced investment by OPG, potentially reducing annual inventory carrying costs, which we estimate as approximately $12 million per year ($170 million @ 7% per year). There appears to be significant potential to "optimize" the existing multiple inventories.

- The quantity of material to be held as "strategic inventory", as OPG's Target Inventory is considered, should be based on a risk assessment that is specific to CANDU reactor operational needs and the OPG fuel supply portfolio. We assume that the one million pound quantity was arrived at earlier based on a "comfortable round number", rather than a quantity which is analytically derived.
- Regarding the existing Finished Fuel Inventory of 12 months refueling requirements, these inventory levels are justifiable due to different fuel designs at Darlington and Pickering. Therefore, we believe that these finished fuel inventories should be viewed as OPG's primary hedge for supply assurance, or "strategic inventory".

- The volume of the UO2 Supplier Contractual Inventory, should provide sufficient in-process inventory to assure continued fuel deliveries in the event of a supply interruption.
- Utilities generally plan for a maximum of one year interruption of deliveries from any one supplier. A determination should be made as to the most significant future supply risk by any of OPG's uranium suppliers. Assessment of each uranium supplier's risk profile would include evaluating political risks, mine operational risks (flooding, strikes, etc.) and financial risks. The U3O8 contained in the finished fuel inventory should be evaluated as a component to mitigate future supply risk.
- Maintaining a "layered" approach to the expiration of individual uranium contracts, i.e. avoiding concurrent expiration dates, as OPG does, mitigates the risk of adverse impact of a default by any one supplier. Importantly, it also keeps OPG in the market on a regular basis to evaluate potential suppliers.

In summary, while we believe that in a stable uranium supply situation OPG's inventory levels could be reduced, in light of uncertainty as to uranium availability due to possible delays in mine development by AREVA, or the ramping up of production at Cameco's Cigar Lake, and the ending of the Megatons-to-Megawatts program in 2013, we suggest that OPG evaluate on an ongoing basis whether inventories should be retained at current levels.

Assessment: We find OPG's Target Inventory consistent with other utilities' inventory policies.

Recommendation: We recommend an ongoing evaluation of uranium concentrate inventory levels based on an assessment of potential risks of physical supply disruption. The evaluation should consider all of the uranium available to mitigate a supply disruption including uranium to be delivered from other sources, inventory on hand, inventory in process, and fresh fuel ready to be inserted into the reactors. We recommend OPG evaluate its inventory situation on an ongoing basis to optimize assurance of supply while seeking to reduce OPG's overall inventory carrying cost.

12.2. OPG's Procurement Strategy

We believe that OPG's procurement strategy is prudent in today's market. Maintaining a layered series of long term contracts, as OPG does, provides assured supplies. Spot purchases can provide economically attractive opportunities. Continued presence in the uranium market is essential for an organization with uranium requirements as large as OPG's. OPG's contract portfolio and procurement strategy achieve a mix of market related and fixed price contracts that allows OPG the flexibility to manage the economics of the uranium supply equally well in up or down markets.

We also believe that OPG's procurement strategy will remain appropriate in the context of foreseeable future market conditions. Situations such as the ultimate impact of the Fukushima accident on new reactor construction and the operating status of reactors in countries such as Germany and Japan, are uncertain. Financial decisions on new uranium mine projects also are not yet defined. There is supply uncertainty regarding the ramp-up of new production to replace the 24 million lbs U3O8e per year of uranium derived from the Megatons-to-Megawatts program which ends in 2013. These are significant risks involved in assuring future supplies, and OPG's balanced approach is appropriate.

However, as pointed out above, the supply demand balance for the world wide uranium market has not been permanently disrupted and the prior balance points of supply and demand will shift further out in the future. L&A regards OPG's strategy as appropriate for the market conditions prior to the events at Fukushima, and with ongoing review, we believe it will remain so in the foreseeable future market conditions.

We believe OPG's procurement strategy is consistent with many other utilities, with a mix of spot and long term contracting. OPG has not undertaken the risky approach of relying totally on spot market purchases as did two large US utilities. At the same time, OPG is not overly reliant on fixed price contracts.

OPG's evaluation criteria, proposal evaluations, and supplier diversity have been well founded and appropriate. We see these as strengths of OPG's uranium procurement program.

In reviewing OPG's contracts we find their terms and conditions appropriate and consistent with those in other contracts.

We offer the following suggestions on contract terms and conditions for future contracting to the extent they can be achieved given market conditions. We recognize, however, that it is not always possible for OPG to get its preferred outcome on each and every item, particularly in a seller's market.

- Term contracts should generally be limited to 3-5 years in order to avoid potentially significant price dislocations. Long-term contracts extending beyond this time frame should have price reopeners.
- *Force Majeure* clauses can present a significant risk to the utility. They tend to provide all-inclusive protection for the seller.
- Flexibility in supply volumes should be taken advantage of when market conditions allow.
- Price ceilings should be included in the contract terms. This will normally require the *quid pro quo* of price floors to share the financial risk. The floors and ceilings can be arrived at in many ways, but they are often tied to price indices.
- Price escalation should not be applied to the entire contract price. Some of the uranium supplier's costs are fixed and, therefore, should not be escalated. A coefficient less than one should be incorporated into any price escalation calculation.
- There should be a termination clause in the contract. It may never be used, but it is prudent to have it in place.
- In our view, frequent spot market and midterm market purchases provide simpler contracting formats, although we recognize that some base level of long term contracting is necessary to stimulate new uranium mine production and mitigate supply risk.
- When market conditions allow, pricing mechanisms in term contracts should be based on a slight discount from an average of multi-month spot postings rather than the then-current long term price postings.

In a term contract, the buyer is providing an assured long-term sales opportunity as an incentive for the producer to extend mine production. In contrast, the future Long Term Price Indicator essentially represents the cost structure for a subsequent increment of production.

In addition, currently there are insufficient data points to provide a valid price assessment using today's Long Term Price Indicators.

Finally, accessing and evaluating comprehensive market information on a constant basis is vital to sustain an effective uranium procurement program, especially for a nuclear organization with requirements as large as those of OPG.

13. Summary Conclusions and Recommendations

Longenecker & Associates provides the following summary conclusions and recommendations:

Conclusions:

- We find OPG's procurement objectives appropriate and fully inclusive of the various factors which should be considered.
- OPG's uranium procurements have been undertaken in a professional manner, using evaluation criteria which give appropriate consideration as to diversity of supply, relative capabilities and performance risk of suppliers, and an appropriate mix of contracts (spot versus long-term, fixed price versus market-related, etc).
- We find OPG's uranium purchasing activities consistent with those of other utilities surveyed.
- We find OPG's forward uranium contract coverage consistent with the aggregated contract coverage of US utilities as published by the US Energy Information Administration (EIA).
- We find OPG's target inventory policy consistent with other utilities' inventory policies, while opportunity exists for an ongoing evaluation of inventory levels based on an assessment of potential physical risks.

Recommendations:

- ***We recommend that OPG maintain, consistent with the physical coverage limits, a continuing presence in the uranium market by frequent market contracting in order to maximize opportunities to achieve attractive contract terms and encourage potential suppliers to solicit OPG's business.***
- ***We recommend that OPG re-assess its Physical and Financial Coverage Limits on a more regular basis.***
- ***Recommendation: We recommend that OPG ensure that its Financial Coverage Limits continue to enable effective monitoring of the degree of price certainty as new pricing determinants emerge.***
- ***We recommend an ongoing evaluation of uranium concentrate inventory levels based on an assessment of potential physical supply disruption risks.***
- ***We recommend that OPG explore "off-market" negotiated transactions that may provide value by lowering its costs and providing terms and conditions that are not offered in open market transactions.***

14. Longenecker & Associates Qualifications

James P. Malone

Mr. Malone is the CEO of International Nuclear Energy Public Private Partners and also serves as Chief Nuclear Fuel Development Officer at Lightbridge Corp, and Vice President Nuclear Fuels at IBC Advanced Alloys. Mr. Malone was Chairman of Hathor Exploration Limited until its purchase by Rio Tinto in December, 2011.

Mr. Malone retired as Vice President, Nuclear Fuels at Exelon Generation Company, LLC at the end of October 2009. As Vice President, Nuclear Fuels Mr. Malone provided the strategic direction and tactical guidance for Exelon's nuclear fuel cycle activities. These activities including procurement of fuel for 17 operating reactors, both PWRs and BWRs. Procurement included uranium, conversion, enrichment and fuel fabrication. Mr. Malone was also responsible for establishing and maintaining an Inventory Policy for Exelon that addressed risks related to security of supply and price. Mr. Malone was also relied upon for guidance for managing used fuel. Mr. Malone's responsibilities also included special nuclear material accounting and safeguards, economics, and fuel cycle cost.

In addition to fuel procurement, Nuclear Fuels also provides reload bundle and core design, safety analysis and plant technical support including fuel reliability, component procurement strategy, and decommissioning strategy. Mr. Malone also guided the interactions of the Nuclear Fuels staff in the regulatory, political and public acceptance areas.

Prior to joining Exelon Mr. Malone served as Vice President and Senior Consultant at NAC International from October 1989 until October 1999. He participated in fuel cycle consulting including the front and backends of the fuel cycle and fuel reliability via NAC's Stoller Nuclear Fuel Division. Mr. Malone gained extensive international and spent fuel cask engineering experience while at NAC. One of his last projects at NAC was the international safeguards system for the Rokkasho Mura reprocessing plant in Japan. This was an IAEA project.

From July 1981 until October 1989 Mr. Malone was at SWUCO, Inc. beginning as a nuclear fuel broker. He was manager, Technical Services and became Vice President in 1986. He also served as Executive Vice President of GRP Consulting providing software Quality Assurance to EPRI and sophisticated software to utilities.

Mr. Malone joined Yankee in 1972 in the fuel procurement group and became Manager of Economic Analysis in 1978. Yankee's fuel procurement group was responsible for Yankee's Inventory Management Policy and Mr. Malone made extensive contributions to establishing and maintaining the Inventory Policy.

Yankee's nuclear fuel inventory policy became very important when the price of uranium began its rapid increase in the mid-1970s. Yankee and the operating companies were able to avoid most of the impact of the price increase as a result of the inventory policy.

In 1968, Mr. Malone began his career in nuclear power as an engineer in the utility reactor core analysis section of the nuclear engineering department of United Nuclear Corporation (UNC). His duties included bundle and core design for Dresden and Yankee Rowe. Mr. Malone also trained in thermal hydraulic analysis while at UNC.

Mr. Malone received a B.S. in chemical engineering (nuclear) at Manhattan College, Bronx, New York in 1968. In 1972 Jim completed an MBA at Iona College, New Rochelle, New York where he was awarded the Graduate School of Business Award for Academic Excellence.

Professional Affiliations

American Nuclear Society:

Past Chairman, Fuel Cycle Waste Management Division

Ronald B. Witzel

Ron Witzel is an independent consultant specializing in utility nuclear fuel procurement and uranium and enrichment marketing. He has over thirty years experience in the nuclear fuel industry and understands both the electric utility and fuel supplier perspective in the nuclear fuel cycle. He has also served as an expert witness, an independent arbitrator, and a uranium marketing agent.

Since March 1993, Mr. Witzel has been consulting for utilities and earlier acted as a marketing agent for uranium producers. After successfully operating as a sole proprietor for three years, Witzel Consulting, Inc. was incorporated in March, 1996.

Mr. Witzel currently provides ongoing procurement consultation to utility fuel managers on uranium and enrichment supply, and has prepared reports for other consulting organizations.

During the 1993-96 period Mr. Witzel served as an expert witness on international uranium trading for a uranium producer involved in a protracted litigation, which was settled in favor of the uranium producer.

In 1995, he provided marketing consultation and facilitated the liquidation of a large uranium inventory held by a former U.S. uranium producer.

During 1996-97 Mr. Witzel acted as marketing agent for a U.S. company developing uranium production in Mongolia, resulting in the successful negotiation of long-term uranium supply contracts with U.S. utilities.

Mr. Witzel is a Principal in Longenecker & Associates, providing expertise in uranium enrichment marketing. In 1998, Mr. Witzel was part of a team seeking to acquire the U.S. enrichment enterprise through a merger or acquisition. The enterprise was subsequently sold through an IPO.

From 1990 through early 1993, Mr. Witzel was employed by NUEXCO Trading Corporation. Initially, his role was to manage NUEXCO's fuel cycle services projects. In August 1991, Mr. Witzel began spending about half of his time working with Global Nuclear Services and Supply (GNSS), NUEXCO's Russian joint venture located in Washington, D.C. In October 1991, Mr. Witzel visited the Urals ElectroChemical Enrichment Plant in Yetkateringburg escorting utility customers.

Prior to 1990, Mr. Witzel was employed by Pacific Gas and Electric (PG&E) for 23 years where his responsibilities included management of out-of-core nuclear fuel. As Director of Nuclear Fuel Management, Mr. Witzel had responsibility for numerous activities including supply/demand forecasting, fuel cost forecasting, contract negotiations, administration, fuel cost and lease accounting.

During his career at PG&E, Mr. Witzel was also involved in the negotiation of two separate nuclear fuel leases for the Diablo Canyon fuel with a line of credit totaling $450 million. His group had full responsibility for the administration and accounting for these financial instruments.

In addition, Mr. Witzel advised PG&E's Washington, D.C. representatives on pending legislation affecting nuclear fuel. In 1989, Mr. Witzel was elected Chairman of the Edison Electric Institute's Nuclear Fuel Committee.

Mr. Witzel has delivered numerous papers and chaired sessions at NEI and WNA nuclear fuel industry forums, frequently gave testimony before the California Public Utilities Commission during his years with PG&E, and early in his career participated in Congressional Subcommittee hearings on international uranium supply and demand.

In November 2010 Mr. Witzel co-authored with Jim Malone an article in FuelCycleWeek on the difficulties in reliance on price reporting for Long Term Contracts. In June 2011, Mr. Witzel authored an article for FuelCycleWeek on the uranium supply impact of the USEC – TENEX Long Term SWU Contract. He has also participated in Energy Daily Enrichment Webinars in the last several years.

Mr. Witzel received his Bachelor of Science degree in Business and Industrial Management in 1967 from San Jose State University and his Masters of Business Administration degree from Golden Gate University in 1971.

ONTARIO POWER GENERATION INC.
TORONTO, ONTARIO

ASSESSMENT OF REGULATED ASSET DEPRECIATION RATES AND GENERATING STATION LIVES

NOVEMBER 2013

Gannett Fleming

Excellence Delivered **As Promised**

November 29, 2013

Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario
M5G1X6

Attention:
Mr. David Bell
Senior Manager, Accounting and Reporting
Ontario Power Generation Inc.

Pursuant to your request, we have conducted a review and assessment of the Regulated Asset Depreciation Rates and Generating Station Lives of Ontario Power Generation Inc. ("OPG"). Our report presents a description of the methods used in the estimation of service life and our recommendations for average service life estimates.

We gratefully acknowledge the assistance of OPG personnel in the completion of the review.

Respectfully submitted,
GANNETT FLEMING CANADA ULC.

LARRY E. KENNEDY
VICE PRESIDENT

LEK/hac
Project: 057677

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ASSESSMENT OF REGULATED ASSET DEPRECIATION RATES AND GENERATING STATION LIVES

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the Gannett Fleming Canada ULC ("Gannett Fleming") review of the Ontario Power Generation Inc. ("OPG" or "the Company") average service life estimates based on December 31, 2012 asset values and for Niagara Tunnel placed in-service in 2013. The average service life estimates recommended in this report are considered in OPG's depreciation review process in establishing the asset depreciation rates and generating station lives for the Property, Plant and Equipment ("PP&E") of OPG's prescribed facilities, including directly assigned corporate PP&E balances. As the depreciation and amortization expense is calculated for revenue requirement purposes, the assets for which average service lives were analyzed include intangible assets.

The facilities for which average service lives were analyzed consist of two nuclear generating stations (Pickering and Darlington) and 54 hydroelectric stations, including six stations (the "previously regulated hydroelectric facilities") that were prescribed by *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998* effective 2005 (Sir Adam Beck I, II and the Pump Generating Station; DeCew Falls I and II; R.H. Saunders) and 48 stations (the "newly regulated hydroelectric facilities") that are proposed to be prescribed, as announced by the Government of Ontario in a proposed amendment to *Ontario Regulation 53/05*.[1]

Given the similarity of the plant making up both the previously and newly regulated hydroelectric facilities, the assets of both groups of facilities are categorized by OPG using the same asset classes, with the same average service lives. As part of this study, Gannett Fleming specifically reviewed the operating considerations and typical station configurations of the newly regulated hydroelectric facilities in order to determine if this approach is reasonable, or if there is a need for additional componentization or changes to average service lives specific to these facilities. This review included site tours of 16 newly regulated facilities and operational staff discussions.

REPORT STRUCTURE

Part I, Introduction, contains statements with respect to the scope and plan of the report and the basis of the study. Part II, Methods Used in the Estimation of Average Service Life, presents the methods used in the estimation of average service lives. Part III, Results of Study, presents a summary of the service life estimates and the comparable peer data used in the development of the average service life estimates. Schedule 1A of this report summarize the average service life estimates for the accounts making up the previously and newly regulated hydroelectric facilities. Schedule 1B of this report summarizes the average service life estimates for all

[1] Notice of proposed amendment can be found in OPG's application to the Ontario Energy Board for new payment amounts under EB-2013-0321 Ex. A1-6-1, Attachment 3.

accounts of the prescribed nuclear assets and also separates the nuclear Asset Retirement Costs ("ARC"), which are depreciated over station lives.

BASIS OF THE STUDY

Background. In March 2007, Gannett Fleming submitted a report titled "Review of the Ontario Power Generation Inc. Depreciation Review Process" (the "2007 Report"). The 2007 Report presented a summary of the findings of an independent review of the processes, procedures and methods used by OPG to review its depreciation expense. The 2007 Report indicated that "Gannett Fleming has found that the processes, procedures and methods followed by Ontario Power Generation Inc. adequately meet regulatory objectives regarding depreciation generally accepted by Canadian regulatory authorities."[2] Additionally, Gannett Fleming found that "OPG's current Depreciation Review Process results in the depreciation expense component of the revenue requirement that reasonably and appropriately reflects the consumption of the average service life of OPG's regulated assets. Gannett Fleming also views that, overall, the DRC process is adequate in meeting the generally accepted regulatory objectives regarding depreciation for regulated North American utilities."[3] Overall, the 2007 Report concluded that the procedural foundation upon which OPG's Depreciation Review Committee ("DRC") has developed average service life estimates is robust and appropriate. The 2007 Report contributed, in part, to the Ontario Energy Board ("OEB") Decision EB-2007-0905 finding that the approach employed by OPG in the development of its depreciation expenses is reasonable.

[2] Cover Letter to the 2007 Report.
[3] 2007 Report, page III-2.

In 2011, Gannett Fleming was retained by OPG to complete a comprehensive assessment of the asset depreciation rates and generating station lives of OPG's regulated assets as of December 31, 2010. As noted in the report titled "Assessment of Regulated Asset Depreciation Rates and Generating Station Lives" dated December 16, 2011 (the "2011 Depreciation Study"), the DRC had continued to follow the methods as outlined in the 2007 Report in the four years since the issuance of that report. Furthermore, Gannett Fleming found that OPG had modified and adapted its processes to address the key recommendations in the 2007 Report. As such, Gannett Fleming viewed that the then currently approved average service life estimates continued to be based on a procedurally sound and reasonable DRC process. In light of this, Gannett Fleming found much of the work prepared by the DRC over the preceding several years to be a reliable information source in the course of conducting the 2011 Depreciation Study. The 2011 Depreciation Study recommended the continuation of the currently approved average service life estimates for all plant accounts for OPG's regulated assets, with three modifications to the average service life estimates to the hydroelectric accounts, including the creation of a new plant account for security systems. OPG implemented these modifications for all of its hydroelectric operations effective January 1, 2012.

The 2011 Depreciation Study also recommended the continuation of the then current life span dates for the regulated stations, including the Pickering A and Pickering B nuclear units (now more generally described as Pickering to reflect the consolidation of the units into a single station), pending the technical results of a pressure tube study. Specifically, Gannett Fleming noted the following: "Gannett Fleming believes that until the review of the Pickering B plant is completed it is premature to adjust the life span date of Pickering A from the current date of December 31, 2021. Gannett Fleming also believes that the use of a life span of September 30, 2014 for Pickering B is appropriate until such time as reviews to determine the economic feasibility of a major pressure tube program are completed, which Gannett Fleming understands is expected in 2012. In the circumstance that the assessment of the condition of the Pickering pressure tubes results in a decision that the Pickering plant cannot continue operations, future depreciation reviews may be required to adjust the life span date of the Pickering A units."[4]

As anticipated in the 2011 Depreciation Study, the results of the work program related to the Pickering B (now known as Pickering Units 5 through 8) pressure tubes confirmed in 2012 that these units could operate beyond September 30, 2014. In addition, the Niagara Tunnel, which represents a significant new addition to the PP&E of OPG's regulated assets, was placed in-service in 2013, and 48 additional OPG hydroelectric facilities are proposed to become subject to OEB regulation. In light of these developments, OPG issued a Request for Proposal in 2013 for a new independent depreciation study. Gannett Fleming was retained to provide an independent professional opinion regarding the average service life estimates used by OPG for the previously and newly regulated assets, leading to the recommendations and conclusions as contained in this report. Gannett Fleming used a similar approach to the 2011 Depreciation Study in arriving at these recommendations and conclusions.

The DRC has continued to follow the methods outlined in the 2007 Report,

[4] 2011 Depreciation Study, page II-12.

having modified and adapted its processes to address key recommendations in that report. As such, the currently approved average service life estimates, as modified by the results of the 2011 Depreciation Study, continue to be based on a procedurally sound and reasonable DRC process. Given this previously-reviewed DRC process, the prior Gannett Fleming findings regarding this process, and the review of the DRC work by Gannett Fleming as part of the 2011 Depreciation Study, Gannett Fleming, to a large extent, continues to find the work prepared over the past several years by the DRC to be a reliable information source. While the 2007 Report and the 2011 Depreciation Study were focused on the prescribed facilities, OPG's internal DRC review process applies to all of OPG's hydroelectric facilities, including the newly regulated hydroelectric plants. In light of this and given the similarity of plant assets and asset management programs across OPG's hydroelectric fleet, Gannett Fleming also finds the DRC work to be, to a large extent, a reliable source of information for the newly regulated hydroelectric facilities.

With the exception of minor fixed assets, which represent approximately 2% of OPG's total regulated investment excluding ARC, OPG continues to depreciate its regulated assets using a straight line method of depreciation, with the depreciation rates being calculated based on the Average Life Group – Whole Life Procedure. The Average Life Group – Whole Life procedure has been used by OPG for a number of years and has previously been approved by the OEB.

Service Life Estimates. The service life estimates presented herein are based on commonly accepted methods and procedures for determining average service life estimates for electric utility plant, and consideration of information obtained about condition assessments through discussion with OPG operating staff and site tours. The service life estimates were based on in-service asset values through December 31, 2012 (with the exception of the Niagara Tunnel which was placed in-service in 2013), a review of the Company's practices and outlook as they relate to plant operation and retirement, and the service life estimates for other electric generation companies.

The average service life estimates for each depreciable group were reviewed based on the professional judgment of Gannett Fleming. In reviewing the average service lives, Gannett Fleming gave consideration to the average service lives currently approved for use by OPG; the results of the 2011 Depreciation Study; the approved service life estimates for a peer group of electric generation companies; the experience of internal OPG operating and management staff; assessment of asset conditions; and the experience of Gannett Fleming in selecting average service lives for similar plant. Gannett Fleming's review of the average service lives for the Niagara Tunnel is discussed specifically in Part II of this report.

<u>Depreciation Policy</u>. In the review of OPG's plant account structure, Gannett Fleming considered the expectation of the diversity of asset retirement ages within each account in the development of the average service life estimate for each account. The use of the Average Life Group - Whole Life Procedure applies the same annual accrual rate to all vintages of plant, which is calculated by dividing 100% by the average service life estimate. As such, a common life estimate is applied to each of the asset vintages, and each of the assets within each vintage. This procedure is widely used by a number of regulated electric utilities throughout North America, and results in a reasonable recovery of capital investment.

Depreciation related to the nuclear asset classes continues to be based on the lesser of the generation station life or asset class life. Hydroelectric generating stations' lives, including those of the newly regulated hydroelectric stations, are considered to be limited by the service lives of the dams; however, since the dams have service lives that exceed those of most other asset classes, Gannett Fleming is of the view that they are not a significant limiting factor at this time.

As discussed later in this report, based on its review, Gannett Fleming has recommended that two new hydroelectric plant accounts and two new nuclear plant accounts be created in order to separate certain assets currently recorded in other accounts. Gannett Fleming also understands that, for ease of future average service life reviews, the DRC is considering a recommendation for a disaggregation of Account 15340000 – Nuclear Process Systems into separate, new plant accounts for major types of systems. The new accounts would have the same average service life of 55 years as Account 15340000. Gannett Fleming agrees with this approach, as it would facilitate future service life reviews.

RECOMMENDATIONS

The average service life estimates set forth herein apply specifically to the PP&E (including intangible assets) of OPG's previously and newly regulated hydroelectric facilities and prescribed nuclear facilities, including directly assigned corporate PP&E, as of December 31, 2012 and the Niagara Tunnel placed in-service in 2013. The average service life recommendations contained in this report should be applied to all assets within each group of assets. As described in the Results section of this report, Gannett Fleming is recommending six changes to the average service life estimates, as follows:

- Account 10318000 – Hydroelectric – Gates, Stoplogs and Operating Mechanisms – Change average service life estimate from the currently approved 50 years to 55 years;
- New Account – Hydroelectric – Roofing – Create a new plant account with an average service life estimate of 30 years;
- New Account – Hydroelectric – Fencing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Roofing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Large Circulating Water Motors (greater than 200Hp) – Create a new plant account with an average service life estimate of 30 years; and
- Reclassification of assets for nuclear turbine generator controls from existing Account 15411100 – Turbines and Auxiliaries with a 55-year average service life to existing Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

Gannett Fleming is also of the view that, as recommended by the DRC in 2012, a new hydroelectric plant account with an average service life estimate of 90 years should be established for the tunnel lining of the new Niagara Tunnel.

Continued surveillance and periodic revisions are required to maintain use of appropriate average service lives and depreciation rates. Each account should be subjected to a complete depreciation study which re-evaluates its average service life estimates periodically. Gannett Fleming notes that the practice of OPG to review its various asset accounts and depreciation service lives over an approximate five-year cycle meets this common depreciation practice.

PART II. METHODS USED IN THE ESTIMATION OF AVERAGE SERVICE LIFE

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DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric generation plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy and obsolescence.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight Line method of depreciation.

As described in earlier sections of this report, the recommendations of this report are to continue to incorporate the depreciation practices historically used at OPG, namely that the depreciation expense be calculated in accordance with the Straight Line method of depreciation, incorporating the Average Life Group - Whole Life procedure in the calculation of the depreciation rate. The calculation of annual depreciation expense based on the Straight Line - Average Life Group - Whole Life procedure requires the estimation of average life as discussed in the sections that follow.

AVERAGE SERVICE LIFE

The use of an average service life for property groups that include large numbers of similar assets implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a life estimate that considers the retirements of units which survive at successive ages. The average service life estimates reviewed by Gannett Fleming were based on judgment which considered a number of factors, including:

- Understanding of the processes used in the development of the currently used average service life estimates through the completion of a prior review of the DRC process filed in EB-2007-0905, and through the completion of the 2011 Depreciation Study;
- Understanding of the assets currently in service through discussions with company staff, including representatives of the nuclear and hydroelectric generation operating units;
- Physical site tours of nuclear and newly regulated hydroelectric generation sites;
- Review of current accounting practices and procedures applied and their consistency with those in place during the review submitted in EB-2007-0905 and those reflected in the 2011 Depreciation Study;
- Review of analyses provided to DRC;
- Average service life estimates from other peer electric generation companies; and,
- The general experience and professional judgment of Gannett Fleming.

Prior Assignments and Review of the DRC Process. Gannett Fleming had been previously retained in 2007 to review the practices and procedures used by the DRC in the completion of prior depreciation studies, and, in 2011, for the completion of a full depreciation study. The 2007 review resulted in a report of the findings of Gannett Fleming which were submitted to the management of OPG in 2007. The 2011 Depreciation Study resulted in a report dated December 16, 2011, which was submitted to management of OPG in 2011 and, in 2013, filed by OPG in OEB proceeding EB-2013-0321. These prior reviews provided Gannett Fleming with an understanding of the processes used by OPG in the determination of average service life estimates, a general understanding of the type of generation plant in service at OPG, and an understanding of the regulatory oversight of the Ontario Energy Board.

Operating Discussions and Site Tours. Discussions with operating representatives and the physical site tours undertaken by Gannett Fleming provided Gannett Fleming with an understanding of the type of assets in service for both nuclear and hydroelectric service. The site tours provide Gannett Fleming with the necessary background to make an assessment of the physical installations of the OPG plant, and to understand the type of plant in service and the operating conditions of the facilities. The operating interviews are undertaken to understand the historic operating conditions that have led to retirement of plant in the past and to understand the current condition of the assets which may impact future retirement plans. The operating interviews were conducted both during the Gannett Fleming tours of the physical facilities and immediately following the tours, and again after Gannett Fleming completed an initial analysis of the average service life expectations.

