UNDERTAKING JT1.1

Undertaking

To provide an explanation of the difference in forecast and actuals for In-service additions for the northeast plant group for 2013.

Response

The following response was provided at the conference (see Day 1 Transcript page 87):

> The in-service addition variance of $18.6M million for the Northeast Plant Group is substantially related to the Matabitchuan Generating Station Penstock replacement project -— and by "substantially" I mean 16.5 million of that variance.
>
> This project was planned to be completed in December 2012, but was not placed in service until early 2013. The project is shown in Exhibit L-4.3.17.SEC30, table 1, line 28.

UNDERTAKING JT1.2

Undertaking

To provide a drawing showing location of seven additional boreholes drilled after contract award.

Response

The following is in addition to the response provided at the Technical Conference (see Day 1 Transcript pp. 84 - 85).

The attached drawings show the location of the seven additional boreholes drilled by Strabag after contract award. Attachment 1 – Summary of Borehole Locations provides a plan view of boreholes in the vicinity of the tunnel at the St. David's gorge and Attachment 2 – Cross-Section Showing Bedrock Elevations for the Buried St. David's Gorge illustrates the Strabag borehole depths. Boreholes designated GB1 through GB7 were drilled by Strabag. Boreholes prefaced by NF or SD were drilled as part of the geotechnical investigations prior to the contract award.

To further elaborate on the response given during the Technical Conference on April 22, 2014 (see Day 1 Transcript pp. 84, line 27 through page 85, line 17), three additional drawings are attached as follows: Attachment 3 – Surface Borehole Locations – Diversion Facilities, Attachment 4 – Surface Borehole Locations – Generation Facilities and Attachment 5 – Location of Boreholes – St. Davids Gorge that collectively illustrate the location of boreholes drilled as part of the geotechnical investigations between 1983 and 1993.

Open (unsealed) borehole NF39 (shown on Attachments 1 and 3) was intersected by the TBM excavation in the Queenston shale at 1,430m on December 2, 2007 without incident.[1] Borehole NF39 was grouted (sealed) about April, 2008 without incident. Strabag's practice was to grout (seal) open boreholes near the tunnel alignment after the TBM excavation passed their location.

On the original Niagara Tunnel alignment, directly below SAB2 Tunnel 1, borehole NF4A (shown on Attachment 3) and nearby borehole NF4 would not have been intersected by the TBM excavation. Realignment of the tunnel, mutually agreed by OPG and Strabag in 2008 due to the adverse rock conditions experienced during TBM excavation in the Queenston shale, shifted the tunnel alignment eastward and much closer to boreholes NF4 / NF4A. Due to the depth of the boreholes and the possibility that they were not drilled perfectly straight, it was not clear that boreholes NF4 / NF4A would actually be intersected by the TBM excavation.

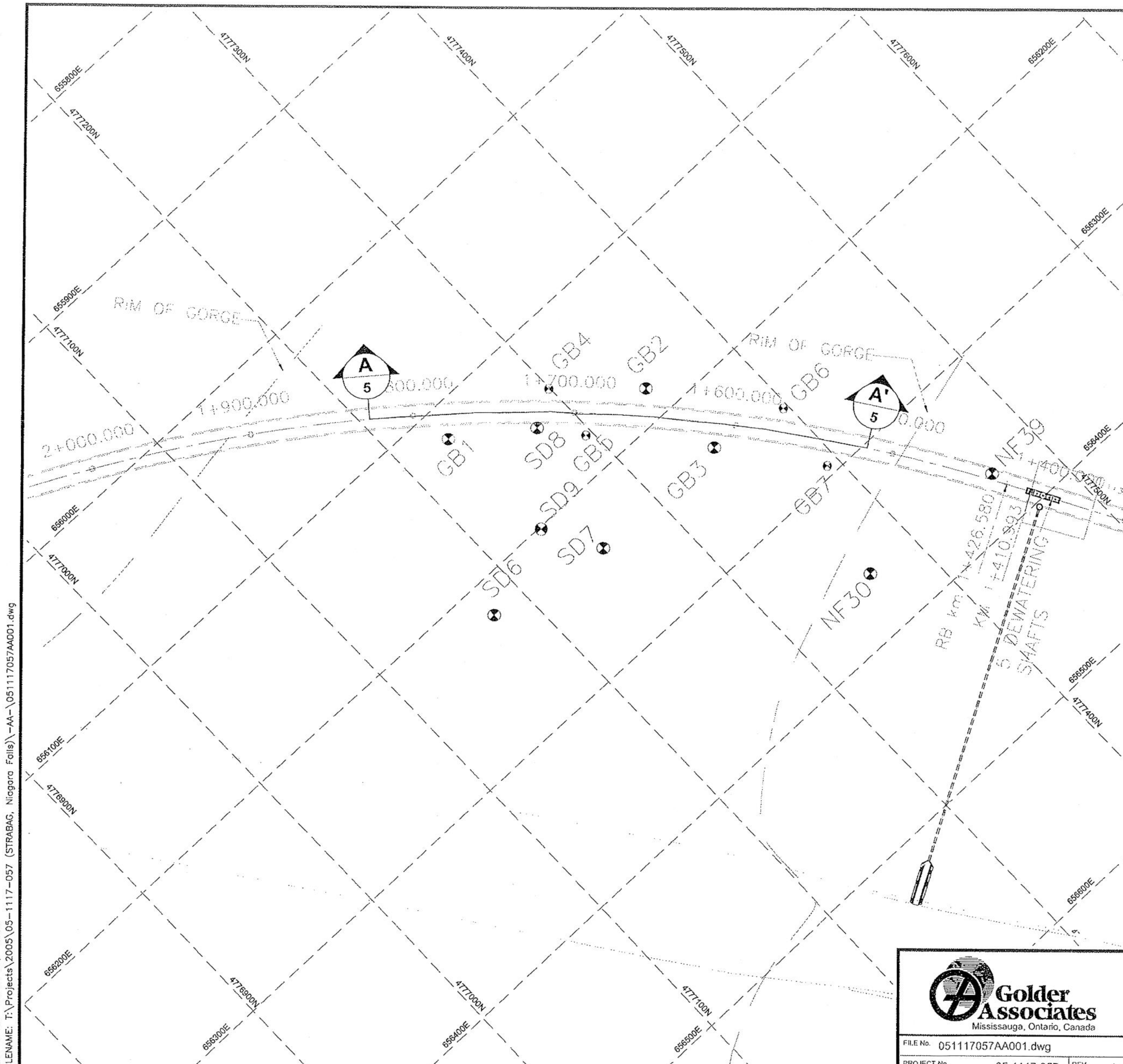
---

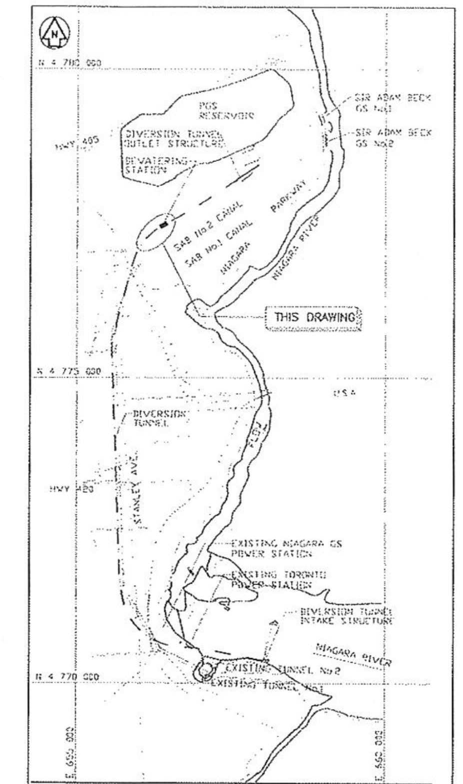
[1] As in Ex. D2-1-1, distances refer to the number of meters from the outlet, where tunnel construction began.

Boreholes NF4 / NF4A were in fact intersected by the TBM excavation in the Queenston shale at 3,600m on February 27, 2009. Consistent with previous practice, after passage of the TBM, boreholes NF4 / NF4A were promptly grouted (sealed) to stop groundwater inflow into the tunnel. Strabag's investigation of the September 11, 2009 fall of ground – 1 ("FOG-1") incident concluded that relatively fresh water in boreholes NF4 / NF4A likely degraded the nearby Queenston shale and was likely a root cause of the FOG-1 incident (Ex L-4.5-17 SEC-037, Attachments 1 and 2). Boreholes NF4 / NF4A had been drilled in 1984 and 1991 respectively as part of the geotechnical investigation program and had remained open (unsealed) until March, 2009 when they were grouted soon after being intersected by the TBM excavation.

In conclusion, boreholes NF4 / NF4A were not grouted (sealed) before the TBM excavation because Strabag's practice was to grout (seal) open boreholes located in close proximity to the tunnel alignment following TBM excavation. This was done without incident for borehole NF39, which had previously been intersected by the TBM excavation in the Queenston shale.

Filed: 2014-05-02
EB-2013-0321
JT1.2
Attachment 1
Page 1 of 1





KEY PLAN
SCALE 1 : 100000

LEGEND:

- AS BUILT LOCATION OF BOREHOLE
- EXISTING LOCATION OF BOREHOLE

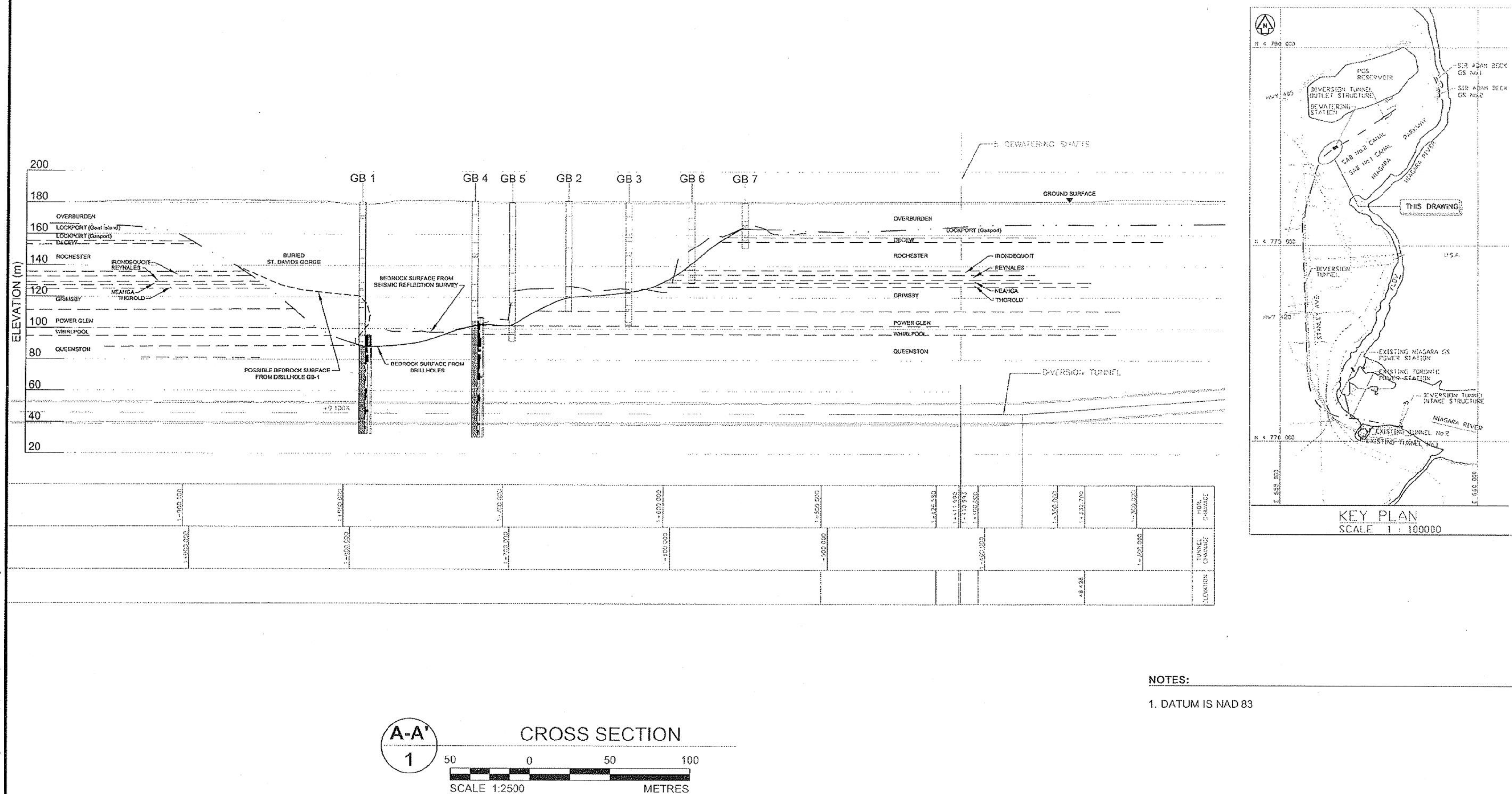
NOTES:

1. DATUM IS NAD 83

REFERENCES:

1. MAPPING BASED ON DRAWING PROVIDED BY STRABAG. DATED OCTOBER 11, 2005

Golder Associates Mississauga, Ontario, Canada	SCALE: AS SHOWN DATE: MAR., 2006 DESIGN: CAD: JFC CHECK: JC REVIEW: MJT	TITLE: SUMMARY OF BOREHOLE LOCATIONS
FILE No. 051117057AA001.dwg PROJECT No. 05-1117-057 REV. A		NIAGARA TUNNEL FACILITY PROJECT — FIGURE 1



NOTES:

1. DATUM IS NAD 83

REFERENCES:

1. TUNNEL ALIGNMENT BASED ON DRAWING BD-01-1164 PROVIDED BY STRABAG. DATED OCTOBER 11, 2005

Golder Associates, Mississauga, Ontario, Canada	SCALE: AS SHOWN	TITLE: CROSS-SECTION SHOWING BEDROCK ELEVATIONS FOR THE BURIED ST. DAVID'S GORGE	
	DATE: MAR., 2006		
	DESIGN:		
	CAD: JFC		
FILE No. 051117057AA005.dwg	CHECK: JC	NIAGARA TUNNEL FACILITY PROJECT	FIGURE 5
PROJECT No. 05-1117-057 REV. A	REVIEW: MJT		

PLOT DATE: March 07, 2006
FILENAME: T:\Projects\2005\05-1117-057 (STRABAG, Niagara Falls)\-AA-\051117057AA005.dwg

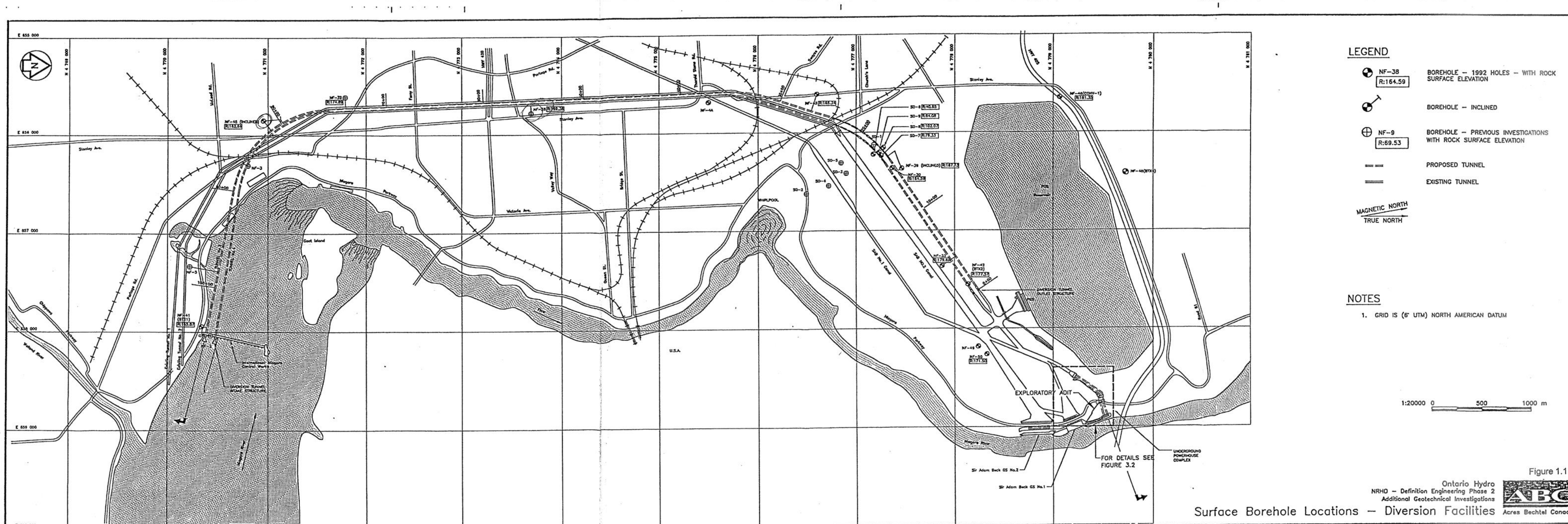
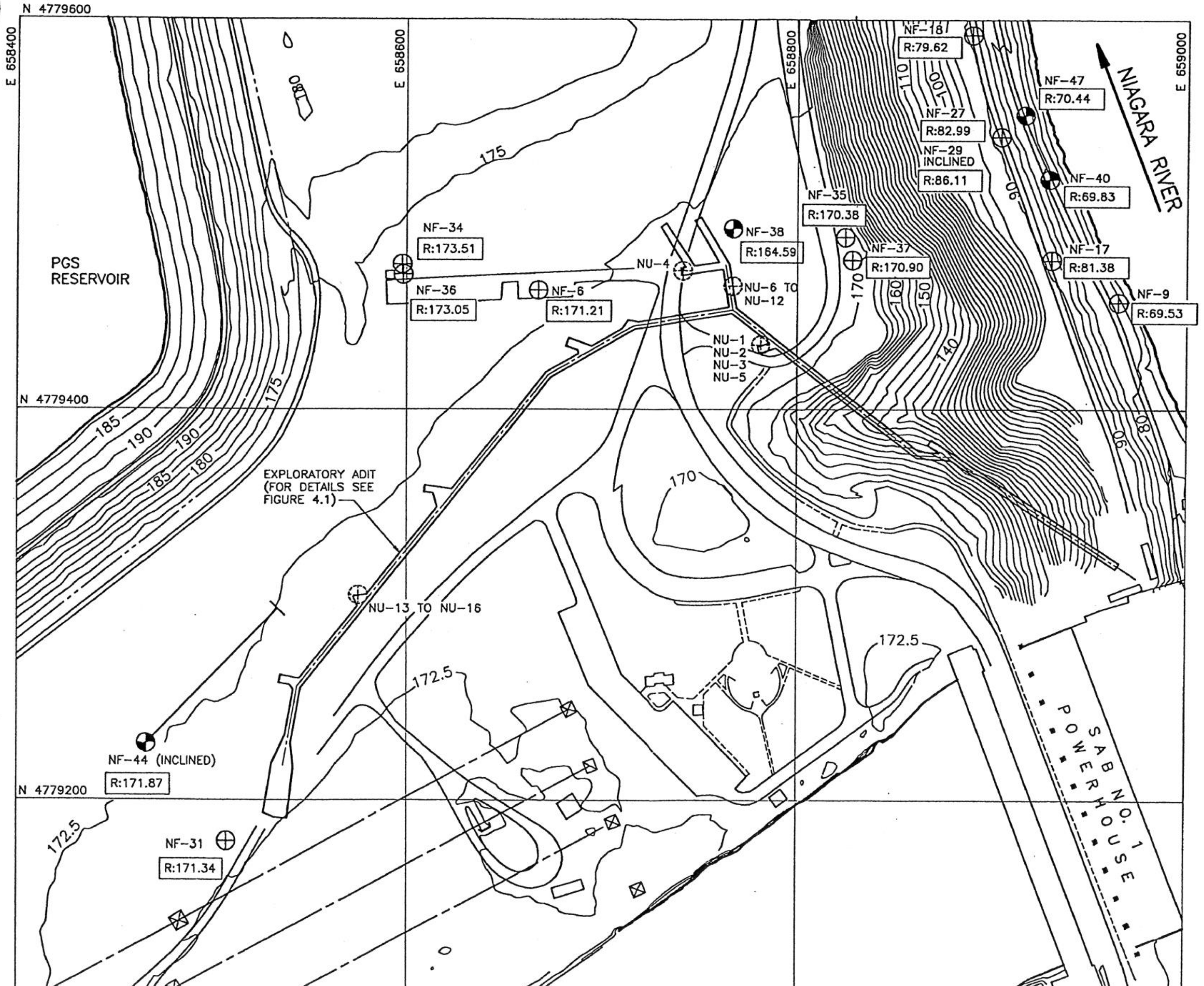


Figure 1.1

Surface Borehole Locations – Diversion Facilities



LEGEND

NF-38 R:164.59	SURFACE BOREHOLE WITH ROCK SURFACE ELEVATION
NF-9 R:69.53	BOREHOLE – PREVIOUS INVESTIGATIONS WITH ROCK SURFACE ELEVATION
NU-4	UNDERGROUND BOREHOLE

MAGNETIC NORTH
TRUE NORTH

NOTES

1. SEE FIGURE 4.9 FOR DETAILED LAYOUTS OF NU SERIES (UNDERGROUND) BOREHOLES
2. BOREHOLE NF-31 ORIGINALLY DRILLED TO 131.41m DEPTH IN 1990 AND EXTENDED TO 182.70m DEPTH IN CURRENT EXPLORATIONS

1:2000 0 25 50 75 100 m

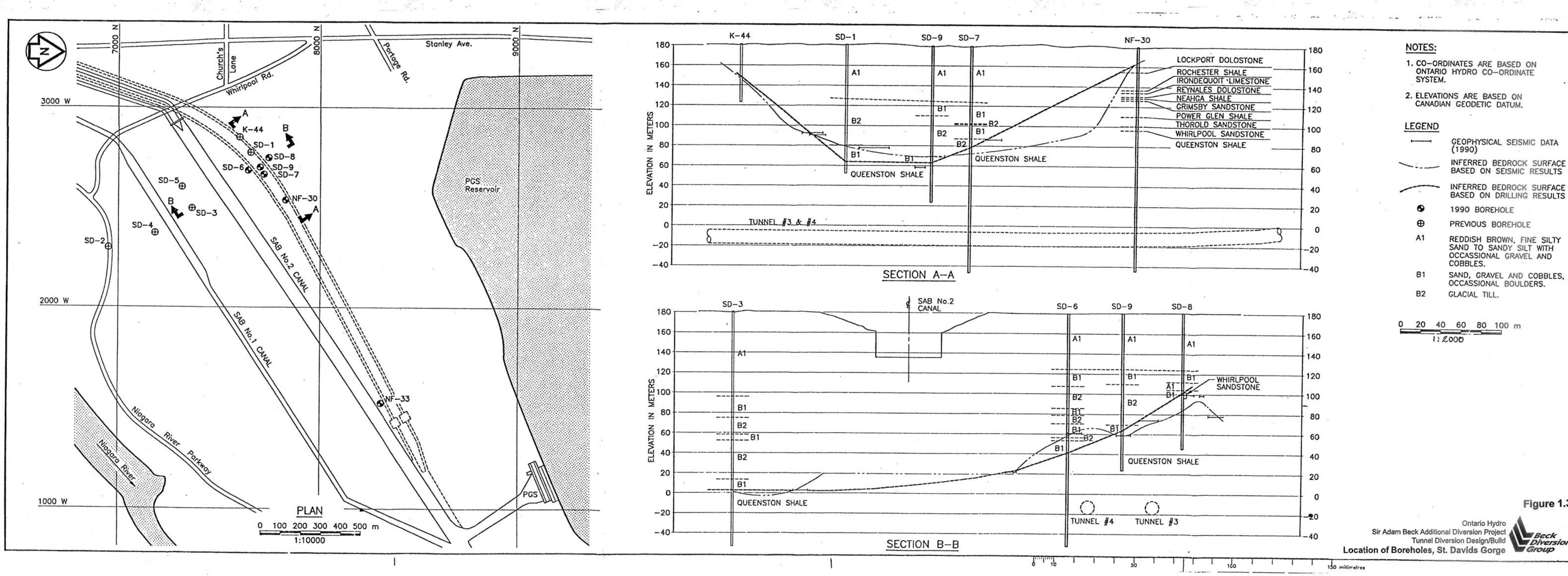
Figure 1.2

Ontario Hydro
NRHD – Definition Engineering Phase 2
Additional Geotechnical Investigations

Borehole Locations – Generation Facilities

ABC
Acres Bechtel Canada

N:\P100004\CIVIL\V1G13-2.DWG
PLOT SCALE 1=2
Plot Date MAY 12, 1998 – 12:55:26


PLAN
0 100 200 300 400 500 m
1:10000
Stanley Ave.
Church's Lane
Whirlpool Rd.
Portage Rd.
3000 W
2000 W
1000 W
7000 N
8000 N
9000 N
K-44
SD-1
SD-8
SD-9
SD-6
SD-7
NF-30
SD-5
SD-3
SD-4
SD-2
NF-33
PGS Reservoir
PGS
SAB No.2 CANAL
SAB No.1 CANAL
Niagara River Parkway
Niagara River
SECTION A-A
ELEVATION IN METERS
TUNNEL #3 & #4
LOCKPORT DOLOSTONE
ROCHESTER SHALE
IRONDEQUOIT LIMESTONE
REYNALES DOLOSTONE
NEAHGA SHALE
GRIMSBY SANDSTONE
POWER GLEN SHALE
THOROLD SANDSTONE
WHIRLPOOL SANDSTONE
QUEENSTON SHALE
SECTION B-B
SAB No.2 CANAL
WHIRLPOOL SANDSTONE
QUEENSTON SHALE
TUNNEL #4
TUNNEL #3
NOTES:
1. CO-ORDINATES ARE BASED ON ONTARIO HYDRO CO-ORDINATE SYSTEM.
2. ELEVATIONS ARE BASED ON CANADIAN GEODETIC DATUM.
LEGEND
GEOPHYSICAL SEISMIC DATA (1990)
INFERRED BEDROCK SURFACE BASED ON SEISMIC RESULTS
INFERRED BEDROCK SURFACE BASED ON DRILLING RESULTS
1990 BOREHOLE
PREVIOUS BOREHOLE
A1 REDDISH BROWN, FINE SILTY SAND TO SANDY SILT WITH OCCASSIONAL GRAVEL AND COBBLES.
B1 SAND, GRAVEL AND COBBLES, OCCASSIONAL BOULDERS.
B2 GLACIAL TILL.
0 20 40 60 80 100 m
1:2000
Figure 1.3
Ontario Hydro
Sir Adam Beck Additional Diversion Project
Tunnel Diversion Design/Build
Location of Boreholes, St. Davids Gorge
Beck Diversion Group

UNDERTAKING JT1.3

Undertaking

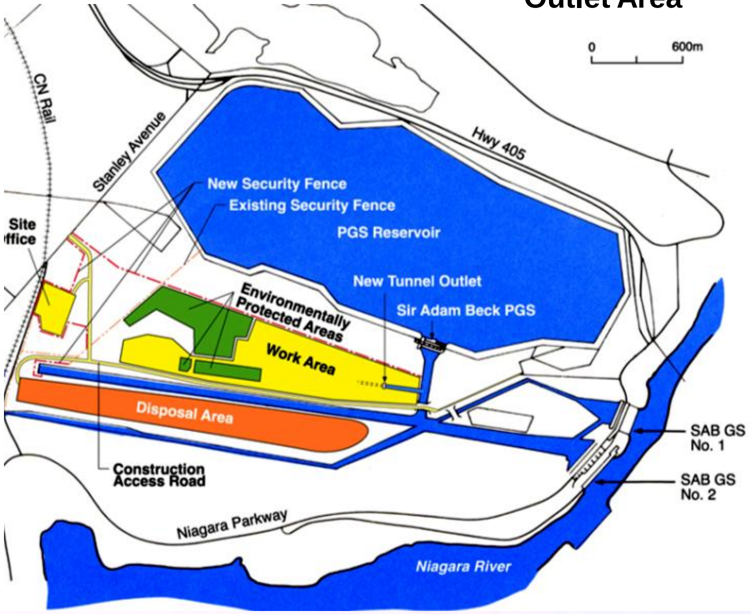
To provide a diagram of the original tunnel alignment.

Response

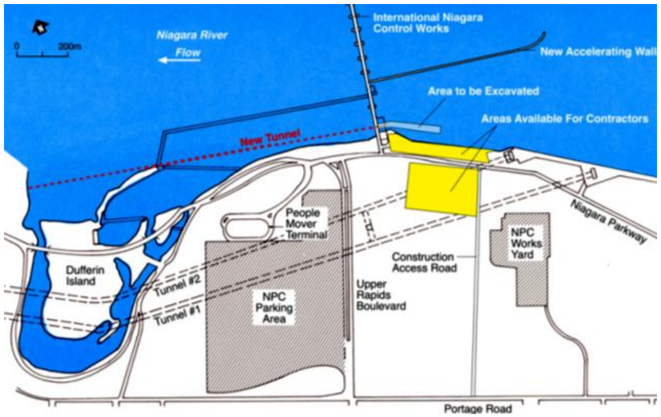
In addition to the response provided at the Technical Conference (see Day 1 Transcript pp. 84 - 85), Attachment 1 (Niagara Tunnel Project Slide 6 from the September 24, 2013 Stakeholder Consultation Session) illustrates the original tunnel profile. Attachment 2 (Slide 12) illustrates the changes in the tunnel alignment corresponding with the realigned tunnel profile illustrated in Ex. D1-2-1, Figure 8 (page 77).

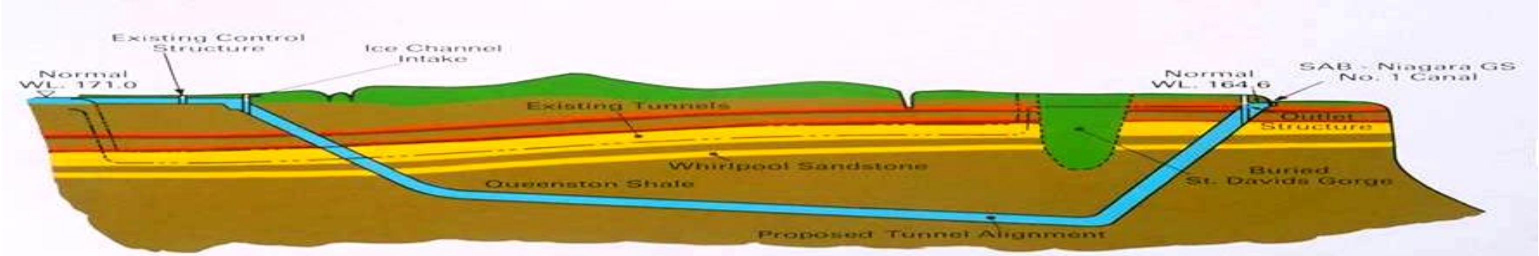
General Arrangement

Outlet Area



Intake Area

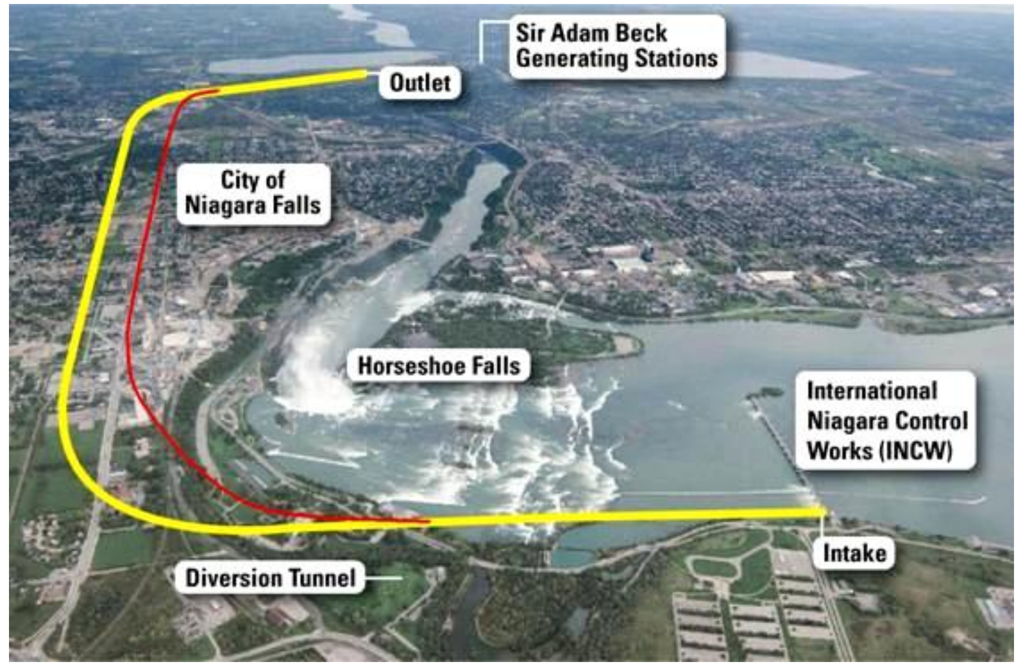


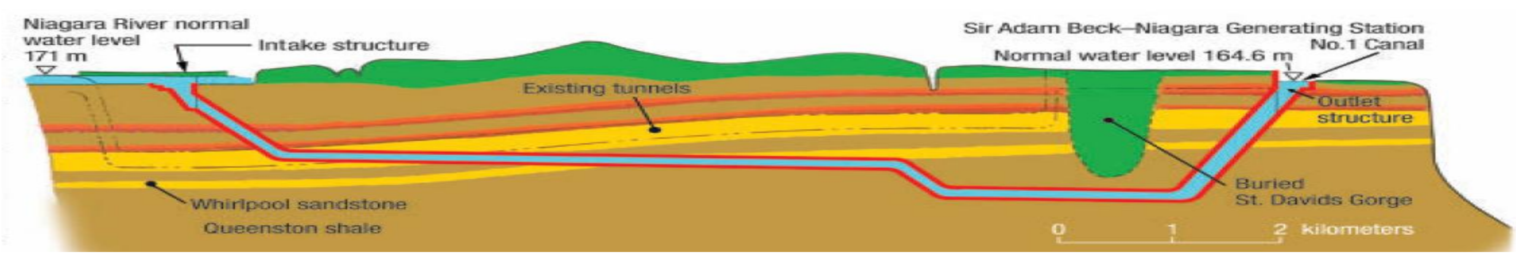


Original Tunnel Profile

Changes in the Tunnel Alignment

- **Amended DBA facilitated the required tunnel realignment.**
- **Horizontal alignment shifted under Stanley Avenue (yellow line to red line) starting at Sta. 3,000 m, reducing the tunnel length by about 200 m.**
- **Vertical alignment raised about 40 m from Sta. 4,000 m to Sta. 9,500 m minimizing the tunnel length in the Queenston shale formation.**
- **Required acquisition of additional subsurface property rights mostly from the Regional Municipality of Niagara (under Stanley Av).**





DRAFT - Privileged and Confidential

UNDERTAKING JT1.4

Undertaking

To provide the incremental costs of time-shifting for 2012 and 2013.

Response

The table below shows the actual incremental costs associated with time-shifting at the PGS for 2012 and 2013.

Actual OPG costs incurred from time-shifting at the PGS		
	2012 M$	2013 M$
Pumping losses	(4)	(3)
PGS GRC costs	(1)	(0)
Pumping non-energy charges	(2)	(2)
Total OPG costs	**(7)**	**(6)**

UNDERTAKING JT1.5

Undertaking

To provide CV of Richard Ilsley.

Response

Please see Attachment 1.

R I GEOTECHNICAL, INC.

ROGER C. ILSLEY
TUNNEL & GEOTECHNICAL CONSULTANT

2670 Topanga Skyline Drive
Topanga, CA 90290
Tel. 310/455-3860
Fax. 310/455-3670
e-mail roktek@aol.com

Experience and Background

Mr. Ilsley's educational background and his broad construction and consulting experience have allowed a synthesis of the related fields of rock and soil mechanics, engineering geology, hydrogeology, and construction methodologies in both soil and rock. He has more than 40 years experience in the field of design and construction of underground construction projects; 12 years working for construction companies and the remaining years in the consulting engineering field. He can provide leadership and technical input to projects that require multi-disciplinary expertise and the ability to combine the qualitative and quantitative aspects of geotechnical engineering with the practical aspects of design and construction.

Representative Underground Excavation Project Experience

- Member of Peer Review Board for the Washington DC Water and Sewer Authority for the Anacostia CSO Control Plan Design. The project entails the design of 13 miles of CSO conveyance and storage tunnels up to 26 feet in excavated diameter in soil and 17 shafts ranging up to 132 feet in diameter. Over 150 borings, including about 50% sonic, have been completed. He has provided peer constructability and geotechnical review of the preliminary engineering plans including exploration plans, field and laboratory testing and data interpretations and the GBR. The majority of the initial 35,000 foot long Blue Plains Tunnel Contract is being constructed beneath the Potomac and Anacostia Rivers and a Design Build project delivery has been used. The tunnels will be excavated using EPB TBM's and supported with a one pass, bolted and gasketed, SFR concrete segment lining system, with water pressure heads up to about 4 bars. He participated in preparation of the completed 30,60 and 100% project documents; in the preparation of the SOQ and the Design Build RFP issued July 1, 2010; in workshops on Design Build project delivery; in identification of Risk Register construction activities and their potential cost and schedule impacts. Conducted peer review of plans and specifications. Served on the committee for the selection of the DB team for the Blue Plains Tunnel and Anacostia River Tunnel segments; the former is under construction. Currently participating in the design review of the third phase of the work, the Northern Boundary Tunnel and review of the conceptual phase of the Potomac rock tunnels.
- Member of Design Review Board for Northeast Ohio Regional Sewer District's Dugway Storage Tunnel which consists of a 26 ft mined diameter, 6.25 miles long rock tunnel with six drop shafts and near surface ancillary work. Tunnel support and lining will be provided by FRC segments. The 30 % level design review has been completed and the 60% review will begin 30 April 2014.
- Consultant to the Bouyges and Jacobs Engineering Design Build team for the Port of Miami Tunnels contract consisting of twin, 42 foot diameter finished highway tunnels, about 8,000 feet total length beneath the main shipping channel, with gasketed bolted SFR concrete segments for support. The tunnel will be excavated using an EPB TBM through ground consisting of very weak to moderately strong limestone with sand layers. He participated in the evaluation of the supplementary geotechnical investigations including sonic and SPT borings and CPT explorations; also a comprehensive laboratory testing program to further characterize the ground conditions, lithology and stratigraphy for design and construction purposes. Provided peer review of the resulting geotechnical reports for the approach works and the channel tunnel crossing.
- Consultant to the Federal Transit Authority for design readiness review for the Los Angeles Metro West Extension. Reviewed conceptual and later preliminary design drawings, specifications, tunnel alignment, station locations and geotechnical reports for the Purple Line, regarding constructability and design level, in order to release federal funds to the project.
- Consultant to the design team (Parsons Brinckherhoff, et. al.) for the Los Angeles Metro System. Duties included resolution of constructability issues arising during construction of the twin, 21-foot diameter Lankershim Blvd. Tunnels (Contract 331) which were constructed in alluvial soils and the Puente Formation using digger shields and the twin Hollywood Hills Tunnels (Contract 311) in rock, using Tunnel Boring Machines (TBMs). Also participated in the design of the Eastside Extension tunnels that examined the use of Earth Pressure Balance TBM's and evaluations of the potential settlement to buildings and its mitigation. Contract 331 required extensive soil modification using silica based chemical grouts to control ground settlement. Compaction grouting was used as the shield passed beneath existing buildings to minimize settlement. Contract 311 required a 400-foot long fault zone to be grouted with micro-fine cement to reduce permeability and strengthen the rock.
- Member of Board of Consultants for the Metropolitan Water District of Southern California's Inland Feeder Project consisting of 90,000 feet of 17-foot diameter tunnel in rock and soil; participated in a comprehensive review of the re-design of the Arrowhead and Badlands Tunnels. A pre-excavation grouting program using ultrafine and regular OPC cement grouts was implemented. A very strict inflow criterion was met as part of a U.S. Forest Service's permit. Gasketed, bolted segments were designed for 900-foot heads.

- Member of Design Review Board for Hatch Mott/ CDM on the Staten Island Subsea Siphon Crossing consisting of about 10,000 feet of 13 foot excavated diameter tunnel. The tunnel is being excavated using an EPB TBM through a varied geology including fresh and extremely weathered rock; glacial soils including sands and gravels with occasional cobble and boulder zones and recent marine sediments including fine and coarse grained soils. Conducted constructability review at 90% design level of GDR, Geotechnical Design Report, GBR, specifications and drawings.
- Consultant to Fugro West Inc. who is providing geotechnical engineering services for the LA County Sewerage Districts Tunnel and Ocean Outfall. The tunnel length is about 7 miles long and up to 20 feet in diameter. He has participated in setting up the GIS data base for existing and new data, exploration plans for onshore exploration and an extensive field and laboratory testing program to provide index and engineering properties for tunnel corridor evaluation and preliminary design. Also assisted with initial project stratigraphy assessments and fault relations. The Outfall Tunnel will be constructed in Quaternary soil deposits and very weak to weak rock of Miocene/Pliocene age.
- Participated with a group of experts in a series of workshops for the NYCDEP in order to evaluate alternative construction methods for the proposed Bypass Tunnel beneath the Hudson River on the Rondout-West Branch Tunnel of the NYC aqueduct. Prepared report describing his suggested approach consisting of a new diversion tunnel beneath the existing tunnel with a lake-tap type connection in order to control inflows and allow subsequent permanent connections; this alternative was adopted by the current designer for the project.
- Project Manager and Engineer for numerous geotechnical engineering studies for tunnels in soil and rock for the Milwaukee Water Pollution Abatement Program. The Program included approximately 35 miles of 6- to 15 foot diameter tunnels in generally poor soil conditions below the water table. Also constructed were approximately 17 miles of 12- to 32-foot diameter TBM tunnels in rock up to 300 feet deep. The deepest shafts had up to 135 feet of variable soil conditions with the groundwater level five feet below the ground surface. As Project Manager he supervised 26 geotechnical engineers and engineering geologists tasked with exploration planning and field inspection of over 400 borings, field and laboratory testing, installation of piezometers and recording of water level data, interpretation and summaries of all data and preparation of Geotechnical Data Reports. Studies included evaluations of settlement and effects upon buildings and utilities; design of instrumentation and construction monitoring program; constructability reports. Also responsible for the preparation of numerous Geotechnical Design Summary Reports.

  Among the pressure faced soil TBMs used were Lovat, Hitachi EPB, and Mitsubishi Slurry Shield. The tunnel support systems included ribs and lagging, jacked pipe, gasketed and bolted concrete segments. During construction, he evaluated contractor's temporary support designs for excavations and control of water in soil and rock. Support and water control systems included slurry diaphragm walls, frozen soil, soldier pile and lagging, steel sheet piling, soil and rock anchors, rock reinforcement and cementitious and chemical grouting of rock.
- Consultant to Lake Forest Park Water District, Seattle regarding excavation of the Brightwater Central Contract tunnel beneath their aquifer. Reviewed Slurry and EPB performance data and results of laboratory analysis of tunnel spoil in order to assess criteria for identifying soil types and thereby evaluating if the aquifer has been breached. Recently conducted inspection of the completed tunnel beneath the aquifer.
- Member of a two-man Design Review Board for Black and Veatch on the Las Vegas SCOP project. The project consists of 44,000 feet of 16 foot diameter mined tunnel under the River Mountains with a hydro-power station at the Lake Mead end. The geology is comprised primarily of lava flows, dykes, pyroclastic deposits, with vesicular and weathered surfaces, flanked with Tertiary sedimentary rock and Quaternary alluvium.
- Consultant to Brown and Caldwell and responsible for the geological engineering aspects of the final design and authorship of the GBR for the North 27th Street ISS Tunnel, Milwaukee, WI. The 10,800 foot long, 23-foot mined diameter rock tunnel is for conveyance and storage of combined storm and sewerage overflow. Supervised geological mapping of the shafts and tunnels.
- Consultant to Jacobs Engineering for the design of the Detroit Upper Rouge CSO tunnels consisting of about 10 miles of 32 foot diameter tunnel, ten drop shafts and a 60 foot finished diameter pump station shaft. The alignment geology generally consists of shale with limestone and dolomite. Identified fissility of shales as a controlling ground behavior characteristic requiring the immediate placement of ground support.
- Member of the tunnel Design Review Board for Black and Veatch on the Ashley River Tunnel Project in Charleston, South Carolina. The seven-foot finished diameter tunnels are 12,500 feet long, about 120 feet deep and will initially be supported by ribs and lagging. The upper 65 feet of soils includes significant thickness of very weak, organic clays with zero blow counts. Of the six planned deep shafts, varying in diameter from 12 to 30 feet, five were constructed using the sinking caisson method and one was a drilled shaft with casing. Five

micro-tunneled sections totaling about 2,300 feet, mostly located within the organic clays, were completed. The proximity of historic buildings adjacent to shaft and tunnel excavation was a particular concern.

- As a member of the Technical Review Board for MWH on the Brightwater Project in Seattle, participated in peer review of the East Tunnel 90% design contract documents and Central Tunnel 30% design contract documents. The 15-foot diameter tunnels are about 50,000 feet long in soil conditions, including peat, glacial outwash and boulder tills. The tunnels were constructed using both EPB and Slurry pressure faced TBM's.

Publications

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Ilsley, R.C., Fradkin, S., McBee, J.M., 1984. Characterization of Rock Conditions for the Deep Tunnel Project in Milwaukee, 25th U.S. Symposium on Rock Mechanics, Chicago, IL.

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Rose, J.P., Ilsley, R.C., Pre-grouting of the North Shore Tunnel, Milwaukee, WI, 1989. Ohio River Valley Seminar on Construction in Rock. Louisville, KY.

Ilsley, R.C., Doyle, B.R., Ramage, J., 1989. Approach for the Design of Tunnels in Weak Soils. R.E.T.C. Proceedings, Los Angeles, CA.

Donnelly, T., Ilsley, R.C., 1991. Remote Vibration Monitoring at Historic Structures. Society of Explosives Engineers, Conference Proceedings, Las Vegas, NV.

Ilsley, R.C., Powers, J.P., Hunt, S.W., 1991. Use of Recharge Wells to Maintain Groundwater Levels During Excavation of the Milwaukee Deep Tunnels. R.E.T.C. Proceedings, Seattle, WA.

Ilsley, R.C., et al., 1991. Ground Movements Around Slurry Shield and Earth Pressure Balance Driven Tunnels in Milwaukee, Wisconsin, 4th International Conference on Ground Movements and Structures, Cardiff, U.K.

Pennock, E.S., Fradkin, S.B., Ilsley, R.C., 1991. Impacts of Solution Features on Mining of the North Shore Tunnel, Milwaukee, WI. 34th AEG Meeting, Chicago, IL.

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Tinucci, J.P., Ilsley, R.C, 2001. Mapping, Seepage and Stability Analysis of a 300-foot High Quarry Wall used as a Dam, 38th U.S. Rock Mechanics Symposium, Washington, D.C.

Halim,I.S., Chen,N., Ilsley R.C., 2008. Initial Support design for Tunnels in Horizontally Bedded Sedimentary Rock, North American Tunneling Proceedings, San Francisco, CA.

Ponti, M.A., Fradkin, S.B., Wone, M. Wang, X, Bizzari, R.E., Cording, E.J., Ilsley, R.C., 2009. Subsurface Characterization for CSO Tunnels in Washington, D.C.; R.E.T.C. Proceedings, Las Vegas, NV.

TUNRES: 4/22/14 SFPUC

UNDERTAKING JT1.6

Undertaking

To review the business case scenario to determine whether OPG has information reflected in Tab 4.5, Schedule 1, Staff 28, Page 2 of 2.

Response

In addition to the response provided at the Technical Conference (see Day 1 Transcript, page 86), Ex D1-2-1, Table 8 (page 128) provides the requested comparable NTP cost breakdown for the business case approved by the OPG Board in August 2005.

UNDERTAKING JT1.7

Undertaking

To provide Q1 2014 production actual versus forecast numbers.

Response

Actual 2014 - Q1 production is compared with forecast 2014 - Q1 production in the following table.

Prescribed Facility	2014 Q1 Plan[1] (TWh)	(c)-(a) Change (TWh)	2014 Q1 Actual (TWh)
	(a)	(b)	(c)
Previously Regulated Hydroelectric:			
Niagara Plant Group	3.5	(0.3)	3.3
Saunders GS[2]	1.5	0.0	1.5
Sub total	5.1	(0.3)	4.8
Newly Regulated Hydroelectric:			
Ottawa-St. Lawrence Plant Group[3]	1.5	0.1	1.6
Central Hydro Plant Group	0.1	0.0	0.2
Northeast Plant Group	0.5	0.0	0.6
Northwest Plant Group	1.0	(0.0)	1.0
Sub total	3.2	0.1	3.3
Total	8.3	(0.2)	8.1

Notes:

1 The reference plan for Previously Regulated Hydroelectric is as updated by the December 6, 2013 Impact Statement, whereas the Newly Regulated Hydroelectric is as per Ex. E1-1-1.

2 Saunders GS values represent total station production (including energy delivered to Hydro Quebec).

3 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group (i.e., Saunders GS production is excluded).

UNDERTAKING JT1.8

Undertaking

To advise of OPG's position re: whether an MNR-approved amount would be credited to ratepayers and how that credit would work within a potential hydroelectric IRM.

Response

Should the MNR ultimately approve OPG's application for a GRC refund, OPG will credit the refund amount back to ratepayers.

As a decision on the GRC refund application is not expected until after the test period, OPG expects that it will in future apply for a variance account to capture the approved amount for return to ratepayers.

The specifics of this account can be discussed with the planned Hydroelectric IRM Working Group to be established by the OEB.

UNDERTAKING JT1.9

Undertaking

To quantify the accuracy of the $100 million estimate for cancellation of the Niagara Tunnel project.

Response

OPG's current standard for "Identification" estimate accuracy is -30% to +50% (Ref: Ex. L-4.2-17 SEC-027).

UNDERTAKING JT1.10

Undertaking

To provide a definition from EUCG or Navigant of what falls into the OM&A for benchmarking purposes.

Response

The following table presents a comparison of OM&A costs included in EUCG and Navigant hydroelectric benchmarking. All cost categories include labour, materials, purchased services and other costs.

#	Cost Category	EUCG	Navigant	Comments
1	**Facilities Operations** Direct and support costs associated with unit dispatch and water management.	√	√	
2	**Power House Maintenance** Costs associated with the maintenance of equipment and facilities which directly support power generation. Includes equipment from downstream of the intake gate to the unit transformer.	√	√	
3	**Water Ways and Dam Maintenance** Cost of activities associated with maintenance of the waterways, dams and penstocks upstream of the headgate or final valve.	√	√	EUCG collects this cost as non-power house maintenance combined with Buildings and Grounds (below).
4	**Buildings and Grounds Maintenance** Cost of activities associated with maintenance of buildings, facilities and grounds.	√	√	EUCG collects this cost as non-power house maintenance combined with Water Ways and Dams (above).

#	Cost Category	EUCG	Navigant	Comments
5	**Environment and Regulatory** Fish & wildlife, recreation, cultural, other.	√	X	Navigant includes these costs as Regulatory Fees (below).
6	**Regulatory Fees** Gross revenue charge, water usage, taxes, FERC fees etc.	X	X	Navigant 's Regulatory Fees includes Environmental costs (see line 5 above). Navigant's benchmarking cost data is presented with and without Regulatory Fees. OPG uses the data that excludes Regulatory Fees because these costs are outside of management's control and can vary to a large degree.
7	**OM&A Investment Projects** Non-recurring maintenance costs, typically performed on cycles from 2 to 7 years.	√	X	Navigant excludes OM&A projects from "Total Cost" analysis. Both OM&A and capital projects are analyzed separately.
8	**Administration Direct** Administrative costs related to plant activities. Includes all plant administration, HR, and finance costs.	√	√	
9	**Administration Indirect** Administrative costs related to Hydro Business/ Corporate activities (e.g. Hydro central support costs, IT costs, Corporate HR and finance)	√	√	Allocation methods are used to distribute these costs.

Note: Sustaining and new capital additions are not included in benchmarking costs.

UNDERTAKING JT1.11

Undertaking

To file CNSC Reg Doc 2.6.3 as finalized.

Response

Please find attached CNSC REGDOC 2.6.3, Fitness for Service Aging Management (published March 2014):

The impact on OPG will not be known until OPG completes a preliminary assessment of the work required and business impact of implementing REGDOC-2.6.3, Fitness for Service Aging Management, which would be used as input for producing a transition plan. The current estimated completion date for this assessment work is December 2014.

Canada's Nuclear Regulator

CNSC CCSN

Fitness for Service
Aging Management

REGDOC-2.6.3

March 2014

Canadian Nuclear Safety Commission
Commission canadienne de sûreté nucléaire

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Preface

This regulatory document is part of the CNSC's Fitness for Service series of regulatory documents, which also covers reliability and maintenance programs for power reactor facilities. The full list of regulatory document series is included at the end of this document and can also be found on the CNSC's website at nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents

REGDOC-2.6.3, *Aging Management*, sets out the requirements of the CNSC for managing aging of structures, systems and components (SSCs) of a power reactor facility. It also provides guidance as to how these requirements may be met. This document replaces RD-334, *Aging Management for Nuclear Power Plants*, which was published in June 2011.

Aging management is the set of engineering, operational, inspection and maintenance actions that control, within acceptable limits, the effects of physical aging and obsolescence of SSCs that occur over time or with use. An aging management program or plan is a set of policies, processes, procedures, arrangements and activities for managing the aging of SSCs of a reactor facility. Effective aging management ensures that required safety functions are reliable and available throughout the service life of the facility, in accordance with the licensing basis.

This document is intended to form part of the licensing basis for a regulated facility or activity. It is intended for inclusion in licences as either part of the conditions and safety and control measures in a licence, or as part of the safety and control measures to be described in a licence application and the documents needed to support that application.

Important note: Where referenced in a licence either directly or indirectly (such as through licensee-referenced documents), this document is part of the licensing basis for a regulated facility or activity.

The licensing basis sets the boundary conditions for acceptable performance at a regulated facility or activity and establishes the basis for the CNSC's compliance program for that regulated facility or activity.

Where this document is part of the licensing basis, the word "shall" is used to express a requirement to be satisfied by the licensee or licence applicant. "Should" is used to express guidance or that which is advised. "May" is used to express an option or that which is advised or permissible within the limits of this regulatory document. "Can" is used to express possibility or capability.

Nothing contained in this document is to be construed as relieving any licensee from any other pertinent requirements. It is the licensee's responsibility to identify and comply with all applicable regulations and licence conditions.

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Aging Management

1. Introduction

1.1 Purpose

REGDOC-2.6.3, *Aging Management*, sets out the requirements of the CNSC for managing the aging of structures, systems and components (SSCs) of a power reactor facility. Guidance is also provided as to how these requirements may be met.

Managing the aging of a reactor facility means to ensure the availability of required safety functions throughout the facility's service life, with consideration given to changes that occur over time and with use. This requires addressing both physical aging and obsolescence of SSCs where this can, directly or indirectly, have an adverse effect on the safe operation of the reactor facility.

This document is intended for use by licensees and applicants in establishing, implementing and improving aging management (AM) programs and plans for reactor facilities.

1.2 Scope

Aging Management sets requirements to provide assurance that aging management is appropriately and proactively considered in the different phases of a reactor facility's lifecycle. The lifecycle phases can apply to individual SSCs as well as the entire reactor facility. Specific requirements are also provided for establishment, implementation and improvement of AM programs and plans through application of a systematic and integrated approach.

This document provides a framework within which codes and standards can be applied to provide assurance that physical aging and obsolescence of SSCs are effectively managed.

Where appropriate, this document may be applied to other nuclear facilities, with due consideration of the differences compared to those of a power reactor facility in hazard potential and complexity of affected systems.

1.3 Relevant legislation

The following provisions of the *Nuclear Safety and Control Act* (NSCA) and the regulations made under it are relevant to this document:

- Subsection 24(4) of the NSCA states that "No licence shall be issued, renewed, amended or replaced – and no authorization to transfer one given - unless, in the opinion of the Commission, the applicant or, in the case of an application for an authorization to transfer the licence, the transferee (*a*) is qualified to carry on the activity that the licence will authorize the licensee to carry on, and (*b*) will, in carrying on that activity, make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed"

- Paragraph 3(1)(*k*) of the *General Nuclear Safety and Control Regulations* states that "an application for a licence shall contain the following information:... (*k*) the applicant's organizational management structure insofar as it may bear on the applicant's compliance with the Act and the regulations made under the Act, including the internal allocation of functions, responsibilities and authority"
- Paragraphs 12(1)(*c*) and (*f*) of the *General Nuclear Safety and Control Regulations* state that "every licensee shall (*c*) take all reasonable precautions to protect the environment and the health and safety of persons and to maintain security of nuclear facilities and nuclear substances;" and "(*f*) take all reasonable precautions to control the release of radioactive nuclear substances or hazardous substances within the site of the licensed activity and into the environment as a result of the licensed activity"
- Paragraphs 6(*d*), (*m*), and (*n*) of the *Class I Nuclear Facilities Regulations* state that "an application for a licence to operate a Class I nuclear facility shall contain", in addition to other information:
  "(*d*) the proposed measures, policies, methods and procedures for operating and maintaining the nuclear facility;"
  "(*m*) the proposed responsibilities of and qualification requirements and training program for workers, including the procedures for the requalification of workers;"
  "(*n*) the results that have been achieved in implementing the program for recruiting, training and qualifying workers in respect of the operation and maintenance of the nuclear facility"
- Paragraphs 14(2)(*a*) and (*c*) of the *Class I Nuclear Facilities Regulations* states that "every licensee who operates a Class I nuclear facility shall keep a record of (*a*) operating and maintenance procedures" and "(*c*) the results of the inspection and maintenance programs referred to in the licence"
- Subsection 14(4) of the *Class I Nuclear Facilities Regulations* states that" Every person who is required by this section to keep a record referred to in paragraph (2)(*a*) to (*d*) or (3)(*a*) to (*d*) shall retain the record for 10 years after the expiry date of the licence to abandon issued in respect of the Class I nuclear facility."

1.4 International standards

This document is consistent with the philosophy and technical content of modern codes and standards. In particular, this regulatory document is based in part on the following international publications:

- *Ageing Management for Nuclear Power Plants*, Safety Guide NS-G-2.12 from the International Atomic Energy Agency (IAEA) [1]
- *Safe Long Term Operation of Nuclear Power Plants*, Safety Report Series No. 57, from the IAEA [2]
- *Glossary of Nuclear Power Plant Ageing* from the Organisation for Economic Cooperation and Development (OECD), Nuclear Energy Agency [3]

2. General Concepts

2.1 Aging and obsolescence of structures, systems and components

Guidance

The SSCs of a reactor facility experience two kinds of time-dependent changes:

- physical aging, in which the physical and/or performance characteristics of SSCs degrade with time or use
- technology aging or obsolescence, in which SSCs become out-of-date relative to current knowledge, standards and technology

Over time, and if not properly managed, physical aging can reduce the ability of a structure, system or component to perform its safety functions within the limits and specifications assumed in the design basis and safety analysis. Several aging mechanisms can combine synergistically to cause unexpected or accelerated aging effects, or premature failure of a component or structural element. The aggregate of multiple degraded components or elements can significantly degrade the safety performance of a system or structure. For instance, while individual degraded components might meet their respective fitness-for-service criteria, the combined effect of all the multiple degraded components could still result in unacceptable safety performance of a system or facility.