In conducting the 2011 Depreciation Study, Gannett Fleming toured the following generation sites:

- R.H. Saunders Hydroelectric Generating Station;
- Sir Adam Beck I Hydroelectric Generating Station;
- Sir Adam Beck II Hydroelectric Generating Station; and
- Darlington Nuclear Generating Station.

The scope of this report includes the review of the newly regulated hydroelectric generation plants. In order to gain a better understanding of these assets and as part of the assessment of nuclear assets, Gannett Fleming toured the generation plants listed below in the course of this assignment. Gannett Fleming toured a total of 16 newly regulated hydroelectric facilities, representing a range of different types and sizes of the facilities.

- Chats Falls Hydroelectric Generating Station;
- Arnprior Hydroelectric Generating Station;
- Stewartville Hydroelectric Generating Station;
- Calabogie Hydroelectric Generating Station;
- Barrett Chute Hydroelectric Generating Station;
- Chenaux Hydroelectric Generating Station;
- Des Joachims Hydroelectric Generating Station;
- Otto Holden Hydroelectric Generating Station;

- Bingham Chutte Hydroelectric Generating Station;
- Big Chute Hydroelectric Generating Station;
- Ragged Rapids Hydroelectric Generating Station;
- Hanna Chute Hydroelectric Generating Station;
- South Falls Hydroelectric Generating Station;
- Elliot Chute Hydroelectric Generating Station;
- Tretheway Falls Hydroelectric Generating Station;
- Big Eddy Hydroelectric Generating Station;
- Darlington Nuclear Generating Station; and
- Pickering Nuclear Generating Station.

Tours of the above generating stations provided Gannett Fleming with the necessary background to complete this assignment. During and immediately following each of the above site tours, interviews of the operational representatives were undertaken by Gannett Fleming. These interviews were conducted at the time of the site tours and covered the following topics, including, where applicable, inquiries regarding operational or other changes since the 2011 Depreciation Study:

- Operating history of both the plant being toured and of other similar plant not toured;
- Replacement history of major plant components and review of significant retirement programs;
- General operating experience of the major plant components;
- Review of any life restricting operational issues;

- Review of any issues that have emerged during the DRC process;
- Review of changes where advancements in technology may cause changes to average service life indications; and
- Discussions of the manner in which OPG's hydroelectric plants may be different than other peer hydroelectric generation plants.

In addition, following the plant tours, discussions were conducted through a number of telephone interviews held between Gannett Fleming and operational representatives of OPG.

Review of Accounting Policies. Gannett Fleming had discussions with management representatives during prior assignments to understand OPG's depreciation and accounting policies and practices. As part of the current assignment, Gannett Fleming confirmed with management representatives whether there had been changes to these policies and practices since the 2011 Depreciation Study and whether these policies and practices are also applied to the newly regulated hydroelectric plant.

An understanding of the accounting policies is required to:

- Understand the accounting entries associated with the retirement of plant. In particular, Gannett Fleming required an understanding of the accounting entries associated with gains and losses on retirement;
- Understand any thresholds or policies with regard to capitalization of major component as compared to the replacement of minor components of plant through operating and maintenance budgets; and

- Determine if a review of the adequacy of the accumulated depreciation reserve is required.

Gannett Fleming notes that, notwithstanding OPG's of adoption of US GAAP, the current DRC and depreciation policies and practices for the previously regulated assets are the same as those reflected in the 2011 Depreciation Study. Gannett Fleming also notes that starting in 2011, all gains and losses on retirement transactions are booked by OPG for all of its assets to the income statement in the year of the retirement transaction. In this manner, the accumulated depreciation account does not include embedded gains or losses from previous retirement transactions. Gannett Fleming understands that, on an OPG-wide basis, the total cumulative undepreciated value of embedded past losses, which OPG removed from the net book value of fixed and intangible assets in 2011, is less than $1M.

Gannett Fleming also notes that any amount of cost of removal (that is not associated with the retirement of an asset for which an Asset Retirement Obligation ["ARO"] is established) is charged directly to the income statement in the year of the transaction. Both the recording of gains and losses to income and the charging of cost of removal to income is in accordance with the provisions of US GAAP. As previously noted in the 2011 Depreciation Study (page II-7), while these are not the traditional practices of regulated utilities, Gannett Fleming believes that the nature of the large plant components and small amount of retirement transactions make this policy viable and reasonable for OPG. Additionally, because the accumulated depreciation account does not include adjustments for past retirement transactions the need to test the adequacy of the accumulated depreciation accounts is eliminated.

Gannett Fleming confirmed that the same DRC and depreciation policies and practices are applied by OPG both to the previously and newly regulated hydroelectric assets.

Analysis and Results of DRC Reviews. OPG is the world's largest operator of CANada Deuterium Uranium ("CANDU") nuclear units, has some of the oldest CANDU units, and has the most extensive operational knowledge of all CANDU operators in the world. OPG is heavily involved in technical exchanges with other CANDU operators, and closely monitors equipment degradation issues in order to assess potential impacts on OPG's units. OPG is often the "lead" utility in terms of the knowledge of degradation issues, which may impact unit and component lives. In the particular circumstance of the CANDU nuclear installations, OPG internal staff is recognized as experts in the technology.

The DRC has continued to complete detailed reviews of the average service life expectations for OPG's plant accounts. The DRC's technical reviews are conducted by internal and external experts in the specific areas associated with a number of accounts. As indicated above, the OPG operational staff is considered to be the world experts in the operational aspects of the CANDU units. As part of the current assignment and the 2011 Depreciation Study, Gannett Fleming reviewed these analyses which provided a significant background on the physical condition of the assets, a meaningful history of the manner in which plant assets have provided electric generation service over the past many years, and identified major upcoming replacement or retirement programs.

Peer Analysis. In order to provide a comparison for each account grouping, Gannett Fleming selected a peer group of companies to use in the development of average service lives. The companies selected for comparison were all companies for which Gannett Fleming has recently completed depreciation studies relating to Canadian electric generation plants. As such, Gannett Fleming is able to make a meaningful comparison giving consideration to factors such as capitalization and retirement policies, maintenance practices, and general operational practices. The companies selected for comparison were:

- BC Hydro;
- Manitoba Hydro;
- New Brunswick Power;
- Newfoundland and Labrador Power Corporation (Nalcor);
- Northwest Territories Power Corporation; and
- SaskPower.

As noted in the 2011 Depreciation Study (page II-8), asset service lives for OPG's hydroelectric asset classes lend themselves to comparison with other utilities due to the similar nature of the technology used in hydroelectric energy production. This applies both to the previously and newly regulated hydroelectric assets. As such, the above utilities provided Gannett Fleming with a comparable base of average service life estimates to use in the development of the service life estimates for OPG's hydroelectric asset classes.

Professional Judgment. The use of professional judgment in the development of average service life estimates is a practice that is appropriate and has been used for many years before North American regulatory jurisdictions. When available, the use of statistical analysis of the historic retirement transactions combined with the use of professional judgment which includes the physical site inspections, review of accounting procedures and practices, use of operational staff interviews, review of prior studies, and review of the approved life estimates of peer companies, provides the most complete method of service life analysis. However, the use of professional judgment alone also provides an appropriate basis for developing average service life estimates, when appropriate factors are considered, and has been accepted as a valuable depreciation analysis tool in many North American jurisdictions.

In the specific circumstances of the OPG average service life estimation, the volume of historic retirement transactions available to be analyzed is not sufficient to undertake a detailed study of retirement history. As such, a retirement rate analysis was not completed by Gannett Fleming. However, all of the remaining life estimation tools were available and were used to develop appropriate average service life estimates.

Life Span Dates. Life expectancy of electric generation plant assets is impacted not only by physical wear and tear of the assets but also by economic factors including the feasibility of the economic replacement of major operating components or the economic viability of the plant as a whole. In circumstances where the replacement of major operating components is not economically feasible, the life of the major component can be the determining factor of the generation plant and all of the assets within the plant. As such, the remaining depreciation life of electric generation plant assets is the lesser of the physical life expectation of the asset or the period to the end of the life span of the generation plant.

The use of life span dates for determining depreciable lives for regulated electric generation plant is common throughout many North American regulatory jurisdictions. The basis for the determination of the life span date is usually based on one or more of the following:

- the physical life estimation of the major and vital components of the generating plant;
- the duration of operating licenses;
- precedent and policy of the regulatory jurisdiction;
- expiration of the supply source for which the generation plant is dependent; and
- expiration of market demand upon which the generation plant is dependent.

In prior depreciation reviews, OPG has determined a life span date for each of the prescribed nuclear plants. The life span dates have been determined through a review of the expected life of the significant components at each nuclear site. Additionally, the life span dates historically have been influenced by the period through to any required major site refurbishment, as the continued operation of the plant is dependent upon the ability to economically refurbish the plant for continued use. It is the experience of Gannett Fleming that the depreciation schedules for most North American nuclear generation plants are dependent upon appropriately developed life span dates. It continues to be the view of Gannett Fleming that the use of life span dates is appropriate for the OPG nuclear generation plants.

In the 2011 Depreciation Study, it was noted that an assessment of the condition of the Pickering Units 5 through 8 (formerly Pickering B) pressure tubes was underway at that time. In that report, Gannett Fleming noted that the use of a life span date of September 30, 2014 for Pickering Units 5 through 8 was appropriate until such time as reviews to determine the economic feasibility of a major pressure tube program are completed, which was expected to occur in 2012. It was also noted that the operation of Pickering Units 1 and 4 (formerly Pickering A) requires the joint operation of certain components of both sets of units. As such, both physical and economic considerations may result in the circumstance that should Pickering Units 5 through 8 be shut down before Pickering Units 1 and 4, there is a significant likelihood that the operation of Pickering Units 1 and 4 would not be viable following the shutdown. At that time, Gannett Fleming was of the view that until the review of pressure tubes at Pickering Units 5 through 8 was sufficiently complete, it was premature to adjust the life span date of Pickering Units 1 and 4 from the then current date of December 31, 2021.

In 2012, the DRC considered the impact of the results of the substantial completion in 2012 of the work program necessary to determine the feasibility of achieving extended service lives of the pressure tubes at Pickering. Upon receiving confirmation that the work program indicated high confidence that the operation of the pressure tubes at Pickering Units 5 through 8 could be extended, the DRC concluded that the following dates, which were reflected in materials submitted by OPG in OEB proceeding EB-2012-0002, appropriately recognize the expected average life spans of the nuclear stations, for depreciation purposes, effective December 31, 2012:

- Pickering Units 1 and 4 (formerly Pickering A) – December 31, 2020; and
- Pickering Units 5 through 8 (formerly Pickering B) – April 30, 2020.

The above station life span dates reflect the following expected life span dates for the individual Pickering units:

- Units 1, 4, 7 and 8 – Q4 2020
- Unit 5 – Q1 2020
- Unit 6 – Q2 2019

The life span dates for Pickering Units 1 and 4 were aligned with the last two units of Pickering Units 5 through 8 in recognition of the technical and economic considerations that likely would have prevailed against the operation of Units 1 and 4 in the absence of continued operation of at least two units of Pickering Units 5 through 8.

Gannett Fleming has reviewed the DRC's analysis in establishing the above station and unit life span dates and has concluded that they are reasonable for use in this study. Gannett Fleming is also of the view that the factors considered and methods used by the DRC in the assessment of life span dates remain appropriate and consistent with common regulatory practices and should continue to be used in future reviews.

As recognized in the previous DRC reviews and the 2011 Depreciation Study, a major refurbishment program is expected to be undertaken at the Darlington nuclear site. This continues to be reflected in the life span date of December 31, 2051 for the Darlington station. Given that the major operating components at the Darlington plant are expected to be refurbished in the near future, Gannett Fleming finds that the

December 31, 2051 date continues to be reasonable, as recommended in the 2012 DRC review.

The previously and newly regulated hydroelectric plant dams are considered to be the life-limiting component of these stations, but since the dams have service lives that exceed that of most other classes, Gannett Fleming is of the view that they are not a significant limiting factor.

Niagara Tunnel. In March 2013, the Niagara Tunnel Project was placed in-service. The scope of the project included the design, construction and commissioning of a new, 10.2 kilometer long diversion tunnel from a new intake under the existing International Niagara Tunnel Works structure in the upper Niagara River above Niagara Falls to a new outlet canal feeding into the existing Sir Adam Beck ("SAB") Pump Generating Station canal. This tunnel supplements the diversion capacity of the two existing tunnels that bring water from the Niagara Falls to the SAB stations, and therefore enables additional generation from these facilities. The new diversion tunnel and related works were delivered under a Design-Build Agreement between OPG and its main contractor.

The new tunnel was constructed using a two-pass tunneling system, with the initial pass consisting of the excavation of the tunnel using a tunnel boring machine and the installation of the initial lining using steel supports in the tunnel roof and a full circumference layer of shortcrete (sprayed concrete). The permanent lining comprised of an impermeable membrane generally surrounding un-reinforced concrete locked in place by cement grout was installed as part of the second pass.

The Niagara Tunnel is a significant investment of approximately $1.5 billion in OPG's rate base. This cost largely related to the tunneling activity (approximately $900 million) and to the installation of the tunnel lining (approximately $375 million)[5.] The life expectation of the investment associated with the tunneling is considered to be the same as the life expectations of the two existing tunnels at the Niagara Falls. As such the investment associated with the tunneling for the project has been grouped with the investment associated with the existing tunnels. Gannett Fleming agrees with this treatment. The material and installation techniques used for the lining of the new tunnel are significantly different than the linings of the existing two tunnels. Based on its review of the technical specifications and requirements for the new tunnel as well as other documentation and discussions, Gannett Fleming supports the recommendation of the 2012 OPG DRC that a longer service life of 90 years (as compared to the 75-year life applied to the lining material in the existing tunnels) be used for the investment specific to the tunnel lining of the new tunnel. A further discussion of the recommended service life for the new tunnel lining is found in Appendix 1.

[5] Amounts are for the Niagara Tunnel addition placed in-service in March 2013.

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The review of the reasonableness, and recommended alternative average service life estimates related to plant in service as of December 31, 2012 and the Niagara Tunnel placed in service in 2013 is the principal result of the study. Continued surveillance and periodic revisions are required to maintain continued use of appropriate average service lives. An assumption that life estimates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and for the change of the composition of property in service.

SUMMARY OF RESULTS

Gannett Fleming has reviewed the life span dates and average service life estimates for all regulated generation plants and asset categories, considering the factors as identified in Part II of this report. While this review included an analysis of all asset categories, additional focus was placed on the investment categories that comprise the majority of the plant in service.

Gannett Fleming recommends the use of the life span dates as discussed in Part II of this report. Furthermore, Gannett Fleming recommends the continued use of the currently approved average service life estimates, as modified for the results of the 2011 Depreciation Study, for all accounts with the following exceptions:

- <u>Account 10318000 – Hydroelectric Head Gates, Stoplogs and Operating Mechanisms</u> – Average service life to be changed from the currently approved 50 years to 55 years;

- New Account – Hydroelectric – Roofing – Create a new plant account with a 30-year average service life to separate roofing from other plant accounts;
- New Account – Hydroelectric – Fencing – Create a new plant account with a 25-year average service life to separate fencing from other plant accounts;
- New Account – Nuclear – Roofing – Create a new plant account with a 25-year average service life to separate roofing from other plant accounts;
- New Account – Nuclear – Large Circulating Water Motors – Create a new plant account with a 30-year average service life to separate large motors (greater than 200 Hp) from other plant accounts; and
- Reclassification Between Accounts – Nuclear –Turbine Generator Controls – Reclassify nuclear turbine generator controls from Account 15411100 – Nuclear – Turbines and Auxiliaries with a 55-year average service life to Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

The above recommendations for the hydroelectric plant accounts apply both to the previously and newly regulated hydroelectric assets. Gannett Fleming also agrees with the 2012 DRC recommendation that a new, separate hydroelectric plant account with an average service life estimate of 90 years be established for the tunnel lining of the new Niagara Tunnel placed in service in 2013.

A detailed discussion of the reasons and factors considered leading to the recommended changes for the above accounts is provided in Appendix 1 to this report.

Additionally, Gannett Fleming is satisfied that it is appropriate for OPG to categorize the assets making up both the previously and newly regulated hydroelectric facilities into the same plant accounts, with the same average service lives. In order for this approach to remain reasonable over time, future reviews of asset service lives for the hydroelectric plant accounts should continue to consider whether the conclusions of such reviews and the underlying analysis are applicable to both groups of assets.

DESCRIPTION OF APPENDICES

Appendix 1 to this report provides a summary of the factors considered in the review of each of the major accounts in which Gannett Fleming is recommending a change, as well as the lining of the new Niagara Tunnel. While Gannett Fleming reviewed all accounts listed in Schedule 1A and Schedule 1B, Appendix 1 only provides detailed analyses of the accounts in which a change to the average service life estimate is recommended, as well as the lining of the new Niagara Tunnel.

Appendix 2 to this report provides a listing of the newly regulated hydroelectric stations.

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
10200000	HYDROELECTRIC - SUBSTRUCTURES AND SUPERSTRUCTURES	$ 1,227,972,792	19.79%	100	100
10101000	HYDROELECTRIC - EXCAVATION, DREDGING, RIPRAPPING AND GROUTING	$ 1,380,649,053	22.25%	100	100
10312000	HYDROELECTRIC - DAMS - CONCRETE	$ 991,676,359	15.98%	100	100
10318000	HYDROELECTRIC - GATES, STOPLOGS AND OPERATING MECHANISMS	$ 361,275,033	5.82%	50	55
10306000	HYDROELECTRIC - SURGETANK, PIPELINE, CONDUIT, PENTSTOCK	$ 292,982,384	4.72%	75	75
10400000	HYDROELECTRIC - TURBINES AND GOVERNORS	$ 213,248,856	3.44%	70	70
10501000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - LESS WINDINGS	$ 221,787,828	3.57%	75	75
10301000	HYDROELECTRIC - LINING OF TUNNELS AND PERMANENT SHAFTS	$ 219,912,108	3.54%	75	75
10510000	HYDROELECTRIC - MAIN POWER AND STATION SERVICE - TRANSMISSION	$ 175,590,706	2.83%	50	50
10500000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - WINDINGS	$ 114,912,729	1.85%	40	40
10311000	HYDROELECTRIC - DAMS - EARTH AND ROCKFILL	$ 106,329,529	1.71%	100	100
10405000	HYDROELECTRIC - TURBINE RUNNERS	$ 96,535,236	1.56%	40	40
10210000	HYDROELECTRIC - SERVICE AND EQUIPMENT BUILDINGS	$ 101,137,556	1.63%	55	55
10502000	HYDROELECTRIC - BUS, SWITCHING AND POWER CABLE	$ 85,327,386	1.37%	45	45
10300000	HYDROELECTRIC - CANAL, FOREBAY, RETAINING WALL LINING	$ 83,670,918	1.35%	75	75
10504000	HYDROELECTRIC - CONTROL BOARDS AND SWITCHBOARDS	$ 77,122,794	1.24%	25	25
10700000	HYDROELECTRIC - AUXILIARY SYSTEMS	$ 72,291,792	1.16%	30	30
10302000	HYDROELECTRIC - SPILLWAYS, SLUICES, FLUMES	$ 72,513,556	1.17%	75	75
10100000	HYDROELECTRIC - LAND	$ 37,317,826	0.60%	100	100
10709000	HYDROELECTRIC - OWNED BRIDGES, RAILWAY TRACK, WHARVES	$ 54,666,182	0.88%	65	65
10505000	HYDROELECTRIC - STATION SERVICE ELECTRICAL EQUIPMENT	$ 44,045,969	0.71%	50	50
10601000	HYDROELECTRIC - MECHANICAL EQUIPMENT - CRANES AND FOLLOWERS	$ 45,064,408	0.73%	55	55
10205000	HYDROELECTRIC - OUTDOOR STRUCTURES	$ 20,878,634	0.34%	75	75
10710000	HYDROELECTRIC - FIRE PROTECTION SYSTEMS	$ 27,019,773	0.44%	20	20
10503000	HYDROELECTRIC - HIGH VOLTAGE SWITCHING	$ 16,335,367	0.26%	40	40
10503100	HYDROELECTRIC - REVENUE METERING - HIGH VOLTAGE SWITCHING, CONTROL BOARDS AND SWITCHBC	$ 13,162,790	0.21%	30	30
10311100	HYDROELECTRIC - DAMS - TIMBER CRIB	$ 8,624,328	0.14%	60	60
16210000	ADMINISTRATION AND SERVICE BUILDINGS - PERMANENT BLDGS. ROADS AND SITE IMPROVEMENT	$ 7,852,168	0.13%	50	50
10991000	HYDROELECTRIC - MAJOR SPARES	$ 7,207,631	0.12%	100	100
10315000	HYDROELECTRIC - STEEL RACKS	$ 6,220,914	0.10%	40	40
10302100	HYDROELECTRIC - PUBLIC SAFETY/WARNING BOOMS	$ 4,066,117	0.07%	15	15
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	$ 3,922,188	0.06%	10	10
10531000	HYDROELECTRIC - CIRCUIT BREAKERS	$ 4,048,211	0.07%	50	50
10720000	HYDROELECTRIC - SECURITY SYSTEMS	$ 1,987,371	0.03%	10	10
16100000	ADMINISTRATION AND SERVICE BUILDINGS - LANDS	$ 591,758	0.01%	N/A	N/A
16560100	ADMINISTRATION AND SERVICE BUILDINGS - ADMINSTRATIVE SYSTEMS SW	$ 830,257	0.01%	5	5
16230000	ADMINISTRATION AND SERVICE BUILDINGS - FRAME & METAL	$ 11,000	0.00%	25	25
18400000	COMMUNICATIONS - POWER LINE EQUIPMENT	$ 591,742	0.01%	15	15
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	$ 105,828	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	$ 644,287	0.01%	25	25
16551000	ADMINISTRATION AND SERVICE BUILDINGS - LAN ELECTRICAL CONNECTING DEVICES	$ 777,362	0.01%	5	5
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	$ 715,860	0.01%	30	30
18540000	COMMUNICATIONS - ADMINISTRATIVE TELEPHONE EQUIPMENT	$ 216,553	0.00%	7	7

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
18600000	COMMUNICATIONS - WOOD POLE, COMMUNICATION CABLE APPARATUS AND BOOTHS	$ 77,039	0.00%	40	40
18530000	COMMUNICATIONS - TIMBER AND STEEL STRUCTURES	$ 17,738	0.00%	40	40
18100000	COMMUNICATIONS - LAND	$ 879	0.00%	100	100
16630000	ADMINSITRATION AND SERVICE BUILDINGS - SYSTEMS & EQUIPMENT	$ 132,754	0.00%	20	20
18200000	COMMUNICATIONS - BUILDINGS	$ 58,601	0.00%	50	50
18500000	COMMUNICATIONS - RADIO EQUIPMENT	$ 5,974	0.00%	15	15
	MINOR FIXED ASSETS	$ 4,094,653	0.07%		
NEW	HYDROELECTRIC - NIAGARA FALLS - NEW TUNNEL LINING	$ -	0.00%	N/A	90
NEW	HYDROELECTRIC - BUILDINGS - ROOFING	$ -	0.00%	N/A	30
NEW	HYDROELECTRIC - FENCING	$ -	0.00%	N/A	25
	GRAND TOTAL	**$ 6,206,228,777**	**100.00%**		

ONTARIO POWER GENERATION

**SCHEDULE 1B. SUMMARY OF CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PRESCRIBED NUCLEAR ASSETS AS AT DECEMBER 31, 2012**

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
15200000	NUCLEAR - BUILDINGS AND STRUCTURES	202,581,250	13.84%	55	55
15340000	NUCLEAR - PROCESS SYSTEMS	165,034,350	11.27%	55	55
15600000	NUCLEAR - INSTRUMENTATION AND CONTROL - PA&BG	163,390,095	11.16%	15	15
15701000	NUCLEAR - SERVICE WATER AND FIRE PROTECTION SYSTEM	122,983,880	8.40%	25	25
15720000	NUCLEAR - COMMON SERVICE SYSTEMS	94,104,574	6.43%	35	35
15121000	NUCLEAR - ELECTRONIC SITE SECURITY SYSTEM	77,170,667	5.27%	15	15
15120000	NUCLEAR - YARD FACILITIES	62,632,092	4.28%	50	50
15450000	NUCLEAR - CONDENSER TUBING	59,936,357	4.09%	30	30
15561000	NUCLEAR - AC STANDBY POWER - PB&DG	45,936,441	3.14%	55	55
15361000	NUCLEAR - IRRADIATED FUEL BAYS - PICKERING B	36,512,986	2.49%	65	65
15550000	NUCLEAR - REACTOR BUILDING CABLING	31,313,114	2.14%	40	40
16310000	ADMINISTRATION AND SERVICE BUILDINGS - NUCLEAR TRAINING SIMULATORS	29,502,112	2.02%	45	45
15991000	NUCLEAR - MAJOR / STRATEGIC SPARES	23,310,388	1.59%	100	100
15341100	NUCLEAR - MODERATOR HEAT EXCHANGERS-PICKERING	21,664,508	1.48%	25	25
16560100	ADMINISTRATION AND SERVICE BUILDINGS - INTANGIBLES ADMINISTRATION SYSTEM SOFTWARE	20,482,148	1.40%	5	5
15510000	NUCLEAR - STATION SERVICE MAIN TRANSFORMERS AND AC POWER DISTRIBUTION SYSTEMS-PA&BG	18,723,596	1.28%	40	40
15460000	NUCLEAR - AUXILIARY SYSTEMS - PB&DG	17,433,082	1.19%	40	40
15500000	NUCLEAR - MAIN POWER OUTPUT SYSTEM	17,311,287	1.18%	35	35
15421000	NUCLEAR - GENERATOR ROTORS, STATORS AND AUXILIARY SYSTEMS - PB&DG	14,463,334	0.99%	55	55
15560000	NUCLEAR - AC STANDBY POWER - PA&BG	12,946,426	0.88%	40	40
15710000	NUCLEAR - WATER TREATMENT PLANT	11,755,949	0.80%	20	20
15352100	NUCLEAR - SHUTDOWN COOLING SYSTEM HEAT EXCHANGERS-DARLINGTON	7,180,243	0.49%	30	30
16540000	ADMINSTRATION AND SERVICE BUILDINGS - ADMINISTRATIVE TELECOM EQUIPMENT	6,817,736	0.47%	7	7
15330000	NUCLEAR - REACTIVITY CONTROL UNITS	6,428,607	0.44%	40	40
15461000	NUCLEAR - AUXILIARY SYSTEMS - PB&BG	5,888,839	0.40%	55	55
15711000	NUCLEAR - CIRCULATING WATER - PA&BG	5,645,173	0.39%	55	55
16210000	ADMINSTRATION AND SERVICE BUILDINGS - PERMANENT BUILDINGS, ROADS AND SITE IMPROVEMENTS	5,189,964	0.35%	50	50
15501000	NUCLEAR - REVENUE METERING - MAIN POWER OUTPUT, INSTRUMENTION AND CONTROL-PICK/DARL	4,420,168	0.30%	30	30
15990000	NUCLEAR - ALTERNATE SPARES	3,870,028	0.26%	100	100
15300000	NUCLEAR - REACTOR VESSELS	3,255,283	0.22%	40	40
16211000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDINGS - LEASED	3,053,583	0.21%	10	10
15700000	NUCLEAR - CIRCULATING WATER	2,967,609	0.20%	40	40
16630000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDING SYSTEMS AND EQUIPMENT	2,378,027	0.16%	20	20
15370000	NUCLEAR - TRITIUM REMOVAL FACILITY	2,367,846	0.16%	30	30
15411100	NUCLEAR - TURBINES, AUXILIARY EQUIPMENT, STEAM REHEATER TUBE - PB&DG	1,920,354	0.13%	55	55
15531000	NUCLEAR - BUILDING ELECTRICAL SERVICE SUPPLIES - PB&DG	1,586,505	0.11%	55	55
15352000	NUCLEAR - SHUTDOWN COOLING SYSTEM HEAT EXCHANGERS-PICKERING	1,259,362	0.09%	25	25
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	1,147,295	0.08%	10	10
18500000	COMMUNICATIONS - RADIO EQUIPMENT	1,030,056	0.07%	15	15
16230000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDINGS- FRAME AND METAL CLAD	1,005,387	0.07%	25	25

ONTARIO POWER GENERATION

SCHEDULE 1B. SUMMARY OF CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PRESCRIBED NUCLEAR ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
15511000	NUCLEAR - STATION SERVICE MAIN TRANSFORMERS AND AC POWER DISTRIBUTION SYSTEMS - PB&DG	896,419	0.06%	55	55
15541000	NUCLEAR - ELECTRICAL AUXILIARY SYSTEM-PB&DG	791,287	0.05%	55	55
15400000	NUCLEAR - TURBINES, AUXILIARY EQUIPMENT, STEAM REHEATER TUBE -PA&BG	693,921	0.05%	40	40
16311000	ADMINISTRATION AND SERVICE BUILDINGS - NUCLEAR SIMULATORS - DESIGN UPGRADES	456,887	0.03%	10	10
15360000	NUCLEAR - IRRADIATED FUEL BAYS - PICKERING A	400,039	0.03%	40	40
15311000	NUCLEAR - FUEL CHANNEL ASSEMBLIES	154,089	0.01%	25	25
15430000	NUCLEAR - EXCITERS	75,910	0.01%	30	30
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	38,917	0.00%	30	30
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	24,631	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	8,636	0.00%	25	25
	MINOR FIXED ASSETS - SERVICE EQUIPMENT	134,697,036	9.20%		
	MINOR FIXED ASSETS - OTHER	8,923,873	0.61%		
NEW	NUCLEAR - ROOFING		0.00%	N/A	25
NEW	NUCLEAR - LARGE CIRCULATING WATER MOTORS - OVER 200 HP		0.00%	N/A	30
	TOTAL	**1,463,762,346**	**100.00%**		
	ASSET RETIREMENT COSTS (ARC)	1,510,363,609			
	GRAND TOTAL	**2,974,125,954**			

APPENDIX 1

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

Account 10318000 – Hydroelectric Gates, Stoplogs and Operating Mechanisms

Current Average Service Life Estimate – 50 years

Recommended Average Service Life Estimate – 55 years

Average of Peer Average Service Lives – 72 years (Range from 50 to 100 years)

Discussion:

This account includes the investment in a number of the operating mechanisms related to the hydroelectric dams, including the head gates and stoplogs. Since the 1990's, OPG has been engaged in a significant gate replacement program. The average replacement age of the original gates has been 40 to 60 years. OPG's Dam Safety Program mandates rigorous annual functional testing, inspection and gate maintenance. Experience gained through these monitoring and assessment programs has shown that after 40-60 years of service life, the gates typically require an extensive rebuild. Replacement parts or components may no longer be commercially available requiring extensive and costly re-engineering to restore original functionality. Replacing with a current gate design takes full advantage of improvements in manufacturing processes, operating mechanism design, material properties, electronic controls, etc. that have occurred over the past 50 years.