Reactor facility safety can also be affected if obsolescence of SSCs is not identified and corrected before associated declines occur in their reliability or availability. This is more likely to apply to systems and components (particularly instrumentation and control) rather than the main structural elements of a facility (although there are examples of the latter, such as concrete expansion anchors). SSCs at risk of obsolescence need to be identified to ensure that an adequate supply of spare parts is available until an appropriate solution is found. The solution will depend on the particular circumstances, but may involve providing alternative components or items of equipment that can carry out the same safety duty. It could also involve redesigning the facility to remove the need for the obsolescent system or components.

Physical aging and obsolescence of SSCs can lead to increased probability of failure or common-cause failures, as well as reduced defence in depth. Other consequences may include:

- the need to de-rate the reactor power to maintain safety margins
- forced or unplanned outages
- significantly extended or more frequent maintenance outages
- additional inspections/monitoring of corrective maintenance and repairs
- increase in dose to the associated workers
- or, in extreme cases, the premature shutdown of a facility

Accordingly, both physical aging and obsolescence of SSCs in reactor facilities should be understood and managed effectively and proactively at each stage of the lifecycle of a reactor facility and its SSCs. This should begin with design, fabrication and construction and commissioning, and continue through operation (including extended or long-term operation, and during any extended shutdowns) and during decommissioning. Particular attention should be paid to aging phenomena that might affect the availability of SSCs that, directly or indirectly, have an adverse effect on the safe operation of the reactor facility. Attention should also be paid to aging effects on SSCs that do not have safety functions, but whose failure could prevent safety-related

SSCs from performing their intended functions for design-basis accidents, or that should be relied upon for design extension conditions. Specific requirements for the different lifecycle phases are provided in section 3.0.

2.2 Systematic and integrated approach to aging management

Guidance

Effective aging management uses a systematic approach providing an integrated framework for coordinating all supporting programs and activities associated with the understanding, control, monitoring and mitigation of aging effects at the facility. This approach (see figure 1) is an adaptation of Deming's "PLAN-DO-CHECK-ACT" cycle related to the aging management of an SSC[1] :

1. Effective aging management of a system, structure or component relies upon an understanding of how it ages. This understanding involves consideration of the design basis (including applicable codes and standards), safety analysis, safety functions, design and fabrication, materials, operation and maintenance history, generic and facility-specific operating experience, relevant research results, and identification of potential obsolescence concerns.
2. The PLAN activity involves coordinating, integrating, and modifying existing programs and activities that relate to managing the aging and obsolescence of a system, structure or component, and if necessary, developing new programs.
3. The DO activity is the minimization of expected degradation of a system, structure or component through its prudent operation or use in accordance with operating procedures and technical specifications.
4. The CHECK activity is the timely detection and characterization of significant degradation through inspection and monitoring of a structure or component, and the assessment of observed degradation to determine the type and timing of corrective actions required.
5. The ACT activity is the timely mitigation and correction of component degradation through appropriate maintenance and design modifications, including component repair and replacement of a structure or component.

This process relies on the continuous improvement of an aging management program, based on improved understanding of component aging and on the results of self-assessment and peer reviews. The information obtained through this approach provides important inputs to existing facility programs, such as maintenance and operations.

In practice, effective aging management requires the involvement and support of many internal and external organizations, and essential facility programs and processes. Examples include:

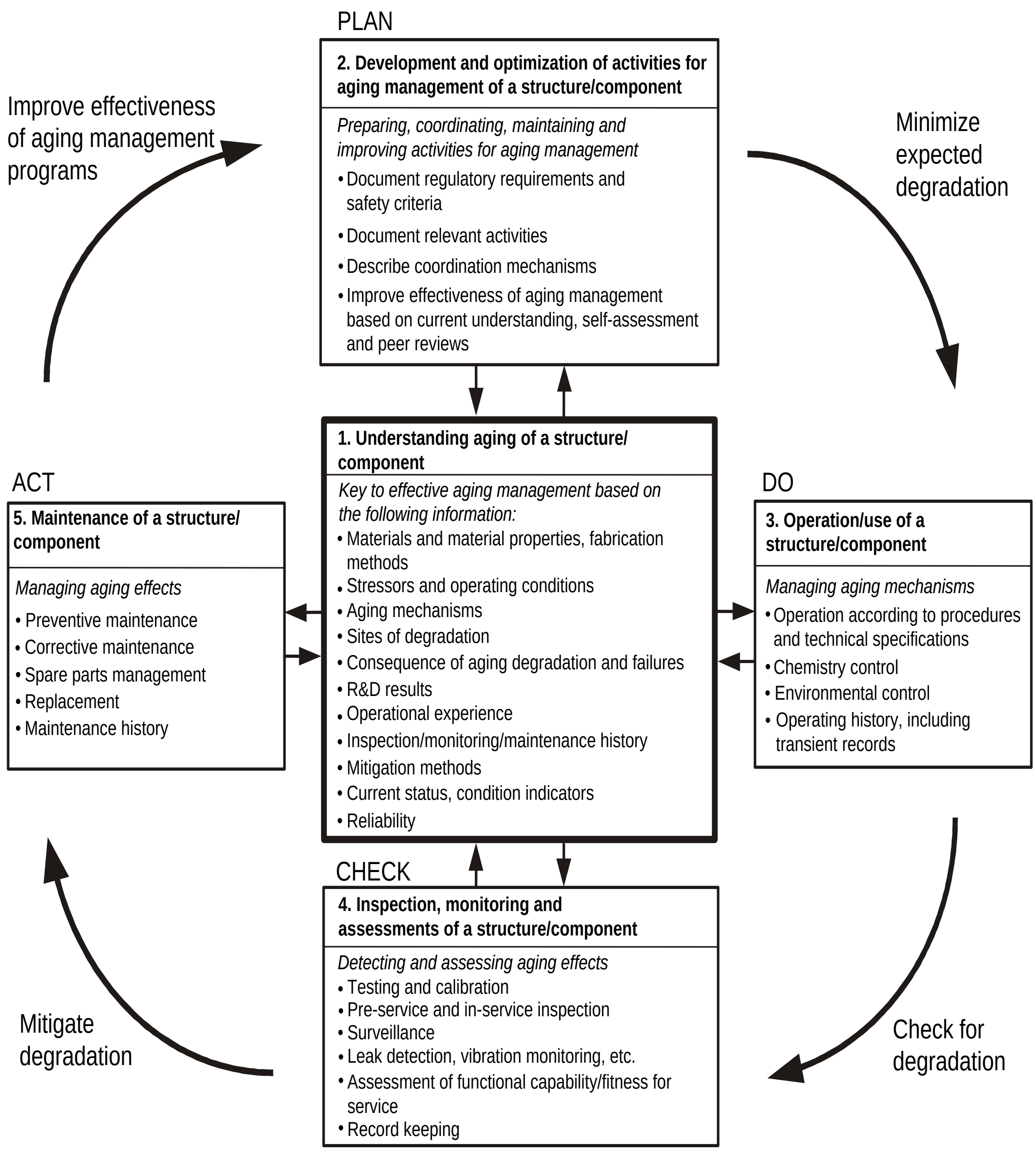
- deterministic safety analysis
- probabilistic safety assessment
- design, engineering change control
- periodic and in-service inspection programs
- equipment reliability
- maintenance programs
- environmental qualification programs

[1] IAEA Safety Report Series No. 57, *Safe Long Term Operation of Nuclear Power Plants*[2]

- system health monitoring programs
- operating procedures, chemistry programs
- operating experience, significant events analysis and research programs

See the References section, items 4–18, for applicable CNSC regulatory documents and CSA Group standards. While each of these facility programs and processes contribute to aging management, this is usually not their primary purpose or focus; none of these programs or processes, provide a complete program or process for managing the aging of SSCs.

Figure 1: A systematic and integrated approach to aging management [2]



Reliability and maintenance programs typically do not include passive, long-life SSCs (such as reactor assembly components, fuel channels, feeders, steam generators, pressure vessels and piping, structures and cables) that are difficult or impossible to replace or change except in an extended maintenance or refurbishment outage. Inspection and surveillance programs provide information used to confirm the current condition or fitness for service of these SSCs.

Lifecycle management plans are developed for structures and components, but do not typically consider the effects of other components or overall system safety performance. An important aspect is the determination of the impact of aging on facility safety, including safety margins as determined through an updated deterministic safety analysis, which requires a systematic and integrated approach to aging management.

The licensee's management system processes should therefore include requirements to ensure there is a documented overall integrated AM program framework for the reactor facility. The integrated AM program framework should provide a comprehensive, umbrella-type program. Alternatively, the AM program framework could include a "road map" document that demonstrates how the current processes and programs meet requirements for effective aging management. Aging management does not necessarily replace existing programs but, on the basis of evaluation, modifies them (reduces, enhances, eliminates, or supplements them) to achieve a systematic, integrated program for effective aging management.

SSC-specific or mechanistic-based AM plans should be established and implemented in accordance with the licensee's integrated AM program framework, and should address the attributes of an effective AM plan as presented in appendix A. The scope of the AM plans for SSCs should be commensurate with the importance to safety, design function and required performance of the SSCs, and its effect on the safe operation of the reactor facility.

Existing facility programs or practices that are credited as AM plans (such as equipment life cycle management plans, system health monitoring programs, water chemistry programs, inspection programs, and environmental qualification programs) should be evaluated against the attributes listed in appendix A. Programs or plans that do not include these attributes should be modified as appropriate. For example, existing system health, maintenance or inspection programs or practices may be adequate for the aging management of an SSC, provided they address the attributes listed in Appendix A.

Specific requirements for the licensee's integrated AM program framework and associated AM plans are provided in section 4.0.

3. Proactive Strategy for Aging Management

Aging management activities shall be implemented proactively throughout the lifecycle of a reactor facility or SSC (e.g., in design, fabrication and construction, commissioning, operating, and decommissioning).

Guidance

This document emphasizes the need for proactive consideration of aging management during each lifecycle phase of a reactor facility: design, construction, commissioning, operation (including long-term operation and extended shutdowns) and decommissioning. The lifecycle phases can apply to individual SSCs as well as the entire reactor facility.

3.1 Design

Appropriate measures shall be taken and design features shall be introduced in the design stage to facilitate effective aging management throughout the lifetime of the reactor facility.

Aging management shall also be considered in the design of modifications to existing operating facilities, and for design changes related to modifications and repairs or replacements of individual SSCs.

Guidance

A proactive approach to aging management begins with the design phase during which important decisions having significant impact for preventing and managing aging effects are made.

RD/GD-337, *Design of New Nuclear Power Plants* [7] and its successor document[2] establish design requirements for new reactor facilities which include taking into account the effects of aging and wear of SSCs. This document applies to new facilities, as well as to future design changes, repairs and replacements that apply to operating facilities and SSCs.

The requirement to take appropriate measures, and to introduce design features – during the design stage – to facilitate effective aging management, complements the requirements in RD/GD-337. The following aspects related to aging management should be considered at the design stage:

1. apply a systematic approach at the design stage to ascertain the understanding of aging of SSCs, in order to evaluate effective approaches and design features for aging prevention, monitoring and mitigation, and to establish AM plans for SSCs (see sections 4.3, 4.4, and 4.6)
2. consider the effects and interactions between mechanical, thermal, chemical, electrical, physical, biological and radiation stressors on materials properties, materials aging and degradation processes. In design documentation, demonstrate how past relevant generic aging issues, relevant aging management experience, and research results are addressed
3. define the safe service life or qualified life for SSCs in the design documentation, with an assessment of design margins that takes into account all known aging and wear mechanisms and potential degradation, including the effects of testing and maintenance processes. Identify SSCs that have shorter service lives than the nominal design life, and provide management strategies in the design documentation
4. consider aging effects under design-basis conditions, including transient conditions and postulated initiating event conditions, in the specifications for equipment qualification programs; e.g., environmental qualification and seismic qualification programs
5. include features in the plant layout and design of SSCs to facilitate inspection, testing, surveillance, maintenance, repair, and replacement activities, and to keep potential radiation exposures from these activities as low as reasonably achievable
6. specify the reference (baseline) and other pre-service, inaugural, or in-service inspection and test data that is required to be collected and documented for aging management purposes during fabrication, construction, commissioning, operation, and decommissioning
7. identify potential obsolescence issues for SSCs, evaluate effects on safety and reliability performance, and provide management strategies

[2] The successor document is entitled REGDOC-2.5.2, *Design of Reactor Facilities: Nuclear Power Plants*

8. in design documents, specify any special process applied to fabrication (or manufacturing) and construction of SSCs that prevent, mitigate, or eliminate known aging mechanisms; e.g., heat treatment, surface finishing, curing regime
9. in design documents, specify critical environmental and operating conditions and any other parameters to be monitored and/or controlled that affect aging assumptions used in design
10. specify required provisions for aging management in procurement documents for new facilities and SSCs, including documents from suppliers and other contractors (design institutions, vendors, manufacturers, inspection agencies, etc.)

Aging management is also to be considered in the design of modifications to existing operating facilities, and for the design of modifications, repairs, and replacements of individual SSCs. This does not preclude the use of like-for-like items for repairs and replacements; however, if failure or degraded performance of a structure, system or component is caused by premature aging, then consideration should be given to incorporating improvements that will prevent or slow down the aging effects. Aging management considerations for repairs and replacements may include, for example, selection of improved materials, increased piping wall thickness, stress relief of pipe bends, and the recording of baseline measurements.

3.1.1 Aging management content in safety analysis reports

The deterministic safety analysis for the reactor facility shall account for the cumulative effects of aging degradation of SSCs on overall systems and facility safety performance.

Periodic reviews of the safety analysis reports are to include operating experience and research findings with respect to aging and the implementation of the results of that analysis (see also section 3.4.1).

Guidance

The deterministic safety analysis and probabilistic safety assessment for the reactor facility should be based on complete and accurate design and operational information and is to account for the cumulative effects of aging degradation of SSCs on overall systems and facility safety performance [3, 4]. For deterministic safety analysis, significant uncertainties in analysis or data relevant to aging assumptions, including those associated with reactor facility performance, operational measurements, and modelling parameters, should be identified and considered.

The safety analysis report for the reactor facility should address the following items relating to aging management:

1. an outline of the proactive strategy for aging management and prerequisites for its implementation
2. safety-significant SSCs of the reactor facility that could be affected by aging
3. assumptions, methods, acceptance criteria, and data used to account for the effects of the aging of SSCs in the safety analysis, including any time-limited assumptions and failure data for probabilistic safety assessments

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[3] RD-310, *Safety Analysis for Nuclear Power Plants* [4] and GD-310, *Guidance on Safety Analysis for Nuclear Power Plants* [5], or the successor document REGDOC-2.4.1, *Deterministic Safety Analysis*
[4] S-294, *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants* [6] or its successor document REGDOC-2.4.2, *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants*

4. critical service conditions, operational limits and conditions, and any other parameters to be monitored and/or controlled that affect aging assumptions used in deterministic safety analyses or equipment qualification
5. data and information to be collected for aging management in order to confirm that deterministic safety analysis assumptions and acceptance criteria continue to be met

3.2 Fabrication, construction, and installation

Aging management shall be considered in the fabrication, construction, and installation processes for new reactor facilities, and the processes for modifications, repairs, and replacements of SSCs for existing operating reactor facilities.

Methods to ensure that fabrication (or manufacturing), construction, and installation processes do not adversely affect aging performance of SSCs shall be defined in relevant procedures.

Guidance

Fabrication and construction practices can have a significant effect on the aging resistance of SSCs, which often only become apparent much later in the operating life. Provisions to monitor, manage, and control aging degradation of SSCs should therefore be established and implemented, to ensure that the fabrication, construction, and installation processes do not adversely affect the aging resistance of SSCs. These provisions should take account of current aging management knowledge and experience, and other relevant factors affecting aging and aging management of SSCs.

The licensee should ensure the following items are taken into consideration:

1. current knowledge about relevant aging mechanisms, effects/degradation, and possible preventive and mitigation measures are taken into account in fabrication, construction, and installation of SSCs
2. prequalification and quality control / quality assurance during construction
3. relevant information on the factors affecting aging management and parameters influencing aging degradation is clearly specified in procurement documents and provided to SSCs suppliers and contractors
4. suppliers and contractors adequately address factors affecting aging management
5. reference (baseline) data required for aging management are collected and documented
6. surveillance specimens for specific aging monitoring programs are made available and installed in accordance with design specifications

3.3 Commissioning

Aging management shall be considered in the commissioning activities for new reactor facilities and in projects for existing facilities that involve major repairs, replacements and modifications of SSCs.

Appropriate measures shall be taken to ensure that baseline data required for aging management of SSCs is recorded during commissioning.

Critical service conditions and parameters, such as those considered in equipment qualification and aging assumptions in the design and safety analyses, shall be verified.

Guidance

The following should be taken into account in commissioning activities:

1. relevant information on the factors affecting aging management and parameters influencing aging degradation should be identified, taken into account, monitored, and controlled in commissioning
2. required baseline or inaugural inspection data for aging management should be recorded
3. critical service conditions and parameters, such as those considered in equipment qualification and aging assumptions in safety analyses, should be verified as being in compliance with the design and safety
4. special attention should be paid to identification and recording of thermal and radiation hot spots, and to measurement of vibration levels

3.4 Operation

Licensees shall establish and implement processes, programs and procedures to manage aging and obsolescence of SSCs, to ensure that required safety functions are maintained during the facility operation phase.

Facility operations shall be monitored and recorded to demonstrate compliance with critical service conditions, operational limits and conditions, and any other parameters that were identified (see section 3.1.1) as affecting aging assumptions used in safety analyses or equipment qualification.

In the event of operational changes or modifications to SSCs, a review of possible changes in environmental or process conditions (e.g., temperature, flow pattern, velocity, vibration, radiation) that could affect aging and failure of SSCs (see section 3.1) shall be performed.

Corrective actions identified by AM plan activities shall be managed within the reactor facility's corrective action program.

Measures shall be taken to store spare or replacement parts and consumables in appropriately controlled environments (i.e., with appropriate temperatures and moisture levels, and to prevent chemical attack or dust accumulation), taking shelf life into account, in order to preclude aging degradation.

Guidance

During the facility operating phase, licensees are expected to establish and implement an overall facility AM program framework that ensures the coordination and communication between all relevant facility and external programs for managing aging and obsolescence of SSCs. A systematic approach (including appropriate organizational arrangements, data collection and record keeping, SSC screening and aging evaluations) should be applied in order to ensure:

1. all SSCs that are susceptible to aging effects or obsolescence that can, directly or indirectly, have an adverse effect on the safe operation of the reactor facility are identified
2. aging effects of SSCs and potential impacts on safety functions due to aging and obsolescence are systematically identified, evaluated and documented
3. effective actions for preventing, monitoring and mitigating aging are evaluated and implemented to ensure that the required SSCs and safety functions will not be impaired

during normal operation and design-basis accident conditions, as well as those relied on for design extension conditions

Additional detail is provided in section 4.0.

Critical service conditions, operational limits and conditions, and other parameters identified as affecting aging assumptions used in safety analyses, design or equipment qualification should be monitored and recorded to ensure compliance, and to provide for timely detection, reporting and evaluation of unexpected service conditions – so that corrective actions can be taken before reactor facility safety is negatively impacted.

Procedures should be in place to ensure that any changes to system operations or design modifications are reviewed for the effect on environment or process conditions (e.g., temperature, flow pattern, velocity, vibration, radiation fluence) of SSCs, including neighbouring or connected SSCs, such that they do not introduce a detrimental aging effect or new failure mechanism. In such cases, AM plans should be updated accordingly.

Procedures should be in place to ensure that if a new aging mechanism is discovered (e.g., through feedback from inspections, surveillance, operating experience or research findings), an appropriate aging management review is carried out.

3.4.1 Review and update of safety analysis

As part of the deterministic safety analysis review and update, licensees shall account for the effects of the aging of SSCs, research findings, and advances in knowledge and understanding of aging mechanisms. This shall include an evaluation of the cumulative effects of the aging of SSCs on overall system and facility safety performance, as well as on risk insights using probabilistic safety assessments.

Guidance

The deterministic safety analysis should be periodically reviewed and updated to account for changes in reactor facility configuration and conditions, operating parameters and procedures, research findings, and advances in knowledge and understanding of physical phenomena.

Data and information collected from AM plans should be reviewed to confirm that deterministic safety analysis assumptions, credited parameters and predictions remain valid, and that limiting criteria and required design margins continue to be met as the facility ages.

The probabilistic safety assessment should be updated periodically, as per S-294, *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants* [6], or its successor document[5], using the data and information collected from AM plans as much as practicable.

3.4.2 Long-term operation

The licensee shall complete an in-depth review of the effects of aging on reactor facility safety and evaluate the effectiveness of AM plans for long-term operation in order to identify corrective

[5] The successor document is entitled REGDOC-2.4.2, *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants.*

actions and areas for improvement. Condition assessments shall be completed as part of the review of aging for long-term operation (see section 4.5).

The review shall demonstrate that:

1. all SSCs that can, directly or indirectly, have an adverse effect on the safe operation of the reactor facility are evaluated for the proposed period of long-term operation
2. the effects of aging will continue to be identified and managed for these SSCs during the planned period of long-term operation
3. all deterministic safety analyses involving time-limited assumptions are validated for the proposed period of long-term operation to ensure that the aging effects will be effectively managed (i.e., to demonstrate that the intended function of an SSC will remain within the design safety margins throughout the planned period of long-term operation)

The results of the review of aging management for long-term operation shall be documented, and the findings shall be addressed.

Guidance

A review of the actual condition of SSCs and of the management of aging for long-term operation should be conducted in accordance with RD-360, *Life Extension of Nuclear Power Plants* [18] or its successor document[6], and IAEA Specific Safety Guide SSG-25, *Periodic Safety Review of Nuclear Power Plants* [19]. Additional guidance on the conduct of aging management review for safe long-term operation is provided in IAEA Safety Report Series No. 57, *Safe Long Term Operation of Nuclear Power Plants* [2] and IAEA Safety Report Series No. 80, *International Generic Ageing Lessons Learned (IGALL) for Nuclear Power Plants* [20].

3.4.3 Extended shutdowns

Licensees shall review and, where necessary, revise SSC-specific AM plans to ensure that relevant factors affecting aging degradation are taken into account for SSCs placed in lay-up or safe-storage states during extended shutdowns.

Required provisions for aging management shall be defined in system lay-up specifications or preservation plans, including requirements for any condition assessments to be completed prior to the return to service of a reactor facility following an extended shutdown (see section 4.5).

Guidance

Extended shutdowns are reactor shutdowns lasting for a period exceeding one year, and exclude regular maintenance outages. During extended shutdowns, SSCs may need to be placed in temporary lay-up or safe-storage states that require supplementary measures and controls to prevent aging degradation.

The review and revision to SSC-specific aging management processes may take into consideration the differences in hazard potential and operating conditions between the temporary lay-up or safe storage states and the normal operating states.

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[6] The successor document is entitled REGDOC-2.3.3, *Operating Performance: Integrated Safety Reviews.*

Provisions for aging management should include defining any requirements for a condition assessment or any other aging management activities. Not all condition assessments in the scope of the aging management program need to be completed prior to return to service from an extended shutdown. The scope of the condition assessments should be based on the lay-up conditions, the results and time since the last condition assessment and the duration of the shutdown.

The provisions for aging management, including scope of condition assessments, should be reassessed if the duration of the shutdown is greatly extended beyond what was originally anticipated (for example, due to unforeseen issues or delays in the return to service).

3.5 Decommissioning

Licensees shall establish and implement aging management activities in decommissioning plans and procedures for SSCs that are required to remain available and functional during decommissioning.

Guidance

During the transition period from reactor unit shutdown to decommissioning and, where required, to facilitate decommissioning, appropriate aging management arrangements need to be continued to ensure that required SSCs remain available and functional. The stabilization activities phase (SAP) and storage and surveillance phase (SSP) may be considered as a subset of decommissioning, where attention must be paid to any equipment related to irradiated fuel bay operations, shutdown cooling, and core defuelling activities (fuelling machines and fuel transfer system equipment). This may require implementing relatively long-term aging management provisions for certain SSCs; for example, containment and spent fuel bay systems, fire protection systems, lifting equipment and monitoring equipment. Such provisions must be consistent with licensing requirements.

AM plans may no longer be required for specific SSCs after they are permanently taken out of service, and the residual risks are low and acceptable. For example, for reactor components this could be after the reactor is de-fuelled and drained, and placed into safe storage. However, AM plans would be required for those SSCs needed to monitor or secure the activated / contaminated reactor components (e.g. fire protection, monitoring equipment, security equipment).

4. Integrated Aging Management

Licensees shall apply a systematic and integrated approach to establish, implement and improve appropriate programs to manage aging and obsolescence of SSCs. Reactor facility management processes shall include requirements to ensure there is a documented overall integrated AM program framework for the reactor facility that addresses the following elements:

1. organizational arrangements
2. data collection and record keeping
3. screening and selection process for aging management
4. evaluations for aging management
5. condition assessments
6. SSC-specific AM plans
7. management of obsolescence
8. interfaces with other supporting facility programs

9. implementation of AM program and plans
10. review and improvement of AM program and plans

SSC-specific AM plans shall be implemented in accordance with the overall integrated AM program framework.

Guidance

The integrated AM program framework should provide a comprehensive, umbrella-type program or, alternatively, a “road map” document that demonstrates how the current processes and programs meet the requirements for effective aging management. The integrated AM program framework would be subject to CNSC compliance program inspections and reviews.

Detailed requirements are provided in the following sections. Alternative approaches may be acceptable, provided these elements are addressed in an equivalent manner that is demonstrated to be effective in managing aging.

4.1 Organizational arrangements for effective aging management

The reactor facility management processes shall include requirements to ensure that appropriate organizational arrangements are established to facilitate the effective implementation of AM plans.

Guidance

The following aspects should be considered:

1. established policy and objectives of the overall integrated AM program framework, allocated resources (such as human, financial, training, tools, and equipment), and processes to monitor the program to ensure it is meeting its objectives
2. defined responsibilities for the implementation of aging management activities
3. provision of training and mentoring to operations, maintenance, engineering, and other pertinent staff to ensure they have adequate awareness and understanding of aging management concepts and program requirements
4. external organizations, if/when required, for specific services related to aging management, such as specialized inspections, assessments, research, and standards development

4.2 Data collection and record-keeping system to support aging management

The licensee shall have an appropriate data collection and record-keeping system to support aging management activities and to provide a basis for decisions on the type and timing of aging management actions.

Data entered into the system shall be auditable to demonstrate an adequate verification of the data entered, detailed description of the basis for any conclusion, and to trace all applicable sources of information.

Guidance

A data collection and record keeping system should be established early in the life of a reactor facility to support the AM plans. Data and records relevant to aging management include:

1. reference (baseline) data on the design, fabrication, and construction of the facility or SSCs and conditions at the beginning of the service life, including results of equipment qualification tests, inspections, commissioning tests, and mappings of environmental conditions during construction and commissioning
2. data on the operating history of the facility, service conditions for SSCs (including transient data), chemistry conditions, SSC condition indicators, event reports, and data on the testing of availability and failure of SSCs
3. results of in-service inspections and material surveillance, including inspection specifications and results, as well as findings that exceed reporting levels
4. data on the maintenance history, including data on the monitoring of the condition and maintenance of components and structures, assessments of aging related failures or significant degradation of SSCs, including results of root-cause analyses
5. records of SSC aging evaluations and condition assessments, performance indicators of AM plans' effectiveness, SSC health indicators, internal and external operating experience, and research results

4.3 Screening and selection of structures, systems and components

A documented screening and selection process shall be used to establish the list of SSCs to be included in the scope of the overall integrated AM program framework. This process shall include SSCs susceptible to aging degradation or aging effects that can, directly or indirectly, have an adverse effect on the safe operation of the reactor facility. The process shall include SSCs that do not have safety functions, but whose failure could prevent safety-related SSCs from performing their intended functions.

Guidance

The screening and selection requirements in section 4.3 are commensurate with RD/GD-210, *Maintenance Programs for Nuclear Power Plants* [16], which covers all SSCs within the bounds of the facility. The selection process for aging management will include long-lived passive SSCs that may not be covered by maintenance programs. The screening and selection requirements for aging management are intentionally broader in scope than those of RD/GD-98, *Reliability Programs for Nuclear Power Plants* [15], which focuses on reliability performance of primarily active components in systems important to safety.

The screening and selection process for SSCs should follow a safety-based approach. The following list is an example of such considerations:

1. from a comprehensive list of all SSCs, identify those whose malfunction or failure could lead directly or indirectly to the loss or impairment of a safety function
2. ensure that the list includes all SSCs whose degradation may challenge or affect the assumptions made in the safety analyses
3. ensure that the list includes all SSCs relied upon for design extension conditions (for example, emergency filtered containment vent, provisions for emergency water makeup, equipment to mitigate hydrogen and combustible gases, and dedicated instrumentation for beyond-design-basis accidents)

4. for each SSC, identify those structural elements and components whose failure could lead directly or indirectly to the loss or impairment of a safety function. This may include consideration of surrounding or neighbouring structures, piping, components and supports that are not safety-related, but whose failure could affect a safety-related item
5. from the list of structural elements and components, identify those for which aging degradation has the potential to cause component failure; provide justification for the excluded components

This screening and selection process should consider relevant operating experience and research findings.

For SSCs that are not included in the AM plan, appropriate provisions should be implemented to ensure their safety significance will not change throughout the facility's life because of degradation due to aging.

The documentation of the screening and selection process should include the information sources and any criteria used, and arrange the final list of elements and components into related categories.

The records produced should be identified as permanent records.

4.4 Evaluations for aging management

The reactor facility's management processes and procedures shall include requirements for conducting, documenting, and keeping records of evaluations for aging management. The evaluations address the following elements:

1. understanding aging
2. preventive actions to minimize and control aging degradation
3. methods for detection, monitoring, and trending of aging effects
4. methods for mitigating aging effects and corrective actions

The procedure for conducting the evaluations for aging management shall be documented, as well as the results of the evaluations.

Guidance

A recommended methodology is to conduct an evaluation of relevant information and then document the findings (see Appendix B).

The results of operating experience, research and development, and available previous aging evaluations (both generic and facility-specific) can be used in the evaluations. Relevant applicable aging management reviews (i.e., those prepared by the licensee, suppliers or support organizations) should be used to minimize duplication of effort, if available. Appropriate references should be made, and an explanation of the use of these references should be provided.

The results of the evaluations should summarize the pertinent aging issues and effectiveness of current practices, such as existing lifecycle management plans, and system health monitoring, inspection and maintenance programs. They should also provide recommendations for activities in the SSC aging management plan and for facility-supporting programs in design, operation, monitoring, and maintenance, and identify areas for further research and development.

4.4.1 Understanding of aging

Reactor facility management processes shall include requirements for the evaluation of the current understanding of aging for the selected structure, system or component.

Guidance

The current understanding of aging for the selected structure, system or component should be documented based on an evaluation of possible and actual aging mechanisms. The evaluation is to consider the effects of aging degradation on SSC safety function, the effect on the ability of other SSCs to perform their intended safety functions, and other consequences of failure.

The evaluation should identify:

1. SSC design and licensing basis requirements relevant to aging and aging management (including applicable codes and standards, deterministic safety analysis, safety functions, and consequences of failure)
2. SSC materials, service conditions, stressors, degradation sites, aging mechanisms and effects
3. indicators of the physical or functional condition of SSCs (condition indicators)
4. anticipated obsolescence issues
5. quantitative or qualitative models for predicting relevant aging effects, and any gaps in understanding
6. SSC life-limiting conditions and acceptance criteria against which the need for corrective action is evaluated
7. a list of data needs for the assessment of SSC aging (including any deficiencies in availability and quality of existing records)

4.4.2 Preventive actions to minimize and control aging degradation

Methods to prevent and control aging degradation shall be evaluated to establish appropriate actions that can be taken.

Guidance

The evaluation should identify:

1. preventive actions to be taken in design, selection of materials and coatings, fabrication and construction practices, commissioning, service conditions, and preventive operation and maintenance practices (including specifications for SSC lay-up conditions)
2. parameters to be monitored or inspected to ensure the preventive actions are effective
3. service conditions (environmental conditions and operating conditions) to be maintained and operating practices aimed at slowing down potential degradation of the structure or component

4.4.3 Methods for detecting, monitoring, and trending aging effects

Methods for the detection, monitoring, and trending of aging effects shall be evaluated to establish appropriate actions that can be taken.

Guidance

The evaluation should identify:

1. parameters and condition indicators for detecting, monitoring, and trending aging degradation of the structure or component
2. effective technology (inspection, testing, surveillance, and monitoring methods) for detecting aging effects – with sufficient sensitivity, reliability, and accuracy – before SSCs fail
3. data to be collected to facilitate assessment of the aging of SSCs
4. data evaluation techniques (including data analysis and trending) for recognizing significant degradation and for predicting future performance of the SSCs

National and international operating experience should be considered in the evaluation. The evaluation of technology and methods should consider the need for the detection of unexpected degradation, depending on how critical the SSC is to safety. For example, while inspections to deal with known degradation mechanisms may incidentally result in discovery of unexpected degradation, there is no assurance that unexpected degradation will always be detected. Surveillance programs involving the removal of items (e.g., pressure tubes, material coupons) can assist in discovery of degradation mechanisms that were not previously known.

As well, it is known that measurements of degradation on specific components can demonstrate a large variation even for similar items (e.g., feeder pipe wall thinning, pressure tube flaws). The evaluation should take into account the need for an appropriate level of statistical confidence that significant degradation will not go undetected.

Where it is critical to life management activities or to fitness-for-service calculations, or where significant changes in inspection techniques are to be implemented, parallel measurements or comparison with existing qualified techniques should be conducted. This is to ensure proper calibration and to correct any bias.

The evaluation should also include an assessment of the safety risks to the facility and workers from the data collection activities.

4.4.4 Methods for mitigating aging effects and corrective actions

Methods for mitigating aging effects shall be evaluated to establish appropriate corrective actions that can be taken.

Guidance

The evaluation should identify:

- operations, maintenance, repair and replacement actions to allow timely mitigation of detected aging effects or degradation
- acceptance criteria against which the need for corrective action is evaluated
- corrective actions if a component fails to meet the acceptance criteria

The effectiveness of existing methods and practices for mitigating aging degradation should take account of relevant operating experience and research results.

4.5 Condition assessments

Reactor facility management processes shall include requirements to evaluate the actual condition of a structure, system or component at the initiation of the SSC-specific AM plan and at periodic intervals throughout the service life of the reactor facility or structure, system or component, as required, to validate the AM plan's effectiveness. The procedure for conducting condition assessments and the results shall be documented.

Guidance

Condition assessments are used to establish the actual condition of an SSC, usually at the initiation of the SSC-specific AM plan, and certain times during the service life of the reactor facility or SSC as required for validating the AM plan's effectiveness. For example, condition assessments are also completed as part of the review of aging for extended or long-term operation (see section 3.4.2), and may be required before a reactor facility returns to service after an extended shutdown period or SSC lay-up (see section 3.4.3).

The condition assessments should provide information on:

- the current performance and condition of the SSC, including assessment of any aging related failures or indications of significant material degradation, previously unidentified aging mechanisms or effects, and comparisons against predictions for the aging mechanisms and acceptance criteria
- estimation of future performance, degradation due to aging, and residual service life, where feasible, of the SSC (i.e., the length of time the SSC is likely to meet its function and performance requirements)
- recommended follow-up or prevention, monitoring, and mitigation measures to be completed and/or incorporated into the AM plan, including appropriate intervals for follow-up condition assessments and areas for further research and development

Condition assessments of SSCs may be conducted as part of the evaluations for aging management (see section 4.4).

4.6 SSC-specific aging management plans

Reactor facility management processes shall include requirements to develop, document, and maintain a specific AM plan for the aging management of SSCs (or groups of structures and components) selected by the screening process, or alternatively an AM plan for managing a specific aging mechanism or effect.

The SSC-specific AM plans shall be documented and address the attributes of an effective AM plan as listed in appendix A.

Guidance

The AM plan should specify what range of outcomes they can reasonably accommodate, and take into account the ability to adjust the plans to outcomes outside of that range.

The scope of the SSC-specific AM plan should be commensurate with the importance to safety, design function and required performance of the structure, system or component, and its effect on the safe operation of the reactor facility. For example, the critical life-limiting SSCs of current

CANDU reactors – such as fuel channels, heat transport feeder piping and steam generators – will have detailed lifecycle management plans as part of their SSC-specific AM plans. AM plans may not necessarily be specific to SSCs, but could instead focus on degradation mechanisms or operational requirements to control or predict degradation; for example, plans or programs for managing flow-accelerated corrosion, water chemistry and fatigue monitoring.

Each SSC-specific AM plan should cover the nine attributes of an effective program (see appendix A). Existing facility programs that are credited as should be evaluated against the attributes listed in appendix A. Programs that do not include these attributes should be modified as appropriate. For example, existing life cycle management plans, system health monitoring, maintenance or inspection programs or practices may be eligible as the AM plan of an SSC, provided they address the attributes listed in appendix A.

The required attributes of SSC-specific AM plans are typically implemented through several facility programs. Recognizing this, the documentation of an SSC-specific AM plan should provide, for each attribute, a summary description of the SSC-specific application of the relevant facility program(s) and references to reactor facility documents containing the supporting basis/evidence.

It is up to the reactor facility licensee to identify its AM plan performance indicators. This could include the program health indicators currently used in system health reports. Other examples of indicators include:

- material condition with respect to acceptance criteria
- trends of data relating to failure and degradation
- comparison of preventive and corrective maintenance efforts (e.g., in terms of person-years or cost)
- number of recurrent failures and instances of degradation
- status of compliance with inspection programs

The AM plan document should also include a summary page that highlights the key information useful for understanding and managing aging, including materials, degradation sites, aging stressors and environment, aging mechanisms and effects, inspection and monitoring requirements and methods, mitigation methods, regulatory requirements, and acceptance criteria.

Additional information and summaries of SSC-specific AM plans are provided in IAEA Safety Report Series No. 80, *International Generic Ageing Lessons Learned (IGALL) for Nuclear Power Plants*. [20].

4.7 Management of obsolescence

The licensee shall have a managed process for obsolescence. The provisions for the management of obsolescence shall be documented in the licensee's management system.

Guidance

The program for management of obsolescence should address the following:

- spare parts supplies for planned service life
- long-term arrangements for manufacturers and spare parts suppliers, and for required technical support

- availability of documentation to support maintenance and replacement of SSCs
- availability of documentation and technology to support development of equivalent SSCs, if needed
- arrangements for modernization and technology updates

4.8 Interfaces with other supporting programs

All supporting programs and activities that are credited as an integral part of the reactor facility's aging management shall be identified, and their interfaces and information requirements defined in the overall integrated AM program framework document.

Guidance

The integrated AM program framework should also identify the aging management information that needs to be provided as inputs into other facility programs and activities, including safety analysis [7, 8], maintenance [9], and reliability programs [10]. As an example, section 3.4.1 includes a requirement for data and information collected from the AM plan to be reviewed within the program for the periodic review and update of the deterministic safety analysis.

4.9 Implementation of aging management programs

The overall integrated AM program framework and SSC-specific AM plans and major actions related to aging management shall be implemented under the licensee's management system for the facility.

Data identified in AM plans shall be collected and recorded to provide a basis for decisions on the type and timing of aging management actions.

Guidance

The implementation of AM plans should provide a systematic aging management process, based on an understanding of aging, consisting of the following aging management tasks (see figure 1):

- planning activities, including documentation of applicable regulatory requirements and safety and reliability criteria, relevant programs and activities
- operation within operating guidelines aimed at minimizing the rate of degradation
- inspection and monitoring activities aimed at timely detection and assessment of aging degradation
- maintenance activities aimed at mitigating aging effects and corrective actions for unacceptable degradation

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[7] RD-310, *Safety Analysis for Nuclear Power Plants* [4] and GD-310, *Guidance on Safety Analysis for Nuclear Power Plants* [5], or the successor document, REGDOC-2.4.1, *Deterministic Safety Analysis*
[8] S-294, *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants* [6] or its successor document REGDOC-2.4.2, *Probabilistic Safety Assessment for Nuclear Power Plants*
[9] RD/GD-210, *Maintenance Programs for Nuclear Power Plants* [16]
[10] RD/GD-98, *Reliability Programs for Nuclear Power Plants* [15]

4.10 Review and improvement

The effectiveness of the overall integrated AM program framework and SSC-specific AM plans shall be periodically reviewed using feedback from the program and performance indicators.

The licensee shall update AM plans and interfacing programs, and their implementation, to improve their effectiveness based on the results of the review as appropriate.

Guidance

The reviews should be conducted on a regular periodic basis and documented. Program reviews should include consideration of the operating performance, inspection and maintenance histories, results of condition assessments, event reports, information from the results of research and development, self assessments, and operating experience, current issues, and future actions. Recommendations and corrective actions for AM plans and supporting programs should be implemented in a timely manner, as appropriate. Aging management is a specific area reported on in the CNSC's annual nuclear power industry safety performance reports.

Consideration should be given to arranging for peer reviews of AM plans to obtain an independent assessment, to establish if they are consistent with generally accepted practices and to identify areas for improvement.

Whenever an AM plan's deficiency is identified, the licensee should assess its significance and, where appropriate, conduct a causal analysis and take corrective actions. AM plans should be adjusted as appropriate in response to the new information. When a component fails to meet the acceptance criteria, the cause of the component failure should be identified and reviewed, in order to determine corrective actions that should be implemented in a timely manner to prevent recurrences. Lead times to plan and implement options can be a significant factor in aging management planning. Therefore, it is recommended for AM plans to identify when work should be started, with regard given to when critical options are needed in order to manage the range of uncertainties. A confirmation process should be established to ensure that corrective actions have been completed and are effective.

Adequately funded research and development programs should be put in place to respond to any new aging issues and to provide for continuous improvement of the understanding and predictability of aging mechanisms and the causes of aging, and associated monitoring and mitigation methods or practices. A strategic approach should be made to promoting relevant long-term research and development programs.

Appendix A: Attributes of an Effective Aging Management Plan

Adapted from the International Atomic Energy Agency Safety Guide *Ageing Management of Nuclear Power Plants* NS-G 2.12 [1].

	Attribute	Description
1	Scope of the aging management (AM) plan, based on understanding of aging	Systems, structures and components (SSCs) subject to aging management (structures include structural elements) Understanding of aging phenomena (significant aging mechanisms, susceptible sites): • design and licensing basis requirements relevant to aging • SSC materials, service conditions, stressors, degradation sites, aging mechanisms and effects • SSC condition indicators and acceptance criteria • quantitative or qualitative predictive models of relevant aging phenomena
2	Preventive actions to minimize and control degradation due to aging	Identification of preventive actions Identification of parameters to be monitored or inspected Service conditions (i.e., environmental conditions and operating conditions) to be maintained and operating practices aimed at slowing down potential degradation of the structure or component
3	Detection of aging effects	Effective technology (inspection, testing and monitoring methods) for detecting aging effects before failure of the SSCs
4	Monitoring and trending of aging effects	Condition indicators and parameters to be monitored Data to be collected to facilitate assessment of structure or component aging Assessment methods (including data analysis and trending)
5	Mitigating aging effects	Operations, maintenance, repair and replacement actions to mitigate detected aging effects / degradation of SSCs
6	Acceptance criteria	Acceptance criteria against which the need for corrective action is evaluated
7	Corrective actions	Corrective actions if a component fails to meet the acceptance criteria
8	Operating experience feedback and feedback of research and development (R&D) results	Mechanism that ensures timely feedback of operating experience and R&D results (if applicable), and provides objective evidence that they are taken into account in the AM plan
9	Quality management	Organizational roles and responsibilities Administrative controls that document the implementation of the AM plan and actions taken Indicators to facilitate evaluation and improvement of the AM plan Confirmation (verification) process for ensuring that preventive actions are adequate and appropriate and all corrective actions have been completed and are effective Record-keeping practices to be followed

Appendix B: Sample Methodology for Aging Evaluation

Adapted from the International Atomic Energy Agency Safety Guide *Ageing Management of Nuclear Power Plants* NS-G 2.12 [1].

Understanding of aging

Design and specifications	Materials and material properties	Service conditions	Performance requirements	Operation and maintenance histories	Generic operating experience	Relevant research and development (R&D) results

Documentation of:

- current understanding of the aging of structures, systems and components (SSCs) (e.g., aging mechanisms and effects, sites of degradation, any analytical/empirical models for predicting SSC degradation, any gaps in understanding of aging)
- acceptance criteria including applicable regulatory or code requirements, set of limits and conditions defining the safe operation envelope
- list of data requirements for the assessment of SSC aging (including any deficiencies in availability and quality of existing records)

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Prevention of aging degradation

Evaluation of the effectiveness of methods and practices for prevention of aging degradation of the SSC

Documentation of the information, including:

- design, materials, fabrication (or manufacturing) and construction, operations and maintenance methods and practices to prevent aging degradation of the SSC
- operating conditions and practices that prevent or minimize the rate of aging degradation of the SSC

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Monitoring of aging degradation

Evaluation of monitoring methods, taking into account relevant operating experience and research results.

Documentation of the information, including:

- functional parameters and condition indicators for detecting, monitoring, and trending aging degradation of the SSC
- an assessment of the capability and practicability of existing monitoring techniques to measure these parameters and indicators with sufficient sensitivity, reliability, and accuracy
- data evaluation techniques for recognizing significant degradation and for predicting future performance of the SSC

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Mitigation of aging degradation

Evaluation of the effectiveness of existing methods and practices for mitigating aging degradation of the SSC.

Documentation of the information, including:

- maintenance methods and practices, condition monitoring (including refurbishment and periodic replacement of parts and consumables) to control aging degradation of the SSC
- operating conditions and practices that minimize the rate of aging degradation of the SSC
- possible modifications to design and materials of the component to control aging degradation of the SSC

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Report on aging management review

SSC-specific information on understanding, monitoring, and mitigating aging

Recommendations for the application of results of the aging management review in facility design, operation and maintenance, and for R&D to address gaps in knowledge and technology

Glossary

acceptance criteria
Specified bounds on the value of a functional indicator or condition indicator used to assess the ability of a structure, system or component to perform its design function.

aging
A general process in which characteristics of a structure, system or component gradually change over time or with use. This process may proceed by a single aging mechanism or by a combination of several aging mechanisms. Non-physical aging is the process of becoming out-of-date (obsolete) owing to the evolution of knowledge and technology and associated changes in codes and standards. Physical aging is due to physical, mechanical, thermal, electrical, chemical, irradiation and/or biological processes (aging mechanisms).

aging degradation
Aging effects that could impair the ability of a structure, system or component to function within its acceptance criteria.

aging effects
Net changes in the characteristics of a structure, system or component that occur with time or use and are due to aging mechanisms.

aging management (AM)
Engineering, operations, inspection, and maintenance actions to control, within acceptable limits, the effects of physical aging and obsolescence of structures, systems and components.

aging management program or aging management plan (AM program/plan)
A set of policies, processes, procedures, arrangements, and activities that provides direction for managing the aging of a nuclear power plant’s structures, systems and components. In this document, AM program refers to the overall integrated aging management program or framework for the reactor facility. AM plan refers to a SSC-specific or mechanistic-based aging management plan.

aging mechanism
A specific process that gradually changes characteristics of a structure, system or component with time or use, such as thermal or radiation embrittlement, corrosion, fatigue, creep, erosion, etc.

commissioning
A process consisting of activities intended to demonstrate that installed structures, systems and components and equipment perform in accordance with their specifications and design intent before they are put into service.

common-cause failure
A concurrent failure of two or more structures, systems, or components due to a single specific event or cause, such as natural phenomena (earthquakes, tornadoes, floods, etc.), design deficiency, manufacturing flaws, operation and maintenance errors, human-induced destructive events, or aging effects.

condition assessment
An assessment performed to determine the current performance and condition of a structure, system or component (including assessment of any age-related failures or indications of significant material degradation), and to predict future performance, extent and rate of aging degradation, and residual service life of the structure, system or component.

condition indicator
A characteristic of a structure, system or component that can be observed, measured, or trended to infer or directly indicate the current and future ability of the structure, system or component to function within acceptance criteria.

defence in depth
The application of more than one protective measure for a given safety objective, such that the objective is achieved even if one of the protective measures fails.

design basis
The range of conditions and events taken explicitly into account in the design of a facility, according to established criteria, such that the facility can withstand them without exceeding authorized limits by the planned operation of safety systems.

design extension conditions
A subset of beyond-design-basis accidents that are considered in the design process of the facility in accordance with best-estimate methodology to keep releases of radioactive material within acceptable limits. Design extension conditions could include severe accident conditions.

extended shutdown
A reactor shutdown lasting for a period exceeding one year and excludes regular maintenance outages.

failure
The inability or interruption of ability of a structure, system or component to function within acceptance criteria.

functional indicator
A condition indicator that is a direct indication of the current ability of a structure, system or component to function within acceptance criteria.

licensing basis
A set of requirements and documents for a regulated facility or activity comprising:

- the regulatory requirements set out in the applicable laws and regulations
- the conditions and safety and control measures described in the facility's or activity's licence and the documents directly referenced in that licence
- the safety and control measures described in the licence application and the documents needed to support that licence application

long-term operation
Operation beyond the assumed design life of the reactor facility, which has been justified by the results of safety assessment, considering life limiting processes and features for structures, systems and components.

maintenance
The organized activities – both administrative and technical – of keeping structures, systems and components in good operating condition, including both preventive and corrective (or repair) aspects.

management system
A set of interrelated or interacting elements (system) for establishing policies and objectives and enabling the objectives to be achieved efficiently and effectively. The management system integrates all elements of an organization into one coherent system to enable all organizational objectives to be achieved. These elements include the organization's structure, resources, and processes. Personnel, equipment, and organizational culture, as well as the documented policies and processes, are all parts of the management system. The organization's processes have to address the totality of the requirements on the organization as established in, for example, IAEA safety standards and other international codes and standards.

obsolescence
With respect to structures, systems and components, the process of becoming out of date in comparison with current knowledge, standards and technology.

operational limits and conditions
The set of limits and conditions that can be monitored by, or on behalf of, the operator and can be controlled by the operator.

reactor facility
Any fission reactor as described in the *Class I Nuclear Facilities Regulations*, including structures, systems and components:

- that are necessary for shutting down the reactor ensuring that it can be kept in a safe shutdown state
- that may contain radioactive material and which cannot be reliably isolated from the reactor
- whose failure can lead to a limiting accident for the reactor
- that are tightly integrated into the operation of the nuclear facility
- that are needed to maintain security and safeguards

root-cause analysis
An objective, structured, systematic and comprehensive analysis that is designed to determine the underlying reason(s) for a situation or event, and that is conducted with the level of effort that is consistent with the safety significance of the event.

safety functions
A specific purpose that must be accomplished by a structure, system or component for safety, including those necessary to prevent accident conditions and to mitigate the consequences of accident conditions.

safety systems
Systems provided to ensure the safe shutdown of the reactor or the residual heat removal from the core, or to limit the consequences of anticipated operational occurrences and design-basis accidents.

service life
The period from initial operation to final withdrawal from service of a structure, system or component.

stressor
An agent or stimulus stemming from pre-service and service conditions that can produce immediate or gradual aging degradation of a structure, system or component. Examples include heat, steam, chemicals, radiation, and electrical cycling.

structures, systems or components (SSCs)
A general term encompassing all of the elements (items) of a facility or activity that contribute to protection and safety. Structures are the passive elements: buildings, vessels, shielding, etc. A system comprises several components, assembled in such a way as to perform a specific (active) function. A component is a discrete element of a system. Examples are wires, transistors, integrated circuits, motors, relays, solenoids, pipes, fittings, pumps, tanks, and valves.

testing
The observation or measurement of condition or functional indicators under controlled conditions to verify that the current performance of a structure, system or component conforms to acceptance criteria.

time-limited assumptions
Assumptions used in certain facility- or SSC-specific safety or design analyses that are based on an explicitly specified length of facility or SSC life; for example, metal fatigue calculation, pressurized thermal shock analysis, radiation-induced deformation and embrittlement, thermal aging, loss of material, and equipment qualification of electrical equipment, instrumentation and control equipment, and cables are included in analyses.

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9. CSA Group, CSA N286, *Management system requirements for nuclear facilities*, Mississauga, 2012
10. CSA Group, CSA N287.1, *General requirements for concrete containment structures for nuclear power plants*, Mississauga, 1993
11. CSA Group, CSA N291, *Requirements for safety-related structures for CANDU nuclear power plants*, Mississauga, 2008
12. CSA Group, CSA N285.4, *Periodic inspection of CANDU nuclear power plant components,* Mississauga, 2009
13. CSA Group, CSA N285.5, Periodic *inspection of CANDU nuclear power plant containment components*, Mississauga, 2008
14. CSA Group, CSA N287.7, *In-service examination and testing requirements for concrete containment structures for nuclear power plants*, Mississauga, 2008
15. CNSC, RD/GD-98, *Reliability Programs for Nuclear Power Plants*, Ottawa, 2012
16. CNSC, RD/GD-210, *Maintenance Programs for Nuclear Power Plants,* Ottawa, 2012
17. CSA Group, CSA N290.13, *Environmental qualification of equipment for CANDU nuclear power plants*, Mississauga, 2005
18. CNSC, RD-360, *Life Extension of Nuclear Power Plants*, Ottawa, 2008
19. IAEA, Safety Standards Series, Specific Safety Guide, SSG-25, *Periodic Safety Review for Nuclear Power Plants*, Vienna, 2013
20. IAEA, Safety Report Series No. 80, *International Generic Ageing Lessons Learned (IGALL) for Nuclear Power Plants*, Vienna, 2014

Additional Information

The following documents contain additional information that may be of interest to persons involved in designing and implementing an aging management program

1. International Atomic Energy Agency (IAEA), Safety Standards Series, Safety Requirements, NS-R-1, *Safety of Nuclear Power Plants: Design*, Vienna, 2000
2. IAEA, Safety Standards Series, Safety Guide, NS-G-2.6, *Maintenance, Surveillance and In-Service Inspection in Nuclear Power Plants*, Vienna, 2002
3. IAEA, Safety Standards Series, Safety Guide, NS-G-2.4, *The Operating Organization for Nuclear Power Plants*, Vienna, 2001
4. IAEA, Safety Standards Series, Safety Requirements, NS-R-2, *Safety of Nuclear Power Plants: Operation*, Vienna, 2000
5. IAEA, Safety Report Series No. 3, *Equipment Qualification in Operational Nuclear Power Plants: Upgrading, Preserving and Reviewing*, Vienna, 1998
6. IAEA, Safety Report Series No. 62, *Proactive Management of Ageing of Nuclear Power Plants,* Vienna, 2009
7. IAEA, Technical Document, TECDOC 1197, *Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: CANDU Reactor Assemblies*, Vienna, 2001
8. IAEA, Technical Document, TECDOC 1188, *Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: In-containment Instrumentation and Control cables, Volumes I & II*, Vienna, 2000
9. IAEA, Technical Document, TECDOC 1025, *Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: Concrete Containment Buildings*, Vienna, 1998
10. IAEA, Technical Document, TECDOC 981, *Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: Steam Generators*, Vienna, 1997
11. IAEA, Safety Report Series No. 15, *Implementation and Review of a Nuclear Power Plant Ageing Management Programme*, Vienna, 1999
12. United States Nuclear Regulatory Commission, NUREG-1801, *Generic Aging Lessons Learned (GALL) Report,* Volumes 1 and 2, Washington, DC, 2011
13. Institute of Nuclear Power Operations, INPO AP-913 Revision 1, *Equipment Reliability Process Description*, Atlanta, Georgia, 2001

CNSC Regulatory Document Series

Facilities and activities within the nuclear sector in Canada are regulated by the Canadian Nuclear Safety Commission (CNSC). In addition to the *Nuclear Safety and Control Act* and associated regulations, these facilities and activities may also be required to comply with other regulatory instruments such as regulatory documents or standards.

Effective April 2013, the CNSC's catalogue of existing and planned regulatory documents has been organized under three key categories and twenty-five series, as set out below. Regulatory documents produced by the CNSC fall under one of the following series:

1.0 Regulated facilities and activities

Series 1.1 Reactor facilities
1.2 Class IB facilities
1.3 Uranium mines and mills
1.4 Class II facilities
1.5 Certification of prescribed equipment
1.6 Nuclear substances and radiation devices

2.0 Safety and control areas

Series 2.1 Management system
2.2 Human performance management
2.3 Operating performance
2.4 Safety analysis
2.5 Physical design
2.6 Fitness for service
2.7 Radiation protection
2.8 Conventional health and safety
2.9 Environmental protection
2.10 Emergency management and fire protection
2.11 Waste management
2.12 Security
2.13 Safeguards and non-proliferation
2.14 Packaging and transport

3.0 Other regulatory areas

Series 3.1 Reporting requirements
3.2 Public and Aboriginal engagement
3.3 Financial guarantees
3.4 Commission proceedings
3.5 Information dissemination

Note: The regulatory document series may be adjusted periodically by the CNSC. Each regulatory document series listed above may contain multiple regulatory documents. For the latest list of regulatory documents, visit the CNSC's website at nuclearsafety.gc.ca/eng/acts-and-regulations/regulatory-documents

UNDERTAKING JT1.12

Undertaking

To provide safety performance data for 2010, 2011 and 2012, if available.

Response

Please see Attachment 1.

Nuclear Specific Safety Metrics

	Collective Radiation Exposure *(person-rem/unit)*		Level 1 Work Protection Events (annual number of events)	
	Target	**Actual**	**Target**	**Actual**
2013	99.86	86.26	8	14
2012	99.22	105.05	8	15
2011	90.36	77.56	12	9
2010	102.14	106.89	No metric in 2010	

Appendix A

2012 OPG Safety Performance Summary

Organization	All Injury Rate (AIR)	AIR Target	Accident Severity Rate (ASR)	Lost Time Injuries	Days Lost	Medical Treatment Injuries	First Aid Injuries	OPG High MRPH Incidents	Contractor High MRPH Incidents	Total High MRPH Incidents
OPG	**0.63**	**0.92**	**2.40**	**4**	**246**	**61**	**152**	**20**	**6**	**26**
Nuclear Fleet Total [1]	**0.34**	**0.92**	**1.52**	**1**	**100**	**21**	**34**	**8**	**3**	**11**
Nuclear	**0.38**	**0.92**	**1.79**	**1**	**100**	**20**	**34**	**6**	**1**	**7**
Darlington	0.34	0.92	6.85	1	100	4	11	3	0	3
Pickering	0.35	0.92	0.00	0	0	8	9	3	1	4
Nuclear - Other [2]	0.44	0.92	0.00	0	0	8	14	0	0	0
Nuclear Projects	**0.10**	**0.92**	**0.00**	**0**	**0**	**1**	**0**	**2**	**2**	**4**
Hydro-Thermal Operations	**2.02**	**1.66**	**7.20**	**3**	**146**	**38**	**108**	**12**	**3**	**15**
Central Hydro PG	0.00	1.66	0.00	0	0	0	8	2	0	2
Niagara PG	1.01	1.66	0.00	0	0	2	12	1	0	1
Northeast PG	2.49	1.66	0.00	0	0	5	10	3	0	3
Northwest PG	1.65	1.66	0.00	0	0	2	5	1	0	1
Ottawa/St. Lawrence PG	1.28	1.66	0.00	0	0	3	11	2	2	4
Lambton GS	3.86	1.66	0.00	0	0	11	18	1	0	1
Lennox GS	2.89	1.66	0.00	0	0	5	22	1	0	1
Nanticoke GS	2.07	1.66	32.00	2	108	5	16	1	1	2
Northwest	1.07	1.66	20.33	1	38	1	6	0	0	0
Hydro-Thermal Support [3]	2.15	1.66	0.00	0	0	4	0	0	0	0
Business & Administrative Services (formerly Business Services & IT)	**0.28**	**N/A**	**0.00**	**0**	**0**	**2**	**6**	**0**	**0**	**0**
Commercial Operations & Environment (formerly Corporate Affairs)	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Corp. Business Development & CRO	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Corp. Executive Operations (formerly Corporate Secretary)	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Corp. Relations and Communications (formerly Corporate Stakeholder Relations)	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Finance	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**1**	**0**	**0**	**0**
People & Culture (formerly Human Resources)	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**3**	**0**	**0**	**0**
Law Division	**0.00**	**N/A**	**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Information reported as of January 9, 2013. Rates are calculated per 200k hours.