Integration of wind and other intermittent renewable sources of generation has increased over time and is expected to continue into the future. As a result, increased cycling of hydro generating units has been experienced, along with a similar increase in gate operation cycles.

In making the recommendation for an increase to the average service life estimate, Gannett Fleming has specifically noted that the life estimates of the peer group have been increasing in recent depreciation studies. A review of peer companies has indicated average service life estimates for the peer group of companies now range from 50 years to as long as 100 years. However, it is noted that the peer companies at the longer end of this range include this investment in their overall dam structures accounts. With the removal of the longer life peer indications from the peer analysis the comparable life estimates of the peer group range from 50 to 80 years with an overall average of 55 years.

The recommended 55-year average service life estimate has been developed giving consideration to all of the above influences. It is expected that improvements in gate design and reliability will be partially offset by moderately increasing frequency of operation, thus the currently assigned life of 50 years can be increased to 55 years, which is consistent with the indications from the adjusted peer analysis.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Hydroelectric Fencing

Current Average Service Life Estimate – 100 years

Recommended Average Service Life Estimate – 25 years

Average of Peer Average Service Lives – 25 to 30 years

Discussion:

This account would include the OPG investment related to site parameter fencing at the hydroelectric facilities. During the operational tours conducted by Gannett Fleming it was specifically noted that OPG had recently undergone a significant program to upgrade its site parameter fencing. OPG intends to continue its focus on public safely through the planned continuation of this program. As such, it is appropriate to set up a separate account for fencing.

A review of the peer companies has indicated average service life estimates ranging from 25 to 30 years with most peer utilities using 25 years. Therefore, based on a peer analysis, an average service life of 25 years is reasonable. Discussions with OPG operational staff have also confirmed that the use of a 25-year average service life for this new account is reasonable.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Hydroelectric Roofing

Current Average Service Life Estimate – 75 to 100 years

Recommended Average Service Life Estimate – 30 years

Average of Peer Average Service Lives – 30 years

Discussion:

This proposed new account relates to the OPG investment in roofing which has shown to have a materially shorter life than the associated buildings. Historically, several of OPG hydroelectric plant roofing systems have reached between 25 to 50 year service life milestones before complete replacement. However, the service life is dependent on the type of roofing material utilized and exposure conditions. The original multi-layer tar and felt roofing systems (with gravel protection) have averaged over 40 years, while the newer roofing systems (EPDM, PVC and TPO) have averaged about 25 to 30 years. The past issues (e.g., premature joint failures, cracking, poor wear resistance, etc.) with the newer systems have been partially resolved through modern material formulations and installation improvements.

A review of the peer companies that have componentized roofing into a separate category has indicated average service life estimates of 30 years. It is also the view of the OPG operational staff that the roofing materials and installations systems currently in place systems will achieve an average service life of 30 years. Therefore, based on the peer analysis, discussions with OPG operational staff, and Gannett Fleming's experience the use of a 30-year average service life for this new account is proposed.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Nuclear Large Circulating Water Motors

Current Average Service Life Estimate – 40 to 55 years

Recommended Average Service Life Estimate – 30 years

Average of Peer Average Service Lives –N/A

Discussion:

This proposed new account relates to the OPG investment in large electric motors of more than 200 horsepower with operating voltages between 2kV and 15kV being used for critical operations and safety systems. A review of operational benchmark information from the Electric Power Research Institute ("EPRI") and the United States Nuclear Regulatory Commission ("US NRC") indicates that the expected life of a large high voltage motor ranges from 24 years to 40 years. Due to the high voltages and large rotating masses involved, the electrical and mechanical wear and tear occurs in these motors at a higher rate than experienced by smaller motors. OPG operational experience has shown that large motors, such as the Darlington Heat Transport Pump Motors, are approaching failure at the rates predicted by the US NRC-sponsored research and EPRI. A complete teardown and rebuild is required to extend the life of these motors. In the case of the Darlington motors, spare motors are being purchased to facilitate the rebuild of the 16 in-service motors.

Given the different average service life expectations associated with these motors, Gannett Fleming recommends the creation of a new account for the investment in large circulating water motors with an average service life of 30 years. The recommended life of 30 years is consistent with the mid-point of the expected lives in the US NRC-sponsored and EPRI reports and OPG's operational experience.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Nuclear Roofing

Current Average Service Life Estimate – 55 years

Recommended Average Service Life Estimate – 25 years

Average of Peer Average Service Lives – N/A

Discussion:

This proposed new account relates to the OPG investment in roofing of Nuclear Buildings and Structures which has shown to have a materially shorter life than the associated buildings. A 2012 Station Roof Replacement Project was initiated as the station roofs were reaching the end of their 25-year design life. OPG's internal assessments have indicated that station roofing requires repair or replacement, with the condition of the roofing deteriorating due to its age. A number of work orders associated with the condition of the roofs been initiated.

Based on the design life and the operating experience of OPG, Gannett Fleming recommends that OPG should create a new account for nuclear roofing, with a 25-year average service life.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

Reclassification of Nuclear Turbine Generator Controls from Account 15411100 – Nuclear Turbines and Auxiliaries to Account 15600000 – Nuclear Instrumentation and Control

Current Average Service Life Estimate – 55 years as part of Account 15411100

Recommended Average Service Life Estimate – 15 years as part of Account 15600000

Average of Peer Average Service Lives – 15 to 25 years

Discussion:

Gannett Fleming recommends a change in the coding of the nuclear turbine generator controls from Account 15411100 – Nuclear Turbines and Auxiliaries to Account 15600000 – Nuclear Instrumentation and Control. It is the view of Gannett Fleming that the emergence of digital technology for turbine generator control equipment results in the 55-year life estimate associated with Account 15411100 being no longer appropriate for these specific assets. It is also noted that, in general, the turbine generator control systems are more similar in technology and life characteristics to the assets recorded in Account 15600000. As such, Gannett Fleming recommends that these assets be reclassified to Account 15600000.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Niagara Tunnel Lining

NEW ACCOUNT – Hydroelectric – Niagara Falls- New Tunnel Lining

Current Average Service Life Estimate – N/A

Recommended Average Service Life Estimate – 90 years

Average of Peer Average Service Lives – N/A

Discussion:

The investment in this account relates to the lining material of the Niagara Tunnel that was placed into service in the first quarter of 2013. The 2011 Depreciation Study conducted by Gannett Fleming and internal OPG depreciation reviews have recommended a life estimate of 75 years for the linings associated with the two original tunnels at Niagara Falls. This estimated service life for existing OPG tunnel linings of 75 years is consistent with industry practice.

The Niagara Tunnel Project ("NTP") was an extremely large, complex, and challenging construction project with an estimated total capital cost of approximately $1.5 Billion. Most of the investment was placed in service in March 2013. Based on its review of the NTP, it is the view of Gannett Fleming that the tunnel excavation investment would have a similar life of 100 years as expected for the existing two Niagara tunnels and other hydroelectric excavation. However, Gannett Fleming's review also specifically noted that the NTP tunnel lining material installation procedures, were specifically designed and the tunnel was specifically constructed for a service life of 90 years. In fact, the 90-year design life was a specific requirement of the NTP to be considered by contractors working on this project. As such, the technical specifications and material used in both the new tunnel construction and tunnel lining have a stated mandatory requirement for a service life of 90 years for the lining system and structures of the Niagara Tunnel Facility.

In making the above recommendation associated with the new tunnel lining, Gannett Fleming's review included:

- A tour of the new tunnel construction activity in 2011 as part of the Sir Adam Beck facility tour conducted as part of the 2011 Depreciation Study;
- Technical design specifications for the project;
- Owner's mandatory requirements for the tunnel facility contained in OPG's Design and Build Contract with Strabag AG;
- A number of discussions with NTP staff regarding the project (and specifically the tunnel lining);
- DRC work and documentation related to the lining investment for the new tunnel; and

- OPG's evidence with respect to the NPT filed with the OEB as part of the EB-2013-0321 proceeding (Ex. D1-2-1).
  .

Gannett Fleming considers the above reviews as sufficient evidence to establish the average service life for the new Niagara Tunnel lining at 90 years, as recommended by the 2012 DRC. As the two existing tunnels are recommended to continue to be depreciated over 75 years, the investment associated with the 2013 tunnel lining should be segregated into a separate account.

APPENDIX 2

APPENDIX 2

ONTARIO POWER GENERATION

NEWLY REGULATED HYDROELECTRIC FACILITIES

Ottawa-St. Lawrence Plant Group:

Arnprior Station
Barrett Chute Station
Calabogie Station
Mountain Chute Station
Stewartville Station
Chats Falls Station
Chenaux Station
Des Joachims Station
Otto Holden Station

Northeast Plant Group:

Abitibi Canyon Station
Otter Rapids Station
Lower Notch Station
Matabitchuan Station
Indian Chute Station

Central Hydro Plant Group:

Auburn Station
Big Chute Station
Big Eddy Station
Bingham Chute Station
Coniston Station
Crystal Falls Station
Elliot Chute Station
Eugenia Falls Station
Frankford Station
Hagues Reach Station
Hanna Chute Station
High Falls Station
Lakefield Station
McVittie Station
Merrickville Station
Meyersburg Station
Nipissing Station
Ragged Rapids Station
Ranney Falls Station
Seymour Station
Sidney Station
Sills Island Station
South Falls Station
Stinson Station
Trethewey Falls Station

Northwest Plant Group:

Aquasabon Station
Alexander Station
Cameron Falls Station
Caribou Falls Station
Kakabeka Falls Station
Manitou Falls Station
Pine Portage Station
Silver Falls Station
Whitedog Falls Station

National Utility Survey
Ontario Power Generation

Survey Findings

September 6, 2013

Prepared by Aon Hewitt
Talent & Rewards Consulting
225 King Street West, Suite 1600, Toronto, Ontario

Presentation to OPG Regulatory Steering Committee

Table of Contents

Section 1: Survey Design

Survey Design

Approach and Methodology

The Terms of Reference describes the approach and methodology for the survey

- Determination of a comparator sample of organizations against whom OPG will be compared
- Identification of the benchmark positions to be surveyed
- Confirmation of the elements of compensation to be collected and reported
- Confirmation of the methodology for collecting data

Survey Design

Determination of Comparator Organizations

Considerations in the selection of comparator organizations:

1. Organizations from which OPG recruits
2. Organizations from which OPG loses talent
3. Organizations representative of the same and/or similar industry sectors
4. Organizations that are reflective of the complexity and size of OPG

The table on page 6 provides a summary of the comparator organizations used to determine the relative competitiveness of Target Total Cash Compensation and Pension and Benefits components.

Survey Design - Comparator Organizations

Organization	Group 1 - Power Generation, Electrical Utilities, and Nuclear Research, Development and Engineering (NRDE)	Group 2 - Nuclear Power Generation and Electric Utilities	Group 3 - General Industry	Group 4 - Pension & Benefits Analysis
AltaLink	√			
Atomic Energy of Canada Limited (NRDE)	√	√		√
BC Hydro and Transmission	√			√
Bruce Power	√	√		
Candu Energy Inc. (NRDE)	√	√		
Enmax Corporation	√			√
FortisAlberta	√			
Hydro Quebec	√	√		√
Independent Electric System Operator	√			
Manitoba Hydro	√			
Nalco Energy	√			√
New Brunswick Power	√	√		
New Brunswick System Operator	√			
Nova Scotia Power	√			
SaskPower	√			
Toronto Hydro	√			
Transalta	√			√
TransCanada	√			√
Yukon Energy Corporation	√			
Aon Hewitt's TCM Survey			√	
Mercer Benchmark Database			√	
Aon Hewitt Benefit SpecSelect (additional 9 companies)				√

Survey Design
Benchmark Jobs

Criteria Used to Determine Benchmark Jobs

- Represented within the comparator groups and business sectors
- A relatively stable position over time
- High number of incumbents

Representative Benchmark Jobs

- Selection of jobs is representative of a cross-sample of
  - All functional groups
  - All levels within OPG
  - All employee groups (i.e. Management, Power Workers Union, and Society of Energy Professionals)
  - Within each segment of power generation (i.e. nuclear, hydroelectric and thermal)
- Survey target was 50% of the total OPG employee population
  - Actual reportable survey results represent 54.3%
  - Number of external companies matched 19 (Canadian) and number of OPG jobs matched 204

Survey Design

Job Families

Information was gathered for the following job families of benchmark jobs:

- Administration
- Corporate Services*
- Engineering
- Environment, Health & Safety
- Finance
- Human Resources
- Information Technology
- Maintenance
- Operations
- Supply Chain, Materials Management & Purchasing

*includes Legal, Public Relations & Regulatory Affairs and Trading

Survey Design

Data Elements

As outlined in the Terms of Reference, the following elements will be reported where available:

- Base salary
- Target short-term incentive
- Target total cash compensation (base salary and target short-term incentive)
- Eligibility and target long-term incentive*
- Other cash compensation**
- Pension and benefits

*Note: insufficient data was reported by survey participants to report on LTI

**Other cash compensation as reported by participants includes nuclear licensing premiums, lump sum merit, bonuses, allowances.

Survey Design

Statistics Reported

Statistics reported are the 50th and 75th percentiles of the sample:

- 50th percentile (or median) represents the position where 50% of observations are lower and 50% are higher
- 75th percentile represents the position where 75% of observations are lower and 25% are higher
- Simulated 75th percentile:
  - Based on the data suppression guidelines outlined on page 11, where insufficient data was available to report the 75th percentile, a simulated 75th was established from the data reported by the broader survey
  - The simulated 75th was calculated by using the average difference between 50th and 75th across all jobs where both percentiles were reportable

Survey Design

Data Suppression Guidelines

To ensure the confidentiality of data supplied by participants, results are presented under the following standards:

	Number of Organizations	Number of Incumbents
Average	3	3
Median (50th Percentile)	3	5
75th Percentile	5	5

Survey Design

Data Aging Methodology

- The National Utility Survey was conducted in the Fall of 2011
- In 2013, the participant base salary data was aged using the following approach:
  - Each survey participant was asked to provide the increase to their job rates and salary structures in 2012 and 2013
  - The compensation data was aged based on the responses provided by each participant
  - Participants were also asked to provide any changes to their short-term incentive plan targets between 2011 and 2013
  - For two companies that did not provide increases to their job rates, the average of all participant results was applied to their data
- The aggregate of these changes were applied to provide total target cash compensation current to 2013

Survey Design

Pensions and Benefits - Methodology

- A quantitative analysis of the pension and benefits programs offered by OPG and the Market comparators has been undertaken to supplement the cash compensation information
- The pension and benefit values for OPG and the Market Data have been determined using Aon Hewitt's Benefit Index® methodology (see Appendix C: Benefit Index® Methodology for more information)
- These values represent the value being delivered to members using a common set of assumptions and demographics for OPG and for the comparator groups and employing relative value techniques to differentiate the plan designs
- The reported values in the table outlined in Section 3: Survey Results – Pension & Benefits should not be confused with cost to the employer which can be influenced by external factors such as underwriting approaches, pension funding policies, administration fees etc.

Section 2: Survey Results – Target Total Cash

Survey Results – Target Total Cash

Interpretation of Competitiveness

- It is common practice to define an individual's target total cash compensation to be "at market", or competitive to the external market, when the differential between current target total cash compensation and intended market position is within +/- 10%
- Data in the following tables are summarized by job family with position vs. market described in terms of a percent differential from the 50^{th} and 75^{th} percentiles
  - 50^{th} percentile represents the median observation of the matching market salaries
  - 75^{th} percentile represents the position where 75% of observations are lower and 25% are higher

Survey Results – Target Total Cash

Comparator Group 1 – Overview

Group 1: Power Generation, Electrical Utilities and Nuclear Research, Development and Engineering (NRDE)

Group 1 was selected by identifying organizations that represent a direct talent pool for nuclear, thermal and hydroelectric power generation positions within OPG. Electric Utilities that operate within the same general sector and hire employees with similar transferable skill sets for some OPG positions were also included. Similarly, Nuclear Research, Development and Engineering organizations with a direct talent pool for nuclear generation positions were included.

- AltaLink
- BC Hydro and Transmission
- Bruce Power
- Enmax Corporation
- FortisAlberta
- Hydro Quebec
- Independent Electric System Operator
- Manitoba Hydro
- Nalco Energy
- New Brunswick Power
- New Brunswick System Operator
- Nova Scotia Power
- SaskPower
- Toronto Hydro
- Transalta
- TransCanada
- Yukon Energy Corporation

NRDE:

- Atomic Energy of Canada Limited
- Candu Energy Inc.

Summary of Survey Results – Target Total Cash

Findings and Observations – Group 1

- OPG's overall competitive position to the survey target total cash findings at the 50th percentile (median) for Group 1 is as follows:
  - OPG's PWU Group's target total cash compensation is above the market competitive zone at the 50th percentile
  - OPG's Society Group's target total cash compensation is within the market competitive zone at the 50th percentile
  - OPG's Management Group's target total cash compensation is within the market competitive zone at the 50th percentile

Survey Results – Target Total Cash

Findings and Observations – Group 1

PWU

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	498	686	36%	***33%***
Engineering	34	26	21%	***10%***
Environment, Health & Safety	75	162	-8%	***-17%***
Finance	98	49	35%	***22%***
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	2,636	4,051	23%	***7%***
Operations	1,043	1,059	5%	***-2%***
Supply Chain, Materials Mgmt & Purchasing	65	163	33%	***13%***
Corporate Services	-	-	-	-
Average: PWU (Weighted by OPG (incumbent matches)			**20.5%**	**8.1%**

Survey Results – Target Total Cash

Findings and Observations – Group 1

Society

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	1	4	-	-
Engineering	1,139	2,641	-1%	*-10%*
Environment, Health & Safety	11	30	10%	*0%*
Finance	40	143	-12%	*-20%*
Human Resources	-	-	-	-
Information Technology	30	106	-1%	*-9%*
Maintenance	226	57	-15%	*-23%*
Operations	27	35	4%	*-5%*
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	9	19	22%	*11%*
Average: Society (Weighted by OPG incumbent matches)			**-2.9%**	**-12.0%**

Survey Results – Target Total Cash

Findings and Observations – Group 1

Management

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	127	200	7%	***-2%***
Engineering	32	245	2%	***-11%***
Environment, Health & Safety	3	29	13%	***0%***
Finance	27	70	-6%	***-16%***
Human Resources	48	70	3%	***-7%***
Information Technology	-	-	-	-
Maintenance	16	29	-8%	***-17%***
Operations	24	51	8%	***1%***
Supply Chain, Materials Mgmt & Purchasing	1	3	-	-
Corporate Services	11	57	-10%	***-20%***
Average: Management (Weighted by OPG incumbent matches)			**3.0%**	**-6.5%**

Survey Results – Target Total Cash

Comparator Group 2 – Overview

Group 2: Nuclear Power Generation and Electric Utilities

Group 2 represents a sub-set of companies from Group 1. It was selected to assess OPG's pay levels vis-à-vis Nuclear Power Generation and Electric Utilities organizations.

- Atomic Energy of Canada Limited
- Bruce Power
- Candu Energy Inc.
- Hydro Quebec
- New Brunswick Power

Summary of Survey Results – Target Total Cash

Findings and Observations – Group 2

- OPG's overall competitive position to the survey target total cash findings at the 50th percentile (median) for Group 2 is as follows:
  - OPG's PWU Group's target total cash compensation is above the market competitive zone at the 50th percentile
  - OPG's Society Group's target total cash compensation is within the market competitive zone at the 50th percentile
  - OPG's Management Group's target total cash compensation is within the market competitive zone at the 50th percentile

Survey Results – Target Total Cash

Findings and Observations – Group 2

PWU

Group 2: Nuclear Power Generation and Electric Utilities

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	498	508	35%	***22%***
Engineering	-	-	-	-
Environment, Health & Safety	75	162	-8%	***-17%***
Finance	-	-	-	-
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	2,353	2,566	22%	***5%***
Operations	550	346	-3%	***-13%***
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	-	-	-	-
Average: PWU (Weighted by OPG incumbent matches)			**19.1%**	**4.3%**

Survey Results – Target Total Cash

Findings and Observations – Group 2

Society

Group 2: Nuclear Power Generation and Electric Utilities

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	-	-	-	-
Engineering	1,094	1,408	-1%	***-10%***
Environment, Health & Safety	-	-	-	-
Finance	-	-	-	-
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	208	29	-18%	***-26%***
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	-	-	-	-
Average: Society (Weighted by OPG incumbent matches)			**-3.8%**	**-12.9%**

Survey Results – Target Total Cash

Findings and Observations – Group 2

Management

Group 2: Nuclear Power Generation and Electric Utilities

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	-	-	-	-
Engineering	24	119	0%	***-9%***
Environment, Health & Safety	2	7	20%	***9%***
Finance	3	8	-24%	***-31%***
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	16	29	-8%	***-17%***
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	-	-	-	-
Average: Management (Weighted by OPG incumbent matches)			**-3.4%**	**-12.6%**

Survey Results – Target Total Cash

Comparator Group 3 – Overview

Group 3: General Industry

Group 3 was selected to obtain data on general industry organizations that OPG shares a talent pool with for general industry positions. Nationally reported data from two published survey sources is represented in the analysis.

- Aon Hewitt's Total Compensation Measurement Survey (TCM) - 251 participating organizations
- Mercer Benchmark Database (MBD) - 799 participating organizations

Summary of Survey Results – Target Total Cash

Findings and Observations – Group 3

- OPG's overall competitive position to the survey target total cash findings at the 50^{th} percentile (median) for Group 3 is as follows:
  - OPG's PWU Group's target total cash compensation is above the market competitive zone at the 50^{th} percentile
  - OPG's Society Group's target total cash compensation is above the market competitive zone at the 50^{th} percentile
  - OPG's Management Group's target total cash compensation is above the market competitive zone at the 50^{th} percentile

Survey Results – Target Total Cash

Findings and Observations – Group 3

PWU

Group 3: General Industry

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	498	13,990	25%	***12%***
Engineering	-	-	-	-
Environment, Health & Safety	-	-	-	-
Finance	98	1,374	53%	***32%***
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	-	-	-	-
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	3	925	56%	***33%***
Corporate Services	-	-	-	-
Average: PWU (Weighted by OPG incumbent matches)			**29.4%**	**15.7%**

Survey Results – Target Total Cash

Findings and Observations – Group 3

Society

Group 3: General Industry

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	1	6	15%	***-31%***
Engineering	-	-	-	-
Environment, Health & Safety	-	-	-	-
Finance	40	4,034	20%	***6%***
Human Resources	-	-	-	-
Information Technology	30	1,818	29%	***17%***
Maintenance	-	-	-	-
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	3	173	6%	***-12%***
Average: Society (Weighted by OPG incumbent matches)			**23.3%**	**9.4%**

Survey Results – Target Total Cash

Findings and Observations – Group 3

Management

Group 3: General Industry

Job Family	#OPG Incumbents	# Market Incumbents	Market Data Differential to P50	Differential to P75
Administration	91	13,990	11%	*1%*
Engineering	-	-	-	-
Environment, Health & Safety	-	-	-	-
Finance	18	1,749	26%	*8%*
Human Resources	51	2,429	39%	*26%*
Information Technology	-	-	-	-
Maintenance	-	-	-	-
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	4	87	-24%	*-34%*
Average: Management (Weighted by OPG incumbent matches)			**20.9%**	**8.4%**

Section 3: Survey Results – Pension & Benefits

Survey Results – Pension & Benefits

Comparator Group 4 – Overview

Comparator Group for Pension & Benefits Analysis

The comparator group for the pension and benefits analysis was obtained from organizations participating in Aon Hewitt Benefit SpecSelect database. These include the 7 organizations listed below, which are also in the Target Total Cash Compensation analysis, and an additional 9 supplementary organizations that are reflective of the sector, complexity and/or size of OPG.