[1] Nuclear Fleet Total = Nuclear + Nuclear Projects

[2] Nuclear - Other includes Nuclear Waste Management Division, Nuclear Engineering, Nuclear Programs & Training, Executive Office, Nuclear Supply Chain (up to May 2), Nuclear Security (up to May 2), Nuclear Oversight (up to May 2), Operations & Maintenance Support (May 3 and on), Security & Emergency Services (May 3 and on), Nuclear Services (May 3 and on), and Business Transformation Project (May 3 and on).

[3] Hydro-Thermal Support includes the former Hydro Support divisions up to May 2 (i.e. Business Services & Water Resources, Dam Safety & Emergency Preparedness, Engineering, Environment, Hydroelectric Development, Supply Chain - Hydro, First Nations & Metis Relations and the Executive Office), the former Thermal Support divisions up to May 2 (i.e. Environment, Programming & Support Services, Supply Chain - Thermal, Thermal Generation Development and the Executive Office) plus the combined Hydro-Thermal Support (May 3 and on) of Engineering & Technical Services, Strategy & Business Support, Hydro-Thermal Project Execution, Dam & Public Safety and the Executive Office.

Prepared by: Performance and Program Analysis

Appendix A

2011 OPG Safety Performance Summary

Organization	Accident Severity Rate (ASR)	ASR Target	All Injury Rate (AIR)	AIR Target	Lost Time Injuries	Days Lost	Medical Treatment Injuries	OPG High MRPH Incidents	Contractor High MRPH Incidents	Total High MRPH Incidents
OPG	**1.10**	**3.12**	**0.56**	**1.13**	**8**	**120**	**53**	**16**	**6**	**22**
Nuclear Fleet Total (5)	**0.59**	**3.12**	**0.32**	**1.13**	**5**	**44**	**19**	**5**	**0**	**5**
Nuclear	**0.70**	**3.12**	**0.33**	**1.13**	**5**	**44**	**16**	**4**	**0**	**4**
Darlington	0.00	3.12	0.18	1.13	0	0	3	0	0	0
Pickering A (to the end of Sep 2011) (6)	0.64	3.12	0.39	1.13	1	5	2	1	0	1
Pickering B (to the end of Sep 2011) (6)	0.00	3.12	0.39	1.13	0	0	5	2	0	2
Pickering (Oct 2011 and on) (6)	0.00	3.12	0.13	1.13	0	0	1	0	0	0
Pickering Totals (Pick A + Pick B + Pickering) (6)	0.18	3.12	0.32	1.13	1	5	8	3	0	3
Nuclear - Other (1)	2.05	3.12	0.47	1.13	4	39	5	1	0	1
Nuclear Projects (2)	**0.00**	**3.12**	**0.27**	**1.13**	**0**	**0**	**3**	**1**	**0**	**1**
Darlington New Nuclear Project	**0.00**	**3.12**	**0.00**	**1.13**	**0**	**0**	**0**	**0**	**0**	**0**
Hydro	**0.19**	**3.12**	**1.56**	**1.54**	**1**	**2**	**15**	**5**	**2**	**7**
Central Hydro PG	0.00	3.12	0.91	1.54	0	0	1	2	0	2
Niagara PG	0.00	3.12	0.00	1.54	0	0	0	1	0	1
Northeast PG	0.00	3.12	3.31	1.54	0	0	7	0	0	0
Northwest PG	0.00	3.12	1.60	1.54	0	0	2	1	2	3
Ottawa/St. Lawrence PG	0.84	3.12	2.52	1.54	1	2	5	1	0	1
Hydro Support (3)	0.00	3.12	0.00	1.54	0	0	0	0	0	0
Thermal	**5.85**	**3.12**	**1.50**	**2.08**	**2**	**74**	**17**	**6**	**4**	**10**
Lambton GS	23.61	3.12	3.51	2.08	2	74	9	2	2	4
Lennox GS	0.00	3.12	1.19	2.08	0	0	2	1	0	1
Nanticoke GS	0.00	3.12	0.82	2.08	0	0	4	3	2	5
Northwest	0.00	3.12	1.09	2.08	0	0	2	0	0	0
Thermal Support (4)	0.00	3.12	0.00	2.08	0	0	0	0	0	0
Business Services & IT	**0.00**	**N/A**	**0.31**	**N/A**	**0**	**0**	**1**	**0**	**0**	**0**
Corporate Affairs	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Corporate Business Development	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Corporate Secretary	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Finance	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Human Resources	**0.00**	**N/A**	**0.37**	**N/A**	**0**	**0**	**1**	**0**	**0**	**0**
Law Division	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**

Information reported as of January 9, 2012. Rates are calculated per 200k hours.

(1) Nuclear - Other consists of Nuclear Engineering, Nuclear Programs & Training, Nuclear Supply Chain, Nuclear Waste Management Division, Nuclear Oversight, Nuclear Security, Executive Office and Projects Design & Equipment Reliability.

(2) Effective July 1, 2011, the SAP organizational group "Nuclear Refurbishment, Projects & Support" has been changed to "Nuclear Projects". Nuclear Projects consists of Inspection Maintenance & Commercial Services, Nuclear Refurbishment, Projects & Modifications, Commercial Services & Contracting, and Other (Executive Office, Construction Management and Secondment).

(3) Hydro Support consists of Business Services & Water Resources, Dam Safety & Emerg Preparedness, Engineering, Environment, Hydroelectric Dvlpt, Supply Chain - Hydro, Aboriginal Relations and Executive

(4) Thermal Support consists of Environment, Programming & Support Services, Supply Chain - Thermal, Thermal Generation Development and Executive Office.

(5) Nuclear Fleet Total = Nuclear + Nuclear Projects + Darlington New Nuclear Project (DNNP).

(6) Effective Oct 1, 2011, the SAP organizational divisions "Pickering A" and "Pickering B" almalgamated to form Pickering. Pickering A & B stats are to end of Sep 2011 and Pickering stats are from Oct 2011 and on. The Pickering Totals = Pickering A + Pickering B + Pickering.

Prepared by: Performance and Program Analysis

Appendix A

2010 OPG Safety Performance Summary

Organization	Accident Severity Rate (ASR)	ASR Target	All Injury Rate (AIR)	AIR Target	Lost Time Injuries	Days Lost	Medical Treatment Injuries	OPG High MRPH Incidents	Contractor High MRPH Incidents	Total High MRPH Incidents
OPG	**2.04**	**N/A**	**0.92**	**N/A**	**9**	**235**	**97**	**24**	**8**	**32**
Nuclear Fleet Total [5]	**0.19**	**4.50**	**0.70**	**1.28**	**1**	**15**	**54**	**5**	**5**	**10**
Nuclear	**0.23**	**4.50**	**0.69**	**1.28**	**1**	**15**	**44**	**5**	**2**	**7**
Darlington	0.00	4.50	0.74	1.28	0	0	13	3	1	4
Pickering A	1.27	4.50	0.76	1.28	1	15	8	0	0	0
Pickering B	0.00	4.50	0.60	1.28	0	0	10	1	0	1
Nuclear Support [1]	0.00	4.50 [1]	0.68	1.28 [1]	0	0	13	1	1	2
Nuclear Refurbish, Prjcts & Suppt [2]	**0.00**	**4.50**	**0.78**	**1.28**	**0**	**0**	**10**	**0**	**3**	**3**
Darlington New Nuclear Project	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Hydro	**2.56**	**4.50**	**1.84**	**2.50**	**3**	**25**	**15**	**11**	**1**	**12**
Central Hydro PG	0.00	4.50	2.00	2.50	0	0	2	0	1	1
Niagara PG	1.44	4.50	0.96	2.50	1	3	1	4	0	4
Northeast PG	2.51	4.50	1.51	2.50	1	5	2	1	0	1
Northwest PG	0.00	4.50	5.78	2.50	0	0	7	3	0	3
Ottawa/St. Lawrence PG	7.34	4.50	1.30	2.50	1	17	2	3	0	3
Hydro Support [3]	0.00	4.50	0.86	2.50	0	0	1	0	0	0
Thermal	**0.85**	**2.41**	**1.69**	**1.09**	**3**	**13**	**23**	**7**	**2**	**9**
Lambton GS	2.11	2.41	2.58	1.09	1	9	10	1	1	2
Lennox GS	0.58	2.41	1.73	1.09	1	1	2	1	0	1
Nanticoke GS	0.00	2.41	0.95	1.09	0	0	6	4	1	5
Northwest	1.54	2.41	2.56	1.09	1	3	4	1	0	1
Thermal Support [4]	0.00	2.41	0.89	1.09	0	0	1	0	0	0
Business Services & IT	**54.41**	**N/A**	**1.49**	**N/A**	**2**	**182**	**3**	**1**	**0**	**1**
Corporate Affairs	**0.00**	**N/A**	**0.61**	**N/A**	**0**	**0**	**1**	**0**	**0**	**0**
Corporate Business Development	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Corporate Secretary	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Finance	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**
Human Resources	**0.00**	**N/A**	**0.36**	**N/A**	**0**	**0**	**1**	**0**	**0**	**0**
Law Division	**0.00**	**N/A**	**0.00**	**N/A**	**0**	**0**	**0**	**0**	**0**	**0**

Information reported as of January 7, 2010. Rates are calculated per 200k hours. Safety targets have been included in this report where available.

[1] Nuclear Support consists of Nuclear Engineering, Nuclear Programs & Training, Nuclear Supply Chain, Nuclear Waste Management Division, Performance Improvement & Nuclear Oversight (PINO) and Other (Executive Office and Equipment Reliability). All Nuclear Support targets are as stated except ASR and AIR targets for PINO are 0.00.

[2] Nuclear Refurbishment, Projects & Support consists of Inspection Maintenance & Commercial Services, Nuclear Refurbishment, Commercial Projects & Facilities, Projects & Modifications, Unit 2/3 Safe Storage, Commercial Services & Contracting, and Other (Executive Office, Construction Management and Secondment).

[3] Hydro Support consists of Business Services & Water Resources, Dam Safety & Emerg Preparedness, Engineering, Environment, Hydroelectric Dvlpt, Supply Chain - Hydro, Aboriginal Relations and Executive

[4] Thermal Support consists of Environment, Programming & Support Services, Supply Chain - Thermal, Thermal Generation Development and Executive Office.

[5] Nuclear Fleet Total = Nuclear + Nuclear Refurbishment, Projects & Support + Darlington New Nuclear Project (DNNP).

UNDERTAKING JT1.13

Undertaking

To confirm with Goodnight Consulting whether adjustments were made to benchmarking numbers for the issue of 35-hour Versus 40-hour work weeks.

Response

Yes, OPG has confirmed with Goodnight Consulting that an adjustment was made for 35 hour work weeks vs. 40 hour work weeks for the following functions; Admin / Clerical, Budget / Finance, Human Resources, Management and Safety / Health. The adjustment can be found in the 4th column of the table labeled “Adjustment for 35 hour week” on page 29 of Ex. F5-1-1 Part b.

The CANDU adjusted 2 unit benchmarks were further adjusted by using a scaling methodology or ratio to determine a 4 unit CANDU benchmark. The “Benchmark Ratio %” found in column 7 of the same table on page 29 had an error that was previously reported in PWU Interrogatory #21. The error has been corrected by Goodnight Consulting and a revised report has been produced (Attachment 1). The revised report updates the charts and calculations for this correction, including confirmation that the variance between OPG 2013 staffing and the 2013 Benchmark is 394 FTEs instead of the 430 FTEs previously reported (page 23 of Ex. F5-1-1 Part b).

2013 Nuclear Staffing Benchmarking Update-Rev 1

An Addendum To The
2011 Nuclear Staffing Benchmarking Analysis

A Report For:

ONTARIO POWER GENERATION

April 29, 2014

GOODNIGHT CONSULTING

CLIENT CONFIDENTIAL INFORMATION

Report Agenda-
Introduction

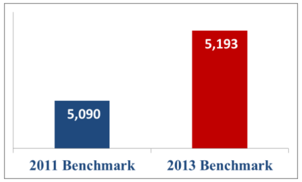
Goodnight Consulting Was Tasked To Update Key Portions Of The 2011 Benchmarking Report

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

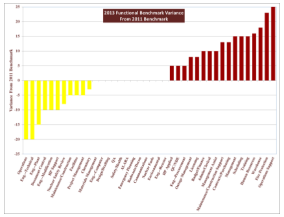
OPG Is Closer To The PWR Benchmarks In 2013 Than It Was In 2011

The 2013 PWR benchmark is 5,193-a 2% rise since the 2011 benchmark of 5,090

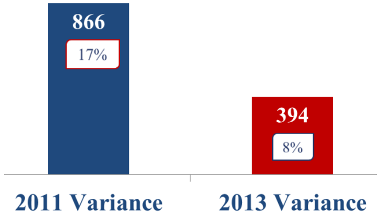
Scale starts at 5000



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



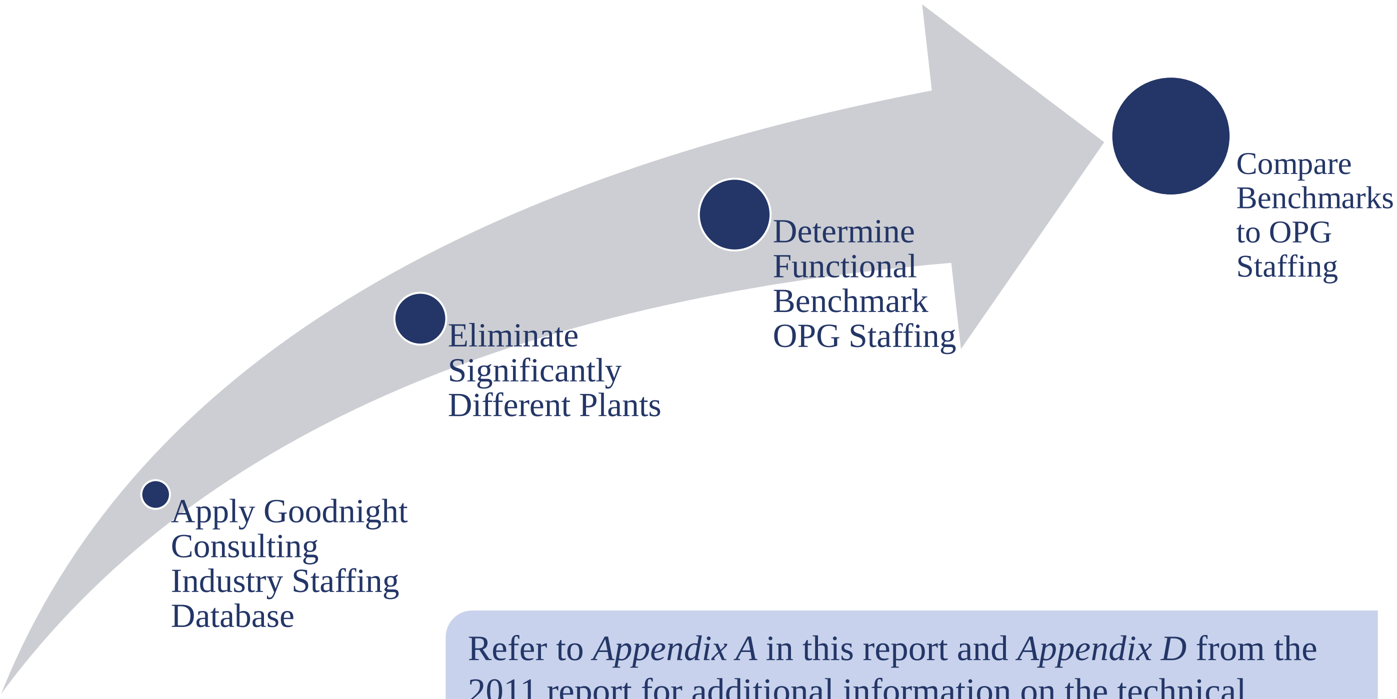
In 2011 OPG was 17% (866 FTEs) above the PWR benchmark, in 2013 OPG is 8% (394 FTEs) above the PWR benchmark



Report Agenda-
Current Nuclear Staffing Benchmarks

- 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

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 5,193

- 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 5,193

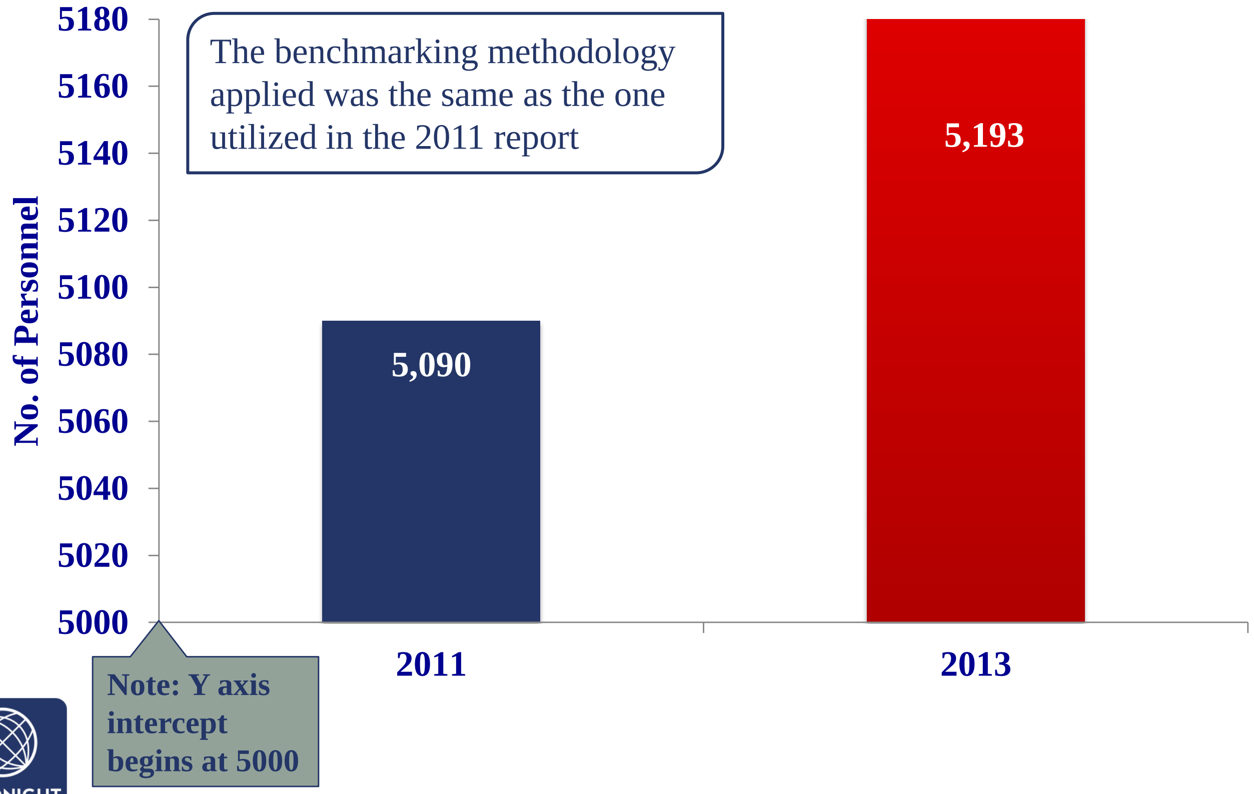
	2-Unit PWR	PA**	PB**	DN	Total
Large 2-Unit US PWR benchmarks	987 *(965)**				
Adjust for 2-Unit CANDU	83 *(82)**				
Preliminary 2-Unit CANDU benchmark	1,070 *(1,047)**	1,070 *(1,047)**	1,070 *(1,047)**	1,070 *(1,047)**	
Adjust for 35 Hour Work Week		58 *(58)**	58 *(58)**	58 *(58)**	
Adjust for PA Units 2 & 3		17 *(17)**			
Adjust for Scaling from 2 to 4 Units			896 *(879)**	896 *(879)**	
		1,145 *(1,122)**	2,024 *(1,984)**	2,024 *(1,984)**	5,193 *(5,090)**

**2011 Number*

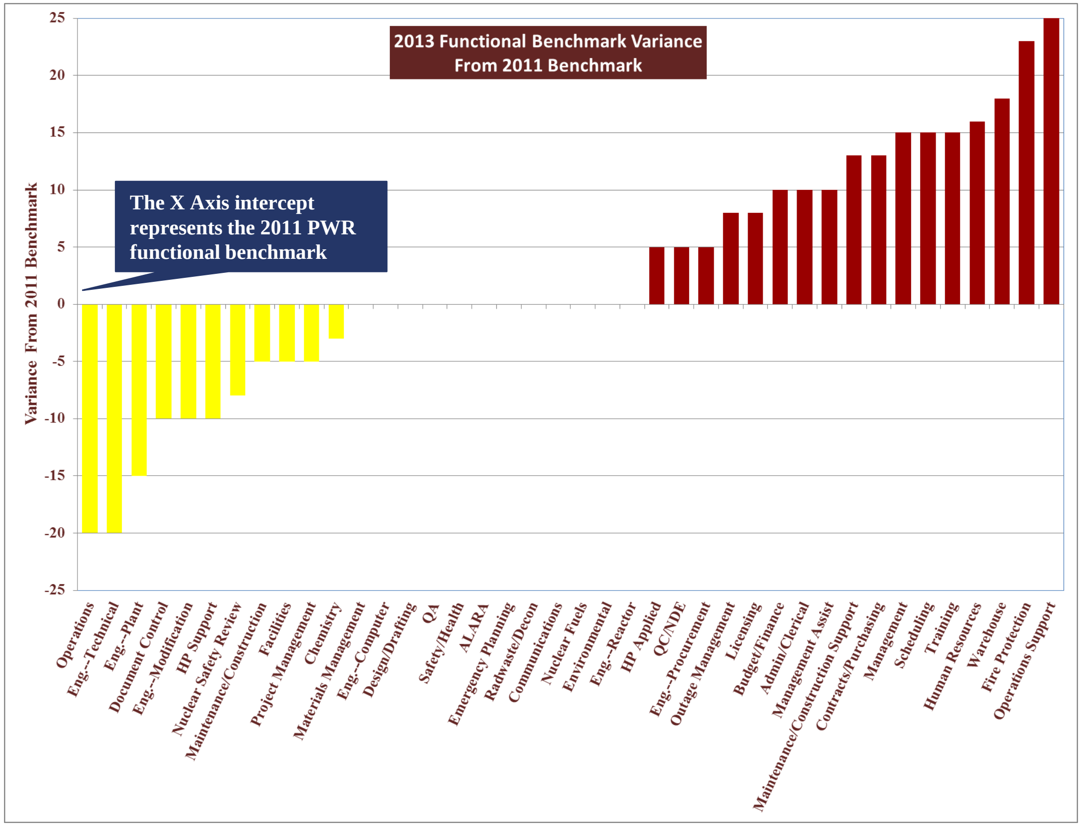
**We did not analyze the impacts of the amalgamation of Pickering A & Pickering B as it was outside the scope of this study-we estimate it would slightly decrease the need for senior management and admin/clerical personnel by ~10 FTEs

Report Agenda-
Comparison of Current & Previous Benchmarks

The 2013 OPG *Staffing Benchmark* Has Increased By 103 FTEs (2%) Since 2011



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



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Report Agenda-
Analysis of Change in Benchmarks

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

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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**

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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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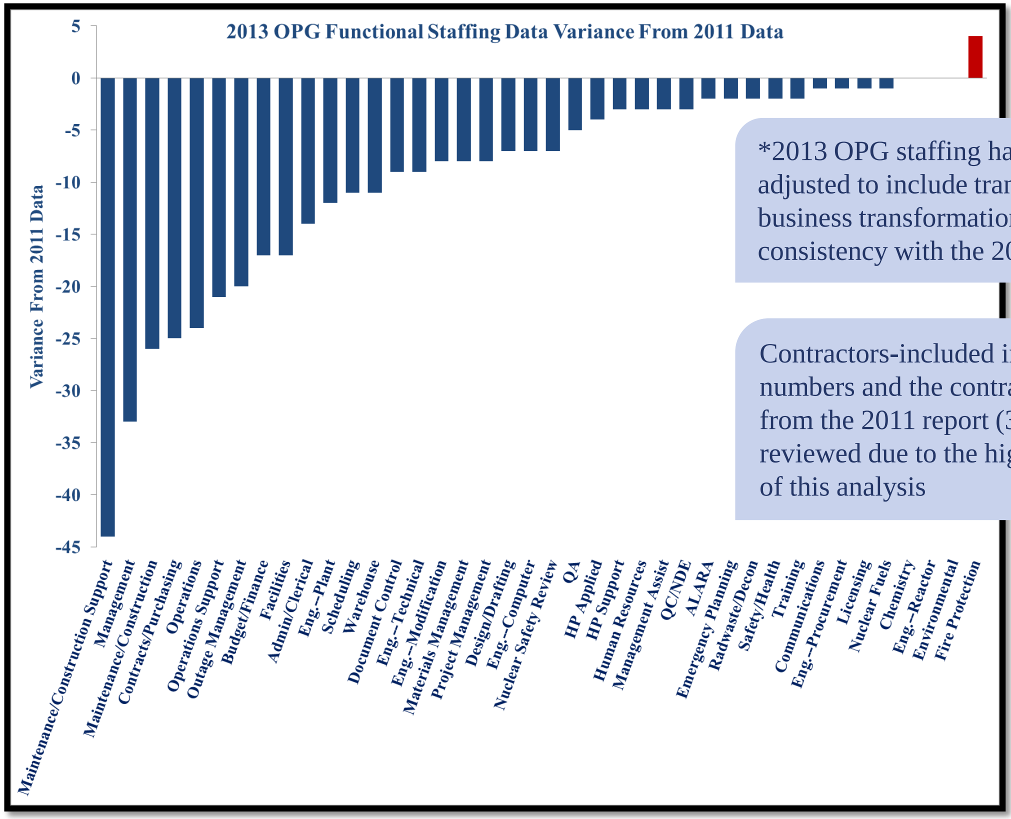
Report Agenda-
Comparison of Current Benchmarks to OPG