- Atomic Energy of Canada Limited
- BC Hydro
- Enmax
- Hydro Quebec
- Nalco Energy
- Transalta
- TransCanada

Survey Results – Pension & Benefits

Findings and Observations – Group 4

- In the table on page 35, pension (defined benefits/defined contribution) and benefits (health, dental, life insurance and disability benefits) values are defined based on employer-paid value, as is standard industry practice
- The values shown in the table are an estimate of the average value (as defined above) at OPG vis-à-vis the Comparator Group
- Benefits which are pay-related (such as pension, life insurance and disability) are reported as a percent of base pay; benefits which are not pay-dependent (such as medical and dental) have been shown as a flat annual amount

Survey Results – Pension & Benefits

Findings and Observations – Group 4

- The actual pension and benefit value delivered at the individual level differs based on age, years of service, family status, and overall health
- While the average pension value delivered (on an employer-paid basis) is 16.10% of pay at OPG, the range would be 9% for a young, newly hired employee to 22% for an employee in the late stages of his or her career
- Similarly, at the comparator organizations, the average pension value delivered by the employer is 10.77% of pay, with an estimated range of 6% for a newly hired employee to 18% for an employee in the late stages of his or her career
- The main provisions of the pension and benefits programs are the same for all employees; any deviations are immaterial to these calculations and have not been taken into account

Survey Results – Pension & Benefits

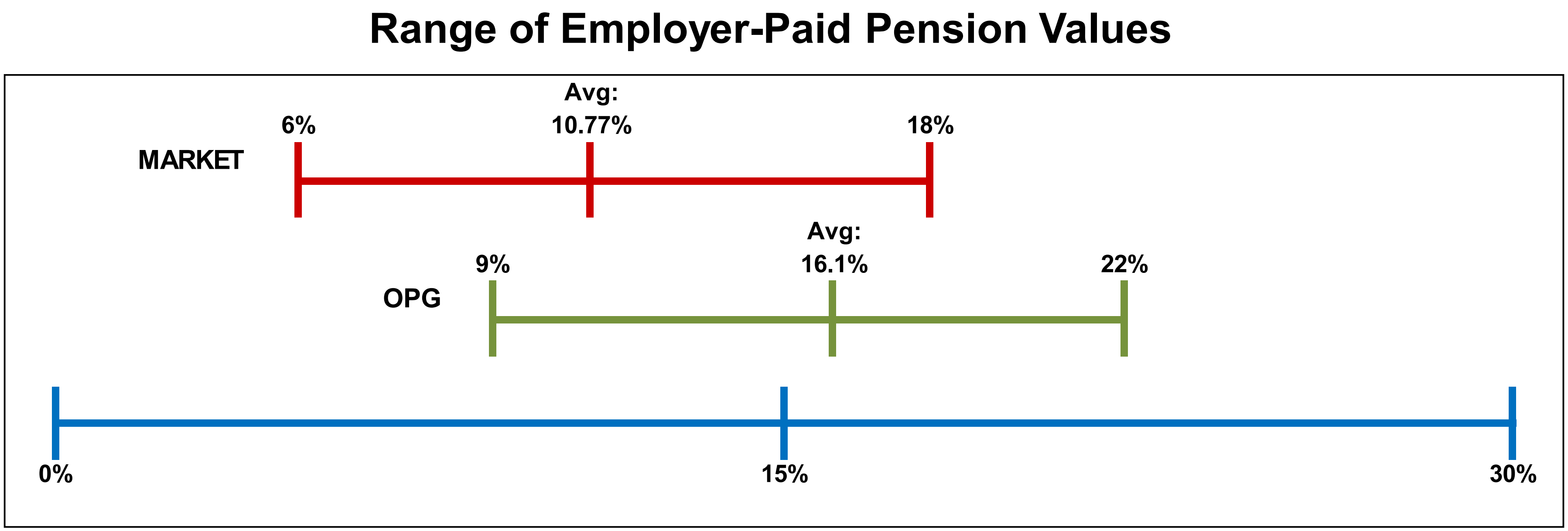
Findings and Observations – Group 4

Pension & Benefits – Employer-Paid Value

Category	OPG	Comparator Group
Pension (% of base pay)	16.10%	10.77%
Life/LTD/STD (% of base pay)	4.18%	3.64%
Medical/Dental ($)	$2,816	$2,471

Survey Results – Pension & Benefits

Findings and Observations – Group 4



- The graph above illustrates the range of employer-paid pension values for OPG and the Comparator Group

Section 4: U.S. Survey Results – Nuclear Premium

U.S. Survey Results – Nuclear Premium

U.S. Organizations

U.S. Power Generation / Electrical Utilities

- Alliant Energy
- Ameren Corporation
- American Electric Power
- Constellation Energy Group, Inc.
- Dayton Power & Light Inc.
- Dominion Resources, Inc.
- Energy Future Holdings Corp.
- Exelon Corporation
- SCANA Corporation
- Xcel Energy

U.S. Survey Results – Nuclear Premium

Approach to Survey Data

- U.S. survey sources were used to gain insight into any differential treatment between nuclear and traditional power generation positions. U.S. data was accessed as only 3 Canadian power generation companies were able to report on both nuclear and traditional power generation jobs in this survey
- In many cases, U.S. comparator organizations used multiple sources of generation
  - Aon Hewitt did not use the absolute salaries from U.S. survey data as they varied substantially given differences in foreign exchange fluctuations, taxation and benefits, regionalization, etc. between U.S. and Canada

U.S. Survey Results – Nuclear Premium

Methodology

- The graph on the page 39 shows the U.S. base pay trend lines for the nuclear jobs and their corresponding non-nuclear counterpart
- In the survey, there were nine instances where U.S. data was available for the same nuclear and non-nuclear job
- These jobs spanned the Maintenance, Engineering and Environment, Health and Safety families and represented Technical, Professional, Management and Executive employees
- The R^2 (coefficient of determination) exceeds 0.9, indicating high correlation in the data comprising the trend lines

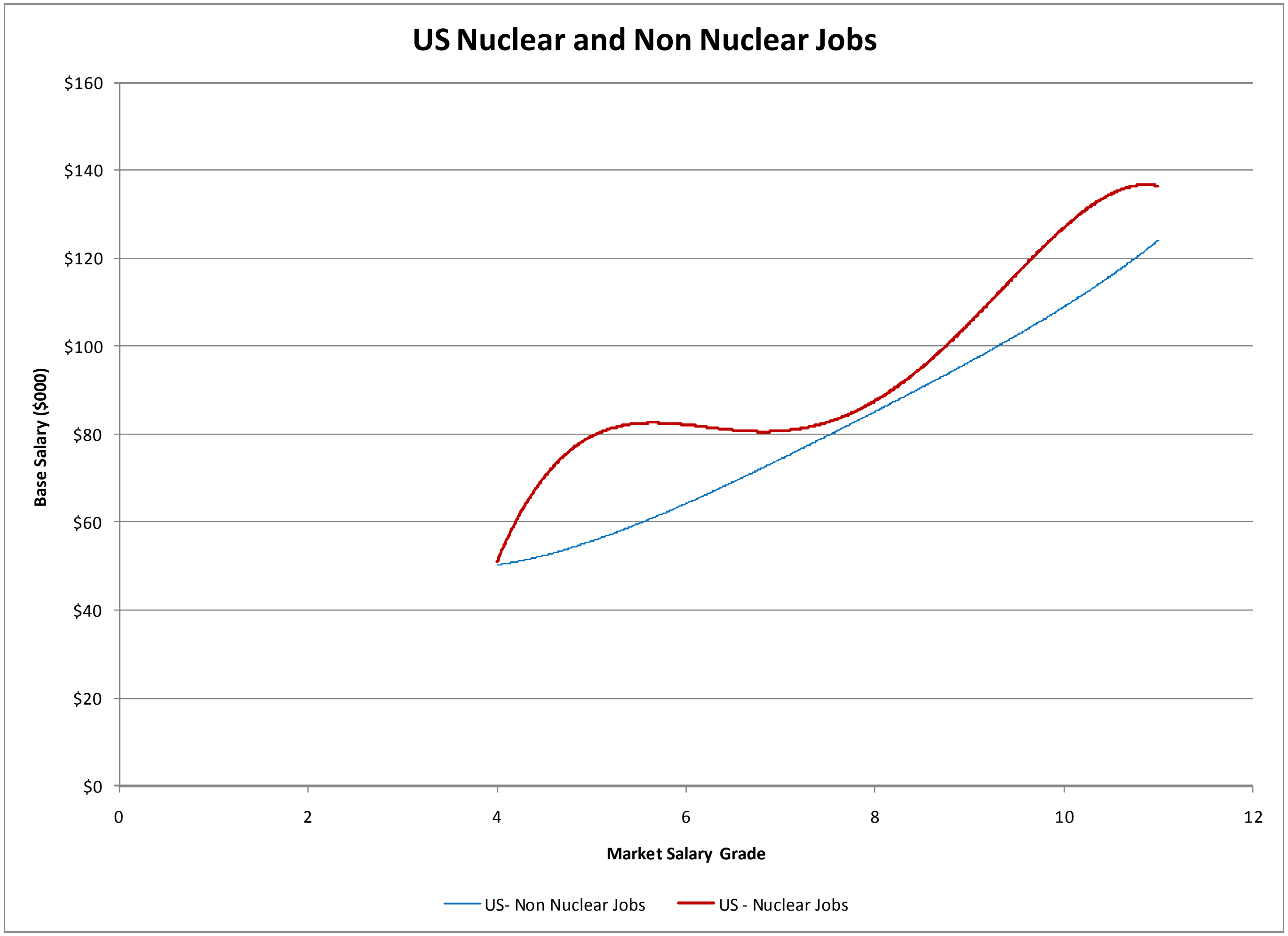
U.S. Survey Results – Nuclear Premium

Findings and Observations

- Our analysis of U.S. companies indicates that nuclear positions are paid a premium of between 0-30% over similar non-nuclear positions; averaging approximately 13% for jobs in the $50,000 to $85,000 salary range
- U.S. companies also indicate a premium for positions in the $120,000 to $140,000 salary range (approximately)

U.S. Survey Results – Nuclear Premium

Findings and Observations



Appendix A: Base Salary Results

Survey Results – Base Salary

Findings and Observations – Group 1

PWU

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	498	686	40%	***37%***
Engineering	34	26	21%	***10%***
Environment, Health & Safety	75	162	-8%	***-17%***
Finance	98	49	35%	***22%***
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	2,636	4,051	26%	***7%***
Operations	1,043	1,059	7%	***0%***
Supply Chain, Materials Mgmt & Purchasing	65	163	35%	***17%***
Corporate Services	-	-	-	-
Average: PWU (Weighted by OPG incumbent matches)			**23.2%**	**9.0%**

Survey Results – Base Salary

Findings and Observations – Group 1

Society

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	1	4	-	-
Engineering	1,139	2,641	0%	***-10%***
Environment, Health & Safety	11	30	21%	***10%***
Finance	40	143	-10%	***-18%***
Human Resources	-	-	-	-
Information Technology	30	106	6%	***-4%***
Maintenance	226	57	0%	***-9%***
Operations	27	35	10%	***3%***
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	9	19	26%	***13%***
Average: Society (Weighted by OPG incumbent matches)			**0.0%**	**-9.3%**

Survey Results – Base Salary

Findings and Observations – Group 1

Management

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	127	200	5%	***-4%***
Engineering	32	245	-6%	***-15%***
Environment, Health & Safety	3	29	8%	***0%***
Finance	27	70	-6%	***-14%***
Human Resources	48	70	4%	***-5%***
Information Technology	-	-	-	-
Maintenance	16	29	-5%	***-14%***
Operations	24	51	4%	***-1%***
Supply Chain, Materials Mgmt & Purchasing	1	3	-	-
Corporate Services	11	57	-13%	***-23%***
Average: Management (Weighted by OPG incumbent matches)			**1.1%**	**-7.2%**

Survey Results – Base Salary

Findings and Observations – Group 2

PWU

Group 2: Nuclear Power Generation and Electric Utilities

Job Family	#OPG Incumbents	# Market Incumbents	Market Data: Differential to P50	Market Data: Differential to P75
Administration	498	508	38%	***25%***
Engineering	-	-	-	-
Environment, Health & Safety	75	162	-8%	***-17%***
Finance	-	-	-	-
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	2,353	2,566	26%	***7%***
Operations	550	346	-3%	***-13%***
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	-	-	-	-
Average: PWU (Weighted by OPG incumbent matches)			**22.4%**	**5.8%**

Survey Results – Base Salary

Findings and Observations – Group 2

Society

Group 2: Nuclear Power Generation and Electric Utilities

Job Family	#OPG Incumbents	# Market Incumbents	Market Data: Differential to P50	Market Data: Differential to P75
Administration	-	-	-	-
Engineering	1,094	1,408	-1%	***-10%***
Environment, Health & Safety	-	-	-	-
Finance	-	-	-	-
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	208	29	-2%	***-11%***
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	-	-	-	-
Average: Society (Weighted by OPG incumbent matches)			**-1.1%**	**-10.5%**

Survey Results – Base Salary

Findings and Observations – Group 2

Management

Group 2: Nuclear Power Generation and Electric Utilities

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	-	-	-	-
Engineering	24	119	-8%	***-17%***
Environment, Health & Safety	2	7	16%	***5%***
Finance	3	8	-11%	***-19%***
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	16	29	-5%	***-14%***
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	-	-	-	-
Average: Management (Weighted by OPG incumbent matches)			**-5.9%**	**-14.8%**

Survey Results – Base Salary

Findings and Observations – Group 3

PWU

Group 3: General Industry

Job Family	#OPG Incumbents	# Market Incumbents	Market Data: Differential to P50	Market Data: Differential to P75
Administration	498	13,990	27%	***15%***
Engineering	-	-	-	-
Environment, Health & Safety	-	-	-	-
Finance	98	1,374	57%	***36%***
Human Resources	-	-	-	-
Information Technology	-	-	-	-
Maintenance	-	-	-	-
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	3	925	60%	***36%***
Corporate Services	-	-	-	-
Average: PWU (Weighted by OPG incumbent matches)			**32.4%**	**18.3%**

Survey Results – Base Salary

Findings and Observations – Group 3

Base Salary - Society

Group 3: General Industry

Job Family	#OPG Incumbents	# Market Incumbents	Market Data Differential to P50	Market Data Differential to P75
Administration	1	6	27%	***-17%***
Engineering	-	-	-	-
Environment, Health & Safety	-	-	-	-
Finance	40	4,034	28%	***14%***
Human Resources	-	-	-	-
Information Technology	30	1,818	38%	***26%***
Maintenance	-	-	-	-
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	3	173	15%	***0%***
Average: Society (Weighted by OPG incumbent matches)			**31.2%**	**17.8%**

Survey Results – Base Salary

Findings and Observations – Group 3

Base Salary - Management

Group 3: General Industry

			Market Data	
Job Family	**#OPG Incumbents**	**# Market Incumbents**	**Differential to P50**	**Differential to P75**
Administration	91	13,990	5%	***-5%***
Engineering	-	-	-	-
Environment, Health & Safety	-	-	-	-
Finance	18	1,749	24%	***8%***
Human Resources	51	2,429	32%	***20%***
Information Technology	-	-	-	-
Maintenance	-	-	-	-
Operations	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-
Corporate Services	4	87	-26%	***-34%***
Average: Management (Weighted by OPG incumbent matches)			**15.0%**	**3.4%**

Survey Results – Base Salary

Findings and Observations – Group 1

All Representations

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

	Differential to Market								
	PWU			Society			Management		
Job Family	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**
Administration	39%	40%	***37%***	22%	-	-	2%	5%	***-4%***
Engineering	20%	21%	***10%***	-1%	0%	***-10%***	-8%	-6%	***-15%***
Environment, Health & Safety	-6%	-8%	***-17%***	20%	21%	***10%***	9%	8%	***0%***
Finance	27%	35%	***22%***	-9%	-10%	***-18%***	-7%	-6%	***-14%***
Human Resources	-	-	-	-	-	-	8%	4%	***-5%***
Information Technology	-	-	-	7%	6%	***-4%***	-	-	-
Maintenance	24%	26%	***7%***	1%	0%	***-9%***	-4%	-5%	***-14%***
Operations	7%	7%	***0%***	11%	10%	***3%***	2%	4%	***-1%***
Supply Chain, Materials Mgmt & Purchasing	27%	35%	***17%***	-	-	-	-18%	-	-
Corporate Services	-	-	-	20%	26%	***13%***	-15%	-13%	***-23%***
Weighted Average:	**21.0%**	**23.2%**	**9.0%**	**-0.1%**	**0.0%**	**-9.3%**	**0.3%**	**1.1%**	**-7.2%**

Survey Results – Base Salary

Findings and Observations – Group 2

All Representations

Group 2: Nuclear Power Generation and Electric Utilities

	Differential to Market								
	PWU			Society			Management		
Job Family	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**
Administration	40%	38%	***25%***	-	-	**-**	-	-	**-**
Engineering	-	-	**-**	-1%	-1%	***-10%***	-9%	-8%	***-17%***
Environment, Health & Safety	-6%	-8%	***-17%***	-	-	**-**	17%	16%	***5%***
Finance	-	-	**-**	-	-	**-**	-8%	-11%	***-19%***
Human Resources	-	-	**-**	-	-	**-**	-	-	**-**
Information Technology	-	-	**-**	-	-	**-**	-	-	**-**
Maintenance	27%	26%	***7%***	-1%	-2%	***-11%***	-4%	-5%	***-14%***
Operations	-2%	-3%	***-13%***	-	-	**-**	-	-	**-**
Supply Chain, Materials Mgmt & Purchasing	-	-	**-**	-	-	**-**	-	-	**-**
Corporate Services	-	-	**-**	-	-	**-**	-	-	**-**
Weighted Average:	**23.4%**	**22.4%**	**5.8%**	**-1.3%**	**-1.1%**	**-10.5%**	**-5.8%**	**-5.9%**	**-14.8%**

Survey Results – Base Salary

Findings and Observations – Group 3

All Representations

Group 3: General Industry

	Differential to Market								
	PWU			Society			Management		
Job Family	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**
Administration	28%	27%	***15%***	7%	27%	***-17%***	6%	5%	***-5%***
Engineering	-	-	-	-	-	-	-	-	-
Environment, Health & Safety	-	-	-	-	-	-	-	-	-
Finance	54%	57%	***36%***	24%	28%	***14%***	21%	24%	***8%***
Human Resources	-	-	-	-	-	-	29%	32%	***20%***
Information Technology	-	-	-	38%	38%	***26%***	-	-	-
Maintenance	-	-	-	-	-	-	-	-	-
Operations	-	-	-	-	-	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	47%	60%	***36%***	-	-	-	-	-	-
Corporate Services	-	-	-	13%	15%	***0%***	-27%	-26%	***-34%***
Weighted Average:	**32.5%**	**32.4%**	**18.3%**	**29.2%**	**31.2%**	**17.8%**	**14.1%**	**15.0%**	**3.4%**

Appendix B: Target Total Cash Summary

Survey Results – Target Total Cash

Summary – Group 1

All Representations

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)

	Differential to Market								
	PWU			Society			Management		
Job Family	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**
Administration	35%	36%	***33%***	16%	-	***-***	5%	7%	***-2%***
Engineering	18%	21%	***10%***	-1%	-1%	***-10%***	-2%	2%	***-11%***
Environment, Health & Safety	-6%	-8%	***-17%***	8%	10%	***0%***	12%	13%	***0%***
Finance	23%	35%	***22%***	-10%	-12%	***-20%***	-6%	-6%	***-16%***
Human Resources	-	-	***-***	-	-	***-***	0%	3%	***-7%***
Information Technology	-	-	***-***	1%	-1%	***-9%***	-	-	***-***
Maintenance	22%	23%	***7%***	-14%	-15%	***-23%***	-8%	-8%	***-17%***
Operations	5%	5%	***-2%***	3%	4%	***-5%***	7%	8%	***1%***
Supply Chain, Materials Mgmt & Purchasing	23%	33%	***13%***	-	-	***-***	-25%	-	***-***
Corporate Services	-	-	***-***	9%	22%	***11%***	-16%	-10%	***-20%***
Weighted Average:	**19.1%**	**20.5%**	**8.1%**	**-3.2%**	**-2.9%**	**-12.0%**	**0.8%**	**3.0%**	**-6.5%**

Survey Results – Target Total Cash

Findings and Observations – Group 2

All Representations

Group 2: Nuclear Power Generation and Electric Utilities

	Differential to Market								
	PWU			Society			Management		
Job Family	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**
Administration	40%	35%	***22%***	-	-	-	-	-	-
Engineering	-	-	-	-1%	-1%	***-10%***	-2%	0%	***-9%***
Environment, Health & Safety	-6%	-8%	***-17%***	-	-	-	22%	20%	***9%***
Finance	-	-	-	-	-	-	-12%	-24%	***-31%***
Human Resources	-	-	-	-	-	-	-	-	-
Information Technology	-	-	-	-	-	-	-	-	-
Maintenance	25%	22%	***5%***	-17%	-18%	***-26%***	-8%	-8%	***-17%***
Operations	-2%	-3%	***-13%***	-	-	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	-	-	-	-	-	-	-	-	-
Corporate Services	-	-	-	-	-	-	-	-	-
Weighted Average:	**22.1%**	**19.1%**	**4.3%**	**-3.9%**	**-3.8%**	**-12.9%**	**-3.4%**	**-3.4%**	**-12.6%**

Survey Results – Target Total Cash

Findings and Observations – Group 3

All Representations

Group 3: General Industry

	Differential to Market								
	PWU			Society			Management		
Job Family	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**	**Avg.**	**P50**	**P75**
Administration	24%	25%	***12%***	-5%	15%	***-31%***	11%	11%	***1%***
Engineering	-	-	-	-	-	-	-	-	-
Environment, Health & Safety	-	-	-	-	-	-	-	-	-
Finance	49%	53%	***32%***	16%	20%	***6%***	23%	26%	***8%***
Human Resources	-	-	-	-	-	-	35%	39%	***26%***
Information Technology	-	-	-	30%	29%	***17%***	-	-	-
Maintenance	-	-	-	-	-	-	-	-	-
Operations	-	-	-	-	-	-	-	-	-
Supply Chain, Materials Mgmt & Purchasing	40%	56%	***33%***	-	-	-	-	-	-
Corporate Services	-	-	-	1%	6%	***-12%***	-28%	-24%	***-34%***
Weighted Average:	**28.0%**	**29.4%**	**15.7%**	**20.8%**	**23.3%**	**9.4%**	**18.8%**	**20.9%**	**8.4%**

Appendix C: Benefit Index® Methodology

Benefit Index® Methodology

General Premises

We use different methods to value the different elements of a benefits program. In developing and refining these methods, we have used the following criteria:

- The method must give a reasonable comparison of the value of the different types of plans within a benefit area (e.g., a reasonable comparison of a final (average) pay pension formula with a career (average) pay pension formula requires an assumption about pay increases; a comparison of the value of medical benefits should not depend on whether or not the benefits are insured)
- The method must give a reasonable comparison of the overall value of the benefits program, recognizing that certain benefits are more valuable than others

Benefit Index® Methodology
Employee Population Base

To facilitate comparisons, one common population is used in determining the relative value indexes. This population has the characteristics of the salaried personnel found in a typical Canadian organization.

This population does not represent your actual salaried employee workforce. However, we do not think the use of your actual salaried employee workforce would have significantly altered the relative values shown in this report or the conclusions to be drawn from them.

Benefit Index® Methodology

Developing the Relative Value Indexes

In general, the value of a benefit is determined in one of two ways:

- For each individual in the population, the probability of an event (such as disability) is multiplied by the lump sum value of all amounts to be paid arising from that event

OR

- A value is calculated by establishing the value as a percent of pay for the year (an allocation of postretirement values to working years)

The actuarial and employee participation assumptions used are chosen with the intention of being as "realistic" as possible. In effect, these values are summed up for all the employees in the model population, recognizing that the value of the various benefits varies with each individual's circumstances - age, service, sex, and compensation level. The relative value in any benefit area then recognizes, on a composite basis, the value to an entire employee group - using a mix of employees who have a variety of individual circumstances.

Benefit Index® Methodology

Treatment of Flexible Benefits

For companies with broad flexible benefits programs, the procedure for developing values is as follows:

- The employees in the model population are assumed to elect the various benefits in the same percentages as each employer’s own experience
- Based on these elections and the price tags associated with each option, the required employee contributions are calculated
- The pool of flexible credits is calculated based on the employer’s credit-generation formula(s)
- Flexible credits are subtracted from employee price tags to determine the net employee contribution for each option
- Where the credits are not generated in respect of a particular benefit area, the credits are allocated to each benefit area in proportion to the price tags.
- Where the flexible credits are in excess of the price tags, these are referred to as “excess credits”

In general, when qualitatively comparing flexible benefits program designs, it is recommended that you focus on those options that either have the highest employee participation (driver of total value) or the option for which the employer pays (driver of employer-paid value).

Benefit Index® Methodology

A Note of Clarification

This study is an analysis of the value of the benefits provided within an organization's benefits program. This has been done with the objective of focusing on the question of benefits program design and is not intended to be an analysis of cost. An organization's benefits "costs" are affected not only by the benefits themselves, but also by accounting and financing decisions and background, such as:

- The use of a conservative versus a liberal basis for funding the pension plan (e.g., low discount rate versus high discount rate);
- The number of years a pension plan has been in existence and its asset performance during that time;
- Decisions to provide directly or insure a particular benefit;
- An organization's internal accounting practices (e.g., for vacation time);
- Pooling of experience among groups (e.g., a disability benefit plan covering both hourly and salaried employees)

The items in the above list do not impact the underlying value of the benefits design and therefore are not elements in this analysis. The question of whether the present funding-financing-accounting decisions are the most appropriate or the best "buy" is a separate subject.

Benefit Index® Methodology

Benefit Areas Included

The benefits included are those which have substantial value and which can be fairly compared. Additional forms of direct compensation and government-required programs are not included.

The benefits are grouped as shown below. Some of the benefits not included are benefits like severance pay, supplemental unemployment benefits, business travel accident insurance, extra individual accident coverage, tuition refund programs, matching donation programs, work and family benefits, and government-required programs.

- Retirement
  - Defined Benefit Pension: Includes all postretirement payments to an employee and spouse. Vested benefits and disability benefits payable from the pension plan after age 65 are included. Preretirement death benefits (lump sum and annuity-type) and the portion of any disability benefit payable from the pension plan prior to age 65 are not included (these benefits are reflected in the Death and Disability indexes respectively)
  - Defined Contribution: Includes savings, profit sharing, money purchase pension, and stock purchase plans with a direct and significant employer subsidy. Only the retirement value of defined contribution accounts has been included. Any assumed payment due to death prior to retirement has been reflected in the Death indexes. Payments that occur upon disability are considered to be retirement benefits

Benefit Index® Methodology

Benefit Areas Included

- Death
  - Includes all lump sum payments and annuity or periodic payments resulting from preretirement death, including those that are insured, self-insured, or payable from the defined benefit and/or defined contribution plans. The traditional “group life” benefits have been shown in a separate index as well to allow some additional analysis
- Disability
  - Has been split into short-term disability and long-term disability by defining short-term benefits as those payable in the first six months, without regard to source. That is, the Short-Term Disability index includes long-term disability plan benefits if they are payable in the first six months of disability. Similarly, the Long-Term Disability index includes accident and sickness and salary continuation benefits payable beyond six months
- Health Care
  - Includes the traditional hospital-medical-surgical benefits as well as dental, hearing, and vision benefits. Preretirement health care values are shown separately for medical and dental plans to allow for specific analysis of each

Legal Disclaimer

ONTARIO POWER GENERATION INC.

REVIEW OF COST ALLOCATION METHODOLOGY FOR CENTRALIZED SERVICES AND COMMON COSTS

Prepared by

HSG Group, Inc.

August 23, 2013

TABLE OF CONTENTS

TABLES

EXHIBITS

Section I. Executive Summary

HSG Group, Inc. is pleased to submit this Report to Ontario Power Generation Inc. ("OPG") on our Review of OPG's Cost Allocation Methodology for Centralized Services and Common Costs ("Review").

OPG is primarily organized by generation technology into Business Segments (i.e., Nuclear, Hydroelectric-Thermal - Table 1). Many of the services required by the Business Segments are provided by Centralized Support and Administration ("CSA") departments (Table 2). In addition, OPG incurs Common Costs on behalf of the Business Segments and Service Providers, comprising i) centrally held costs which are primarily labour-related costs (e.g., Pension and OPEB) and insurance premiums, and ii) hydroelectric / Ottawa St. Lawrence ("OSL") shared engineering and operating costs. Together the CSA costs and the Common Costs are referred to as Centralized Services and Common Costs ("CSCC").

The purpose of OPG's cost allocation methodology is to distribute the CSCC among the Business Segments and generating stations[1], using direct assignments and cost drivers selected based on cost causation. The EB-2010-0008 Decision With Reasons accepted OPG's cost allocation methodology and applied the results in setting OPG's approved payment amounts for generation.

HSG Group was engaged by OPG to perform this Review to evaluate if OPG's cost allocation methodology for CSCC costs continues to meet best practices and precedents established by the OEB, including the 3-prong test, in view of OPG's Business Transformation organizational changes.

OPG's generating Business Segments are also charged cost-based Asset Service Fees ("ASFs") for the use of certain assets owned and operated by OPG. A portion of the costs charged is included in the CSA costs. HSG Group was engaged to evaluate the ASF methodology as well.

Our Review included the following steps:

- Understand OPG's business, especially changes from 2010;

[1] The term "stations" is used throughout the report to refer to a generating station for the nuclear and thermal operations and, unless specifically distinguishing between the currently unregulated facilities expected to be regulated and those subject to a supply agreement, to a plant group consisting of a number of individual stations for the hydroelectric operations.

- Review and evaluate OPG's cost allocation methodology including overall design, use of direct assignment, selection of cost drivers and documentation;
- Review the model developed by OPG to implement the methodology;
- Review and evaluate OPG's compliance with the 3-Prong Test, including surveying and interviewing Business Segments and service providers; and
- Review and evaluate the methodology for ASFs.

Based on our Review, which provided sufficient information to support our conclusions, we conclude that OPG's cost allocation methodology is appropriate for OPG, and distributes costs using direct assignments and cost drivers supported by principles of cost causality, consistent with best practices and OEB, including the 3-prong test.

We also conclude that:

- OPG's model correctly calculates the amount to be distributed to each Business Segment and station in accordance with the methodology;
- OPG's use of cost-based ASFs to charge generating Business Units for the use of certain Information Technology ("IT") assets, joint-use hydro-electric properties (including dams) and buildings is reasonable based on the operation of OPG's business and the principles of cost causality; and
- The transfer of employees from generation Business Segments to CSA departments as part of OPG's Business Transformation, did not cause any cost shifts between Business Segments; the costs for the transferred employees have been directly assigned to the Business Segments, which they continue to support.

HSG Group recommended changes to the cost drivers selected for several activities. OPG accepted the changes and will implement them in its Business Plan 2014-16. The effect of these changes in 2014, based on the current business plan, would not be material.

HSG Group recommended changes to OPG's cost allocation model to make the iterative calculation process (which is unavoidable due to the use of internal allocators) more efficient. The effect of these changes on the total cost distributed to any Business Segment was not material. OPG is evaluating these recommendations.

Section II. Introduction

HSG Group, Inc. ("HSG Group" or "we") is pleased to submit this Report to Ontario Power Generation Inc. ("OPG") on our Review of OPG's Cost Allocation Methodology for Centralized Services and Common Costs ("Review").

HSG Group was engaged by OPG to perform this Review to evaluate if OPG's cost allocation methodology for the cost of Centralized Services and Common Costs ("CSCC") continues to meet best practices and precedents established by the Ontario Energy Board ("OEB"), in view of OPG's Business Transformation organizational changes. CSCC includes the cost of Centralized Support and Administrative ("CSA") services, and Common Costs incurred on behalf of Business Segments and Service Providers, comprising i) centrally held costs which are primarily labour-related costs (e.g., Pension and OPEB) and insurance premiums, and ii) hydroelectric / Ottawa St. Lawrence ("OSL") shared engineering and operating costs.

OPG's generating Business Segments are also charged cost-based Asset Service Fees ("ASFs") for the use of certain assets owned and operated by OPG. A portion of the costs charged is included in the CSA costs. HSG Group was engaged to evaluate the ASF methodology as well.