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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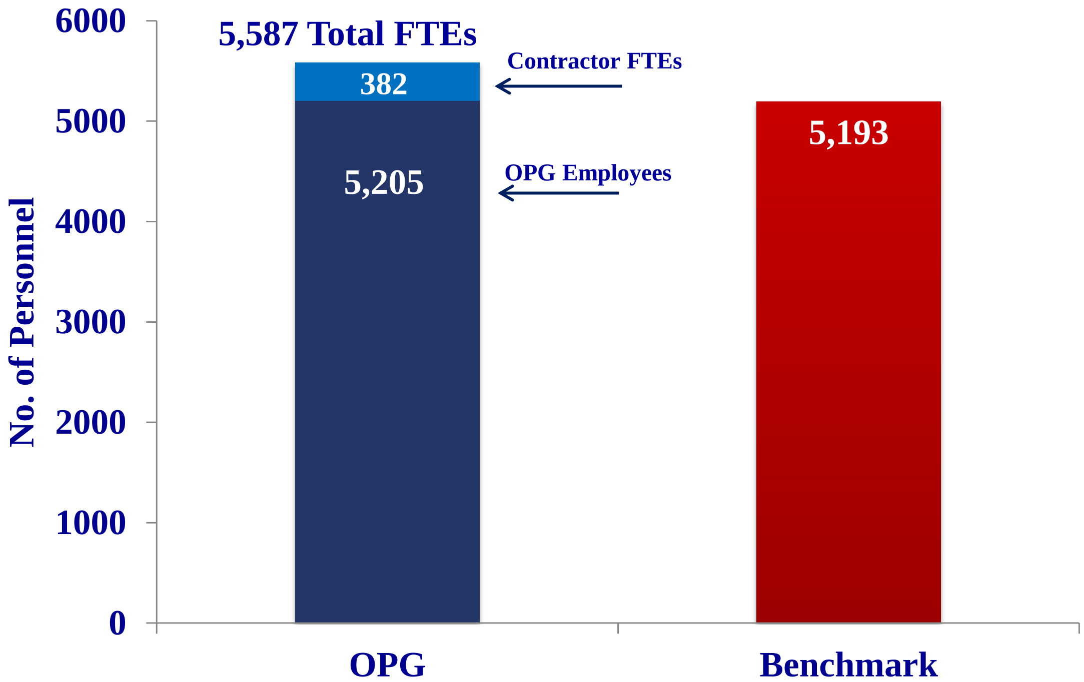
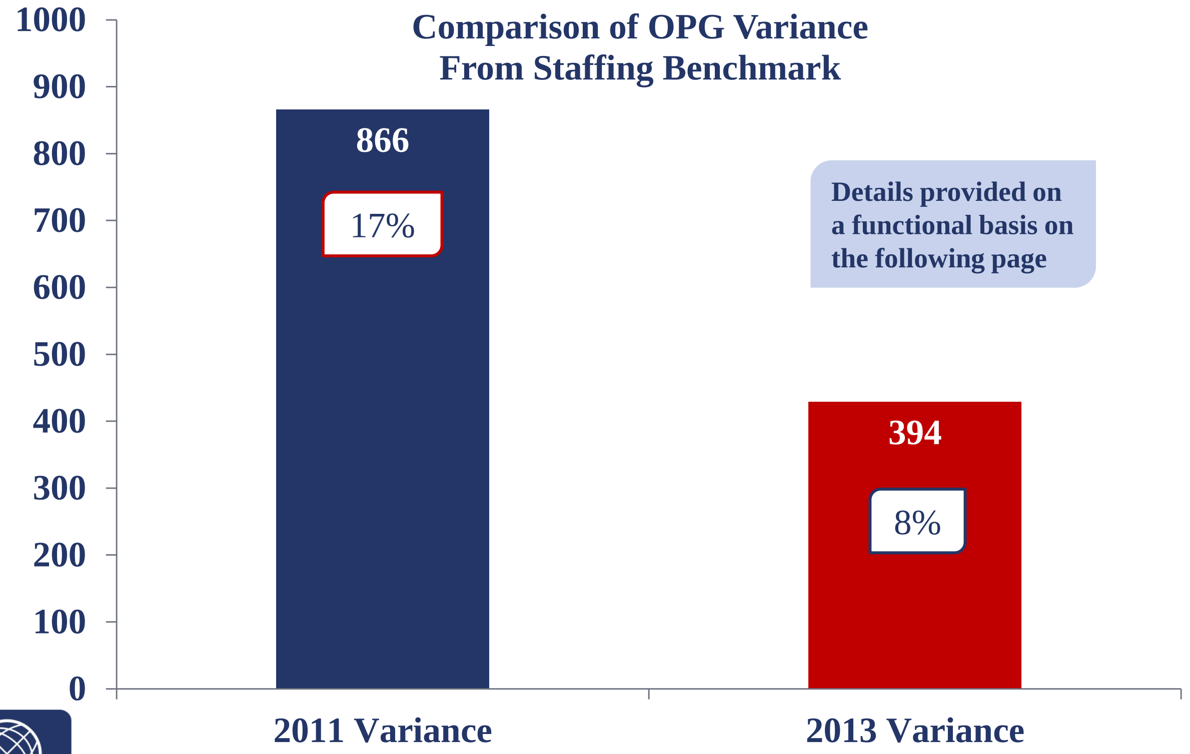
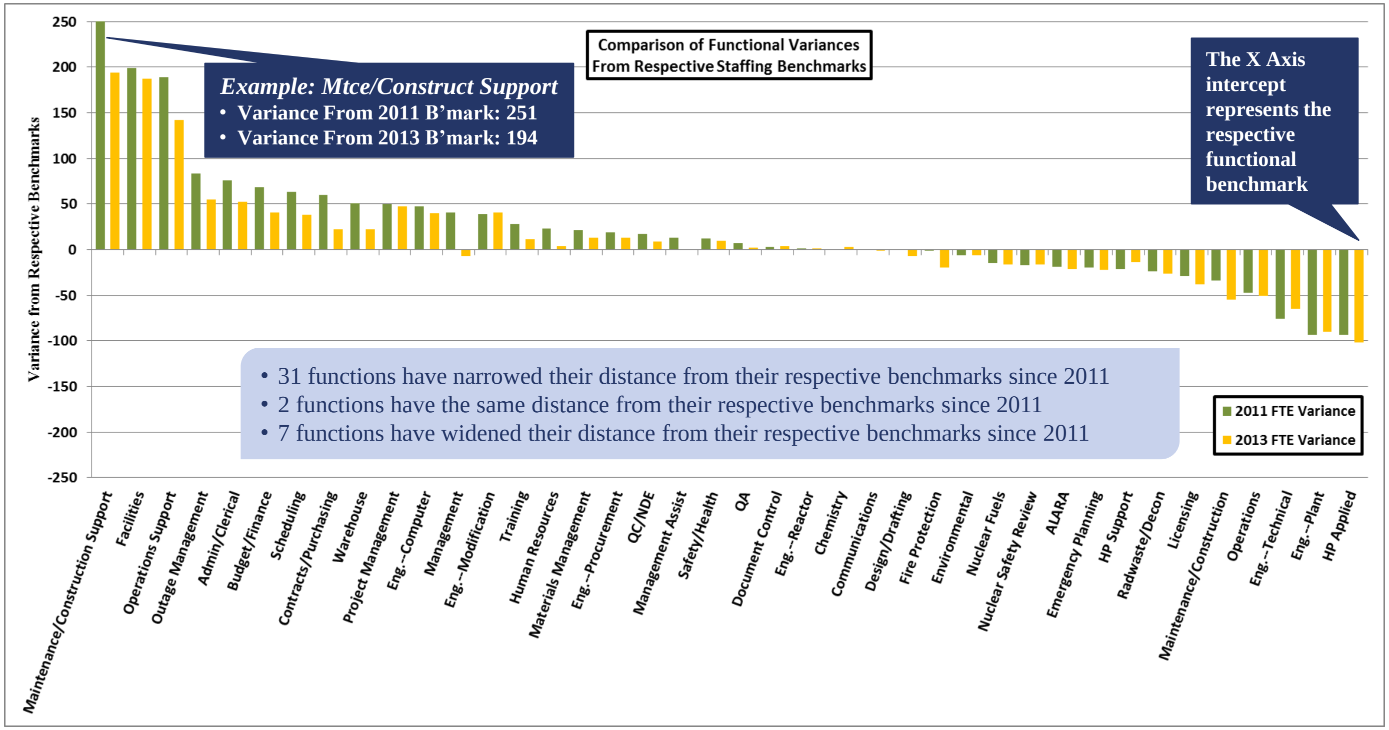
The Variance Between OPG 2013 Staffing & 2013 Benchmark Is 394 FTEs (8%)



The Gap Between OPG & The Benchmark Is 472 FTEs Smaller In 2013 Than It Was In 2011



OPG's Variance From The Applicable Benchmark Has Narrowed In 31 Functions Since 2011



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Report Agenda-
Comparison of Current Benchmarks to OPG

- 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

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 2,024 (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		3.95%	72	72
ALARA	8		8	1.8	14			14
Budget/Finance	14	1	16	Ratio		1.32%	24	24
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		0.71%	13	13
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		4.05%	74	74
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**		**192**	**2024**

- 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 58 FTEs (5%)
- 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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UNDERTAKING JT1.15

Undertaking

To file PSA summary document once available.

Response

Please see Attachment 1 and 2.

ONTARIOPOWER GENERATION Report

OPG Proprietary	
Document Number: NA44-REP-03611-00036	Usage Classification: N/A
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Title:
PICKERING A RISK ASSESSMENT SUMMARY REPORT

Pickering A Risk Assessment Summary Report

NA44-REP-03611-00036-R000

2014-04-25

Other Reference Number:
K-410077-REPT-0001, Rev. 02

OPG Proprietary

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Pickering NGS
OPG

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Revision Summary

Revision Number	Date	Comments
R000	April 2014	Initial issue.

Executive Summary

The objective of the Pickering NGS A Probabilistic Safety Assessment (PSA) was to provide a comprehensive and integrated assessment of the safety of the station as currently designed and operated. The Pickering NGS A PSA was prepared to meet the intent of OPG nuclear program N-PROG-RA-0016 *Risk and Reliability Program* and to comply with Canadian Nuclear Safety Commission Regulatory Standard S-294 *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants*.

The Pickering NGS A PSA identified the sequences that lead to severe core damage and large releases of radioactive material to the environment, estimated the frequency of these sequences, and identified the major contributors to severe core damage and large releases.

The Pickering NGS A PSA analyzed in detail five hazards:

1. Internal events, e.g. Loss of Coolant Accident or Main Steam Line Break.
2. Internal fires.
3. Internal floods.
4. Seismic events.
5. High winds.

The assessment for each of the above hazards addressed both high power operation and shutdown operation.

Other hazards affecting the reactor were addressed through screening or other deterministic hazard studies.

The Pickering NGS A PSA was limited to hazards affecting the reactors. Accidents affecting other sources of radioactivity such as the Irradiated Fuel Bay were outside of the scope of the Pickering NGS A PSA.

The Pickering NGS A PSA was prepared following a quality assurance plan consistent with Canadian Standards Association standard CSA N286.2-00 *Design Quality Assurance for Nuclear Power Plants*. The PSA was prepared using computer programs that were consistent with Canadian Standards Association standard CSA N286.7-99 *Quality Assurance of Analytical, Scientific and Design Computer Programs for Nuclear Power Plants.*

The Pickering NGS A PSA was prepared following methodologies consistent with the current state of practice. All methodologies used in the preparation of the Pickering NGS A PSA were accepted by the Canadian Nuclear Safety Commission.

The following table presents the Severe Core Damage Frequency (SCDF) and the Large Release Frequency (LRF) for each of the analyzed hazards. The table also lists OPG's risk based safety goals. The intent of these goals is to ensure that the radiological risk arising from nuclear accidents associated with the operation of OPG's nuclear power reactors is low in comparison to risks to which the public is normally exposed.

The SCDF and LRF for each hazard are less than OPG's safety goal limit.

Results of the Pickering NGS A PSA

PSA Element	SCDF (x 10^{-5} per r-year)	LRF (x 10^{-5} per r-year)
Internal Events At-Power	1.63	0.47
Internal Events Shutdown	0.66	< 0.1
Internal Fires At-Power	4.73	0.84
Internal Fires Shutdown	(Note 1)	(Note 1)
Internal Floods At-Power	1.02	0.20
Internal Floods Shutdown	(Note 1)	(Note 1)
Seismic Events At-Power	0.26	0.26
Seismic Events Shutdown	(Note 1)	(Note 1)
High Wind At-Power	2.69	0.80
High Wind Shutdown	(Note 1)	(Note 1)
OPG's Safety Goal Limit	10	1

Notes:

1. The risk for a shutdown unit was shown to be bounded by the risk for an at-power unit. These results conservatively assume that all units are continuously at-power.

1.0 INTRODUCTION

The objective of a Probabilistic Safety Assessment (PSA) is to provide a comprehensive and integrated assessment of the safety of a nuclear generating station. OPG prepares PSAs for each of its nuclear generating stations to meet the intent of corporate governance [R1] and to comply with Canadian Nuclear Safety Commission (CNSC) Regulatory Standard S-294 *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants* [R2].

The Pickering NGS A PSA identified the sequences that lead to severe core damage and large releases of radioactive material to the environment, estimated the frequency of these sequences, and identified the major contributors to Severe Core Damage Frequency (SCDF) and Large Release Frequency (LRF).

Table 1 lists OPG's risk based safety goals. The intent of these goals is to ensure that the radiological risk arising from nuclear accidents associated with the operation of OPG's nuclear power reactors is low in comparison to risks to which the public is normally exposed.

The Pickering NGS A PSA analyzed in detail five hazards:

1. Internal events, e.g. Loss of Coolant Accident or Main Steam Line Break.
2. Internal fires.
3. Internal floods.
4. Seismic events.
5. High winds.

The assessment for each of the above hazards addressed both high power operation and shutdown operation.

The Pickering NGS A PSA was prepared following a quality assurance plan consistent with Canadian Standards Association standard CSA N286.2-00 *Design Quality Assurance for Nuclear Power Plants* [R3]. The PSA was prepared using computer programs that were consistent with Canadian Standards Association standard CSA N286.7-99 *Quality Assurance of Analytical, Scientific and Design Computer Programs for Nuclear Power Plants* [R16].

The PSA was prepared following methodologies consistent with the current state of practice. All methodologies used in the preparation of the Pickering NGS A PSA were accepted by the CNSC.

A PSA is intended to be a realistic model of the plant; however, if realistic analysis was not available to support PSA modelling and assumptions, conservative analysis was used instead. If the conservative analysis significantly over-estimated risk, new supporting analysis was performed and the PSA model was revised.

1.1 Objectives

The principal objectives of the Pickering NGS A PSA were:

1. To provide a comprehensive and integrated assessment of the safety of the plant as currently designed and operated. This included the estimation of risk metrics and the identification of the key contributors to risk.

2. To prepare a risk model in a form that can be used to assist in safety-related decision making.

1.2 Scope

The Pickering NGS A PSA is referred to as the PARA. The elements of the PARA are as follows:

1. A Level 1 at-power PSA for internal events. This PSA studies the likelihood of severe core damage resulting from events occurring within the station while the reactor is at full power. This report is referred to as PARA-L1P.

2. A Level 2 at-power PSA for internal events. This PSA studies the likelihood of a large airborne release of radioactive material to the environment resulting from events occurring within the station while the reactor is at full power. This report is referred to as PARA-L2P.

3. A Level 1 outage PSA for internal events. This PSA studies the likelihood of severe core damage resulting from events occurring within the station while the reactor is in the Guaranteed Shutdown State (GSS). This report is referred to as PARA-L1O.

4. A limited assessment of the likelihood of a large release of radioactive material to the environment resulting from events occurring within the station while the reactor is in the GSS.

5. A PSA-Based Seismic Margin Assessment. This PSA studies ability of the plant to accommodate an earthquake with a return period of 10,000 years and provides order of magnitude estimates of SCDF and LRF while the reactor is at full power. This report is referred to as PARA-SEISMIC.

6. A PSA for internal fires. This PSA studies the likelihood of severe core damage and a large airborne release of radioactive material to the environment resulting from fires originating within the station while the reactor is at full power. This report is referred to as PARA-FIRE.

7. A PSA for internal floods. This PSA studies the likelihood of severe core damage resulting from floods originating within the station while the reactor is at full power. This report is referred to as PARA-FLOOD.

8. A limited assessment of the likelihood a large airborne release of radioactive material to the environment resulting from floods originating within the station while the reactor is at full power.

9. A PSA for high winds. This PSA studies the likelihood of severe core damage and a large airborne release of radioactive material to the environment resulting from high winds while the reactor is operating at full power. This report is referred to as PARA-WIND.

10. Bounding assessments of the likelihood severe core damage and a large airborne release of radioactive material to the environment resulting from:

    - seismic events;
    - internal fires;
    - internal floods; and
    - high winds

    while the reactor is in the GSS.

The Pickering NGS A PSA does not cover the following potential sources of risk:

- Fuelling machine accidents while the fuelling machine is in transit between the reactor face and the Irradiated Fuel Bay (IFB). Analysis demonstrated that fuelling machine accidents while in transit cannot result in a large airborne release of radioactive material to the environment.
- Hazards from chemical materials used and stored at the plant.
- Other external initiating events such as external floods, airplane crashes, train derailment, etc.
- Other internal initiating events such as turbine missiles.

These types of hazards were addressed separately through screening studies or deterministic hazard studies.

The Pickering NGS A PSA was limited to hazards affecting the reactors. Accidents affecting other sources of radioactivity such as the IFB were outside of the scope of the Pickering NGS A PSA.

The response of the two Pickering NGS A units to various initiating events is essentially identical. Therefore, it was generally only necessary to model a single unit, with this unit considered representative of the other unit. Unit 4 was selected as the reference unit. Design differences between units were not analyzed in detail as they were not expected to be significant in terms of risk.

1.3 Organization of Summary Report

In addition to the general information presented in this introductory section, this Summary Report provides:

(a) A short description of the Pickering NGS A station and units (Section 2.0).

(b) An overview of risk assessment methods (Section 3.0) and discussions of the methods used for Level 1 PSA (Section 4.0) and Level 2 PSA (Section 5.0).

(c) A discussion of the main results of the PARA (Section 6.0).

Appendix A contains a list of the abbreviations and acronyms used in this report.

2.0 PLANT DESCRIPTION

The following sections provide a short description of the Pickering site and plant.

2.1 Site Arrangement

Pickering NGS A comprises four CANDU nuclear reactors, four turbine generators and their associated equipment, services and facilities. Currently Units 1 and 4 are operating and Units 2 and 3 are in safe storage. The arrangement of the eight-unit Pickering site is shown in Figure 1.

The design net electrical output of each unit is 515 MWe at a 90 percent power factor, yielding a total station net output of 1030 MWe. Power is produced at 24 kV and delivered at 230 kV and 60 Hz to the Southern Ontario grid. The station is designed for base-load operation.

Each unit comprises a power source capable of operating independently of the other units with reliance on certain common services. The power generating equipment of each unit is a conventional steam-driven turbine generator. The associated heat source is a heavy water moderated, pressurized heavy water cooled, natural uranium dioxide fuelled, horizontal pressure tube reactor. This type of nuclear steam supply is used in all nuclear power stations built in the province of Ontario.

2.2 Buildings and Structures

The principal structures at the Pickering A site are as follows:

(a) Four reactor buildings.
(b) A reactor auxiliary bay.
(c) A powerhouse, including the turbine hall and turbine auxiliary bay.
(d) A Vacuum Building, together with associated Pressure Relief Duct (PRD) and Pressure Relief Valves (PRV).
(e) A service wing.
(f) An administration building.
(g) An auxiliary irradiated fuel bay.
(h) A heavy water upgrading building.
(i) A screenhouse.
(j) A water treatment building
(k) Six standby generator enclosures.
(l) An auxiliary power supply building.
(m) A High Pressure Emergency Coolant Injection (HPECI) pumphouse.
(n) An HPECI water storage tank.
(o) Two buildings housing unitized instrument rooms for Shutdown System Enhancement (SDSE).

The administration and service buildings, the heavy water upgrading building, the vacuum building, the HPECI structures and the auxiliary power supply building serve the entire eight-unit station.

The containment boundary is formed by the reactor buildings, the PRD, the vacuum ducts and the vacuum building. Each reactor building is a reinforced concrete structure with cylindrical walls and an elliptical dome. The vacuum building is also a reinforced-concrete structure with a cylindrical wall and a flat roof. A tank in the top of the vacuum building contains water for the dousing system. A reinforced concrete ring around the vacuum building, outside the perimeter wall near the base, provides additional pressure retaining capability. The PRD, also a reinforced concrete structure, is rectangular in section and is linked to the vacuum building by steel vacuum ducts 1.8 m in diameter.

The reactor auxiliary bay runs the full length of the station, joining at its eastern end, the 'B' station reactor auxiliary bay. It is a conventional four-story steel frame building fitted around the northern halves of the four reactor buildings. It houses some reactor auxiliary systems, the Main Control Room (MCR) and the IFB.

The service wing extension is located at the eastern end of the Pickering A station, i.e., in the center of the eight units, and provides additional space for waste management, laboratories, stores, locker and change facilities, maintenance shops, fuelling machine dismantling facilities and offices.

2.3 Reactor

The reactor consists of a horizontal cylindrical structure, the calandria, filled with heavy water. The calandria is penetrated by 390 horizontal fuel channel assemblies, and reactivity monitroing and control units. Below the calandria is a large cylindrical tank, the dump tank, connected to the calandria by four goose neck pipes. These pipes provide for rapid draining of the heavy water from the calandria to the dump tank.

The calandria and dump tank are housed in an air-filled, concrete vault, the calandria vault. The ends of the calandria assembly, the end shields, are located in the walls of the calandria vault and form part of the calandria vault enclosure. The end shields and shield plugs in the fuel channels provide sufficient shielding against radiation to allow personnel to access the fuelling machine vault when the reactor is shutdown.

An arrangement of embedded pipes carrying natural water provides cooling for the calandria vault concrete.

A typical Pickering NGS A reactor assembly is illustrated in Figure 2.

2.4 Fuel and Fuel Handling

The fuel is in the form of compressed and sintered natural uranium dioxide pellets, sheathed and sealed in Zircaloy-4 tubes. Twenty-eight tubes are assembled between two end plates to form one fuel bundle. Each of the reactor's 390 fuel channels contains 12 fuel bundles.

The reactors are fuelled on-power. Each reactor is serviced by two remotely controlled fuelling machines, one at each reactor face, which operate at opposite sides of the same fuel channel.

Irradiated fuel is transferred from the fuelling machines to the IFB. The irradiated fuel remains in the IFB, or an auxiliary IFB, until it can be transferred to dry storage containers in the Pickering Waste Management Facility.

2.5 Reactivity Control Mechanisms and Systems

In-core neutron flux detectors and ion chambers are used to measure neutron flux in specific areas of the reactor. Signals from these detectors are supplied to the Reactor Regulating System (RRS) and the Shutdown System (SDS).

Fast shutdown of the reactor following a plant upset is accomplished by the SDS. The SDS releases stainless steel clad cadmium shutoff rods into the reactor core. To augment shutdown, the heavy water moderator in the calandria can be dumped into the dump tank.

A liquid zone control system is used for reactivity control and consists of vertical tubes containing natural water. Varying the level of the water in each tube changes the local neutron absoption, thereby controlling local neutron flux. Varying the water level in all of the tubes provides control of overall reactor power.

2.6 Heat Transport System

The Heat Transport System (HTS) consists of two identical loops, linked by two interconnect valves, one of which is open during full power operation. Each loop consists of fuel channels filled with natural uranium fuel bundles surrounded by pressurized heavy water, boilers, circulation pumps, valves and associated piping. The coolant in the fuel channels removes the heat generated by the fuel. During normal operation the heat from the fuel is generated by nuclear fission, following shutdown heat from the fuel is generated by fission product decay. During normal operation, the HTS main circulating pumps transport the heat to the boilers.

The HTS interfaces with a number of systems, e.g.:

- the Shutdown Cooling System (SDCS), which removes decay heat when the reactor is shutdown;
- the feed and bleed system, which provides pressure and inventory control for the coolant;
- the D_2O recovery system, which recovers lost heavy water from leaks; and
- the Emergency Coolant Injection System (ECIS), which adds light water following a loss of coolant accident beyond the capacity of the D_2O recovery system.

2.7 Moderator System

During normal plant operation the moderator system is used to slow the neutrons produced by the reactor in order to maintain a critical fission reaction. During normal operation a small fraction of the heat produced by the fuel is transferred to the moderator. The moderator system includes pumps and heat exchangers to remove this heat.

After an accident, the calandria sprays can be used as an additional heat sink to remove decay heat from the reactor.

2.8 Feedwater and Condensate System

The main role of the HTS is to transport the heat generated in the fuel channels to the boilers. The role of the boilers is to transfer this heat and boil the light water on the secondary side of the boilers. The steam generated in the boilers is then used to spin the turbine generator to convert the thermal energy to electrical power. During this process, the boiling water condenses. The condensate is returned to the feedwater system and eventually returned to the boilers to continue the process.

2.9 Main Steam System

Steam is produced in 12 boilers and fed into four separate steam mains which pass through the reactor building wall to the turbine building where they connect to the turbine steam chest. Over-pressure protection is provided by the steam relief system.

2.10 Steam Relief System

Overpressure protection of the main steam system is provided by 16 safety valves, four on each steam main. The safety valves have staggered setpoints between 5.38 and 5.54 MPa(g).

Eight steam reject valves, six large valves and two small valves, are provided to permit a poison prevent capability. The large steam reject valves also provide the capability to rapidly depressurize the boilers and the HTS in an emergency.

2.11 Boiler Emergency Cooling System

The Boiler Emergency Cooling System (BECS) is designed to provide a short term supply of cooling water to the boilers in the event of a total loss of feedwater. This system is designed to be used until an alternative heat sink can be placed in service.

2.12 Emergency Boiler Water Supply System

The Emergency Boiler Water Supply System (EBWS) supplies emergency make-up to the Pickering NGS A boilers from the Pickering NGS B High Pressure Service Water System (HPSW). The piping system runs from the Pickering B HPSW through the basement of the turbine auxiliary bay to the Pickering A units. The piping contains manual valves and motorized valves. The motorized valves are supplied from the Class III power system, with a backup from the Site Electrical System via the interunit transfer busses. The motorized valves may also be opened manually.

The Pickering NGS A PSA includes models for the Pickering NGS B systems that are required to support the Pickering NGS B HPSW.

2.13 Powerhouse Emergency Venting System

The powerhouse emergency venting system is used to mitigate harsh environments caused by high temperature or high humidity in the powerhouse due to steamline or feedline breaks.

2.14 Special Safety Systems

Three special safety systems are incorporated into the plant design to limit radioactive releases to the public following an abnormal event:

(a) Shutdown System (SDS).

(b) Emergency Coolant Injection System (ECIS).

(c) Negative Pressure Containment System (NPCS).

2.14.1 Shutdown System

The function of the SDS is to shut down the reactor when any one of the trip parameters in either SDSA or SDSE exceeds it setpoint. SDSA and SDSE each have channelized instrumentation to monitor their trip parameters and channelized logic to activate the shutdown mechanisms. SDSA monitors 10 parameters and SDSE monitors 4 parameters.

The shutdown mechanisms are:

- The shutoff rod system.

  Each reactor has 23 shutoff rods normally suspended above the reactor. When a trip signal is received, an electromagnetic clutch on each shutoff rod is de-energized and the shutoff rod falls into the core.

- Moderator dump.

  A moderator dump system is provided to augment the shutoff rods. A dump signal causes large valves between the calandria and the dump tank to open, equalizing the pressure between the two tanks, allowing the heavy water moderator in the calandria to rapidly drain to the dump tank.

2.14.2 Emergency Coolant Injection System

The ECIS provides cooling water to the HTS following a loss of coolant accident. The Pickering NGS A ECIS includes an initial high pressure injection from the HPECI system, shared with Pickering NGS B, and a low pressure recovery injection.

2.14.3 Negative Pressure Containment System

The NPCS provides a physical barrier designed to limit the release of radioactive material to the environment which might result from a process or system failure. The containment system is a reinforced concrete envelope around the nuclear components of the reactor cooling system, with provisions for controlling and maintaining a negative pressure within the envelope before and after accidents.

The NPCS includes a number of sub-systems required for providing normal and post-accident functions such as reactor building cooling, pressure suppression, control of hydrogen, and air discharge filtration.

2.15 Support Systems

Support systems are considered in the risk assessment as they provide common services to the systems described above. Failure of the support systems can result in failure of the mitigating systems credited to remove heat after an initiating event.

2.15.1 Electrical Power Systems

The electrical systems at Pickering A are organized into four classes:

1. Class IV power is the normal alternating current supply to service unit loads.

2. Class III power is the alternating current supply for safety related equipment and auxiliaries.

3. Class II power is primarily used to supply control and monitoring systems, instrumentation, and protection systems.

4. Class I power is a continuous direct current supply primarily used to supply motive power to electrical breakers.

Class II and Class I both have battery backup supplies.

Standby power supplies to the unit loads are provided by three distinct systems:

1. The Site Electrical System. This standby power source is comprised of two permanently energized busses to which all eight units at the Pickering site have access.

2. The Standby Generators. This power source is comprised of six independent gas turbine driven generators. The standby power is available to only the portion of the service loads required to support safe shutdown of a unit.

3. The Auxiliary Power System. This system is comprised of two 100% redundant combustion turbine units that can supply Class 4 power to the station through the Site Electrical System. The APS supply is independent of the Bulk Electrical System and the normal station Class IV power supply.

2.15.2 Service Water Systems

The service water systems provide cooling water for various loads. The service water systems for Pickering NGS A consist of:

(a) High and Low Pressure Service Water System.

The service water system provides cooling water from Lake Ontario for various loads. Service water is drawn from Lake Ontario through an open canal bounded by two rock filled groynes extending into the lake. The water is drawn from the canal to an open forebay, then through a common screen house into an enclosed concrete duct or intake channel. The service water system is divided into two sub-systems referred to as low pressure service water and high pressure service water. The low pressure service water pumps, powered from the Class IV electrical system, draw water from the intake channel. The high pressure service water pumps, also powered from the Class IV electrical system, draw water from the discharge of the low pressure service water pumps, and provide a pressure boost to deliver service water to higher elevations in the plant. Service water is used once and returned to the lake.

In the event of a failure of the Class IV electrical power system, service water is provided to key safety related loads by the emergency low pressure service water system and the emergency high pressure service water system. These systems are powered from the Class III electrical system and draw water directly from the intake channel.

(b) Recirculated Cooling Water System (RCWS).

The RCWS provides clean, demineralized cooling water to equipment that might become contaminated or plugged if supplied by lake water. The RCWS recirculates water via a set of pumps and cools the water via a set of heat exchangers. The low pressure service water system is used on the secondary side of the RCWS heat exchangers for cooling purposes.

2.15.3 Instrument Air Systems

The instrument air supply is a support system providing compressed air. This compressed air is used for various plant activities including operating valves, starting motors, and inflating airlock seals. The instrument air systems are comprised of the high pressure instrument air system, the low pressure instrument air system and the backup instrument air system.

The backup instrument air system is designed to provide instrument air to key safety related loads following failure of the high and low pressure systems. Its source is a central bottle station, consisting of compressed air cylinders, and piping to critical equipment in the reactor auxiliary bay and the pressure relief duct.

2.15.4 Powerhouse Heating and Ventilation Systems

The cooling and ventilation system provides heating and cooling to the station buildings. Failure of the cooling and ventilation in these rooms may result in equipment failures in the support or mitigating systems.

2.16 Emergency Mitigating Equipment

The EME is stored in a light frame structure located north of the Brock Road security building. The EME building is not seismically robust; however, collapse of the building is not expected to damage the EME. The EME building is not robust with respect to wind damage; however, the EME itself will be tied down to prevent wind induced topling or sliding. Provision has been made to clear the damaged structure following an earthquake or wind storm, and allow access to the EME.

Following an Initiating Event (IE), the EME is deployed to pre-determined locations in the plant and connected to the designated tie-in points. Deployment of the EME is initiated by the Shift Manager in the Main Control Room and follows pre-approved procedures. EME deployment is routinely drilled.

Provision has been made to clear debris from the path between the EME building and the plant following an external event.

The EME is comprised of:

- Two portable uninteruptable power supplies per unit to provide short-term power to the instrumentation necessary to monitor key plant parameters.

- One diesel generator per unit to provide long-term power to the instrumentation necessary to monitor key plant parameters.

- One self powered pump for each unit that can be deployed either in the Reactor Auxiliary Bay or the Turbine Auxiliary Bay. The pump draws lake water through hose routed from the suction channel of the Condenser Cooling Water pumps, and can provide make-up to the secondary side of the boilers, to the Heat Transport System (HTS) and to the calandria.

The EME is currently included in only two Pickering PSAs: PARA-FIRE and PARA-WIND.

3.0 OVERVIEW OF PSA METHODS

Risk is defined as the product of the frequency of a hazardous event and the consequences of the event. Risk is expressed in units of consequence per unit time.

Risk = Frequency x Consequences

Risk provides a means of quantifying the degree of safety associated with a potentially hazardous activity and provides a common basis for comparing the relative safety of different activities. One of the principles of risk assessment is that the larger the numerical value of risk for a particular event, the more important the event is to safety. Thus, measures taken to reduce risk improve the level of safety.

OPG uses PSA to quantify the risk associated with accidents at its nuclear generating stations. For a nuclear generating station, the events studied are those leading to fuel damage in the reactor core or airborne releases of radioisotopes into the environment.