Our evaluation included the following criteria:

- Is the methodology appropriate for OPG based on current and anticipated business and regulatory considerations?
- Does the methodology continue to meet best practices and precedents established by the OEB, including the 3-prong test for affiliate transactions[2]?
- Has the methodology been implemented correctly in the models developed by OPG?
- Are the allocators selected by OPG appropriate and consistent with prior allocators?
- Has the methodology been appropriately applied, considering business and organizational changes at OPG?
- Is OPG's methodology for computing ASFs appropriate?

[2] EBRO 493/494 Decision With Reasons describes the three-pronged test. The three prongs are identified and discussed in Section VI, Part 0

In this Report "regulated" and "unregulated" refer only to regulation by the OEB with respect to the payment amounts OPG receives with regard to its generating stations.

OPG's cost allocation methodology has been reviewed in the past. In *Report on Cost Allocation Methodology Review* dated April 30, 2006 ("2006 Report"), the independent consulting firm R. J. Rudden Associates, Inc. stated, "The methodology used by OPG to distribute the CSA Costs separates the CSA Costs between regulated and unregulated Business Units in a manner that meets current best practices and is consistent with cost allocation precedents established by the OEB". The 2006 Report was filed in EB-2007-0905 as Exhibit F4-T1-S1.

In *Review of Centralized Support and Administrative Cost Allocation Methodology* dated March 5, 2010 ("2010 Report"), the independent consulting firm Black & Veatch Corporation reaffirmed the findings in the 2006 Report, and also stated, "OPG's allocated Centralized Support and Administrative services costs meet the requirements of the OEB's 3 prong test." The 2010 Report was filed in EB-2010-0008, Exhibit F5-2-1. The EB-2010-0008 Decision With Reasons accepted OPG's cost allocation methodology and applied the results in setting OPG's approved payment amounts for generation.

HSG Group is an independent consulting firm specializing in electric and gas utility rate and regulatory matters. Howard Gorman, the President of HSG Group, performed this Review. He was the lead consultant in performing the reviews for the 2006 Report and the 2010 Report. His professional experience is presented in Exhibit D.

Section III. Organization of Ontario Power Generation

A. Service Recipients- Business Segments

Ontario Power Generation Inc. is wholly owned by the Province of Ontario. Its principal business is the generation and sale of electricity in Ontario and to interconnected markets. OPG is primarily organized by generation technology. The "Service Recipients" are the Business Segments that receive CSA services, and to which the costs of those services as well as Common Costs are distributed; the Service Recipients are listed in Table 1.

Table 1: Service Recipients- Business Segments Receiving CSA Services and Centrally Held Costs

Nuclear Generation	Regulated *Nuclear Waste Management is a separate segment for financial reporting but included with Nuclear Generation in this Review*
Hydroelectric Generation	Regulated (A)
Hydroelectric Generation	Unregulated (A)
Thermal (Fossil) Generation	Unregulated (A)
Other Business (Non-generation)	Unregulated *Includes Energy Markets which supports the generation businesses and performs other activities as well*
(A) The Hydroelectric- Regulated, Hydroelectric- Unregulated and Thermal generation business segments are operated together as the Hydro Thermal Operations ("HTO") group. They are represented separately in OPG's cost allocation to allow better matching of cost drivers with cost causation.	

B. Service Providers

Many of the services necessary to support the Business Segments are performed by centralized Service Provider groups within OPG. These groups are listed in Table 2. Exhibit A presents the departmental budgets for 2014 for the CSA Service Providers. Table 2 also includes Common Costs.

Table 2: Service Providers and Common Costs

Group	Primary Departments or Services	2014 Budget ($ millions)	% Total
BAS – IT Outsourcing	Infrastructure Management, Application Management, Data Centre, Service Management, Data & Voice Network	$72.8	12.1%
BAS- IT Work Programs	Application Software, Telecom, IMO Services, IM Projects, Hardware, Non-capital projects	52.6	8.8%
BAS – Supply Chain	Nuclear Supply Chain, Corporate Supply Chain Corporate Supply Chain and HTO Supply Chain	69.3	11.6%
BAS - Real Estate and Business Services	Real estate services, Enterprise services, Facility Services, Fleet services	124.6	20.8%
People and Culture	Training (Fleet operations, Fleet support services, Fleet maintenance, Fleet simulator), Total rewards & solutions, Safety & wellness, Talent management, Employee & labour relations, Business partnerships	117.2	19.5%
Finance	Finance and controllership, Corporate financial processing, Treasury, Investment planning, Assurance (Internal audit and Nuclear oversight), Fund management, CFO office	62.2	10.4%
Corporate Centre	Executive, Law, Corporate relations & communications, Executive operations, Corporate business development, Strategic initiatives, Business transformation	59.0	9.8%
CO&E	Integrated revenue planning, Market operations, Term trading & outage management, Fuels, Commercial services, Bruce lease management, Environment, Regulatory affairs, OEB costs	42.0	7.1%
Total CSA Costs		**599.7**	**100.1%**
Hydroelectric / OSL Shared		76.6	
Centrally held costs in OPG's cost allocation model- primarily labour-related costs, insurance premiums		479.7	
Total Common Costs		**556.3**	
Total CSCC (CSA costs plus Common Costs)		**$1,156.0**	
BAS = Business & Administrative Services; CO&E = Commercial Operations & Environment			

Starting in 2012, OPG implemented a Business Transformation, in which employees who had reported to generation Business Segments were transferred to CSA departments. As a result, the total dollars in the CSA department budgets, and in OPG's cost allocation, increased. However these costs have been directly assigned to the Business Segments that are supported, and the transfer of employees as part of OPG's Business Transformation did not cause any costs shifts between Business Segments. The increase in costs allocated to a Business Segment in the allocation process was offset by an equal decrease in directly incurred costs. The Business Transformation is discussed further in Section V Part A. A summary of the effect of the Business Transformation on the 2013 Budget for Service Recipients and Service Providers is presented in Exhibit C.

Section IV. Summary of Review Approach

A. Overview of OPG's Cost Allocation Methodology

Most of the departments in the Service Provider groups support more than one Business Segment. For those departments, it is necessary to distribute the cost of the department's resources among the Business Segments. In many cases, specific resources (individual employees and specific costs) can be identified to a particular Business Segment or station, or the portions of resources (employees' time and other costs) that are spent on each Business Segment or station can be estimated. In these cases, there is a direct relationship between the department's costs and the Business Segments or stations that cause the costs to be incurred.

In addition, the Common Costs reflecting centrally held labour-related costs and insurance premiums are incurred on behalf of all the Business Segments and Service Providers, and Common Costs reflecting hydroelectric / OSL shared costs are incurred primarily on behalf of the hydroelectric plants.

In cases where neither specific identification nor estimation of costs to a Business Segment are possible, it is necessary to allocate the costs of the resources to the Business Segments or stations using cost drivers. A cost driver is a formula for sharing costs among those who cause the costs to be incurred. The use of cost drivers to allocate costs of shared resources conforms to regulatory precedent and is widely accepted.

The selection of cost drivers should be based on cost causation, with consideration to the practicality of obtaining the data necessary to develop the allocator, the stability of the data over time and whether additional data would materially affect the result of the cost allocation.

The types of cost drivers used typically include:

- Physical (e.g., full-time employees or FTEs; LAN IDs)
- Financial (e.g., labour costs; total OM&A cost;)
- Blended (e.g., capital plus OM&A); and
- Internal (e.g., BAS costs allocated for Finance are re-allocated to Business Segments and stations in proportion to the overall allocation of Finance costs).

The criteria for the selection of cost drivers, and the types of cost drivers used by OPG, have remained the same in the 2006 Report, the 2010 Report and this Report.

B. Description of Tasks

Our Review comprised the tasks listed in Table 3.

Table 3: Tasks	
Task	**Description**
Task 1	Understand OPG's business and organization, and the departments included in CSA Costs, and identify changes from 2010.
Task 2	Review and evaluate the methodology used by OPG to distribute 2014 CSA costs, as well as Common Costs, including overall design, use of direct assignment, selection of cost drivers and documentation.
Task 3	Review the model developed by OPG to implement the methodology.
Task 4	Review and evaluate OPG's compliance with the 3-Prong Test.
Task 5	Review Asset Service Fee methodology.
Task 6	Prepare Report on the Review, including conclusions and recommendations.

C. Scope

Consistent with standard practice for independent review consulting assignments, HSG Group relied on the genuineness and completeness of all documents (including spreadsheets) presented to us by OPG and we accepted factual statements made to us by OPG (e.g., budget dollars; specific time assignments), subject only to overall reasonableness considerations and actual contrary knowledge, but without independent confirmation.

The total CSA Costs for 2014 in OPG's Business Plan 2013-2015 are budgeted to be $599.7 million. This amount was the basis for our judgments based on materiality in this Report.

Section V. OPG's Cost Allocation Methodology

A. Understand OPG's business and organization (Task 1)

The purpose of this task was to understand how OPG is organized, to identify the departments included in CSA Costs, and to identify changes from 2010. Information was obtained from OPG public and internal documents and discussions with OPG personnel.

OPG's business and organization are discussed in Section III. The Service Recipients for the CSA services are the Business Segments identified in Table 1; the Service Providers also support each other (e.g., BAS supports Finance and People & Culture). The Service Providers are the groups and departments identified in Table 2.

Common Costs includes centrally held labour-related costs that are applicable to all Business Segments and Service Recipients (approximately 89% of Common Costs), insurance premiums approximately (6%) and other items (approximately 5%).

There were no organizational changes from 2010 that would indicate the cost allocation methodology is not appropriate or should be revised.

Business Transformation

Starting in 2012, OPG implemented a Business Transformation, in which employees who had reported to operating Business Segments (e.g., Nuclear) were transferred to the CSA Service Providers (e.g., Finance). The purpose of the Business Transformation was to create a more center-led organization. OPG believes that the center-led organization will provide opportunities for cost-saving by facilitating standardization and cross-training, and making it easier to share resources and achieve economies of scale.

A summary of the effect of the Business Transformation on the 2013 Budget for each of the Service Recipients and Service Providers is presented in Exhibit C.

As a result of the Business Transformation, the total dollars in the CSA departments, and in OPG's cost allocation, have increased; but the costs for individuals who were transferred have been directly assigned in the cost allocation to the Business Segments they support. The activities performed by the transferred employees did not change, only their reporting relationships. The Business Transformation did not cause any costs shifts between Business Segments. The increase in costs allocated to a Business Segment in the allocation process was offset by an equal decrease in directly incurred costs.

Some employees of CSA groups who at present provide services to only one Business Segment and are directly assigned to that Business Segment, will, in the future, provide services to more than one Business Segment. OPG believes that it will be possible to allocate their time appropriately because much of the work will be project-based, and management will be able to estimate their time accurately.

The allocation of Common Costs is not affected by Business Transformation.

B. Review and evaluate OPG's cost allocation methodology (Task 2)

In this task, we review and evaluate OPG's cost allocation methodology for CSA costs, and Common Costs, including overall design, use of direct assignment, selection of cost drivers and documentation.

The purpose of the methodology is to distribute CSA Costs, and Common Costs, among the Business Segments and generating stations. Information was obtained from the following sources:

- Discussions with OPG personnel
- Review of 'Allocation Templates' for each department, discussed below
- Review of the methodology for consistency with that presented by OPG in EB-2010-0008.
- Review of the document "OPG Revenue and Cost Assignment and Allocation Methodology", draft provided by OPG as of April 18, 2013.

The costs are distributed based on the following relationships:

- Direct assignment to Business Segment or to generating station
- Time and cost basis, using actual records or estimates
- Allocation using cost drivers; the primary cost driver types used by OPG are: OM&A and Capital Blend; FTEs; Labour costs; LAN IDs

If the relationships identified above do not have sufficient detail to enable costs to be distributed to stations, a re-distribution is needed. For example, certain Business & Administrative Services costs are distributed to the Business Segments, then re-distributed to the stations based on the users of the applications.

Design

In evaluating the design of OPG's methodology, we considered the following:

- *Does the methodology reflect how the business is organized and operated?*

Evaluation: OPG's methodology follows its organizational structure, in which the majority of the CSA services are integral to running the Business Segments (e.g., and human resources and information technology), and Business Segments receive many of their necessary support services from CSA departments rather than decentralized resources reporting to the business units, however a significant portion of these resources are located at business unit sites. This permits extensive use of direct assignment of the CSA costs.

Most of the Common Costs are centrally held labour-related costs and can also be directly assigned.

In addition, the use of internal allocators to re-distribute costs initially distributed to CSA Service Provider departments (e.g., Finance), is appropriate because the purpose of the CSA groups is to support the Business Segments and stations.

- *Are sufficient resources devoted to the cost allocation process? Do management and the users understand and support the process*?

Evaluation: OPG's cost allocation process has the support of senior management including the assignment of dedicated resources to the process. The heads of the organizations that HSG Group interviewed are knowledgeable about the cost allocation methodology and understand how to work within it to meet the needs of their businesses. The Service Recipients can, and do, challenge and influence decision-making by Service Providers regarding the services to be provided and the costs to be incurred, through forums such as budget meetings and Executive Leadership Team meetings. The Service Recipients are aware of how their decisions (regarding services provided by the CSA groups) affect their costs.

- *Is sufficient information gathered from reliable sources to support specific identification, time estimation and selection of appropriate cost drivers?*

Evaluation: Consistent with OPG's approach in EB-2010-0008, the methodology relies on the judgments of department and Business Segment managers to make specific identification of labour and non-labour costs, and time estimation. These are the people in the best position to determine how resources are used. Representatives of the Controller's department that support each Business Segment, as well as representatives of Business Segments, review the resulting estimates.

The department heads that we interviewed believe the cost drivers selected are appropriate, and they have the opportunity to review and challenge them if they believe necessary. Obtaining input from the people closest to the resources improves the quality of decisions as to cost drivers.

<u>Conclusion on Design</u>: OPG's methodology reflects how OPG is organized and operated. OPG has devoted substantial and sufficient resources to the cost allocation process. The process is understood and supported by management and the users. Sufficient information is gathered from reliable sources to support specific identification, time estimation and selection of cost drivers.

Use of Direct Assignment

- *Is the use of direct assignment appropriate?*

<u>Evaluation</u>: Direct assignment is preferable to allocation because it is means there is a direct relationship between the costs incurred and the Business Segment or Station causing it to be incurred. OPG informed us that costs are directly assigned whenever possible; Table 4 shows that approximately 80% of the total costs to be distributed (CSA costs incurred by Service Providers plus Common Costs) are directly assigned.

<u>Conclusion on Direct Assignment</u>: The OPG methodology uses direct assignment wherever possible.

Selection of Cost Drivers

- *Are the cost drivers selected by OPG appropriate*?

<u>Evaluation</u>: Exhibit B lists the cost drivers selected by OPG for those instances where less than all costs could be distributed by direct assignments. OPG's cost driver selections are appropriate based on the nature of the costs, are consistent with the principles stated in the 2006 Report and re-affirmed in the 2010 Report, and are consistent with the allocators used in OPG's presentations in EB-2007-0905 and EB-2010-0008.

In the cost allocation methodology, Service Provider department budgets are broken into many detailed activities, and labour and non-labour costs are assigned or allocated separately; greater detail permits OPG to distribute costs based on direct assignment or allocation, in a manner that most closely reflects cost causation.

OPG has standardized the allocators used in the cost allocation methodology, which promotes transparency and consistency.

HSG Group recommended changes to the cost drivers selected for several activities. OPG agreed that the allocators that we recommended were more appropriate based on cost causality, and will implement them in its Business Plan 2014-2016. The effect of these changes in 2014, based on the current Business Plan 2013-2015, would not be material. The 2013 budget was completed before our Review, therefore the changes were not made in 2013 in order to make actual results comparable to budget; we agree with this treatment.

Conclusion on Selection of Cost Drivers: The cost drivers used by OPG are appropriate based on the principles and selection criteria discussed in this Report and on the operation of OPG's business, and are consistent with the allocators used in EB-2007-0905 and EB-2010-0008 which were accepted by the OEB.

- *Is the documentation for the methodology adequate? Does it support the implementation of the methodology?*

Evaluation: The document "OPG Revenue and Cost Assignment and Allocation Methodology" is a detailed description of OPG's cost allocation methodology. The document presents the information in a standardized format, tailored to the many different areas it addresses. Because people with many perspectives participate in the CSA cost allocation process, this is important.

The 'Allocation Templates' developed for each department provide excellent documentation of the activities performed by the department, the budgeted resources for that activity, and the rationale for directly assigning or allocating the cost of those resources. The 'Allocation Templates' provide a useful link between the inputs to the model and the results.

Conclusion on Documentation of the Methodology: OPG's documentation for its cost allocation methodology provides a reasonable explanation of the methodology, promotes consistent application of principles and makes the methodology easier to adapt as the business changes. OPG has developed an interface for users of the model, which encourages consistency and completeness.

Overall Conclusion on OPG's Cost Allocation Methodology for CSA Costs and Common Costs

The cost allocation methodology used by OPG for CSA costs and for Common Costs (together, CSCC) reflects how the company is organized and operated. The process is understood and supported by management and the users. Sufficient information is gathered from reliable sources to support specific identification, time estimation and selection of cost drivers. Direct assignment is used wherever possible. The cost drivers selected and implemented for OPG's Business Plan 2013- 2015 are appropriate based on the principles and selection criteria discussed in this Report and on the operation of OPG's business, and produce a result that fairly allocates the cost of the CSA groups and Common Costs.

The documentation prepared by OPG explains the methodology, promotes consistent application of principles and makes the methodology easier to adapt as the business changes. The 'Allocation Templates' provide excellent documentation of the implementation of the methodology, including the rationale for the direct assignments and allocations selected.

HSG Group believes that OPG's cost allocation methodology is appropriate for OPG, and it allocates costs based on cost drivers / allocation factors supported by principles of cost causality, consistent with best practices and OEB precedent.

C. Review the model developed by OPG to implement the methodology (Task 3)

HSG Group reviewed a working copy of the Cost Allocation Model ("CAM") developed by OPG. The purpose of the CAM is to automate calculations, to make it easier to update information and to support compliance with the cost allocation methodology. The CAM comprises numerous Excel® spreadsheets, with a user interface to manage the input and output process; the inputs are now directly accessed from OPG's accounting system in order to reduce the potential for input errors.

Our review included tracing the inputs to the CAM back to the Allocation Templates; confirming all calculations; and reviewing the logic of the CAM to determine if it reflects OPG's cost allocation methodology. Based on our review, we conclude the following about the CAM:

- The CAM faithfully reflects OPG's cost allocation methodology.
- Inputs from the Allocation Templates are properly reflected in the CAM.
- The CAM correctly calculates allocation percentages for external and internal allocators. The use of an iterative process is reasonable due to the use of internal allocators and the need to re-allocate some of the costs (i.e., costs that are allocated from one CSA department to another must be re-allocated to the Business Segments).

However the model and the calculations could be more efficient, and we have provided our suggestions to OPG on doing so.

- The CAM correctly calculates the amount to be allocated to each Business Segment and each station, based on the inputs and the methodology.

D. Summary of Direct Assignments and Cost Drivers Selected- Exhibit B

This Section describes Exhibit B, which shows how the cost of each major service performed by the CSA Service Provider departments is distributed to the Business Segments and to the stations.

Column A lists the CSA Service Providers and the major services they provide to the Business Segments.

Column B shows each activity's percentage of the 2014 departmental budget. Each department sums to 100%.

Columns C-F show how departmental costs are distributed to the Business Segments and the stations. If a portion of costs are directly assigned to one or more Business Segments or stations, Column C shows the direct assignment method, and Column D shows the cost as a percentage of the 2014 budget for the Service Provider. The primary direct assignment methods listed in Column C are:

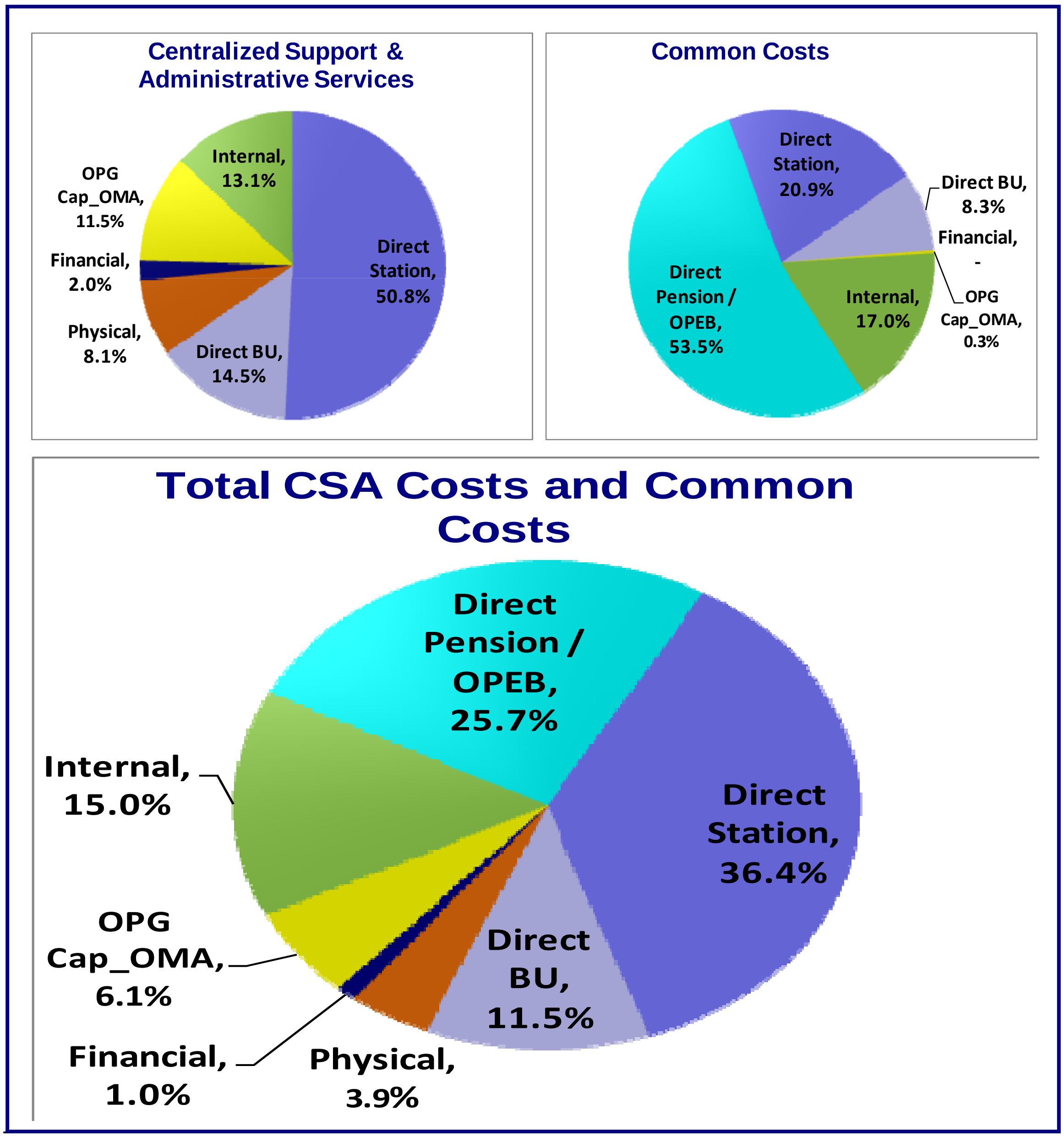
- Specific, indicating specific identification of labour or other resources;
- Estimates, indicating management estimates of time;
- Asset Service Fees, for utilities costs based on location; and
- Pension / OPEB, based on amounts charged to payroll.

Column E shows the allocation type for costs that were not directly assigned, and Column F shows the cost as a percentage of the 2014 budget for the Service Provider.

E. Summary of Cost Driver Types

Table 4 summarizes the types of costs drivers used to distribute CSA Costs and Common Costs (together, CSCC) to the Business Segments and the stations; the percentages are based on the 2014 Budget.

Table 4: Direct Assignments And Cost Drivers Used For Distribution Of CSA Costs and Common Costs To Business Segments



Section VI. 3-Prong Test

As discussed below, the three-prong test applies to corporate centre costs that are allocated among affiliates, and to transactions between affiliates. The CSA costs meet this definition and fall under the test. Common Costs do not fall under the three-prong test; they do not involve services provided or other transactions between affiliates, they are merely reflect how OPG records and pays for these items.

A. Approach to determine OPG's compliance with 3-Prong Test (Task 4)

Background for evaluation of 3-prong test

In its Decision with Reasons for OPG's filing at Docket EB 2007-0905, the OEB wrote, "The Board expects the next independent review to include an evaluation of the cost allocation methodology and consideration of the Board's 3-prong test." In the 2010 Report, OPG's methodology was found to comply with the 3-prong test. The 3-prong test is summarized as follows:

1. Cost incurrence: Were the corporate centre charges prudently incurred by, or on behalf of, the utility for the provision of services required by Ontario ratepayers?
2. Cost allocation: Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?
3. Cost / benefit: Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?

At OPG, many of the shared CSA services are provided to the Service Recipients (i.e., the Business Segments) by dedicated personnel at the Service Providers; therefore the OPG methodology must capture the costs of specific personnel and activities so they can be assigned correctly.

As discussed in Section V, as a result of OPG's Business Transformation, the total dollars in the CSA departments, and in OPG's cost allocation, have increased. The Business Transformation did not cause any costs shifts between Business Segments. The increase in costs allocated to a Business Segment in the allocation process was offset by an equal decrease in directly incurred costs.

In addition, the majority of the costs of the CSA services are integral to running the Business Segments (e.g., human resources and supply chain). The Service Providers for these services and the Service Recipients must work together closely to ensure the needs of the Service Recipients are met, the level of service is appropriate and the costs are correctly assigned or allocated.

Use of surveys

We evaluated OPG's compliance with the 3-prong test in part by asking Service Recipients and Service Providers to complete surveys and by reviewing the completed surveys with them. Each survey question was designed to provide information about one or more of the prongs; similar surveys completed for the 2010 Report were used as a starting point for developing the survey questions.

Selection of Service Recipient and Service Provider Respondents

HSG Group requested that surveys be completed by the following groups:

- *Service Recipients*: Nuclear Business Segment and Hydro Thermal Operations Business Segment, which includes all regulated operations (and some unregulated). These two segments represent over 90% of the allocated CSA costs, and
- *Service Providers*: BAS Chief Information Office, BAS Supply Chain, BAS Real Estate Services, Finance, People & Culture and Corporate Relations & Communication (department in Corporate Office), representing over 80% of CSA Service Provider costs.

These surveys, and our review and follow-up interviews (discussed below), provided sufficient evidence for us to evaluate the 3-prong test and reach our conclusions.

Review of Survey Responses

HSG Group reviewed all of the survey responses. Each of the responses provides information as to whether the services provided are prudently incurred in order to serve to Ontario ratepayers, and how the Service Providers take into account the needs of the Service Recipients in determining the level and quality of service and cost effectiveness.

In addition, HSG Group contacted the survey respondents. The purpose of these discussions was to validate the survey responses, to confirm the respondents' familiarity with the allocation process and methodology and to obtain further information on specific items. We found that the respondents completed the surveys based on their personal experience. The Service Recipients discussed how their Business Segments work with the Service Providers to establish the services to be provided, as well as the level and quality of service, and how these decisions are made. The Service Providers discussed this process from their perspectives.

HSG Group also confirmed that the survey responses applied to costs that are charged through Asset Service Fees.

B. Cost Incurrence

Were the corporate centre charges prudently incurred by, or on behalf of, the utility for the provision of services required by Ontario ratepayers?

Both Nuclear and HTO confirmed the description of the services they receive, and described how each service is used in their respective Business Segments.

Nuclear and HTO explicitly stated that the services they receive from the Service Providers are necessary to running their Business Segments. The descriptions of services received by Nuclear and HTO are detailed and demonstrate familiarity with the nature of the services received, which was confirmed in the interviews with Nuclear and HTO.

HTO stated that the services received are required for it to: 1) fulfill the Shareholder mandate/relationship; 2) maintain stewardship of hydro and thermal assets; 3) ensure compliance with typical corporate governance and the Ontario Business Corporation Act; 4) operate and comply with all external regulatory and other requirements; and 5) ensure proper due diligence in the areas of safety, environment, and risk and asset management.

HTO also stated that there is extensive input and shared decision-making regarding the services provided and level of service, for any item that affects it. For OPG-wide required services (e.g., external financial reporting; compliance with labour laws), HTO follows the requirements established by the corporation.

BAS is the largest service provider, and HTO has determined that approximately 80% of the IT costs charged to it are "core" costs associated with WAN, LAN, specific HTO business systems such as ERIS/EPAS, specific Hydro projects such as fibre optics and SCADA upgrades. The costs are flat or declining over the planning period, and HTO believes they may be able to improve further. HTO confirmed that if the BAS group disappeared, it would have to put in its own systems because they are required.

Nuclear stated that each of the CSA services, and the level of service received, are essential to its operations, and provided examples of how the CSA services are required in its operations. Nuclear also provided examples of how it has been working with

Service Providers to identify and meet its changing needs, and to reduce costs while providing the required levels of service. Nuclear identified instances where it was served by dedicated resources within the Service Providers, but also where the center-led organization is helping to identify and introduce efficiencies.

For example, Nuclear and BAS are increasing efficiency by increasing the automation of data transfers. Nuclear and Supply Chain are working to reduce inventory levels and to remove specialists from the ordering process (but not specification or vendor qualification) for commodity-type consumables. Nuclear relies on People & Culture for succession planning, performance management, shift schedules, training and talent management. In addition, People & Culture is the lead organization for Business Transformation. Finance supports many non-finance initiatives, such as benchmarking studies and demonstrations of prudency of costs to stakeholders.

The Service Providers BAS work with Nuclear, HTO and other users (e.g., Service Providers such as Finance and People & Culture) to determine the services needed and the levels of service. These decisions are based on collaborative cost / benefit analyses. The Service Providers stated that the needs of the users are the primary criteria in determining the services they perform and the level of service they provide. BAS has Customer Relationship Managers who work with users to determine what new projects are needed and what benefits are expected. The users participate in ranking the projects to determine which are approved; the ranking process includes measures of financial return.

While the Service Recipients work closely with BAS to determine the need for and cost of any incremental projects, BAS is responsible to manage its baseline services and related costs. For baseline services, BAS must balance the cost goals established for it against the performance expectations of the Service Recipients. An important reason that BAS is able to do this, is that its costs are scalable due to the structure of its outsourcing contract for many baselines services.

Finance and People & Culture also report that they must balance the cost goals established for them against the performance expectations of the Service Recipients.

<u>Conclusion on Cost incurrence</u>: The Service Recipients / Business Segments have very close working relationships with the Service Providers, and rely on them for many aspects of operations. The Service Providers tailor their services to meet the needs of the Service Recipients, and the levels of service they provide are adequate but not excessive. The Service Providers must balance meeting the balance the cost goals

established for them (top-down) against the performance expectations of the Service Recipients (bottom-up). OPG has controls in place to determine that costs are reasonable based on the requirements of the users. The CSA costs were prudently incurred for the benefit the Service Recipients, to enable them to meet the needs of the Ontario ratepayers they serve.

C. Cost Allocation

Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?

HSG Group reviewed OPG's cost allocation methodology as part of Task 1, Task 2 and Task 3 identified in Table 3.

In addition, HSG Group found that the Service Recipients are familiar with the cost allocation methodology, and understand that costs can be either directly assigned or allocated to their Business Segment. They have the opportunity to challenge both the level of services provided and the costs they are allocated.

HTO believes that OPG's cost allocation methodology is based on "rationale and logic", and has been refined as business activities have changed.

Nuclear reports that they understand which Service Providers their costs are coming from and what they have to do to reduce costs. HSG Group considers the ability of a cost allocation methodology to respond to changes in levels of service, as a strong indicator of its appropriateness.

These are important secondary indicators of the appropriateness of the cost allocation methodology. For example, the ability to produce reasonably stable costs enables Service Recipients to forecast costs. In addition, the ability of a methodology to reflect changes in the level of service received is very important.

<u>Conclusion on Cost allocation</u>: HSG Group reviewed the cost allocation methodology separately, as discussed in Section V of this Report, has concluded that it is appropriate for OPG, and it distributes costs based on direct assignment and cost drivers / allocation factors that are supported by the principles of cost causality. In addition, the Service Recipients are familiar with the cost allocation methodology, and believe the cost allocations are appropriate and reflect differences in levels of service.

D. Cost / Benefit

Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?

Nuclear and HTO work with Service Providers in BAS such as Real Estate & Business Services, Outsourcing and Work Programs and Supply Chain to determine the nature and level of services provided in a collaborative process, and costs are considered in this process. For BAS , many activities and service offerings are discretionary or at least can be provided at varying levels of service, therefore a collaborative planning process is appropriate and provides the opportunity to weigh explicitly the benefits and costs for each potential activity service offering.

As discussed above under *Cost incurrence*, BAS works with the users to rank potential projects; the ranking process includes measures of financial return. BAS manages its baseline costs to meet cost and performance targets; these costs are scalable due to the structure of its outsourcing contract for many baselines services.

Nuclear stated that services and the level of service are tailored to its needs- the level of service received is adequate but not more than is needed.

HTO meets with senior BAS management on a regular basis to validate and prioritize IT base and project work; the objective is to ensure that the IT project plan provides the best overall value for OPG and that it remains consistent with OPG's strategic business direction, strategic IT direction, ROI expectations as well as being consistent with OPG's safety, reliability, regulatory and environmental objectives.

Nuclear and HTO work collaboratively with Service Providers Finance and People & Culture to determine their service requirements, but these Service Providers do not involve them in setting cost budgets. This is appropriate because certain services provided by Finance and People & Culture relate to statutory and legal requirements (e.g. external reporting, taxation, safety), therefore it is not possible to compare benefits and costs for an individual business unit as this work is executed in order to operate the entire corporation of which the business is a part.

In addition, services can be challenged by the Executive Leadership Team, where the cost / benefit value of the service to the company as a whole can be evaluated.

Corporate Relations and Communications helps both Nuclear and HTO to build relationships with stakeholders including towns, cities, First Nations and community groups.

Supply Chain was formed as a result of BT initiatives. Supply chain organizations from three business units were amalgamated to form one centrally lead organization in May 2012. In 2013 and the near future, the people that transferred to Supply Chain still work exclusively (or nearly exclusively) on the Business Segments from which they transferred. The costs incurred by Supply Chain, and distributed to the Business Segments, are driven by the purchasing requirements of the businesses.

OPG uses benchmarks extensively to identify opportunities to improve service and reduce costs, and works with other businesses to develop plans to do so.

Conclusion on Cost / benefit: Service Providers explicitly consider the needs of the Service Recipients in developing their budgets, and often weigh explicitly the benefits and costs of activities they are considering. Service Providers are continually evaluating how to meet the needs of the Service Recipients and other users, while meeting cost targets; to do so they are actively planning work and managing costs.

E. Overall Conclusion on 3-Prong Test

The Service Providers and Service Recipients (Business Segments and other users) at OPG work together in a collaborative effort to determine what CSA services should be provided and what should be the level and quality of service. There is continual communication in both directions. Both Service Providers and Service Recipients discussed the need to meet service requirements, to reduce costs and to improve both continuously. As a result, services and the level and quality of service are tailored to meet the needs of the Service Recipients, and the levels of service they provide are adequate but not excessive.

Service Providers are measured by OPG senior management against spending targets, including comparisons to industry benchmarks. Service Providers continually balance the needs of the Service Recipients against the costs to provide the services.

In conclusion, the CSA costs are prudently incurred for the benefit the Service Recipients (and other users), to enable them to meet the needs of the Ontario ratepayers served by OPG. The responses to the surveys, including the interviews conducted by HSG Group, as well as other information reviewed, provide sufficient, reliable evidence that OPG's allocated CSA costs meet the requirements of the OEB's 3 prong test.

Section VII. Asset Service Fees

OPG generating Business Segments are also charged Asset Service Fees ("ASFs") for the use of certain assets owned and operated by OPG. A portion of the costs charged is included in the CSA costs. The ASFs are cost based charges. The assets for which ASFs are computed include Real Estate assets and IT assets. HSG Group was engaged to evaluate the ASF methodology.

ASFs include depreciation expense, return on net book value including income taxes, and operating costs not otherwise charged (e.g., property taxes). In the 2006 Report and 2010 Report, the methodology OPG uses to determine ASFs and to allocate them to the users of the assets was found to be reasonable. OPG confirms that the same approach is used at present, and HSG Group believes OPG's approach remains reasonable based on the operation of OPG's business and the principles of cost causality.

Asset Service Fees for Newly Regulated Hydro

Hydroelectric generating assets that are currently unregulated and not subject to Hydro-electric Supply Agreements ("HESAs") with the Ontario Power Authority may become subject to regulation by the OEB in the future ("newly regulated hydro").

OPG has facilities such as control dams and service centers that support both newly regulated hydro stations and stations that sell output pursuant to a HESA.

For assets where more than 90% of the aggregate station capacity served represents newly regulated hydroelectric capacity, the asset is considered a newly regulated hydro-electric facility and is included in the regulated rate base.

Other joint-use assets are not included in the regulated rate base; the newly regulated hydroelectric stations and HESA stations are charged a cost-based ASF for the use of these assets, based on the capacity of the stations (i.e., MW). The asset fee structure is the same used to charge certain real estate and corporately held IT costs to regulated operations.

HSG Group believes that OPG's treatment of these assets is reasonable. It is reasonable for assets used exclusively or nearly-exclusively by a business to be directly assigned to that business, and the application of cost-based ASFs reflects the operation of OPG's business and cost causality.

Section VIII. SUMMARY OF CONCLUSIONS

OPG's cost allocation methodology for Centralized Services and Common Costs (including Asset Service Fees) distributes / charges those costs to Business Segments and to stations in a manner that meets current best practices and is consistent with cost allocation precedents established by the OEB. The responses provided by Service Recipients and Service Providers to the surveys, and the interviews conducted by HSG Group as well as other information reviewed, provide sufficient, reliable evidence that OPG's allocation of CSA costs meets the OEB's 3 prong test. The results of the allocation based on the 2014 year in the Business Plan 2013-15 are presented in Table 5.

Table 5: Results of Allocation for 2014 in Business Plan 2013-15 ($ millions)

Service Provider	Nuclear	Hydro-Regulated	Hydro Unregulated	Thermal	Other Business	Total
BAS - Outsourcing	$57.3	$2.7	$6.4	$3.2	$3.2	**$ 72.8**
BAS- Work Programs	33.3	3.4	7.7	5.2	3.0	**52.6**
BAS – Supply Chain	60.8	1.4	2.5	2.9	1.7	**69.3**
BAS - Real Estate	114.2	1.5	3.2	4.3	1.4	**124.6**
People & Culture	92.1	4.4	9.3	7.5	3.9	**117.2**
Finance	45.5	3.4	6.0	4.6	2.7	**62.2**
Corporate Centre	32.7	5.1	11.6	6.7	2.9	**59.0**
CO&E	17.9	8.0	6.4	5.8	3.9	**42.0**
CSA Groups	**453.8**	**29.9**	**53.1**	**40.2**	**22.7**	**599.7**
Hydro / OSL Common	3.8	7.6	56.5	8.5	0.2	**76.6**
Centrally held costs	358.1	21.1	49.1	49.0	2.4	**479.7**
Total	**$ 815.7**	**$ 58.6**	**$ 158.7**	**$ 97.7**	**$ 25.3**	**$1,156.0**

BAS = Business & Administrative Services; CO&E = Commercial Operations & Environment

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
IEW OF CENTRALIZED SUPPORT AND ADMINISTRATIVE COST ALLOCATION METHODOL
DEPARTMENTAL BUDGETS FOR 2014 (BP 2013-2015)

DEPARTMENT / Activities	2014 Budget $000s	% of CSA Costs	% of All Costs
People & Culture	$117,155	19.5%	10.1%
Corporate Center Group			
Executive Office	4,959	0.8%	0.4%
Law	7,358	1.2%	0.6%
Strategic Initiatives	4,355	0.7%	0.4%
Business Transformation Project	3,650	0.6%	0.3%
Corporate Relations and Communications	18,079	3.0%	1.6%
Corporate Executive Operations	3,457	0.6%	0.3%
Corporate Business Development	17,177	2.9%	1.5%
	59,035	9.8%	5.1%
Finance Group			
Finance & Chief Controller	42,847	7.1%	3.7%
Treasury	2,288	0.4%	0.2%
Investment Planning	3,463	0.6%	0.3%
Assurance	9,468	1.6%	0.8%
Fund Management	1,448	0.2%	0.1%
CFO Office	2,637	0.4%	0.2%
	62,150	10.4%	5.4%
Commercial Operations & Environment	42,010	7.0%	3.6%
	42,010	7.0%	3.6%
BS&IT Group			
BS&IT Outsourcing	72,782	12.1%	6.3%
BS&IT Work Programs	52,637	8.8%	4.6%
Supply Chain	69,318	11.6%	6.0%
	194,736	32.5%	16.8%
Real Estate Group			
Real Estate Services	29,511	4.9%	2.6%
Enterprise Services	43,758	7.3%	3.8%
Facilities Services	47,838	8.0%	4.1%
Fleet Services	377	0.1%	0.0%
Vice President's Office	3,112	0.5%	0.3%
	124,596	20.8%	10.8%
Total CSA Costs (excl. Centrally Held and Hydroelectric	**599,681**	**100.0%**	**51.9%**
Hydroelectric Common Costs	76,649		6.6%
Centrally Held Costs	479,648		41.5%
Total	**$1,155,978**		**100.0%**

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

BP2014 - BP2013-2015

		DISTRIBUTION TO BUSINESS UNITS			
		Direct Assignment		Allocation	
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %
(A)	(B)	(C)	(D)	(E)	(F)
PEOPLE & CULTURE					
Fleet Operations Training	22.6%	Specific/Estimates	22.6%		-
Total Rewards & Solutions	8.7%	Specific/Estimates	2.5%	FTEs	6.2%
Fleet Support Services	8.6%	Specific/Estimates	8.6%	FTEs	0.0%
Business Partners Hydro Thermal	8.1%		8.1%		-
Safety & Wellness	8.1%	Specific/Estimates	5.6%	FTEs	2.5%
Fleet Maintenance Training	7.9%	Specific/Estimates	7.9%	FTEs	0.0%
VP Learning & Development and Other Training	7.9%	Specific/Estimates	7.8%	FTEs	0.1%
Fleet Simulator & CBT	7.6%	Specific/Estimates	7.6%		-
Employee & Labour Relations	4.1%	Specific/Estimates	1.4%	FTEs	2.7%
Senior Vice President's Office	3.6%		-	FTEs	3.6%
Talent Management & Business Change	3.5%	Specific/Estimates	2.2%	FTEs	1.3%
Business Partners Nuclear	3.2%	Specific/Estimates	3.2%		-
Training Primary Pay	1.7%	Specific/Estimates	1.7%	FTEs	0.0%
HR Labour Adjustment	1.7%		-	FTEs	1.7%
Business Partners Corporate	1.5%	Estimates	0.8%	FTEs	0.7%
HR Primary Pay	1.3%		-	FTEs	1.3%
	100.0%		79.9%		20.1%
CORPORATE CENTER GROUP- EXECUTIVE OFFICE					
Executive Office	100.0%		-	Blend - OM&A / Capital	100.0%
	100.0%		-		100.0%
CORPORATE CENTER GROUP- LAW					
Law Division	96.8%	Specific/Estimates	67.4%	Blend - OM&A / Capital	29.3%
Law Payroll	1.7%		-	Blend - OM&A / Capital	1.7%
SVP Office	1.6%		-	Blend - OM&A / Capital	1.6%
	100.0%		67.4%		32.6%
CORPORATE CENTER GROUP- STRATEGIC INITIATIVES					
Strategic Initiatives	100.0%		-	Blend - OM&A / Capital	100.0%
	100.0%		-		100.0%
CORPORATE CENTER GROUP- BUSINESS TRANSFORMATION PROJECT					
Business Transformation Project	100.0%		-	Blend - OM&A / Capital	100.0%
	100.0%		-		100.0%
CORPORATE OFFICE - CORPORATE RELATIONS & COMMUNICATIONS					
Corp & Comm Centre	54.9%	Specific/Estimates	29.6%	Blend - OM&A / Capital	25.3%
Communication Services	24.3%	Specific/Estimates	19.4%	Blend - OM&A / Capital	4.9%
Stakeholder & Government Relations	19.3%	Specific/Estimates	9.9%	Blend - OM&A / Capital	9.4%
Corp & Comm Payroll	1.5%		-	Blend - OM&A / Capital	1.5%
	100.0%		58.9%		41.1%
CORPORATE OFFICE - CORPORATE EXECUTIVE OPERATIONS					
Corporate Executive Operations	100.0%		-	Blend - OM&A / Capital	100.0%
	100.0%		-		100.0%

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS
BP2014 - BP2013-2015

		DISTRIBUTION TO BUSINESS UNITS			
		Direct Assignment		Allocation	
DEPARTMENT / Activities	**Activity % of Dept.**	**Method**	**BU Direct Assign %**	**Cost Driver**	**BU Allocation %**
CORPORATE OFFICE - CORPORATE BUSINESS DEVELOPMENT					
Hydro Business Development OM&A Projects	20.6%	Specific/Estimates	20.6%		-
Enterprise Risk Management	18.5%	Estimates	0.9%	Blend - OM&A / Capital	17.6%
Thermal Business Development	18.4%	Specific/Estimates	18.4%		-
Corporate Strategy	11.8%		(0.4%)	Blend - OM&A / Capital	12.2%
CBD Payroll	8.5%		-	Blend - OM&A / Capital	8.5%
Business Development Services	7.1%	Specific	7.1%		-
Hydro Business Development	6.5%	Specific/Estimates	6.5%		-
SVP Office	5.0%		-	Blend - OM&A / Capital	5.0%
CBD VP Office	3.5%	Specific/Estimates	3.5%		-
	100.0%		56.8%		43.2%
FINANCE GROUP- FINANCE & CHIEF CONTROLLER					
Business Planning & Reporting	19.4%	Estimates	1.2%	Blend - OM&A / Capital	18.2%
Nuclear Controllership	19.2%	Estimates	19.2%		-
Accounting	16.5%	Estimates	7.2%	Blend - OM&A / Capital	9.3%
Corporate Financial Processing Services	15.1%	Estimates	3.1%		11.9%
Hydro Thermal Controllership	12.7%	Estimates	12.7%		-
Corporate Functions Controllership	8.4%	Estimates	0.8%	Blend - OM&A / Capital	7.6%
Income & Commodity Tax	6.6%		-	Blend - OM&A / Capital Blend - Material & EPS	6.6%
VP Finance, Chief Controller & CAO Office	2.1%			Blend - OM&A / Capital	2.1%
	100.0%		44.4%		55.6%
FINANCE GROUP- TREASURY					
Treasury Financing & Operations	100.0%	Estimates	11.8%	Blend - OM&A / Capital	88.2%
	100.0%		11.8%		88.2%
FINANCE GROUP- INVESTMENT PLANNING					
Investment Planning	100.0%	Specific/Estimates	84.2%	Blend - OM&A / Capital	15.8%
	100.0%		84.2%		15.8%
FINANCE GROUP- ASSURANCE					
Nuclear Oversight	55.8%	Specific/Estimates	55.8%		-
Internal Audit	44.2%	Specific/Estimates	17.9%	Blend - OM&A / Capital Re-allocate EM	26.3%
	100.0%		73.7%		26.3%
FINANCE GROUP- FUND MANAGEMENT					
Fund Management Services	100.0%	Specific	62.5%	Blend - OM&A / Capital	37.5%
	100.0%		62.5%		37.5%

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS
BP2014 - BP2013-2015

		DISTRIBUTION TO BUSINESS UNITS			
		Direct Assignment		Allocation	
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %
FINANCE GROUP- CFO OFFICE					
CFO Primary Pay	72.9%		-	Internal - Finance Overall	72.9%
CFO Office	21.0%		-	Internal - Finance Overall FTE	21.0%
Pension Fund Review	6.1%		-	FTE	6.1%
	100.0%		-		100.0%
COMMERCIAL OPERATIONS & ENVIRONMENT					
Environment	21.2%	Specific/Estimates	18.8%	Blend - OM&A & Capital	2.3%
Integrated Revenue Planning	16.8%	Specific/Estimates	8.7%	Blend - OM&A & Capital Re-allocate EM	8.1%
Market Operations	14.6%	Specific	14.6%		-
OEB	13.4%	Specific	13.4%		-
Regulatory Affairs	9.8%	Specific/Estimates	6.4%	Blend - OM&A & Capital Re-allocate EM	3.5%
Term Trading & Outage Management	9.3%	Specific/Estimates	9.1%	Blend - OM&A & Capital	0.2%
Fuels	6.4%	Specific/Estimates	5.5%	Blend - OM&A & Capital	0.8%
Commerical Services	4.4%	Specific	4.4%		-
CO&E Payroll variance	2.4%		-	Internal	2.4%
CS&C - Bruce Relationships	1.4%	Specific	1.4%		-
CO&E - SVP's Office	0.3%		-	Blend - OM&A & Capital	0.3%
	100.0%		82.4%		17.6%
BAS GROUP- Outsourcing					
Infrastructure Mgmt Service	31.3%	Specific	24.9%	Primary driver - LAN ID's & storage	6.4%
Application Mgmt Service	13.0%	Specific	9.7%	Primary driver - Users of variable applications maintenance	3.3%
Data Centre Services	9.4%	Specific	8.3%	Primary driver - Data Centre support	1.0%
Disaster Recovery & BCP Services	1.4%	Specific	0.9%	Primary driver - Allocation of major applications	0.4%
Service Management Services	1.2%	Specific/Estimates	0.8%	Primary driver - Service management support	0.4%
Data & Voice Network Services	0.9%	Specific/Estimates	0.8%	Primary driver - Field technician support	0.1%
Common Base Services	0.6%	Estimates	0.5%	Lan ID's	0.1%
Application Maintenance Services	0.2%		-	Primary driver - Allocation of fixed application maintenance support	0.2%
End Users Services	0.0%	Specific	0.0%	Primary driver - end Uuers	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS
BP2014 - BP2013-2015

		DISTRIBUTION TO BUSINESS UNITS			
		Direct Assignment		Allocation	
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %
BAS GROUP- WORK PROGRAMS					
Application Software	9.9%	Specific/Estimates	7.0%	Primary driver - Lan ID's based on major users	2.9%
Telecom	7.0%	Estimates	5.0%	Primary Driver - Historical data / Management estimate	2.0%
IMO Services	5.5%	Estimates	3.6%	Primary Driver - Management estimate	1.9%
IM Projects	2.8%	Estimates	1.9%	Primary Driver - Management estimate	0.8%
SVP - BAS	2.7%	Estimates	-	Blend - OM&A & Capital Internal- CIO Allocation	2.7%
IM Transition	1.8%	Estimates	1.1%	Primary Driver - Management estimate	0.8%
Hardware	1.6%	Specific/Estimates	1.3%	Lan ID's	0.3%
Non-Capital Projects	10.7%	Specific / Estimates	7.4%		3.2%
	100.0%		73.3%		26.7%
Note: Outsourcing Contract renegotiated for 2010					
Supply Chain GROUP - WORK PROGRAMS					
Nuclear Supply Chain (new)	93.5%	Estimates	90.2%	Blend - OM&A & Capital	3.3%
Corporate Supply Chain	6.5%	Specific/Estimates	5.0%	Blend - OM&A & Capital	1.5%
	100.0%		95.2%		4.8%
REAL ESTATE GROUP- REAL ESTATE SERVICES					
Rent & Utilities- Nuclear Facilities	76.3%	Specific	76.3%		-
Rent & Utilities- OPG Head Office	18.1%	Service Fees	18.1%		-
Labor Costs	9.3%	Estimates	9.3%		-
Rent & Utilities- Kipling Site	7.4%	Service Fees	7.4%		-
External Purchase Services	5.1%	Specific/Estimates	5.1%		-
Rent & Utilities- Wesleyville Site	2.0%	Service Fees	2.0%		-
Rent & Utilities- Hydro Thermal	1.0%	Specific	1.0%		-
Murray St/Tenant Imp/COGS (Other Business)	(19.2%)	Specific	(19.2%)		-
	100.0%		100.0%		0.0%
REAL ESTATE GROUP- ENTERPRISE SERVICES					
NSS Admin	35.7%	Estimates	35.7%		-
Records/Admin	31.6%	Estimates	31.6%		-
Business Services East	23.9%	Estimates	23.9%		-
Business Services - Office Services	8.8%	Estimates	2.5%	FTEs	6.2%
	100.0%		93.8%		6.2%

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS
BP2014 - BP2013-2015

		DISTRIBUTION TO BUSINESS UNITS			
		Direct Assignment		Allocation	
DEPARTMENT / Activities	**Activity % of Dept.**	**Method**	**BU Direct Assign %**	**Cost Driver**	**BU Allocation %**
REAL ESTATE GROUP- FACILITY SERVICES					
Facility Services Nuclear	72.1%	Specific/Estimates	72.1%		-
Facility Services Central	8.1%	Service Fees	0.8%	Internal - Corp. Functions Overall Re-allocate EM	7.3%
Facility Services West - Admin	5.7%	Service Fees	4.4%	Internal - Corp. Functions Overall Re-allocate EM	1.3%
Facility Services East	4.7%	Estimates	4.5%	Internal - Corporate Functions Overall	0.2%
Facility Services West - Bruce	3.5%	Estimates	3.5%		-
OPG Head Office	3.1%	Service Fees	1.5%	Internal - Corporate Functions Overall	1.6%
Facility Services Admin	2.8%	Estimates	0.9%	Internal - Corporate Functions Overall	2.0%
	100.0%		87.6%		12.4%
REAL ESTATE GROUP- FLEET SERVICES					
Fleet Services	100.0%		-	FTEs	100.0%
	100.0%		-		100.0%
REAL ESTATE GROUP- VICE PRESIDENT					
Real Estate Pay	86.8%		-	Internal - Real Estate Overall	86.8%
Real Estate Vice President's Office	13.2%		-	Internal - Real Estate Overall	13.2%
	100.0%		-		100.0%
CENTRALLY HELD COSTS					
Pension / OPEB- Amortization of Deferred Costs	79.1%	Pension / OPEB Costs	61.6%	Pension / OPEB Costs	17.5%
Employee Incentives	6.1%	Specific (historical)	6.1%		-
Insurance Premiums	4.0%	Specific	4.0%		-
Ontario Nuclear Funds Management	2.7%	Specific	2.7%		-
Provincial Fee- CNSC	1.5%	Specific	1.5%		-
Vacation Accrual	1.5%	Labour costs	1.5%		-
Fiscal Calendar Payroll Adjustment	1.2%	Labour costs	1.2%		-
First Nations Provision	1.0%	Specific	1.0%		
Burden Rate True-up	1.0%	Specific	1.0%		-
BS&IT Contingency	1.0%			BT Overall allocator	1.0%
Pension Guarantee Fee	0.4%			Blend - OM&A & Capital	0.4%
Pandemic Provision	0.4%	Specific	0.4%		-
Bruce - LLW/ILW	0.0%	Specific	0.0%		-
	100.0%		81.0%		19.0%

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS
BP2014 - BP2013-2015

		DISTRIBUTION TO BUSINESS UNITS			
		Direct Assignment		Allocation	
DEPARTMENT / Activities	**Activity % of Dept.**	**Method**	**BU Direct Assign %**	**Cost Driver**	**BU Alloc-ation %**
HYDROELECTRIC THERMAL BUSINESS UNIT COMMON SUPPORT COSTS					
Engineering & Technical Services	72.0%	Specific	72.0%		-
Strategy & Business Support	11.9%	Specific	11.9%		-
Dam & Public Safety	5.4%	Specific	5.4%		-
Project and Delivery Execution	3.8%	Specific	3.8%		-
Hydro Thermal Pay	3.2%	Estimate	3.2%		-
Executive Vice President's Office	3.2%	Specific	3.2%		-
Coal Closure	0.6%	Specific	0.6%		-
	100.0%		100.0%		0.0%
OTTAWA-ST. LAWRENCE COMMON SUPPORT COSTS					
Production/Project Mgt - Madawaska	46.6%	Specific	46.6%		-
Production/Project Mgt - Ottawa	39.5%	Specific	39.5%		-
Compliance & Environment	4.7%	Specific	4.7%		-
Drafting Services	1.1%	Specific	1.1%		-
Engineering & Technical Services	3.8%	Specific	3.8%		-
Programming	2.4%	Specific	2.4%		-
Plant Group Management	3.1%	Specific	3.1%		-
Asset Management & Technical Support Services	(0.1%)	Specific	(0.1%)		-
Other	(0.9%)	Specific	(0.9%)		-
	100.0%		100.0%		0.0%

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
BUSINESS TRANSFORMATION TRANSFERS

Business Area		2013 Budget, $ millions Transfers Out	Transfers In	Net Effect
Service Recipients (Business Segments):				
Nuclear Generation	*Details below*	$215,101	$2,378	($212,723)
Hydro / Thermal Generation	*Details below*	30,392		(30,392)
Service Providers:				
Commerical Operations and Environment		17,973	10,285	(7,688)
Business Applications & Services			143,920	143,920
Finance		4,595	13,264	8,669
People & Culture		2,607	66,910	64,303
Corporate Business Development & Risk			16,428	16,428
Corporate Relations & Communications			20,239	20,239
Corporate Executive Operations		439		(439)
Law		3,090		(3,090)
Strategic Initiatives			773	773
		$274,197	$274,197	$0

Transferred from Nuclear to:	
Commerical Operations and Environment	$5,504
Business Applications & Services	139,806
Finance	12,972
People & Culture	56,819
	$215,101

Transferred from Hydro / Thermal to:	
Commerical Operations and Environment	$4,334
Business Applications & Services	4,114
People & Culture	7,001
Corporate Business Development & Risk	12,122
Corporate Relations & Communications	2,048
Strategic Initiatives	773
	$30,392

RESUME OF
HOWARD S. GORMAN
PRESIDENT – HSG GROUP, INC.