OPG used a two level approach to assess risk in the Pickering NGS A PSA:

- A Level 1 PSA to assess the frequency of severe core damage. Events resulting in severe core damage release radioactive material from the fuel into containment.
- A Level 2 PSA to assess the frequency and magnitude of airborne releases of radioactive material from containment to the environment.

OPG has defined two risk parameters based upon the PSA approach: Severe Core Damage Frequency (SCDF) and Large Release Frequency (LRF). These parameters are estimated in the Level 1 PSA and the Level 2 PSA, respectively.

OPG has defined safety goals for both SCDF and LRF, these are shown in Table 1. The intent of these goals is to ensure that the radiological risks arising from nuclear accidents at OPG's nuclear power reactors is low in comparison to risks to which the public is normally exposed.

For Pickering NGS-A, detailed Level 1 PSAs were prepared for:

- Internal events while both reactors are at full power.
- Internal events while one reactor is in the GSS.
- Seismic events while both reactors are at full power.
- Internal fires while both reactors are at full power.
- Internal floods while both reactors are at full power.
- High winds while both reactors are at full power.

The methodologies for the detailed Level 1 PSAs are summarised in Section 4 of this report.

For Pickering NGS A, a detailed Level 2 PSA was prepared for internal events while both reactors are at full power. This study also analyzed events involving both Pickering NGS A and Pickering NGS B. The methodology for the detailed Level 2 PSA is summarised in Section 5 of this report.

Limited Level 2 PSAs were prepared for internal events while one reactor is in the GSS, and internal fires, internal floods, seismic events and high winds while both reactors are at full power. The methodologies for these limited assessments are summarised in Sections 5.7 to 5.11 of this report.

For Pickering NGS-A, bounding assessments were prepared for seismic events, internal fires, internal floods and high winds while one reactor is in the GSS. The rationale for these bounding assessments is described below.

3.1 Bounding Assessments for Shutdown Units

OPG did not prepare detailed PSAs for internal floods, internal fires, seismic events and high winds while one Pickering NGS A unit was shutdown. The rationale for this approach is based upon five high level premises:

1. The level of detail in a PSA should reflect the level of risk.

2. The risk from each of these hazards while a unit is shutdown is low and bounded by the risk from the equivalent hazard for a high power unit. The key factors supporting this assertion are that:

    - An event and failure to remain shutdown is not a significant contributor to risk. This results from the provision of two reliable lines of defence to prevent criticality: the shutdown guarantee and the shutdown system.

    - Given the above, the risk from these hazards is dominated by sequences involving the failure of all heat sinks.

      Initial reactor power is *at least* two orders of magnitude less for a shutdown unit than for a high power unit. Therefore, fuel temperatures will be lower, accident progression will be slower, and the amount of energy deposited into containment will be lower for a shutdown unit.

      Analysis demonstrated that:

      - For single unit sequences, only those sequences in which Early Calandria Vessel Failure (ECVF) occurs progress from severe core damage to a large release. Only 13% of the sequences that progress to severe core damage will progress to a large release as a result of ECVF.

- Single and two-unit sequences only progress to a large release if the transient is initiated in the earliest part of an outage.

- The operation of key containment systems is unaffected if a single unit is shutdown.

3. Accident progression for a shutdown unit is well understood from the analysis prepared in support of the limited Level 2 PSA for internal events while the reactor is in the GSS. Therefore, additional analysis of accident progression is not warranted.

4. On average, a Pickering NGS A unit is shutdown for a planned outage for approximately 22% of the operating cycle. Therefore, the exposure to these low frequency hazards is much lower for a shutdown unit than for a high power unit.

5. Risk management programs at the station are adequate to control the risk from these hazards while a unit is shutdown.

4.0 LEVEL 1 PSA METHODS

The goal of the Pickering NGS A Level 1 PSA was to identify the events at the plant that can challenge fuel cooling, to identify the systems that can mitigate the event, to determine if the event results in severe core damage should the mitigating systems fail, to determine the total frequency of events that result in severe core damage, and to identify the major contributors to SCDF.

Typically, the first PSA study for a station is the Level 1 at-power PSA for internal events. The Level 1 at-power PSA for internal events is used as an aid in the development of the Level 1 at-power PSAs for the other hazards; therefore, the methodology for the Level 1 at-power PSA for internal events will be described in the most detail.

4.1 Level 1 At-Power PSA for Internal Events

The PARA-L1P for internal events was prepared following the methodology described in [R4]. This methodology was accepted by the CNSC in [R5].

The major activities of the PARA-L1P were:

(a) Identification and quantification of initiating events.

(b) Development of a Fuel Damage Category (FDC) scheme.

(c) Development of event trees.

(d) Development of system-level fault trees needed to quantify the probability of failure of the mitigating systems credited in the event trees.

(e) Development of a component reliability database using, to the extent possible, information specific to Pickering NGS A.

(f) Assessment of the effect of human error on accident progression and system performance using Human Reliability Analysis (HRA).

(g) Integration of the event trees with the system-level fault trees, and risk quantification.

Each of the above activities is summarised in the following sections of this report.

Although the activities listed above are generally carried out in the indicated order, the PSA process is iterative in nature and entails re-assessing the results of an earlier task based on insights gained from a later task.

4.1.1 Initiating Events Identification and Quantification

An Initiating Event (IE) is a disturbance at the plant that challenges reactor operation or fuel integrity either by itself or in conjunction with other failures. Identifying the IEs and quantifying the frequency of IEs are the first steps in a Level 1 PSA.

In the PARA-L1P, the initiating events under consideration were those plant failures that could lead directly, or in combination with other failures, to severe core damage in a Pickering NGS A reactor. The list of initiating events in the PARA-L1P included:

- Events that only affect a single unit at Pickering NGS A.
- Events that can affect both units at Pickering NGS A. This includes, for example, events leading to a hostile environment in the powerhouse (e.g. steam line breaks), losses of off-site power and events leading to failure of the service water intake.
- Events occurring at Pickering NGS B that can also affect Pickering NGS A.

The objective of initiating event selection is to develop a comprehensive list of credible initiating events. For the PARA-L1P, the initiating event list was developed from past OPG PSAs, other published PSAs, safety reports for OPG's nuclear generating stations, operating experience from CANDU nuclear generating stations, and insights gained from the system-level fault tree modelling. The complete set of initiating events used in the PARA-L1P is listed in Table 2.

The frequency of initiating events was quantified primarily using Bayes' Theorem. In a Bayesian approach, generic experience is updated with station-specific experience. This technique allows general experience and knowledge about a given event to be combined with actual operating experience gained at the station under study. It is especially useful for quantifying the frequency of IEs unlikely to be experienced within the lifetime of a single station.

4.1.2 Fuel Damage Categorization Scheme

Each accident sequence, consisting of an initiating event and failures of mitigating systems, may result in a different end state. The end states may vary in terms of the severity and the timing of fuel damage. Fuel damage categorization is carried out to simplify the subsequent evaluation of consequence and frequency.

Each FDC represents a collection of event sequences judged to result in a similar degree of fuel damage. The FDCs are used as end-states in the Level 1 event trees, discussed in Section 4.1.3 of this report, and are used to transition from the Level 1 PSA to the Level 2 PSA, see Section 5.1 of this report.

The PARA-L1P used three FDCs:

1. Fuel Damage Category 1 (FDC1). This FDC represents the loss of core structural integrity due to the failure to shutdown the reactor following an initiating event.
2. Fuel Damage Category 2 (FDC2). This FDC represents the loss of core structual integrity due to the failure of post-accident heat sinks following a successful shutdown in response to an initiating event.

3. Core Structural Integity Maintained (CSIM). This FDC represents all other end states for the event sequences.

SCDF is defined to be the sum of the frequencies of FDC1 and FDC2.

4.1.3 Event Tree Analysis

The potential for an accidental release of fission products contained in the nuclear fuel constitutes the main risk from a nuclear power plant. In the Level 1 PSA, event trees are used to systematically review the possible ways that radioisotopes can be released from the fuel into containment.

The accident sequences are constructed using inductive logic. The graphical representation of this inductive logic is called an Event Tree (ET). The start of this inductive method is the IE, usually a plant malfunction. Following the identification of the IE, the next step is to identify the systems required to mitigate the IE and to show how the accident would progress if the mitigating systems were also to fail.

ET analysis requires the following to be predefined:

(a) The list of IEs to be considered (Section 4.1.1 of this report).

(b) The definition of sequence end states (Section 4.1.2 of this report) .

(c) The identification of mitigating systems.

A simplified ET for a large Loss Of Coolant Accident (LOCA) is presented in Figure 3. Following a large LOCA, three systems can mitigate fuel damage: the SDS, the ECIS and the heat sink function of the moderator system. The plant state must be assessed if one or more of these mitigating systems fail. These three systems form the branch points in the event tree.

The event tree is read from the left:

- Starting at the left is the initiating event “IE-LOCA”.
- Moving to the right, the first system credited with preventing fuel damage is the SDS. Failure of the shutdown system is represented by the ET branch point “SD”.

  The convention used to read an ET is that success of the mitigating system is the top branch of the event tree and failure is the lower.

  If the SDS fails, rapid loss of core structural integrity is expected. This sequence is assigned to the FDC1 end state.
- If reactor shutdown is successful, the decay heat must still be removed from the fuel to prevent fuel damage.

  Two systems are credited for this function: the ECIS and the moderator as a heat sink. If both systems fail, a slow loss of structural integrity is expected. This sequence is assigned to the FDC2 end state.

- If either the ECIS or the moderator as a heat sink are successful, core structural integrity is maintained. These sequences are assigned to the CSIM end state.

In the PARA-L1P, an ET was prepared for each of the IEs listed in Table 2.

Once the Level 1 event trees have been created, the failure probability of the mitigating systems that have been identified in the ET must be assessed. This is achieved using fault tree analysis.

4.1.4 Fault Tree Analysis

A Fault Tree (FT) is a logic diagram that is used to model the possible causes of a particular fault and to estimate the probability that the fault occurs.

In the PARA-L1P, FT analysis was used to calculate the probability of ET branch points. That is, FTs were used to quantify the probability of failure of the mitigating systems that appear in the ET. FTs were also used to calculate the probability of failure of the systems that support the mitigating systems that appear in the ETs.

Figure 4 depicts the relationship between the ETs and the FTs. Table 3 lists the systems modelled by FTs in the PARA-L1P.

For example, consider the moderator dump function of Shutdown System A. For this system, the failure mode of interest is "moderator dump fails to shutdown the reactor following a SDSA trip". Figure 5 shows a partially completed FT with this event at the top. Starting from this top event, the FT analyst poses the question "*How can this event occur?"* The answers to this question are inputs to this top event. For example, Figure 5 shows that the moderator dump function of SDSA can fail if the dump valves fail, the SDSA logic fails, or if a combination of SDSA logic failures and dump valve failures occur. For each of these contributors, the process of examining how they can occur is repeated until no further insights can be obtained about the behaviour of the system. Typically, a FT is developed either to predefined system boundaries or to individual system components.

The basis for system capability and the failure criteria, e.g. the number of dump valves that must open in Figure 5, is based on analysis from a variety of sources. In the PARA-L1P, these sources included the Pickering NGS A Safety Report, the Operational Safety Requirements, the Abnormal Incidents Manuals, and other assessments and regulatory submissions.

Once a FT is constructed, it is linked with a database containing the information required to calculate the probability of each event in the FT. In the PARA, failure rate, test data and maintenance data are assigned to the FT primary events from a central type-code table that is linked to the system reliability database. The use of the CAFTA compatible reliability database and a central type-code table ensures that the same type of component is assigned the same failure rate for the same failure mode in all system FTs.

The FTs include both equipment failures that occur prior to the IE and equipment failures that occur following the IE. Failures that occur following the IE are called mission failures. In the Level 1 PSAs for Pickering NGS A, the mission time in the reliability analysis was chosen to either reflect the expected mission of a particular system, e.g. approximately one hour for the BECS, or as 72 hours.

In the PARA-L1P, a Bayesian approach was adopted for estimating component failure rates. The Bayesian approach uses both generic data and plant-specific data in deriving failure rates. In the PARA-L1P, generic data was obtained from the U.S. Nuclear Regulatory Commission (NRC) [R13], the T-book [R14] and the Westinghouse Savannah River generic database [R15]. The Pickering NGS A plant-specific data documented in the 2011 Annual Reliability Report [R12] was used for the Bayesian update.

The reliability database also contains information on human errors modelled in the fault tree and event trees. The analysis of human errors and their quantification is discussed in the next section of this report.

4.1.5 Human Reliability Analysis

Human errors can affect accident progression and the performance of mitigating systems, and in some cases can be significant contributors to risk. Thus, the potential for human errors must be systematically identified and incorporated into the event trees and the system level fault trees. Probabilities for the identified human errors must be estimated in a systematic fashion.

In principle, every piece of equipment or system in the plant is susceptible to failure because of human error; however, human errors that contribute directly to the failure of individual components are reflected in the components' failure rates and need not be identified in fault trees.

The human errors of interest to the ET / FT analyst arise under five sets of circumstances:

1. Where a system or component is inadvertently disabled by a human action prior to an IE. For example, a component may be left inadvertently disabled following a routine test or routine maintenance.

2. Where a system or component fails prior to an IE, and the failure is annunciated, but the operator fails to respond to the annunciation prior to an IE.

3. Where an operator action or a closely related series of actions simultaneously disables more than one piece of parallel / redundant equipment prior to an IE.

4. Where an operator fails to respond appropriately following an IE, either by not taking an action or by taking an inappropriate action.

5. Where an operator can *plausibly* interfere with the correct response of a mitigating system following an IE either by inhibiting the system or by activating the system.

Items 1 to 3, above may occur while performing normal operating, testing and maintenance procedures. Items 4 and 5, above may occur while following an emergency operating procedure.

Wilful or vengeful actions were not included in the PARA-L1P.

In order to systematically quantify the human interactions in the PARA, OPG used a human interaction taxonomy. This taxonomy classified human interactions in the PARA-L1P as one of: *simple* interactions, *complex* human interactions that occur prior to an IE; and *complex* interactions that occur after an IE.

Simple human interactions have the following characteristics:

(a) They occur while performing written or learned procedures (as opposed to cognitive or creative tasks).

(b) They involve directly manipulated components (e.g., a valve handwheel or a handswitch) or directly viewed main control room display devices.

(c) They occur prior to an IE.

The task of assigning preliminary (screening) human error probabilities for the simple human interactions uses a simple method requiring only the selection of an unmodified basic human error probability and predefined modifying factors. This method quantifies the human interaction based on the type of task, the location where the task is performed, whether the error can be detected in the main control room, and if any annunciations or inspections can detect the error.

For the complex human interactions that occur prior to an IE, the same process may be followed to obtain a preliminary (screening) quantification. These human interactions are complex because they include system-level functions that involve more than just direct physical manipulation of a component, such as the setting of computer control program parameters or modes.

Post-initiating event complex human interactions occur during abnormal conditions and are, therefore, more difficult to identify, analyze, and quantify. Additionally, interactions involved in handling unit upsets are also unlike other interactions as they may take place in dynamic and uncertain situations. These actions are knowledge-based; they are based on fundamental principles of process and safety system operation and on an understanding of the interactions amongst these systems. For the post-initiating event complex human interactions, the preliminary (screening) human error probabilities are assigned based on three criteria: complexity of the task, the time available, and the quality of indication available in the main control room to indicate that action is required.

Human interactions that are identified as risk significant can be further refined using a detailed methodolgy such as THERP.

4.1.6 Fault Tree Integration and Evaluation

Integration is the process of merging the system FTs with the ETs to create a logic model for each FDC. The goal of integration is to use the logic model to calculate the frequency of occurrence of each FDC. Combining the information in one model allows dependencies between systems to be identified and quantified correctly.

In order to combine the FTs and ETs, the ET logic is first converted into FT logic with a top event for each FDC. These fault trees are referred to as the high level logic. The events in the high level logic are the IEs and the branch points from the event trees. The high level logic is then integrated with the mitigating system FTs; the top events in the mitigating system FTs are inserted where the mitigating system branch point labels exist in the high level logic model. Finally, the support systems are added to the integrated high level logic. Figure 6 illustrates this process.

In the PARA, CAFTA [R17] was used to evaluate the integrated fault trees and FTREX [R18] was used as the solution engine to quantify the results.

The solution of a FT is expressed as a listing of the combination of an initiating event, equipment failures, and human errors that leads to the occurrence of the FDC. Each combination contains the minimum number of failures that have to occur to cause the top event, such combinations are called minimal cutsets.

The solution of the fault tree calculated using CAFTA is truncated. That is, contributors below a certain frequency are not included in the solution. Truncation is necessary because of computational limits. The truncation limit selected should be low enough that all significant contributors are captured. The Level 1 at-power PSA guide for internal events [R4] recommends that the solution of the integrated fault tree for each FDC be truncated at either four orders of magnitude below the most likely minimal cutset in that FDC or at 1×10^{-12} occ/yr, whichever is the highest. For FDC2 in the PARA-L1P, the frequency of the top minimal cutset was 6×10^{-7} occ/yr and a truncation of 1×10^{-11} occ/yr was used.

Following the development of the baseline PSA results, an additional understanding of the station risk is obtained by supplementing the baseline solution with the following:

- Accident sequence quantification to provide sequence by sequence cutset ranking.
- Importance analysis to identify systems and components that are important to the FDC results.
- Parametric uncertainty analysis to determine the lower and upper limits of the two-sided 90% confidence interval for the frequency of each FDC.
- Sensitivity analysis to evaluate the impact on the results of a number of potentially critical assumptions made in the study.

4.2 Level 1 Outage PSA for Internal Events

The PARA-L1O was prepared following the methodology described in [R19]. This methodology was accepted by the CNSC in [R20].

The PARA-L1O considered internal events occurring while a reactor is in the GSS. At Pickering NGS A, a reactor is in the GSS for approximately 22% of the operating cycle.

A Level 1 outage PSA for internal events is developed following the same steps and general methodology as a Level 1 at-power PSA for internal events. However, an outage PSA must reflect the changing status of the plant through an outage, e.g. not all initiating events are possible during all phases of an outage and not all mitigating systems are available during all phases of an outage. This section of this report highlights the differences between an at-power PSA and an outage PSA.

4.2.1 Plant Operational State (POS) Identification and Analysis

The purpose of POS analysis is to manage the dynamic nature of an outage, specifically the varying system configurations, process parameters and system failure mechanisms. This is achieved by grouping the various outage configurations into a manageable number of POSs during which the plant configuration and system failure criteria can be considered to be constant.

The first step in the POS analysis is to define Pre-Plant Operational States (Pre-POSs). Pre-POSs are defined as unique outage plant configurations during which all parameters of interest are stable. Pre-POS are developed based upon actual experience from planned outages and are the highest resolution of the outage states.

The Pre-POSs are then grouped into POSs. The POSs are bounding states based on the pre-POSs; the conditions in a POS are considered to be sufficiently stable for the purposes of an outage PSA. In the PARA-L1O, six pre-POSs were grouped into three POSs. Table 4 defines the three POSs used in the PARA-L1O.

4.2.2 Initiating Event Identification and Quantification

The development of a Level 1 outage PSA requires the identification, grouping and quantification of a set of outage IEs. IE identification and quantification for a Level 1 outage PSA for internal events follows the same steps and general methodology as for a Level 1 at-power PSA for internal events (Section 4.1.1 of this report). However, it is important to note that:

- There are system failures unique to an outage, e.g. failure of an ice plug on a HTS feeder.
- There are at-power IEs that cannot occur on a shutdown unit, e.g. a main steam line break.

- Not all IEs can occur in all POSs. For example, a large LOCA can only occur in a POS where the HTS is pressurized.

- IEs on the adjacent at-power units can affect the shutdown unit, e.g. a main steam line break on Unit 1 can induce a transient on U4.

Table 5 lists the outage IEs used in the PARA-L1O and lists the POSs in which each IE can occur.

4.2.3 Fuel Damage Category (FDC) Analysis

In the PARA-L1O, event tree sequences were assigned to either FDC2 or CSIM.

The PARA-L1O did not model loss of core structural intergrity due to failure to shutdown, i.e. FDC1. FDC1 was not modelled due its very low frequency. The very low frequency results from the provision of two very reliable lines of defence to prevent the reactor from regaining criticality, i.e. the shutdown guarantee and the SDS.

In a shutdown unit, the SDS is only required to prevent a reactor from regaining criticality. The SDS is not required to lower power following a total loss of heat sinks. If the reactor remains in the GSS, power is only a function of the decay heat level which itself is only a function of the time since shutdown.

4.2.4 Event Tree Analysis

The development of a Level 1 outage PSA requires the preparation of an ET for each outage IE.

ET analysis for a Level 1 outage PSA for internal events follows the same steps and general methodology as for a Level 1 at-power PSA for internal events (Section 4.1.3 of this report). However, a separate ET must be prepared for each IE/POS combination.

4.2.5 Outage System Fault Tree Analysis

The development of a Level 1 outage PSA requires the preparation of a FT for each branch point in the outage ETs. FT analysis is used to calculate the probability of ET branch points.

FT analysis for a Level 1 outage PSA for internal events follows the same steps and general methodology as for a Level 1 at-power PSA for internal events (Section 4.1.4 of this report). However, the outage FTs may be significantly different from the at-power FTs, these differences reflect the differences in system configuration and success criteria. For example, the automatic logic of the ECIS is usually blocked during an outage; therefore, only manual initiation of ECIS can be credited in the ECIS FT for a shutdown unit.

Table 3 lists the systems modelled by fault trees in PARA-L1O.

4.2.6 Reliability Data Analysis

Reliability data analysis for a Level 1 outage PSA for internal events follows the same steps and general methodology as for a Level 1 at-power PSA for internal events (Section 4.1.4 of this report).

4.2.7 Human Reliability Analysis

The possibility of component or system failure due to human error is recognized by the inclusion of human interactions in the FTs and ETs.

Human reliability analysis for a Level 1 outage PSA for internal events follows the same steps and general methodology as for a Level 1 at-power PSA for internal events (Section 4.1.5 of this report). However, in an outage PSA, human error probabilities for the same action may vary between POSs and may be different from the values calculated in the at-power PSA. These differences reflect the different outage configurations.

Human interactions that can only occur during an outage are also addressed in this task.

4.2.8 Fault Tree Integration and Evaluation

Integration is the process of merging the system FTs with the ETs to create a logic model for each FDC. The goal of integration is to use the logic model to calculate the frequency of occurrence of each FDC. Combining the information in one model allows dependencies between systems to be identified and quantified correctly.

Fault tree integration and evaluation for a Level 1 outage PSA for internal events follows the same steps and general methodology as for a Level 1 at-power PSA for internal events (Section 4.1.6 of this report). However, it is important to note that:

1. Only the frequency of FDC2 was estimated in the PARA-L1O.
2. The integration was performed for FDC2 separately for each POS.
3. The estimated SCDF is time averaged. That is, the SCDF for each POS is weighted according to the fraction of a year that a unit is expected to be in that POS.

4.3 Level 1 At-Power PSA for Internal Fires

The Pickering NGS A at-power fire PSA (PARA-FIRE) was prepared following the methodology described in [R6]. The methodology described in [R6] is based upon NUREG/CR-6850 [R8] and was accepted by the CNSC in [R7].

The objectives of the PARA-FIRE were:

- To identify areas of the plant particularly vulnerable to fires while both units are at high power.
- To identify the fire scenarios that make the greatest contribution to risk while both units are at high power.
- To characterize differences between the units that may affect risk.
- To estimate the SCDF and the LRF for both single-unit and multi-unit fire scenarios.

The methodology described in [R6] is broken into 17 tasks; these tasks are briefly descibed in Sections 4.3.1 to 4.3.14 of this report. The relationship between the 17 tasks is shown in Figure 7.

Seismic-fire interaction (Task 13) was outside the scope of the PARA-FIRE and is not addressed in this report .

The PARA-FIRE was prepared following an iterative approach. That is, the initial estimate of risk was based upon conservative and simplifying assumptions. With each subsequent iteration, the methods used to estimate risk for the various scenarios were refined, with effort focused on the most important contributors to risk.

4.3.1 Plant Boundary Definition and Partitioning (Task 1)

In this task the global boundary of the analysis is identified, i.e. the areas within the site where a fire could affect risk, and then partitioned into smaller Physical Analysis Units (PAU).

In the PARA-FIRE, a PAU is an area of the plant within which all fire scenarios are subject to similar conditions. In general, the boundaries of PAUs are defined by either physical barriers or a change in the fire detection and suppression capability. In some cases, large areas with no physical boundaries or changes in detection and suppression capability were subdivided into multiple PAUs to make the analysis more manageable.

The PAUs used in the PARA-FIRE were based on those identified in the Pickering NGS A Fire Hazard Assessment (FHA) [R9]. This approach allowed the PARA-FIRE to rely on the existing programmatic controls and design requirements for maintaining the integrity of the associated compartment boundaries.

4.3.2 Fire PSA Component (Task 2) and Cable Selection (Task 3)

In these tasks, the components and associated cables necessary for safe shutdown and long-term decay heat removal following a fire are identified. The cables may be associated with power supply to or control of the affected components.

In the PARA-FIRE, components and cables were divided into three groups:

1. Group B is the set of systems and components credited in the Fire Safe Shutdown Analysis (FSSA) [R10] for safe shutdown and decay heat removal. For these systems cable routing data was available from the FSSA.

2. Group A is the set of systems and components that, although not credited in the FSSA, may be capable of mitigating fires. These systems were only credited for fires which could be shown not to affect cables.

3. Group A was augmented by two additional functions:

   i) Make-up from the Emergency Mitigating Equipment (EME) to the boilers and to the calandria.

   ii) Make-up from the firewater system to the calandria.

   The cables and cable routing required for operation of these additonal functions were identified using the online wiring database.

The above grouping of components and cables was for the purposes of the PARA-FIRE only; it does not reflect any design or operational consideration.

4.3.3 Qualitative Screening (Task 4)

This task involves the identification and screening of PAUs that can be shown qualitatively to have little or no risk signficance. This task was not performed in the PARA-FIRE; all PAUs were conservatively retained for later tasks.

4.3.4 Fire-Induced Risk Model (Task 5)

This task involves the development of a logic model that reflects plant response to a fire.

The fire-induced risk model was developed from the PARA-L1P event tree for a forced shutdown. The PARA-L1P event tree was augmented to include:

- The impact of fire upon operator response (Task 12).
- The EME supply to the boilers and the calandria.
- The firewater supply to the calandria.

In fire PSA quantification (Task 14), this model was used to calculate the Conditional Core Damage Probability (CCDP) for each postulated fire scenario.

In the PARA-FIRE, the fire induced risk model was limited to scenarios that may result in severe core damage due to the failure of all heat sinks. Sequences involving failure to shutdown were not modelled as the potential for internal fires to adversely affect the fail safe shutdown system was judged to be minimal.

4.3.5 Fire Ignition Frequencies (Task 6)

To calculate the risk due to an internal fire, fire ignition frequencies (FIFs) for each PAU identified in Task 1 must be assessed.

The key steps in the development of FIFs are:

- Plant walkdowns to identify fixed ignition fire sources. In the PARA-FIRE, the walkdowns were completed for PAUs in Unit 4 and PAUs in common areas that may affect Unit 4, e.g. the Main Control Room.

- Where Pickering experience was available, a Bayesian update of the generic fire frequencies obtained from [R8] and [R11] with Pickering site specific experience was performed.

  Where Pickering experience was not available, the generic FIFs from [R8] and [R11] were used. A review of Canadian CANDU fire data performed as part of the Darlington fire PSA indicated that use of generic data would not lead to an under-estimate of the FIFs.

- Development of transient fire ignition frequencies. This was based upon walkdowns and engineering judgment from site personnel who were familiar with plant operation.

4.3.6 Quantitative Screening (Task 7)

In the PARA-FIRE, this task was perfomed in conjunction with Task 8.

In this task, a bounding assessment is made of the risk impact of fires in each PAU. The bounding assessment assumes that the FIF for each PAU is the sum of the FIFs for all equipment inside the PAU and that all credited equipment in the PAU fails. If the SCDF based on the bounding assessment is very low, then no further analysis is performed for the PAU and the conservatively estimated SCDF is carried forward for use in Level 1 quantification (Task 14).

4.3.7 Scoping Fire Modeling (Task 8)

This task is a conservative and simplified initial refinement to the bounding treatment in Task 7. Ignition sources that do not pose a threat to targets in a PAU are screened out of the PSA.

The scoping fire modelling is used to develop explicit fire scenarios for individual fixed ignition sources, transient ignition sources, and self-ignited cable fires within the risk significant PAUs. The development of these detailed fire scenarios was supported with plant walkdowns, during which information was collected on each ignition source, and distances measured from each ignition source to potential target equipment and cabling.

Only the target cables and equipment within the zone of influence of a particular ignition source were assumed to fail in the fire scenario and then carried forward into the PSA quantification (Task 14). The zone of influence for a particular fire was determined using generic fire models.

4.3.8 Detailed Circuit Failure (Task 9) and Failure Mode Likelihood Analysis (Task 10)

The purpose of these tasks is to:

- Screen out cables that do not affect a component's response to a fire.
- Determine the response of components to the different cable failure modes.
- Estimate the probability of the cable failure modes that can affect the operation of components.

For Group B components and cables, the analysis completed in the Pickering NGS A FSSA [R10] was used in the PARA-FIRE.

The only components included in the PARA-FIRE that were not in the Pickering NGS A FSSA were the Group A components, the EME supply to the boilers and the calandria, and the firewater make-up to the calandria:

- For Group A components, fires were either shown not to affect the control circuits and power cabling of Group A components or the whole of Group A was assumed to fail. Therefore, these tasks were not required for Group A components.
- The routing of the cables for the EME and firewater systems were identified from the online wiring database, and a simplified and bounding approach for these tasks was applied to these cables.

4.3.9 Detailed Fire Modeling (Task 11)

The purpose of this task is to develop more detailed fire models that more realistically assess the impact of fire scenarios upon equipment, cables and human response.