SUMMARY

Mr. Gorman has more than 25 years of experience in the energy industry, including 15 years in rate and regulatory proceedings, and more than 30 years experience overall in accounting, finance and rate and regulatory matters.

Mr. Gorman has testified as an expert witness regarding utility revenue requirements, class cost of service, revenue allocation and rate design. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New Hampshire Public Utilities Commission, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission.

Mr. Gorman has performed financial analyses of energy infrastructure projects for acquisitions and in support of due diligence for financing, and has negotiated and completed construction and term loans, tax-exempt and taxable bonds and subordinated debt. His experience includes financial modeling, financial analysis and forecasting.

Mr. Gorman also has experience in financial accounting, as Controller and Treasurer of Trigen Energy Corporation, where he built the finance function, managed subsidiary controllers and supported an IPO with NYSE listing.

PROFESSIONAL EMPLOYMENT

2010 - Present	HSG Group, Inc. • *President*
1997 - 2010	Black & Veatch Corporation (R.J. Rudden Associates, Inc. before 2005) • *Principal Consultant*
1995 - 1997	Independent Consultant
1987 – 1995	Trigen Energy Corporation • 1987-1993 *Corporate Controller*; Trigen was formed in 1987 • 1993-1995 *Treasurer*; Trigen had IPO with NYSE listing in 1994
1982 - 1987	Coleco Industries, Inc. • *Director, Treasury*
1976 - 1979	Touche Ross & Co. • *Staff Accountant*

PROFESSIONAL EXPERIENCE

Rate and Regulatory Support for Utilities

Mr. Gorman has provided rate and regulatory support for numerous electric and gas utilities in several jurisdictions, including performing the following:

- Developing utility revenue requirements
- Performing class cost allocation studies and marginal cost studies
- Recommending class revenue allocation
- Analyzing and recommending rate design structures
- Reviewing interaffiliate cost allocation methodology

A list of rate case dockets in which Mr. Gorman has provided expert testimony is presented in the table '**Expert Testimony'** at the end of this resume.

Energy Project Analysis

Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses included developing cash flows and financial statements for both regulatory and accounting purposes, and included review of assumptions, analysis of data, modeling, sensitivity testing and stress testing.

Among these analyses are: valuations of power plants, financial projections for cogeneration heat and power plants and energy companies for the purpose of acquisition, valuation of waste-to-energy assets, valuation of a publicly traded multi-jurisdiction utility, and assessment of strategic fit and valuation for a utility considering diversifying into energy-related services.

Energy Project Financing

Mr. Gorman has sourced, structured, negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities.

Mr. Gorman has supported energy projects in connection with due diligence for financing, including contract review, financial modeling, supply analysis, forward price projections, and economic valuation with cash flow forecasting, and the identification, assessment and mitigation of financial and operating risks for the project and its investors.

Financial Management

Mr. Gorman has extensive experience in financial accounting. As Controller and Treasurer of Trigen Energy Corporation, he built the finance and accounting function, developed reports, procedures and management tools, and managed subsidiary controllers across North America, including an IPO with NYSE listing (1994).

He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries.

Computer Modeling and Decision Support

Mr. Gorman is an accomplished modeler with expertise in spreadsheet and database applications, as well as the use of programming tools. He has developed analytical tools to perform valuations, projections and simulations. These models have been applied to financial analysis, cost allocations, rate design and pricing, forecasting revenue requirements, numerous tax and accounting matters, supply modeling and optimizations. Several of these models have contained interactive modules for automated scenario testing and sensitivity analysis.

Publications And Presentations

"What Wall Street Needs From FERC," published in R. J. Rudden Financial, LLC's *Energy Capital Markets Report*, September 2002

"A Balanced Look at Balance Sheets," published in R.J. Rudden Financial, LLC's *Energy Capital Markets Report*, June 2002

"From Wires To Riches: Shareholder Value Creation In The T&D Business," April 2002 (co-authored).

"Assessment of Retail Choice Programs," presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

"Value Creation With Transmission Assets," quoted in *Electrical World's Special Edition Quarter 1, 2002*, March 2002

"The Remarkable Story on Enron," published in Scudder's *Annual End of Year Issue*, December 2001

Education

New York University, B.S., Accounting, 1976

Harvard Business School, MBA, 1981

Expert Testimony Submitted by Howard S. Gorman				
Jurisdiction	**Docket**	**Client**	**Date**	**Subject Matter**
Pennsylvania	R-2013-2372129	Duquesne Light Company	2013	Electric class cost of service; revenue allocation; rate design
New Hampshire	DE13-063	Granite State Electric Company	2013	Electric class cost of service (marginal cost); revenue allocation; rate design
New York	12-E-0201	Niagara Mohawk Power Corporation	2012	Electric class cost of service; revenue allocation
Rhode Island	RIPUC 4323	Narragansett Electric	2012	Electric class cost of service
New York	11-E-0590	Village of Rockville Centre	2011	Electric revenue requirements; rate design; sales forecast
New York	11-G-0142	Chautauqua Utilities, Inc.	2011	Gas revenue requirements, rate design
Pennsylvania	R-2010-2179103	Kellogg Company (intervener)	2010	Water class cost of service; revenue allocation
Pennsylvania	R-2010-2179522	Duquesne Light Company	2010	Electric class cost of service; revenue allocation; rate design
Pennsylvania	R-2010-2172662	Wellsboro Electric Company	2010	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2010-2172665	Citizens' Electric Company of Lewisburg, PA	2010	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2010-2174470	Valley Energy, Inc.	2010	Gas revenue requirements, rate design
Pennsylvania	R-2010-2161592	PECO Energy (Gas)	2010	Gas class cost of service; revenue allocation; rate design
Pennsylvania	R-2010-2161575	PECO Energy (Electric)	2010	Electric class cost of service; revenue allocation; rate design

Expert Testimony Submitted by Howard S. Gorman

Jurisdiction	Docket	Client	Date	Subject Matter
New York	10-E-0050	Niagara Mohawk Power Corporation	2010	Electric class cost of service
New York	09-E-0862	Jamestown Board of Public Utilities	2009	Electric revenue requirements
Pennsylvania	R-2009 2139884	Philadelphia Gas Works	2009	Gas class cost of service; revenue allocation
Rhode Island	RIPUC 4065	Narragansett Electric	2009	Electric class cost of service; revenue allocation; rate design
Massachusetts	DPU 09-39	Massachusetts Electric and Nantucket Electric	2009	Electric revenue requirements; adjustment mechanisms; class cost of service; revenue allocation; rate design
Pennsylvania	R-2008-2028394	PECO Energy (Gas)	2008	Gas class cost of service; revenue allocation; rate design
Pennsylvania	R-00072350	Wellsboro Electric Company	2007	Electric revenue requirements; rate design
Pennsylvania	R-00072348	Citizens' Electric Company of Lewisburg, PA	2007	Electric revenue requirements; rate design
Pennsylvania	R-00072349	Valley Energy, Inc.	2007	Gas revenue requirements; rate design
Pennsylvania	R-00061931	Philadelphia Gas Works	2006	Gas class cost of service; revenue allocation; rate design
New York	06-E-0911	Village of Freeport	2006	Electric revenue requirements; rate design
Ontario	EB-2007-0905 et al	Ontario Power Generation Inc.	2006, 2010	Electric Cost allocation methodology
Pennsylvania	R-00061346	Duquesne Light Company	2006	Electric class cost of service; revenue allocation; rate design

Expert Testimony Submitted by Howard S. Gorman				
Jurisdiction	**Docket**	**Client**	**Date**	**Subject Matter**
Ontario	EB-2005-0378 et al	Hydro One Networks Inc.	2005, 2006, 2008, 2009, 2010, 2012	Electric Transmission and Distribution Cost allocation; OH capitalization rates
New York	03-E-1568	Village of Rockville Centre	2003	Electric revenue requirements; rate design; sales forecast
New Jersey	ER02080506 et al	Gerdau AmeriSteel aka Co-Steel (intervenor)	2002	Electric cost allocation and rate design; industrial rates
New Jersey	ER02050303 et al	Gerdau AmeriSteel aka Co-Steel (intervenor)	2002	Electric cost allocation and rate design; industrial rates
Pennsylvania	M-00021612	Philadelphia Gas Works	2002	Gas rate unbundling
Pennsylvania	R-00017034	Philadelphia Gas Works	2002	Gas class cost of service
Pennsylvania	R-00006042	Philadelphia Gas Works	2001	Gas class cost of service; recovery of fixed costs

NIAGARA DIVERSION

TUNNEL REPORT

Prepared for Ontario Power Generation

Roger C. Ilsley

9 September 2013

Page of Contents

NIAGARA DIVERSION TUNNEL PROJECT

1.0 Executive Summary

I was requested by Tory's to review all pertinent geotechnical investigations conducted and reports prepared for the design and construction of the 14.4 m excavated diameter, approximately 10.4 Km long (as designed vs. 10.2 Km as constructed), Niagara Diversion Tunnel.

I have done so and formed an opinion that these site investigations addressed the appropriate design and construction issues and that the studies undertaken were completed to professional standards and exceeded those standards in some cases.

I was also requested to review the design work undertaken by Strabag during their proposal preparation and subsequently during the work. I have done so and formed an opinion that the design work performed was conducted to an appropriate professional standard.

In addition, I was requested to form an opinion as to whether it was appropriate to refer the dispute between OPG and the contractor Strabag for a hearing conducted by the Dispute Review Board (DRB) and to form an opinion as to the way OPG conducted the hearing. I have done so and found that it was appropriate to take the dispute before the DRB and further that OPG conducted the hearing in a proper manner.

Finally, after review of the subsequent DRB recommendations coupled with my own evaluation of the circumstances, I formed the opinion that the decision to re-negotiate a revised contract with Strabag was appropriate and reasonable given the circumstances of the dispute and the status of the project.

2.0 Project Investigations Overview and Scope of Document Review

The design and construction of the Niagara Diversion Tunnel as part of the Niagara River Hydroelectric Development was the culmination of various geotechnical investigations and design efforts beginning in 1983.

2.1 Concept Phase Geotechnical Investigations

The main objectives were to provide the essential geotechnical data for conducting technical feasibility and economical comparison of various development alternatives being studied for increasing the generating capacity at the Sir Adam Beck (SAB) complex.

The investigations were initiated in 1983 and conducted successively in 1984, 1984/85, 1986 and 1988/89. The geotechnical data collected during this period were for various project arrangements considered at that time and were not solely for the project actually constructed. Refer pages 2-1 to 2-18 of the Geotechnical Data Report (GDR) for a comprehensive description of the various studies done. (GDR is discussed below at the end of section 2.2)

In addition geological and geotechnical data were acquired by OPG during the construction of the SAB Generating Station (GS) 2 in the 1950s.

The results of these investigations were summarized in Feasibility Report 87269 Rev.1 dated March 1989.

2.2 Definition Engineering Phases

In the fall of 1988 OPG advanced the project into the Definition Engineering Phase in which environmental assessment and preliminary engineering were carried out. Phase 1 was completed in 1990 and included various site investigations. [Refer to GDR pages 3-1 to 3-20 for a full description]. A final report [Report 91150] consisting of five volumes was issued in May 1991.

This was followed by Phase 2 consisting of an Exploratory Adit (Adit) excavated in the Queenston Formation (Queenston) to the elevation of the proposed tunnels and enlarged at the end to the approximate diameter of the proposed tunnels. This work was completed in 1992/93 [Refer GDR pages 4-1 to 4-44 for a full description] and a seven volume draft report [Report NAW130-P4D-10120-0005-00] issued to OPG in December 1993.

Additional laboratory testing was done from 1994 to 1996 on samples of core from the Adit and a final draft report [Report NAW130-P4D-10120-007-00] issued in February 1997.

The geological and design issues studied in these investigations are addressed in detail below in Section 3.0 as is the manner in which the work was completed.

The GDR was prepared for inclusion in the document package issued to the selected Design-Build teams for their use in the preparation of their proposals. The GDR consisted of 12 volumes and incorporated all of the pertinent data collected during the phases of the work described above. It included a bibliography listing all of the investigation reports. A Geotechnical Baseline Report (GBR) was also prepared and issued in the RFP as GBR A. The GBR is discussed further below in section 6.1

3.0 Site Investigations

The primary aim of site investigations for a rock tunnel is to characterize the rock mass conditions sufficiently so that the design approach and selected construction methods can address the indicated ground conditions. The appropriate approach was adopted for the Niagara Tunnel, which was to phase the investigations beginning with general studies for the Conceptual Phase that began to define rock mass properties, overall stratigraphy, in situ stress conditions, the groundwater regime and other geologic hazards such as the presence of gas. Based on these results and preliminary analyses, a second phase of investigation was done for the Definition Engineering Phase which included additional borings with field and laboratory testing that resolved data gaps and focused on acquiring data to address design issues. Additional phases were completed as necessary until an appropriate level of confidence was reached that the geotechnical related risk issues had been mitigated to an acceptable level.

3.1 Design Challenges

It was recognized from the beginning that the tunnel design and construction presented several design challenges; chiefly the high horizontal stress, the presence of the St. David’s Gorge, time dependent deformation of the rock mass and the presence of sulphates in the groundwater. The various site investigations were directed at recovering physical data and making qualitative geological assessments for preliminary analyses and so address these challenges. The related design and constructability issues are discussed below. The subsequent discussion will cover the actual investigations performed during the Concept and Definition Phases of the work.

3.1.1 Ground Characterization Along Alignment

The tunnel length of 10.4 km results in a natural variability in the rock mass characteristics of the rock formations to be excavated, including; rock mass strength, rock structure (presence and character of discontinuities such as bedding and joints), lithology (nature of the rock material such as siltstone, mudstone or shale) and the piezometric level of groundwater as well as its quality, in the formations to be excavated.

All of these characteristics needed to be quantified and the tunnel length characterized appropriately, with differences identified. The rock mass was generally known to vary from weak to moderately strong.

The depth of the tunnel was dictated by the necessity of passing beneath the glacial soil filled ancestral river channel some 800 m wide, named the St. David's Gorge (Gorge). The location and character of the top of rock in the Gorge and in relation to the tunnel roof (crown) was therefore an issue.

3.1.2 High Horizontal Stresses

The presence of high horizontal stress had been recognized in the region and on previous OPG construction at the site. The identification of the stress magnitude and direction was an important objective due to the high stresses that develop around the excavation perimeter upon excavation and the resulting potential for overstress of the rock mass. The nature of the failure which would occur if the rock remained unsupported after excavation is termed the 'rock mass behavior'. This relates to the type of initial support to be placed and the timing of placement of the support – the elapsed time of stable rock conditions is commonly referred to as the 'stand-up time' and is the window for erection of the initial tunnel support. Because the stand-up time is affected by the chosen construction method it is deemed to be a constructability issue as well as a design issue. The large size of the proposed tunnels would also be part of the concern regarding tunnel stability upon excavation.

3.1.3 Time Dependent Deformation

During the construction of the vertical shaft Wheel Pit of the Canadian Niagara and Toronto Power Plants, the 5.5 m wide and 50 m deep slots showed an inward movement of both walls. The total maximum inward movement of both walls over a 68 year period was approximately 7 cm. The data shows a general trend of decreasing rate of rock movement with time. These long term deformations were in the rock formations above the Queenston and it was known that the Queenston was prone to swelling, hence both of these mechanisms could potentially generate long term loading on the lining. The presence of saline and sulphate bearing groundwater with the resulting potential for corrosion effects on steel and sulphate attack on concrete, plus high operating pressures in the finished tunnel; all became issues bearing on the design of the tunnel lining. These factors and the requirement for a 90 year design life would define the design and eventual thickness of the concrete lining, in itself a very significant challenge.

3.2 Conceptual Phase Investigations

As described in general above, this phase occurred in the period from 1983 to 1989. During this period the investigations were broadly based so only the parts relating to the tunnel alignment will be discussed. A list of the activities is presented below:

- Geological mapping including joint measurements of rock outcrops;
- Drilling and core recovery of 5 boreholes, SD-1 to 5, coupled with seismic reflection surveys to determine the location of the top of rock in the Gorge;
- Drilling of 25 borings NF-1 to NF -26 (not NF-16) along potential tunnel alignments, surface and underground power house locations and around the PGS reservoir;
- Installation and monitoring of multi-level Westbay piezometers in 4 borings (NF-2 to NF-4 and NF-6);
- In-situ stress measurements by over-coring in boring NF-1 and by hydraulic fracturing in boreholes NF-3 and NF-4; and

- Laboratory testing on rock samples including physical and mechanical properties, compression and tensile strength tests; also tests on the time dependent deformation characteristics of core samples from the Queenston.

The results of these Conceptual Phase investigations were presented in Volume 11 of the GDR. A review of these investigative reports indicates that in general the following important activities (Sections 3.2.1, 3.2.2, 3.2.3, 3.2.4) were accomplished in regard to the three principal areas (described in Sections 3.1.1, 2, and 3 above) of design issues for the tunnel.

3.2.1 Drilling Along Tunnel Alignment

To quantify the natural variability of the rock mass along the alignment it was necessary to drill exploratory holes, conduct field tests, recover core for the purpose of identification of the lithology, to identify stratigraphic relations between different rock formations, to identify groundwater levels and groundwater quality and to provide core for various laboratory tests.

In 1983 four vertical boreholes (NF-2 to NF-5) were drilled south of the Gorge using wireline core recovery methods, each penetrating 30m into the Queenston. The core lithology was logged to define stratigraphic relations between formations; also Core Recovery (CR) and Rock Quality Designation (RQD) were recorded and the character of the discontinuities logged. Constant head permeability tests were carried out as the holes advanced. In situ permeability tests were done in borings NF-2 and NF-4 in 1984 in the various rock strata to be excavated by the tunnel. Also a series of Westbay multi-level piezometers were installed in boreholes NF-2 to NF-4. These were designed to allow groundwater samples to be taken at any of the ports located in the various strata for water quality (chemistry) testing.

3.2.2 Exploration in the St. David's Gorge Area

It was necessary to define the bottom of the glacial sediment filled gorge so that the tunnel could be optimally located in the most favorable rock conditions.

In 1983 a single borehole (SD-1) was drilled into Queenston bedrock sufficiently to define top of rock. In 1988/89 four vertical holes (SD-2 to SD-5) were drilled east of the alignment to the top of rock to define the deepest part of the Gorge. A Gravity Survey was also done to attempt to define the bedrock surface and gave indications of the deepest part of the Gorge. In addition a seismic reflection survey was completed but was ineffective as the energy source was too low.

A second seismic survey was done in 1988 which gave insufficient definition resulting in a third survey in 1989 using explosives as the energy source. Based on the seismic and borehole data an inferred bedrock surface plan was produced along with several profiles.

3.2.3 In Situ Stress Measurements

The identification of the stress magnitude and direction was an important objective due to the resulting high stresses that develop around the tunnel periphery during excavation.

In 1983 in situ stress measurements were made in Borehole NF-1 using overcoring methods, located at the SAB GS 1 access shaft. Although not on the tunnel alignment all in situ stress measurements were useful in an attempt to gain an overall picture of both magnitude and direction of the principal stresses; especially because of the inferred effects of the Niagara River Gorge and St. David's Gorge on these parameters. In 1983/84 hydro-fracturing stress measurements were made in boreholes NF-3 and NF-4. In 1988 a single piezometer was placed in the Queenston in boring SD-3.

3.2.4 Laboratory Testing of Rock Core Samples

In order to conduct appropriate analyses for the design, rock material parameters were provided from a comprehensive laboratory testing program of the rock core recovered from the boreholes.

In 1983 samples from the Whirlpool and Queenston Formations were tested. Values were measured for the following parameters; uniaxial compressive strength (UCS); static elastic modulus; Poisson's Ratio; compressive wave velocity, dynamic elastic modulus, water content; density; free swell rate and calcite content.

In 1984/85 core samples for the rock formations to be excavated from boreholes NF-2 to NF-5 were tested. Values were measured for the following parameters: UCS; tensile strength, Schimdt hammer hardness and free swell tests. Also core samples from various formations in borehole NF-7 were tested. Values were measured for the following parameters: anisotropic Poisson's Ratio and elastic modulus; UCS; free swell and semi-confined time dependent deformation of Queenston samples.

In 1986, seventeen core samples from the Queenston containing one or more clay seams were tested. Values were measured for the shear strength of the clay seams in both multi-stage direct shear and biaxial tests. Index testing consisting of grain size analysis and Atterberg Limits of the clay fillings were also done and mineralogical analyses of the clay. These results were used in the Wedge Analysis described below in Section 4.2.2.

In 1988/89 core samples from the Queenston were tested. Values were measured for the following parameters: anisotropic Poisson's Ratio; elastic modulus; UCS; tensile strength and free swell tests. A time dependent deformation test program on samples from the Queenston was also completed. The purpose of these tests was to evaluate the swell pressures that could be experienced by the finished lining system and so allow for them in the design.

The results of these laboratory test programs were incorporated in a data base of engineering and index parameters for the overall purpose of characterizing the rock formations present with respect to rock mass strength, modulus and swelling characteristics.

Initial stability analyses were performed using closed formed solutions with elastic properties and preliminary numerical modeling using finite element analysis using an early (1980) Hoek and Brown constitutive model with assumed rock mass factors based broadly on evaluations of Rock Mass Rating by Z.T. Bieniawski. These initial studies indicated that generally for the diameters considered, the Queenston rock would not be overstressed. It was recognized that UCS test values declined in proportion to the shale vs. siltstone content in the samples tested leading to a division of the Queenston into sub-units based on changes in lithology, particularly the proportion of siltstone versus mudstone and shale present. Also the UCS values of core box dried samples of Queenston were significantly stronger than saturated samples.

3.3 Definition Engineering Phase 1

Phase 1 site investigations related to the Diversion Tunnel were carried out in 1990 and included drilling boreholes with core recovery for laboratory testing, a geophysical program, and in-situ stress measurement.

Phase 2 consisted primarily of the excavation of an Exploratory Adit (Adit) located in the area of the power generation complex; also additional borings were completed as well as some additional long term swell tests.

The objectives of the program were as follows:

- Further definition of the bedrock surface location in the Gorge;
- Additional in-situ stress measurements, especially the Queenston;
- Further definition of the lateral and vertical variations in the Queenston along the tunnel alignment; and
- Investigation of potential for inflows of groundwater and methane gas.

The results of the Phase 1 investigations were presented in Report No. 91150 consisting of five volumes issued in May 1991. The results of the Adit related investigations were issued as Definition Engineering Phase 2 Geotechnical Investigations and Evaluation in seven volumes in December 1993 (Report NAW130-P4D-10120-0005-00).

A review of the investigative reports indicates that the rock characterization along the alignment, better definition of the bottom of the St. David's Gorge, measurement of the in-situ stresses, definition of the groundwater regime and groundwater quality analysis and measurement of rock material parameters, were accomplished in regard to the three principal areas (see section 3.1.1, 2, and 3 above) of design issues for the tunnel.

3.3.1 Drilling Along Tunnel Alignment

The following five vertical borings to the tunnel level were done in Phase 1: NF-4A, NF-28, NF-30, NF-32 and NF-33; also four borings at the Gorge of which SD-7 and SD-8 penetrated to the tunnel level and SD-5 and SD- 6 ended at the top of rock. In Phase 2 the following borings were done: existing borehole NF-31 was extended from el. 41 m to el. 10 m; NF-45 inclined at 53 degrees; NF-43 vertical boring; NF-39 inclined at 53 degrees at the Gorge.

Core recovery, RQD and the character of the discontinuities encountered, were recorded on the log for each borehole. The inclined borings were done to intersect sub-vertical to vertical joints. Also borehole photography with core orientation and permeability testing were done in NF-45, NF-39 and geophysical logging in NF-43 to further define the orientation, frequency and character of discontinuities. Permeability tests were done in borings NF-45 and NF-39 and ground water samples retrieved for water chemistry tests and piezometric heads in the various formations measured.

3.3.2 Exploration in the St David's Gorge Area

It was ascertained that within a zone of 15 to 25 m below the bedrock surface, the rock was slightly weathered with RQD values varying from 31 to 71 %. Bedding joints were frequent and some slickensides (surfaces of discontinuities with evidence of former movement and therefore of very low shear strength) were present. At depths greater than 30m below the bedrock surface, the RQD values improved significantly and were generally higher than 90% generally indicating that with increasing depth below the bedrock surface, rock conditions improved significantly.

3.3.3 In-Situ Stress Measurement

Hydro-fracture tests were done in borehole NF-31 (at a distance of 400 m from the Niagara River gorge) and NF-38 (powerhouse area) in order to locate the proposed Adit enlargement in an area where the in-situ stresses would be similar to those anticipated in the deep section of the diversion tunnels, as well as for the design of the underground powerhouse.

3.3.4 Laboratory Testing of Rock Core Samples

The testing for the Definition Engineering Phase 1 investigations was focused primarily on the Queenston along the diversion tunnels and at the underground powerhouse locations.

The laboratory test program consisted of the following components:

- Strength and deformation testing;
- Time dependent deformation testing-swell tests;
- Petrographic analyses of thin sections from the Lockport and Queenston Formations;
- Point Load Strength Index testing;
- Chemical analysis of groundwater samples from piezometer installations; and
- Testing for hydraulic fracturing tensile strength and biaxial testing for deformation modulus of samples from over-coring tests (for in situ stress measurement).

A summary of the tests completed was presented in Tables 3.5 and 3.6 in the GDR and described in more detail in Section 12.1.2 of the GDR.

The 1992/3 Definition Engineering Phase 2 laboratory testing program addressed the following key issues regarding the engineering properties of the Queenston:

- Uniaxial (UCS), triaxial and tensile strength of intact rock;
- Direct shear strength tests of the major (very persistent and clay filled showing signs of movement) bedding planes sampled in the Adit; and
- Time dependent swelling characteristics of the Queenston in confined and unconfined tests to ascertain potential load on the final lining of the tunnel.

The scope of the testing program was presented in Table 4.9 of the GDR. Particular emphasis was placed on the proper sealing and storage of the rock core, with early testing of the samples to preserve the in situ moisture content. The results of the program were described in more detail in Section 12.4.3 of the GDR.

Additional testing on the time dependent deformation characteristics of the Queenston was done from 1994 to 1996 to further define the pressures to limit swelling; to investigate the effects of increasing axial load (analogous to swelling pressure build up on the tunnel lining); to investigate anisotropy by providing results for horizontal cores and to determine the swelling characteristics with pore water of different saline concentrations. The results of the program were presented in Section 12.4.4 of the GDR.

3.4 Definition Engineering Phase 2 Exploratory Adit

The excavation of the Adit represents a level of exploration rarely achieved due to the cost and was therefore a significant commitment to achieving the objective of ascertaining the rock behavior in an excavation of comparable size to the planned tunnel.

The Adit, excavated in 1992/93 entirely within the Queenston, was located in the vicinity of the power generating complex in order to provide access to and to develop the powerhouse test area and to allow over-coring stress measurements. The objectives of the program were to:

- To record qualitative observations of rock mass behaviour and to measure rock mass behaviour with instrumentation;
- Conduct in situ stress measurements;
- Record geological data by mapping of the excavation, photography and coring of the exposed rock; and
- Conduct in situ testing.

3.4.1 Adit Enlargement

Stage 3B Excavation mainly comprised of widening the end of the Adit as part of a trial enlargement. The main objective was to evaluate the full face Tunnel Boring Machine (TBM) excavation method by observing and measuring the rock mass response around an opening similar in span to the final excavation dimension. The test program was as follows:

- Developed an opening 12m wide and 4m high with a circular arch of radius 6.8m to simulate the upper part of the diversion tunnel;
- Rock deformations and the extent of the overstressed zone were measured with rod extensometers and surface convergence points. Stress changes at the roof were also measured;
- The excavation was supported with dowels and mesh; and
- The last approximately 5m of the enlargement was left unsupported for 48 hours to assess stand-up time of the arch.

Stage 3C Excavation consisted of further deepening of the opening by benching downwards to a full height of 12m to further observe the effects on stability of the crown, invert and face. Additional extensometers were installed at the springline of the full depth excavation and in the end wall invert to monitor deformation.

A detailed description of the Stage 2 Exploratory Adit Investigation Program was provided in Section 4.3 of the GDR.

4.0 Site Investigation Results

The results of all the phased site investigations conducted for the Conceptual Phase and the Definition Engineering Phases 1 and 2 were presented in the GDR as follows:

- Section 6 Surface Geological Mapping;
- Section 7 Results of Surface Drilling: Logging and Downhole Testing;
- Section 8 Results of Underground and In Situ Testing;
- Section 9 Exploratory Excavations- Geotechnical Conditions and Observations;
- Section 10 Results of Adit Enlargement and Field Instrumentation and Testing;
- Section 11 Groundwater and Gas; and
- Section 12 Results of Laboratory Testing of Rock Samples.

The GDR was a comprehensive document which gathered all of the data from numerous studies for a variety of concepts of power generation with various configurations and included detailed studies for the diversion tunnels inlet and outlet works and for underground power stations.

In my review I have focused on the site investigations related to the diversion tunnels which remained within a defined corridor from the start of the studies. The number of borings was appropriate given the relative uniformity of the Queenston. I have reviewed a sufficient number of examples of laboratory and field test results to form an opinion that they were completed in an appropriate manner. I will discuss below how the objectives of the investigations were met, in that the necessary data was provided for the appropriate design analyses and for evaluation of the perceived constructability issues.

The issues listed below are broadly described above in section 3.1:

- 3.1.1 Ground Characterization Along the Alignment;

- 3.1.2 High Horizontal Stresses; and
- 3.1.3 Time Dependent Deformations.

4.1 Ground Characterization for Design Analyses Along the Alignment

In order to characterize the ground conditions, the rock mass characteristics were required including intact rock UCS and triaxial strength and elastic modulus; rock structure, including RQD, core recovery, frequency of discontinuities such as bedding planes and joints; the characterization of the discontinuities including type of filling, roughness and persistence; the shear strength of prominent bedding planes; groundwater levels and the presence of gas; the chemistry of the ground water and logging of the rock type (lithology). All of this data was incorporated on a geologic profile prepared for the approximately 10.4 km long, 14.4 m diameter tunnel (Refer Strabag ILF Drawing No. PD-0101002). In this manner the alignment was split up into sections with similar properties for the purposes of analysis and subsequent support design.

4.2 Rock Mass Strength for Design Analysis

Strabag's designer ILF conducted design analyses including elastic beam-spring models, wedge analysis and convergence-confinement methods. These analyses, completed by ILF as part of the Strabag design-build proposal, were incorporated in two reports titled "Outline Design Basis and Method Statements" and "Structural Analysis for the Diversion Tunnel", both dated April 2005. Figure 3.1 Flow Chart for the Geotechnical Design was presented in the "Outline of Design Basis" and shows the steps and inputs required to arrive at the type of support to be used, beginning with the geotechnical parameters provided in the GDR and derived from the GDR data. The geotechnical data used in the various analyses was based on data from Table 6.16 of the GBR for rock mass strength and deformation and GDR Volume 2 and Fig. 12.1 for major bedding plane shear strength parameters.

4.2.1 FEM Analysis

The 2D and 3D finite element modeling (FEM) conducted by ILF as part of the design, enabled analysis of rock overstress at the tunnel periphery during excavation. The method used a rock mass constitutive model (or rock mass failure criteria) derived by Hoek and Brown in 1980 and then successively improved by them with the last iteration issued in 2002. The model assumed isotropic conditions as evaluated by consideration of the block size formed in the mass by the discontinuities present. The inputs to the model were derived from the intact rock UCS and triaxial test data and a Geological Strength Index (GSI) that incorporated the rock structure. The model provided rock mass strength parameters for the numerical analysis. Also the Owner's Mandatory Requirements, chapter 8.3.4 of the Design Build Agreement (DBA) stipulated Hoek-Brown residual rock mass strength parameters 'mr = 1' and 'sr = 0.001'and a plastic shear strain in rock for peak to post-peak strength ranging from 0.5 to 2.0%.

The FEM modeling incorporated the measured existing high rock stress and could allow for the presence of the identified major bedding planes, as well as the delay in placing rock support sufficiently stiff to prevent further convergence and loosening of the rock mass. Direct shear tests on the major bedding planes provided the necessary shear strength parameters for this analysis.

Strabag's designer ILF conducted other analyses including elastic beam-spring models, wedge analysis and convergence-confinement methods for the purpose of initial and final support design which are described below.

4.2.2 Wedge Analysis

The wedge analysis identified kinematically feasible blocks that may slide or fall into the excavation. Logging of the discontinuities in the core and mapping of outcrops, coupled with evaluation of downhole photography, provided the characterization, orientation and frequency of joint sets and bedding present. Direct shear tests on discontinuities from recovered core provided the shear strength parameters for limit equilibrium analyses of the resulting blocks. This approach allowed appropriate initial support to be designed for a given set of geologic conditions in the Queenston and for the formations above.

4.2.3 Convergence-Confinement Method

The convergence-confinement method of analysis provides the interaction of ground behaviour, represented by a ground-reaction curve and tunnel support, represented by a support reaction curve. The available support pressure was evaluated from computations of the initial lining characteristics including rock reinforcement, shotcrete, and steel ribs. An essential input was the convergence measured during the excavation of the Exploratory Adit enlargement to the approximate planned tunnel diameter. The method was used for preliminary tunnel support design; short term time dependent load distribution of ground load to the initial support and long term time dependent load distribution of ground load to the final lining.

4.2.4 Beam-Spring Model

The Beam-Spring Model used linear elastic analyses to evaluate static loading of the tunnel lining from self weight, hydrostatic pressures, temperature, shrinkage and live loads from post lining grouting. The rock mass strength and deformation properties used were based on Table 6.16 from the GBR.

4.3 High Horizontal Stress

Extensive in situ testing was done to determine the stress regime along the alignment which enabled the tunnel to be divided into three parts and stress magnitudes and directions assigned to each. The results presented in the GDR and summarized in Table 6.14 of the GBR B covered the concept alignment in the RFP. Table 3.3 Stress Regimes for Design Purposes in “Outline Design Basis and Method Statements”, lists the in-situ stress conditions for different tunnel sections that were used in the proposal design.

4.4 Time Dependent Deformations

In their structural design analysis ILF analyzed swell pressure data using FEM and concluded that the area with swelling potential was small. This was mainly based on the advantages of the proposed dual shell lining system. In addition the existence of high horizontal stresses >5 MPa suppressed the swelling potential. This conclusion was based upon laboratory test results which reported that application of stress in one direction not only suppressed the swelling in that direction but reduced it in the orthogonal direction.

ILF concluded that the swelling potential was negligible due to the secondary stress state and the dual shell lining system.

ILF also considered in the final lining design the recognized long term deformation (which they termed rock squeeze behaviour) that had been observed and measured in previously constructed OPG underground facilities. The long term rock mass behaviour was considered by calculating a reduced stiffness modulus for the design life of 90 years using a creep rate based on the measured deformations.

4.5 Constructability Considerations

The presence of high horizontal stress had been recognized in the region and on previous OPG construction at the site. The identification of the stress magnitude and direction was an important objective due to the resulting high stresses which develop around the excavation perimeter upon excavation and to the potential for overstress of the rock mass. The nature of the failure which would occur if the rock remained unsupported after excavation is termed the 'rock mass behavior'.

This relates to the type of initial support to be placed and the timing of placement of the support – the elapsed time of stable rock conditions is commonly referred to as the 'stand-up time' and is the widow for erection of the initial tunnel support. Because the stand-up time is affected by the chosen construction method it is deemed to be a constructability issue as well as a design issue. The large size of the tunnel would also be part of the concern regarding tunnel stability upon excavation.

A review of the various design documents prepared by ILF and described above in 4.2 shows that these considerations were evaluated in detail by the contractor as described below. This in turn was made possible by the sufficiency and appropriateness of the geotechnical and geological data gathered in the site investigations described in Section 3 above and provided in the GDR and GBR for the contract.

4.5.1 Excavation and Support

As described by ILF in Section 3.5 of "Outline Design Basis and Method Statements" the requirements for excavation methods and support were based on the following factors:

- Worker safety;
- Structural stability of support system;
- Avoidance of rock mass loosening;
- Initial lining capacity; and
- Allowable deformations.

Section 3.5.4 Tunnel Support Application of the ILF report, describes the planned locations and type of support to be placed. These were carried through into the actual TBM configuration used and the detailed support designs provided.

5.0 Conclusions in Regard to the Scope and Quality of the Tunnel Site Investigations

It is my opinion that both the quality and standard of the site investigations met the generally recognized professional standards for work of a similar type and magnitude.

The natural variability of the 10.4 km alignment as manifested by variable lithology, high horizontal stresses in varying directions, rock strength anisotropy, adverse groundwater chemistry, methane gas potential, swelling pressures and long term deformation, provided significant challenges to OPG in providing the necessary and sufficient data to the Strabag design-build team for their use in the design and construction of the work. The geotechnical and geologic data gathered in the various site investigations as previously described, was sufficient and appropriate to meet these challenges. The field and laboratory testing provided appropriate data for the empirical and numerical analyses conducted. The excavation and instrumentation of the Exploratory Adit provided key data on the ground characterization and behavior. In conclusion, the appropriate and comprehensive designs and construction procedures developed by Strabag (summarized above) were based upon the geological and geotechnical data provided to them in the GDR and GBR.

6.0 OPG Decision to Bring the Dispute to the DRB for a Hearing

This section describes the background leading up to the decision to resolve a dispute on differing sub-surface (ground) conditions by taking it before the Dispute Review Board (DRB) for a hearing and the appropriateness of OPG actions in doing so.

6.1 Design Build Agreement

The Design-Build Agreement (DBA) between OPG and Strabag included Section 11 Dispute Resolution, which described the establishment and operation of a DRB as an alternative method of dispute resolution in that it provided a means of resolving disputes without resorting to arbitration or litigation. This was part of a risk sharing initiative provided by OPG; other elements included the provision of a GDR and a jointly negotiated GBR C (as discussed below) in the contract and for the contractor to place in escrow at the time of bid, data pertinent to the development of the cost estimate for the work. The DBA also included Section 5 Changes in Work with sub-sections 5.5 Differing Subsurface Conditions and 5.7 Resolution of Claims.

To further assist the parties in the resolution of any issues arising from the encountered ground conditions, Section 5.5 Differing Subsurface Conditions was included in the DBA. In particular Section 5.5(c) which states: “Notwithstanding Sections 5.5(a) and 5.5(b) and in lieu of the procedures described in Sections 5.5(a) and 5.5(b), the following procedure shall apply in full satisfaction of any change to the Contract Price and Contract Schedule relating to rock support resulting from differing subsurface conditions (the “Rock Support Adjustment”):

> (1) on a continuous basis during the performance of the Work, the contractor will record the rock conditions (as defined in the GBR) encountered during the performance of the Work and measure the tunnel lengths thereof and OPG will review and verify such determinations. If the parties cannot agree, the positions of both parties shall be recorded. The resolution of any disagreements will be held in abeyance until the step described in section (4) below has been completed, unless the parties mutually agree that the issue is sufficiently material that the issue should be referred to dispute resolution in which event the matter be resolved in accordance with Section 11;
>
> …

(4) OPG shall promptly thereafter issue a one-time Project Change Directive setting out the net change to the Contract price and Contract Schedule determined by completing the Rock Support Table as set out in (3) above."

The referenced table was included in Section 8.1.3.7 of the GBR C as follows:

"Tunnel rock support will be designed to accommodate the Rock Conditions as given below. The in-situ Rock Conditions shall be determined based on the closest match to the Rock Characteristics within each Rock Condition defined below."

The table is presented on page 37 of GBR C.

By this means the parties intended to provide a way to avoid protracted disagreements in regard to the type and placement of appropriate support for the encountered conditions. Note that Section 3.3 No OPG Control of the Work of the DBA, expressly makes Strabag responsible for "the Contractor's means, methods, techniques, sequences or procedures respecting the work".

The interpretation of these clauses by the parties in relation to the referral of a dispute for Differing Site Conditions to the DRB for a hearing is discussed further in section 6.4 below.

6.2 GDR and GBR

The geological and geotechnical aspects of the project were fully developed to the 100% level for inclusion in the RFP issued to the pre-selected design-build teams. The twelve volumes of the GDR consisted of material excerpted and summarized from the numerous studies and reports completed from 1983 to 1997. Version A of the GBR, termed GBR A, was also included in the RFP. GBR A provided baselines which were an assessment by OPG of the various geological and geotechnical risks to be encountered on the project; these baselines were distilled to a quantification of the physical parameters governing a particular risk, coupled with assessments of parameters such as ground behaviour, based on professional judgment. Version B of the GBR termed GBR B was provided by Strabag in their proposal. Version C of the GBR, termed GBR C was prepared and negotiated by both parties and included in the DBA for the work.

In providing these documents in the contract, OPG shared the risk with Strabag in that any differences that could potentially occur in regard to the actually encountered ground conditions were limited in that if ground conditions encountered were more adverse, the baselines would provide the means for resolving the ensuing claims. If the parties could not negotiate a resolution of the claim then it could be brought before the DRB for a hearing and the issuance of recommendations as to resolution.
By sharing the risk in this manner, OPG benefitted in that the cost estimate for the work did not include contingencies for these risks which otherwise would be included.

6.3 Dispute Review Board

The DRB was formed at the start of the project and manned with recognized experts in the field of tunnel construction. The DRB visited the job on a regular basis and received documentation related to the progress of the work and the issues that arose during the course of the work. In this manner the DRB became familiar with the site staff and with the construction progress and the problems which arose in the course of the work. The contract required the DRB, if requested by either party, to hold a hearing on a particular dispute and to then issue non-binding recommendations.

6.4 DRB Hearing on Strabag Claim for a Differing Site Condition

Strabag filed a claim (PCN 017) for differing site conditions on 18/05/07, related to the ground conditions encountered at the Whirlpool/Queenston Formation contact, from chainage 0+806.5 to 0+839.7. The claim was filed under Section 5.5 (a) of the DBA, and was rejected by OPG on the basis that as it was a clearly a claim relating to rock support resulting from differing subsurface conditions, it must be resolved through the procedure as negotiated and agreed by the parties in Section 5.5 (c) and cannot fall within Section 5.5 (a). The procedure in Section 5.5 (c) is to apply "in full satisfaction of any change to the Contract Price and Contract Schedule relating to rock support resulting from differing subsurface conditions."

Subsequently after several exchanges on the issue Strabag filed Dispute Notice No. 001 under Section 5.7 (a) of the DBA on 05/11/07. OPG again responded on 12/11/07 to the effect that the dispute notice was premature because the claim in PCN 017 must be resolved through the procedure as negotiated and agreed by the parties in Section 5.5 (c) and cannot fall under Section 5.5 (a). However OPG indicated that the first issue to put before the DRB was if they had jurisdiction of the dispute.

Strabag responded on 14/11/07 as follows: “The “rock support adjustment” clause allows for contract price and schedule adjustments to be made relative to the variation in the distribution of the Encountered vs. Expected GBR denoted rock conditions. The PCN 017 encountered rock conditions are clearly not within those denoted rock conditions nor were they anticipated by the GBR and are subsequently a Differing Subsurface Condition. Contrary to OPG’s stated position (letter of 31 October 2007), it was not the intention nor would it be reasonable to expect that the Rock Condition 6 would become a “catch all” for any possible rock condition ever encountered in the tunnel that did not fit into the conditions 4Q or 5 whether anticipated in the GBR or not.”

OPG responded on 28/11/07 in a memo confirming an agreement, reached in the meeting of 27/11/07, the following: “If the parties are unable to achieve a mutually acceptable plan for tunnel realignment within the next 3 months, that also resolves PCN 017 and as many other open issues under the contract as possible, the threshold issue will be the first to go to the DRB as soon as possible after February 29, 2008.”

On 27/02/08 Strabag issued Dispute Notice No.002 as per Section 5.7(a) and Section 5.7(c) of the DBA regarding PCN 017 in which they noted that the parties had agreed that the dispute should be placed before the DRB for resolution under Section 11 of the DBA.

On 05/03/08 OPG responded as follows:

> “1.Strabag’s inability to achieve the agreed TBM advance rates and any “excessive” overbreak described in Strabag’s Proposal for Optimized Alignment and Revised Schedule are a direct consequence of the design, means and methods of construction eventually adopted by Strabag on this project. Pursuant to Section 5.4 of the DBA, Strabag accepted sole and exclusive responsibility and commercial risk for its choice of design, means and methods. Section 5.4 therefore precludes Strabag’s claim in its entirety. This is the preliminary issue for the DRB’s consideration under Section 11 of the DBA before any possibility of differing subsurface conditions under Section 5.5 of the DBA may be considered;

2. To the extent Strabag's claim is not fully disposed of under Section 5.4 of the DBA, Strabag's claim is a Rock Support Adjustment claim under Section 5.5(c) of the DBA and is premature. The parties agreed at the time of contact that the procedures set out in Section 5.5(c) were in full satisfaction and in lieu of any change to the Contract Price or Contract Schedule. Section 5.5(c) is mandatory.

Consequently no Section 5.7(a) "Dispute" is properly before the DRB at this time."

Eventually the parties agreed to hold a hearing starting on 23/06/08, on the differing site condition issue which had grown to include the following issues:

- Large Block Failures;
- Ground Conditions beneath St. David's Gorge;
- Insufficient Stand-up time;
- Excessive Overbreak; and
- Inadequate Table of Rock Conditions and Rock Characteristics.

6.5 Conclusions

In my opinion OPG's decision to go before the DRB with the issue was appropriate because of the following reasons. Section 5.5(c) (1) of the DBA provided that: "unless the parties mutually agree that the issue is **sufficiently material** that the issue should be referred to dispute resolution in which event the matter be resolved in accordance with Section 11." [Emphasis added]. It was eventually apparent that the ground conditions and support methods were severely impacting the work and would continue to do so as long as the tunnel excavation was in the Queenston Formation.

Given the merits of OPG's position a consideration of forcing Strabag to comply with the contract by invoking arbitration and bypassing the dispute resolution laid out in Section 11 of the DBA was a possibility. However, given the losses being sustained by Strabag at the time they would likely have stopped work and spent their project management efforts on the dispute thereby piling up additional substantive costs in addition to those being experienced. Also an adversarial relationship would inevitably have arisen between the parties, a further detriment to the completion of the work.

OPG may also have considered termination of Strabag's contract in order to cure the problems. This would have resulted in a long delay to allow preparation of new contract documents and procurement of a new contractor and afterwards a protracted litigation between the parties. All of which would have delayed the contract completion with concomitant revenue loss and the further unknowns of the re-bid amount and the litigation costs and outcomes.

I was on the DRB on a major tunneling project in Canada and have direct experience where such a course of action was adopted in that the differing site condition issue was not brought before the DRB and the contractor was terminated after stopping work for six months. This led to about a year delay in re-bidding and the new bid coming in at about 1.8 times the original bid with about 60 % of the work completed; plus litigation is ongoing 5 years afterwards.

I have formed the opinion after my extensive review of the circumstances pertaining to this dispute, that OPG's decision to bring it before the DRB was appropriate.

7.0 OPG Performance at the DRB Hearing

Section 11-Dispute Resolution of the DBA provides general guidelines as to the procedures to be adopted by the DRB when conducting a hearing and the preparation of their subsequent recommendations. It is also made clear that the DRB is in charge of the proceedings.

Following the provisions in Section 11, in preparation for the hearing, each party submitted Position Papers on the dispute to the DRB and each other, followed by Rebuttal Papers. All this was done on a mutually agreed timetable.

The hearing was convened by the DRB and conducted from 23/06/08 to 26/06/08. The DRB issued their recommendations dated 30/08/08.

Importantly the construction of the work continued throughout this period with the parties cooperating fully in its prosecution.

7.1 OPG Position and Rebuttal Papers

The principal arguments put forth by OPG are those bulleted in section 6.4 above and were prepared in the main by Hatch Mott McDonald staff (Owner Representative of

OPG) with retained experts and oversight from OPG. The experts were Dr. Dougal McCreath for rock mechanics and design issues, Dr. Ed Cording for design and constructability issues and Larry Snyder for TBM design related issues; all of whom are very experienced and experts in their fields as evidenced by the reports provided as part of the Position and Rebuttal Papers.

The Position Paper prepared by OPG was clear and comprehensive in its presentation of the issues; the history of development of the design and the construction history; the discussion related to the collaborative effort with Strabag in the preparation of the DBA and the GBR included in the contract. Similarly, the Rebuttal Paper further clarified OPG’s position.

7.2 DRB Recommendations

The recommendations provided by the DRB on the five issues listed in section 6.4 are summarized below.

Large Block Failures: The DRB indicated that this condition was adequately forewarned in the GBR and no DSC was warranted.

St. David’s Gorge: The DRB found that the Contractor was not entitled to make a claim of DSCs within the 800m width of the Gorge as stipulated in the GBR.

Insufficient Stand-Up Time: The DRB indicated that there was a serious misunderstanding between the parties with respect to the anticipated rock conditions and rock behaviour at the time the contract GBR Version C was being negotiated. Since both parties developed the GBR jointly, any misunderstanding was the shared responsibility of both Parties.

Excessive Overbreak: The large overbreak quantity encountered throughout much of the Queenston Formation mined at that time, had impacted the rate of advance of the TBM and it appeared that the total quantity of overbreak would exceed the GBR quantity by a significant amount. Although the DBA indicated that if DSCs are encountered, the resolution of such claims should be held in abeyance until tunnel excavation was complete, the DRB believed that the consequences of the misunderstandings that had led to both the large overbreak quantities and the related impacts had been so material that some form of resolution was needed.

Whether the GBR was defective or simply misleading, both Parties developed the GBR jointly and therefore both Parties must share in the consequences in resolving the issue.

Inadequate Table of Rock Conditions and Rock Characteristics: The DRB agreed that the Table of Rock Conditions and Rock Characteristics was inadequate to be used for the identification of DSCs and, further, that the inclusion of such terms as the "closest match" and "all other conditions" essentially rendered the concepts of DSCs meaningless and made the GBR defective. In this Design-Build contract, both parties jointly developed the GBR document and both parties should share the shortcomings of the resulting document.

8.0 OPG Decision to Renegotiate a Revised Contract with Strabag

In my opinion there was sufficient weight to Strabag's positions, particularly regarding the issues relating to ground behaviour and the removal of loose rock, to engender acceptance of the DRB's recommendations, at least in part. In addition the first three major issues were resolved in OPG's favour. Taking into account the DRB recommendations and their delineation of the various joint areas of responsibility for the encountered conditions and the subsequent mitigating actions of the parties, in my opinion the decision of OPG to renegotiate a new contract with Strabag was appropriate. The alternatives of arbitration or termination discussed above in section 6.5, would have very likely led to protracted delays and unknown cost expansion in order to complete the project.

9.0 Summary and Conclusions

There were significant challenges to OPG in providing the necessary and sufficient data for the design and construction of the proposed 10.4 km Diversion Tunnel. The natural variability of the alignment was manifested by variable lithology, high horizontal stresses in varying directions, rock strength anisotropy, adverse groundwater chemistry, methane gas potential, rock swelling pressures and long term deformation of the rock mass. OPG conducted a series of phased site investigations from 1983 to 1997. The results of all the investigations conducted for the Conceptual Phase and the Definition

Engineering Phase 1 and Phase 2, were presented or referenced in the twelve volume GDR which was included in the proposal issued to the design-build teams as well as GBR Version A. It is my opinion that the site investigations addressed the appropriate design and construction issues and that the studies undertaken were professionally completed and met or exceeded in some cases, the professional standards for work of similar type and magnitude.

As part of the DBA, Strabag was required to conduct appropriate analyses for the initial support and final lining design; the final lining had a mandatory 90 year design life. Strabag's designer ILF conducted design analyses including Finite Element Modeling, Wedge Analysis, Convergence-Confinement Analysis, and Beam- Spring Model Analysis. Constructability issues were also evaluated in relation to the timing of placement of the initial support. I concluded that the geotechnical and geological data gathered from the various site investigations was sufficient and appropriate for ILF's comprehensive design analyses and further that the analyses were conducted to an appropriate professional standard.

In my opinion the decision to present the disputes to the DRB was appropriate because it was apparent that the ground conditions and support methods were severely impacting the work. I believe that bypassing the DRB process and proceeding to arbitration or terminating Strabag would have resulted in long delays with protracted litigation. All of which would have delayed the contract completion with related revenue loss and the further unknowns of the re-bid amount and the litigation costs and outcomes. I also formed the opinion that OPG's conduct of the hearing was appropriate.

Finally, after review of the subsequent DRB recommendations coupled with my own evaluation of the circumstances, I formed the opinion that the decision to re-negotiate a revised contract with Strabag was appropriate and reasonable given the circumstances of the disputes and the status of the project.

GLOSSARY

Anisotropic: The material properties are different in different directions.

Atterberg Limits: Laboratory tests measuring the moisture content of a clay soil at its consistency (resistance to deformation) limits, termed the liquid and plastic limits.

Closed Formed Solution: A calculation method which assumes that the rock is a homogenous, isotropic, linearly elastic material.

Core Recovery: The length of actual core recovered during core drilling of a measured interval, referred to as a core run, expressed as a percentage of the core run length, which is typically 3m. It is an indirect measure of core loss which is indicative of general rock quality.

Dynamic Elastic Modulus of Elasticity: The Modulus of Elasticity derived from the measured sonic velocity of sound waves propagated in the rock sample.

Free Swell Test: Test for determining the swelling strain developed in an unconfined rock sample submersed in water as described in the International Society of Rock Mechanics Suggested Test Methods 1979.

Geotechnical Baseline Report (GBR): A report that is part of the contract documents, the purpose of which is to mitigate contingencies in the bid amount and to prevent litigation by promoting dispute resolution in a timely way at the site level. The report incorporates values of the rock's physical parameters as measured during the site investigations, ground characterization and an assessment of rock behavior, which are termed baselines. Generally speaking if the presented baselines are found to be materially different during the work then the resulting Differing Site Condition forms the basis for a contract modification.

Geotechnical Data Report (GDR): The GDR incorporates all of the geotechnical and geotechnical data gathered for the project and/or refers to documents containing such data.

In-Situ Stress Measurement: The existing stresses in the rock mass are measured by hydro-fracture field tests in which water is injected into a discrete section of a borehole isolated by packers, at a pressure sufficient to induce a vertical fracture in the rock. From the data collected, the magnitude and direction of the principal field stresses in the rock mass are estimated.

Isotropic: The material properties are the same in all directions.

Limit Equilibrium Analysis: Analytical method which compares the induced shear stresses on a given set of discontinuities forming a block, to the shear strength of the discontinuities for the purpose of ascertaining the stability of the block in the tunnel crown.

Lithology: The nature of the rock material such as siltstone, mudstone, shale, sandstone.

Numerical Modeling: Calculation methods for numerical stress analysis using computer models such as the Finite Element Method.

Over-Coring Method of In-Situ Stress Measurement: Another method of measuring in –situ stresses in the rock mass, in which a series of strain gauges attached to a plug are inserted in a core hole and the hole over-cored; during this process the induced strains are measured. From this data, the magnitude and direction of the principal field stresses are calculated.

Permeability Testing: A field test conducted in a borehole in which the rate of water injected into a discrete interval isolated by packers under a given pressure is measured; from this data the rock permeability or hydraulic conductivity is calculated.

Petrographic Analysis: Examination of very thin sections of rock under a polarizing light microscope which enables the identification of the minerals present.

Point Load Strength Index Testing: A measure of rock strength using a testing device consisting of two opposing pointed platens actuated by a hydraulic ram. The load at failure and the distance between the platen points at the start of the test is measured. The Point Load Strength Index is calculated by dividing the load at failure by the square of the initial distance between the points of the platens and expressed in Mpa. It can be normalized to the equivalent distance for a 50 mm diameter core. The test is principally conducted axially or diametrically on core samples but can be used on lumps of rock.

Rock Mass Behaviour: The performance of the rock mass after it is excavated; the term is usually applied to the unsupported condition.

Rock Mass Rating (RMR): An empirical, quantitative measure of a rock mass as initially proposed by Z.T. Bieniawski in 1976 and subsequently revised.

Rock Quality Designation (RQD): The total length of core pieces greater than 10 cm expressed as a percentage of the core run length, generally of 300 cm.

Rock Structure: General term referring to the presence of discontinuities in the rock mass such as bedding planes, joints, faults.

Poisson's Ratio: The ratio of the axial and radial strains as measured during the Uniaxial Compressive Strength Test.

Seismic Reflection Survey: A field test in which an array of geophones are used to record reflected seismic waves emanating from a surface of interest as a result of an energy input on the ground surface.

Stand-up Time: The elapsed time of stable rock conditions is referred to as the stand-up time and is the window for erection of the initial tunnel support.

Modulus of Elasticity: A measure of the rock stiffness expressed as the ratio of the axial stress and the axial strain, as measured in the Uniaxial Compressive Strength test.

Stratigraphy: Describes the spatial relationships between the various rock formations identified by core logging from boreholes spaced along the alignment.

Triaxial Strength Test: A compressive strength test conducted on a specially prepared rock sample placed in a cell which is capable of applying a radial pressure to the sample to simulate in-situ stress. An axial load is applied to the sample through end platens.

Tunnel Crown: Roof of tunnel.

Tunnel Invert: Floor of tunnel.

Tunnel Springline: The location on the tunnel wall which is intersected by a horizontal plane through the center of the tunnel.

Uniaxial Compressive Strength: A compressive strength test of a properly prepared rock core sample conducted by applying an axial load to each end of sample through the platens of the testing machine. The axial load and axial deformation are recorded in real time until failure occurs. The uniaxial compressive strength is calculated by dividing the load at failure by the initial cross sectional area of the sample expressed as Mpa. The axial deformation is used to calculate the Modulus of Elasticity. Radial deformation can also be recorded if the Poisson's Ratio is required.

Westbury Piezometer: Instrument located in a borehole which enables recording of water levels and recovery of water samples at selected elevations within the borehole.

Wireline Core Recovery: A drilling method in which the core is recovered from the borehole by a wireline for each core run without removing the drill string and core barrel.