In the PARA-FIRE, three fire-related scenarios were developed in greater detail:

1. Hot Gas Layer (HGL) Formation.

   The HGL analysis evaluated the potential for temperature related failures of equipment and cables due to the formation of a HGL. HGL formation increases the zone of influence of an ignition source fire, potentially increasing it to the whole of the PAU.

2. Multi-Compartment Analysis (MCA).

   The main objective of MCA is to evaluate the potential for a HGL formed in one PAU affecting a second PAU following the failure of a barrier. This can further increase the zone of influence of an ignition source.

   Non-HGL interactions between two PAUs were separately analysed in Task 8.

3. Main Control Room Abandonment.

   A fire in the MCR may force the operators to abandon the MCR. This degrades the capability of operations staff to control the configuration of the plant, including the deployment of emergency heat sinks.

   In the PARA-FIRE, MCR abandonment times were assessed for electrical fires and transient combustibles within the MCR envelope.

4.3.10 Post-Fire Human Reliability Analysis (Task 12)

The purpose of this task is to evaluate the impact of fire scenarios upon the human actions addressed in fire induced risk model (Task 5) and to identify new actions that may be specific to the fire PSA, e.g. the plant’s fire response procedures. The probability of failure of each of these actions is estimated and used as input to the Level 1 fire PSA quantification (Task 14).

The fire risk model was developed from the forced shutdown event tree in the PARA-L1P. Therefore, the first step in this task was to identify the post-initiator operator actions modeled as human failure events in the fire risk model / forced shutdown event tree. Pre-fire operator actions and operator actions associated with non-fire induced events were not revised.

For each human failure event that represents a post-fire operator action, multipliers were developed to adjust the human error probability assumed in the forced shutdown event tree. The multipliers considered the following factors:

- Location (either inside the MCR actions or outside the MCR actions).
- Time available.
- Complexity of the action.
- Availability of instrumentation.
- Availability of the path to equipment in field actions.

In addition, human error probabilites were calculated for the deployment and monitoring of the EME.

4.3.11 Level 1 Fire PSA Quantification (Task 14)

The development of a fire PSA requires the integration of the fire risk model with the damage consequences calculated for each scenario. The development of the fire risk quantification is typically an iterative process, as various analysis refinement strategies are developed, they are incorporated into the fire risk model.

The impact of each fire scenario upon equipment and cables determined in Tasks 8 – 11 is reflected in the fire PSA model (Task 5), and the fire PSA model is solved to estimate the CCDP for each fire scenario.

The CCDP is multiplied by the appropriate FIF to estimate the fire induced SCDF for each of the fire scenarios. The total fire SCDF is the sum of the SCDFs from all of the fire scenarios.

The SCDF contribution from the PAUs that were screened out as part of quantitative screening analysis (Task 7) was added to estimate the total fire-induced SCDF.

4.3.12 Uncertainty and Sensitivity Analysis (Task 15)

Sources of uncertainty were identified and the sensitivity of the results of the PARA-FIRE to the sources of uncertainty was assessed. In general, uncertainties associated with each of the fire PSA tasks were minimized and those that remained lend a conservative bias to the results.

Sensitivity studies were performed for:

- Credit for incipient fire detection and suppression.
- Credit for EME following the loss of all Group A mitigating functions.
- Credit for firewater make-up to the boilers.
- The probability of fire-induced hot shorts.

4.3.13 Level 2 Analysis (Task 17)

Refer to Section 5.3 of this report.

4.3.14 Alternate Unit Analysis (Task 18)

The PARA-FIRE used Unit 4 as the reference unit. A walkdown was completed to identify differences between Units 1 and 4.

The comparison of Unit 1 to Unit 4 from the fire risk perspective confirmed that the units are generally symmetrical and consistent in their construction. The differences in equipment placement and cable routing are relatively minor and are not expected to have a significant impact upon risk. Therefore, the Unit 4 fire risk analysis can be used as a surrogate for an evaluation of the fire risk for Unit 1.

4.4 Level 1 At-Power PSA for Internal Floods

The PARA-FLOOD was prepared following the methodology described in [R21]. This methodology was accepted by the CNSC in [R22].

The major tasks of a Level 1 at-power PSA for internal floods are:

- Identification of Flood Areas and Affected Systems Structures and Components (Task 1).
- Identification of Flood Sources (Task 2).
- Plant Walkdowns (Task 3).
- Qualitative Screening (Task 4).
- Flood Scenario Characterization (Task 5).
- Internal Flooding Initiating Event Frequency Estimation (Task 6).
- Flood Consequence Analysis (Task 7).
- Evaluation of Flood Mitigation Strategies (Task 8).
- PSA Modelling of Flood Scenarios (Task 9).
- Level 1 Flood PSA Quantification (Task 10).

These tasks are briefly described in Sections 4.4.1 to 4.4.9 of this report. The relationship between these tasks is shown in Figure 8.

Seismic-flood interaction was outside the scope of the PARA-FLOOD and is not addressed in this report.

The PARA-FLOOD was prepared following an iterative approach. That is, the initial estimate of risk was based upon conservative and simplifying assumptions. With each subsequent iteration, the methods used to estimate risk for the various scenarios were refined, with effort focused on the most important contributors to risk.

4.4.1 Identification of Flood Areas and Affected SSCs (Task 1)

The first step of the PARA-FLOOD was to partition the plant into the flood areas that form the basis of the analysis. Flood areas are defined based on physical barriers, mitigation features, and propagation pathways. The flood areas were initially based on the partitions in the FSSA [R10].

In the PARA-FLOOD, the Systems, Structures and Components (SSC) that can mitigate the consequences of a flood were classified as being either:

- Group B – these are the systems that support flood mitigation in Pickering NGS A but that are supplied from Pickering NGS B. In the PARA-FLOOD, these systems were the EBWS, the Inter-Station Transfer Bus (ISTB) and the HPECI.

- Group A – all other systems credited in the forced shutdown event tree of the PARA-L1P.

The above grouping of components and cables was for the purposes of the PARA-FLOOD only; it does not reflect any design or operational considerations.

The potential for floods originating in Pickering NGS A and affecting Group B mitigating equipment located in Pickering NGS B was addressed in this task.

4.4.2 Identification of Flood Sources (Task 2)

This task identified the potential flood sources in the plant and the associated flooding mechanisms. This task included:

- Identifying or confirming the flood sources in each flood area. The potential flood sources included:

  - Normally operating systems that contain water.

  - Standby safety systems that contain water, e.g. the ECIS.

  - Tanks or pools located in the flood area.

  - External sources of water, e.g. Lake Ontario, that are connected to the flood area through a system or structure.

  - In-leakage pathways from other flood areas, e.g. drains and doorways.

- Determining or confirming the flooding mechanisms associated with each flood sources.

- Determining or confirming the characteristics of each flooding mechanism.

- Identifying drains and sumps in each flood area, and determining the capacity of these mitigating functions.

- Identifying flood propagation paths.

The potential for floods from Units 2 and 3, currently in safe storage, and the potential for floods originating in Pickering NGS B propagating to Pickering NGS A were considered in this task.

4.4.3 Plant Walkdowns (Task 3)

This task supported the other tasks by identifying or confirming plant data by observing it at the plant during walkdowns.

4.4.4 Internal Flood Qualitative Screening (Task 4)

This task involved the identification and screening of flood scenarios that can be shown qualitatively to have little or no risk significance. The following rules were used when screening:

- Screening criteria for flood areas:
  - The area contains no credible flood source or no sources that could propagate from one area to another.
  - Flooding of the area does not cause an initiating event or the need for an immediate plant shutdown.
- Screening criteria for flood sources:
  - The flood source is insufficient to cause failure of SSCs.
  - The area flooding mitigation systems are capable of preventing unacceptable flood levels and the nature of the flood does not cause equipment failure through other failure mechanisms.
  - The flood only affects the system that is the flood source and the PARA-L1P already addresses this type of failure.
  - Mitigating human actions can be shown to be effective, i.e. all of the following can be shown:

    i) Flood indication is available in the MCR.

    ii) The flood source can be isolated.

    iii) The mitigation action can be performed with high reliability.
- The flood source is a high energy line already considered in the PARA-L1P.

4.4.5 Flood Scenario Characterization (Task 5) and Consequence Analysis (Task 7)

These tasks identified and characterized the potential flood scenarios to be included in the analysis. The consequences for each flood-induced initiating event were characterized by considering the following factors:

- The specific flood area, flood source, flood source failure mode and flood magnitude.

- The flood failure mechanism, e.g. spray, jet or flood.
- The consequences of the flood, including:
  - Flood propagation.
  - SSCs damaged by the flood.
  - Identification of the type of initiating event caused by the flood. As a minimum all floods were assumed to cause a forced shutdown.
- Operator and mitigation system responses to terminate the flood.
- The means to be used to define the interface with the PARA-L1P model for estimating SCDF.

4.4.6 Initiating Event Frequency Estimation (Task 6)

This task estimated the frequency of internal flood initiating events.

The frequency of internal flood initiating events was estimated by multiplying generic pipe rupture frequencies, expressed in units of per foot of piping per year, by the length of the piping within a specific flood area. Separate frequencies were estimated for sprays, floods and major floods.

The generic pipe rupture frequencies were obtained from [R23].

4.4.7 Flood Mitigation Strategies (Task 8)

This task identified and evaluated the strategies that can be employed by plant operators to mitigate the consequences of a flood. These actions can include terminating the source of the flood by isolating the break, stopping the pumps that supply the flood source, or opening doors to divert water away from sensitive equipment.

The evaluation of human failure events in the PARA-FLOOD is similar to that used in the PARA-L1P; however, flood scenario-specific Performance Shaping Factors were considered for all credited operator actions. The flood specific Performance Shaping Factors addressed:

- Additional workload and stress above that for similar sequences not caused by internal floods.
- Availability of indications.
- Time available.
- Complexity of the action.

- Availability of flooding-specific job aids and training.
- Effect of the flood upon the mitigation actions, e.g. accessibility restrictions due to the flood.

4.4.8 PSA Modelling of Flood Scenarios (Task 9)

This task involved the development of a logic model that reflects plant response to a flood.

The flood-induced risk model was developed from the PARA-L1P event tree for a forced shutdown.

In the PARA-FLOOD, the flood induced risk model was limited to scenarios that may result in severe core damage due to the failure of all heat sinks. Sequences involving failure to shutdown were not modelled as the potential for flooding events to adversely affect the fail safe feature of a shutdown system was judged to be minimal.

4.4.9 Level 1 Flood PSA Quantification (Task 10)

This task involved the construction of an integrated PSA model to evaluate the risk from internal flooding. To quantify the internal at-power flood model, new flooding events were added to the existing integrated loop cut internal events model and this was integrated with the high level logic developed from the flood specific event trees.

Qualitative sensitivity and uncertainly analyses were prepared as part of this task.

4.5 Level 1 At-Power PSA Based Seismic Margin Assessment

OPG prepared a PSA-based Seismic Margin Assessment (SMA) for Pickering NGS A. The PSA-based SMA was prepared following the methodology described in [R24]. This methodology was accepted by the CNSC in [R25].

The major tasks in a PSA-based SMA are:

- Seismic Hazard Characterization (Task 1).
- Plant Logic Model Development (Task 2).
- Seismic Response Characterization (Task 3).
- Plant Walkdown and Screening Reviews (Task 4).
- Seismic Fragility Development (Task 5).
- Seismic Risk Quantification (Task 6).

These tasks are briefly described in in Sections 4.5.1 to 4.5.6 of this report. The relationship between these tasks is shown in Figure 9.

The PARA-SEISMIC was prepared following an iterative approach. That is, the initial estimate of risk was based upon conservative and simplifying assumptions. With each subsequent iteration, the methods used to estimate risk for the various scenarios were refined, with effort focused on the most important contributors to risk.

4.5.1 Seismic Hazard Characterization (Task 1)

The first step in the PARA-SEISMIC was to develop the site-specific seismic hazard.

The seismic hazard is a representation of the seismic activity that can be experienced at the site. The seismic hazard is a plot of the peak ground acceleration versus the annual frequency that the ground acceleration will be exceeded (typically described as the frequency of exceedance). Figure 10 shows a typical seismic hazard curve. The curve shows that very small ground accelerations are more likely than very large ground accelerations.

Two hazard curves were produced:

1. Review Level Earthquake (RLE).

   The RLE was the basis of the in-structure response used in estimating the seismic demand upon equipment. The spectral shape for the RLE was based upon the 10 000 year return period 84th percentile Uniform Hazard Response Spectrum (UHRS) for the Pickering site.

2. Mean Hazard Curve.

   The mean hazard curve was used in conjunction with the plant level High Confidence of Low Probability of Failure (HCLPF) to estimate the seismically induced SCDF. The mean hazard curve was filtered through the application of the Cumulative Absolute Velocity filter. The Cumulative Absolute Velocity filter is applied to limit the contribution of low frequency, low severity earthquakes to SCDF.

   As a Pickering specific mean hazard curve filtered with the Cumulative Absolute Velocity filter was not available, the equivalent filtered mean hazard curve for Darlington NGS was used. The use of the Darlington specific curve was considered acceptable given the level of uncertainty in these types of calculations and that estimating SCDF is not normally a part of a PSA-based SMA.

4.5.2 Plant Logic Model Development (Task 2)

This task involves two related but separate sub-tasks: development of the seismic event tree logic and development of the Seismic Equipment List (SEL).

The seismic event tree displays and accounts for the impact of a seismic event upon SSCs required for safe shutdown and decay heat removal following an earthquake. The seismic event tree must address:

- The seismically induced failure of buildings such as the powerhouse. The collapse of a building was assumed to result in the failure of all equipment contained in that building.

- The seismically induced failure of the seismic route. The seismic route is a qualified pathway that allows operators to safely travel to areas of the plant in which manual field action is required to maintain the long term post-accident heat sink.

- The seismically induced failure of unqualified equipment. For example, seismic events were assumed to cause a loss of Class IV power. The loss of Class IV power, in turn, fails many other systems, e.g. main HTS pumps and main boiler feed pumps.

- The seismically induced rupture of the HTS and/or the main steam system. Failure of one or both of these systems can significantly affect seismic risk.

- The seismically induced failure of rugged equipment. This branch point represents equipment screened in Task 4.

- The failure, seismically induced and random, of equipment in the systems that mitigate the consequences of a seismic event.

The SEL is the list of all components that are required to safely shutdown the reactor and remove decay heat following an earthquake. The SEL was derived from:

- The Seismic Safe Shutdown Equipment list that was prepared as part of the Pickering NGS A SMA issued in 1998 [R28]. This list was subsequently updated in 2009 [R29] and 2013 [R30].

- The equipment credited in seismic event tree.

4.5.3 Seismic Response Characterization (Task 3)

The next step in the seismic PSA is to characterize how the station buildings respond to a seismic event. The response of the building will not be the same on each elevation. For example, the small earthquakes occasionally experienced in southern Ontario are typically undetectable to people in the basement or lower floors of buildings, but can be easily detected by people in the higher floors of tall buildings.

The ground oscillation of any seismic event can be described by a combination of frequencies. This is called the spectrum of the seismic event. Each seismic event may have a different spectrum. The different frequencies in an earthquake's spectrum will be transferred to the building in different ways. The response of site buildings determines how the earthquake will affect the equipment in the SEL and is used to calculate the probability of equipment failure due to a seismic event.

The building responses developed in the Pickering NGS A SMA issued in 1998 [R28] were used in the PARA-SEISMIC. This was considered to be reasonable and bounding as the UHRS developed in 1998 bounded the UHRS developed for the PARA-SEISMIC in the range of spectral frequencies of concern for building response.

4.5.4 Plant Walkdown and Screening Reviews (Task 4)

The role of the plant walkdown is to:

- Observe as many of the SEL items as possible and record any defieciencies.
- Screen out SSCs from further evaluation on the basis of high demonstrable seismic capacity. In the PARA-SEISMIC, a peak ground acceleration of 0.3g was used as the screening criterion.
- Define the failure modes of SEL items.
- Identify equipment and structures that are not included in the SEL, but whose structural failure may affect nearby SEL items.

The walkdowns were completed by a team of system engineers, seismic capability engineers and escorts. Each item on the walkdowns was independently assessed by two qualified seismic capability engineers, and the results of the walkdowns were recorded on a Screening Evaluation Worksheet.

4.5.5 Seismic Fragility Development (Task 5)

The seismic fragility of a piece of equipment is the conditional probability that the equipment will fail when subjected to a specific seismic demand. The likelihood that equipment will fail increases as it is subject to greater seismic demands. Figure 11 shows an example fragility curve; it shows that if the example equipment is subject to an acceleration of 1g, its failure probability is 0.8.

The fragility analysis conducted for a PSA-based SMA is limited to that of the Conservative Deterministic Failure Margin whereby the seismic capacity is calculated in terms of a HCLPF value using a generic representation of the variabiltiy.

4.5.6 Seismic Risk Quantification (Task 6)

The process of evaluating seismic risk is similar to that used for the PARA-L1P (Section 4.1.6 of this report). That is:

- The branches of the seismic event tree that result in severe core damage are converted to high level logic in the form of a fault tree.
- The high level logic is then integrated with the fault trees for the mitigating systems and their support systems. It is important to note that the system fault trees must be revised to include seismically induced failures of SSCs based upon tasks 4 and 5.

- All seismically induced failures are assigned a failure probability of 1 and the high level logic is solved using FTREX [R18]. This results in three types of cutsets:
  - i) Those including only seismically induced failures.
  - ii) Those including only random, non-seismically induced failures.
  - iii) Those including a mixture of seismically induced failures and non-seismically induced failures.
- The cutsets including seismically induced failures are reviewed using the MIN-MAX method to identify the limiting accident sequence and the plant level HCLPF.
- The plant level HCLPF is convolved with the mean seismic hazard curve (Task 1) to estimate the seismically induced SCDF.
- The cutsets that included only non-seismically induced failures are evaluated. Human error probabilities are adjusted by a series of multipliers dependent upon the severity of the earthquake.
- The total SCDF is the sum of seismically induced SCDF and the SCDF from cutsets that include only non-seismically induced failures.

The SCDF was estimated for the full range of earthquake recurrence intervals. However, for comparison of the SCDF to OPG's risk goals, the convolution was limited to earthquakes with a recurrence interval up to and including 10 000 years.

In the PARA-SEISMIC, the seismic risk model was limited to scenarios that may result in severe core damage due to the failure of all heat sinks. Sequences involving failure to shutdown were not modelled as the potential for seismic events to adversely affect the fail safe shutdown system was judged to be minimal.

4.6 Level 1 At-Power PSA for High Winds

The Pickering NGS A Level 1 at-power high wind PSA (PARA-WIND) was prepared following the methodology described in [R31]. This methodology was accepted by the CNSC in [R32].

The major tasks of a Level 1 at-power high wind PSA are:

- High Wind Hazard Analysis (Task 1).
- Analysis of Windborne Missile Risk (Task 2).
- High Wind Fragility and Combined Fragility Analysis (Task 3).
- Plant Logic Model Development (Task 4).
- Plant Response Model Quantification (Task 5).

These tasks are briefly described in Sections 4.6.1 to 4.6.5 of this report. The relationship between these tasks is shown in Figure 12.

The PARA-WIND was prepared following an iterative approach. That is, the initial estimate of risk was based upon conservative and simplifying assumptions. With each subsequent iteration, the methods used to estimate risk for the various scenarios were refined, with effort focused on the most important contributors to risk.

4.6.1 Task 1 - High Wind Hazard Analysis

The purpose of this task is to evaluate the frequency and intensity of occurrence of various straight wind and tornado wind hazards based on site-specific and region-specific data.

In the PARA-WIND, the spatial extent of these hazards was analyzed or estimated based on available data sets from sources such as Environment Canada, Ontario Climate Centre, US National Weather Service Storm Prediction Centre, US National Oceanic and the Atmospheric Administration Storm Prediction Center. The tornado point hazard curves were combined with the point hazard curves for other high winds to produce the combined high wind hazard curves. These wind hazards are considered to be independent stochastic events.

A wind hazard analysis was completed for the Pickering NGS B Level 1 at-power PSA for high winds. This Pickering NGS B high wind hazard curve was enhanced for use in the PARA-WIND:

- The tornado hazard was improved through the use of a more complete data set provided by Environment Canada.
- The straight line wind hazard was improved by using all data available in the database rather than a single annual extreme. This provides more accurate extraploations for rare events and a more accurate assessment of uncertainties.
- The number of wind speed intervals used in the Level 1 quantification (Task 5) was increased to capture the rapid change in the wind hazard curve. This produced a more refined estimate of risk.

The all-winds hazard curve used in the PARA-WIND is shown in Figure 15.

4.6.2 Task 2 - Analysis of Windborne Missile Risk

The purpose of this task is to develop wind-borne missile fragilities for the plant targets.

Windborne missile fragility is defined as the probability of target damage (failure) from windborne missiles for a given value of peak gust wind speed. A list of high wind targets was generated in Task 4. The missile risk was derived based on missile sources, plant layout, and plant design information, supplemented by plant walkdowns.

The EPRI-developed TORMIS methodology was utilised to estimate the probability of tornado missile impact and damage to plant structures and components [R33] [R34].

4.6.3 Task 3 - High Wind Fragility and Combined Fragility Analysis

The purpose of this task is to evaluate the fragility of high wind targets identified in Task 4 due to high wind loading effects.

The SSCs identified in task 4 include both safety related systems and their support systems. For each component in a safety related system, a chain of dependencies from the components through its support systems can be identified. The weakest link in the chain of dependencies with respect to high wind and water exposure was considered in the fragility analysis.

The median wind capacity and associated uncertainty was calculated for the weakest links. These calculations were based on data available from design documentation, National Building Codes and plant walkdowns. The median wind capacities and associated uncertainties were used to derive wind fragility curves.

A refined fragility analysis was prepared for the metal cladding on the Turbine Hall, Turbine Auxiliary Bay, and Class I and II structures inside the turbine building. This provided a more accurate assessment of the cladding fragility and an assessment of the portion of the cladding over the whole building that might fail.

4.6.4 Task 4 - Plant Logic Model Development

This task addresses two related but separate sub-tasks: development of the high wind event tree logic and development a list of components to be credited / analyzed in the high wind PSA.

The high wind event tree displays and accounts for the impact of a high wind event upon SSCs required for safe shutdown and decay heat removal following a storm. The high wind event tree must address:

- The wind induced failure of buildings. The collapse of a building was assumed to result in the failure of all equipment in that building.
- The failure of SSCs that are required to safely shutdown the reactor and remove decay heat following a storm. This includes both wind-induced failures and random, independent failures.

  In the PARA-WIND, the EME supply to the boilers, the EME supply to the moderator and the firewater system to the moderator were incorporated into the high wind event tree.

The list of SSCs that are required to safely shutdown the plant and remove decay heat was developed from the high wind event tree and its associated fault trees. This list formed the basis for the list of targets to be considered in the analysis of wind borne missile risk (Task 2) and high wind fragility analysis (Task 3).

4.6.5 Task 5 - Plant Response Model Quantification

The purpose of this task is to integrate the risk model and estimate the SCDF due to high winds.

The branches of the high wind event tree that result in severe core damage were converted to high level logic in the form of a fault tree. The high level logic was then integrated with the mitigating system fault trees that had been updated to include both high wind failures and random component failures. The high level logic was then integrated with the wind hazard curve. That is, the model was solved for each of the wind speed sub-intervals (Table 13) using the mean hazard curve and the appropriate component wind fragilities for that sub-interval.

In addition to providing the frequency for each sequence, quantification identifies the dominant accident sequences, component failures, and human actions with respect to high wind risk.

The SCDF was estimated for the full range of high wind recurrence intervals. However, for comparison of the SCDF to OPG's risk goals, the convolution was limited to high winds with a recurrence interval up to and including 10 000 years.

In the PARA-WIND, the wind induced risk model was limited to scenarios that may result in severe core damage due to the failure of all heat sinks. Sequences involving failure to shutdown were not modelled as the potential for high winds to adversely affect the fail safe shutdown system was judged to be minimal.

5.0 LEVEL 2 PSA METHODS

A Level 2 PSA studies the system failures and accident phenomena that might result in an airborne release of radioactive material to the environment, and the timing and magnitude of the release. This information is combined with the Level 1 PSA to quantify the frequency of releases.

The Level 2 at-power PSA for internal events is used as an aid in the development of the Level 2 at-power PSAs for the other hazards; therefore, the methodology for the Level 2 at-power PSA for internal events will be described in the most detail.

5.1 Level 2 At-Power PSA for Internal Events

The Pickering NGS A Level 2 at-power PSA for internal events was prepared following the methodology described in [R37]. This methodology was accepted by the CNSC in [R38].

5.1.1 Interface with Level 1 PSA

The PARA-L1P identified sequences resulting in severe core damage and estimated their frequency. These sequences form the starting point of the PARA-L2P.

The PARA-L1P categorized the severe core damage states into FDCs. The first step of a Level 2 PSA is to assign the sequences in these FDCs to Plant Damage States (PDS). The PDSs are the interface to the Level 2 PSA and are used as a means of managing the many different scenarios that can result in severe core damage.

Four PDSs were assigned in the PARA-L2P:

1. PDS1 represents sequences resulting in severe core damage as the result of failure to shutdown. That is, all sequences in FDC1 were assigned to PDS1.

2. PDS2 represents sequences resulting in severe core damage at a single unit as the result of failure of all heat sinks. That is, single unit sequences in FDC2 that do not result in a bypass of containment were assigned to PDS2.

3. PDS3 represents sequences resulting in severe core damage at more than one unit. That is, multi-unit sequences in FDC2 were assigned to PDS3.

   In the PARA-L2P, PDS3 was subdivided into two categories:

   i) PDS3-2U which represents severe core damage at both Pickering NGS A units.

   ii) PDS3-6U which represents severe core damage at one or more Pickering NGS A units *and* severe core damage at one or more Pickering NGS B units.

4. PDS4 represents sequences resulting in severe core damage at a single unit as the result of failure of all heat sinks with a release pathway that bypasses containment, e.g. boiler tube leaks.

PDS2 was further sub-divided into eight, labeled PDS2B to PDS2K, to reflect various random containment failures. The random containment system failures were identified by means of a Bridging Event Tree (Figure 13) and are listed in Table 6.

It is important to note that the branch points in the Bridging Event Tree that represent failures of the Filtered Air Discharge System (FADS) were subsequently eliminated from the PARA-L2P. It was determined that FADS may be initiated many hours into a transient when command and control of the plant has been transferred to the Emergency Response Organization (ERO). OPG's current methodology for human reliability analysis does not include actions initiated by the ERO.

Accident sequences assigned to a particular PDS are expected to result in a similar fission product release to containment and a similar containment response. Therefore, the characteristics of each PDS can be represented and modelled by a single representative accident sequence.

The representative accident sequence for each PDS was chosen by:

- Identifying the initiating events from the PARA-L1P that were the largest contributors to the frequency of the PDS.

- Reviewing the sequences identified above to select a representative sequence that bounds the consequence.

The above approach follows the guidance of the International Atomic Energy Agency. The representative sequences chosen for each PDS are summarized in Table 6.

5.1.2 Containment Event Tree Analysis

A Containment Event Tree (CET) serves two main purposes:

1. It is a logic model that describes the progression of a severe accident, in particular, how severe accident phenomena can challenge the containment boundary.

2. It is a means to estimate the frequency of the various sequences that challenge the containment boundary. This, coupled with an estimate of releases for each sequence (Section 5.1.5), is an input to the estimate of LRF (Section 5.1.6).

Figure 14 shows a generic CET.

CET branch points are not built from system based "success criteria" but from questions that are intended to ascertain the magnitude of phenomenological challenges to the containment boundary (e.g., "Is containment integrity maintained?" or "Does core concrete interaction occur?"). The CET branch points represent major events in accident progression and the potential for fission product release to the environment. The CET also represents the evolution of the progression with time so the same nodal question may appear more than once in the tree as conditions inside containment change.

Most of the CET branch points represent alternative possible outcomes of a given physical interaction. Depending on the availability of suitable models and data for a given physical interaction or phenomenon, the methods of branch point quantification can vary. The acceptability of these probability estimates is supported via an expert review process.

5.1.3 Containment Fault Trees

Containment system fault trees are required to quantify the frequencies of the end-states of the Bridging Event Tree (Figure 13). FTs are required for the following containment sub-systems:

- Large breach of containment (LCEI). This is defined as a breach greater than 0.1 m^2 and may result from breaches through:
  - an airlock;
  - a penetration;
  - the D_2O vapour recovery system; and
  - the boiler SRVs following a steam line break inside containment.
- Small breach of containment (SCEI). This is defined as a breach less than 0.1 m^2 and may result from the same sub-systems as a large breach.
- Failure of the PRVs to open and limit containment pressure (PRV).
- Failure of the air cooling units to condense steam and reduce containment pressure (ACU). This includes:
  - the east fuelling machine vault ACUs;
  - the west fuelling machine vault ACUs; and
  - the boiler room ACUs.
- Failure of the hydrogen ignition system to control hydrogen concentration inside containment (IGN). This includes:
  - the igniters in the west fuelling machine vault;
  - the fans in the west fuelling machine vault ACUs;
  - the igniters in the east fuelling machine vault; and
  - the fans in the east fuelling machine vault ACUs

The FTs were prepared following the same general methodology as the FTs for the PARA-L1P (Section 4.1.4). Where systems are shared between Pickering NGS A and

Pickering NGS B, the FTs from the Pickering NGS B Level 2 at-power PSA for internal events were used.

5.1.4 Release Categorization

The release categories in the PARA-L2P were limited to those that result in a large release of radioactive material to the environment. The Release Categories (RC) are listed in Table 7.

5.1.5 MAAP-CANDU Analysis

MAAP-CANDU (Modular Accident Analysis Program – CANDU) [R39] is a severe accident simulation code for CANDU nuclear stations. It is used to simulate the evolution of a severe accident through events such as core melt, primary heat transport system failure, calandria vessel failure, calandria vault failure, and containment failure. It is also used to estimate the magnitude of airborne releases of radioactive material from containment to the environment.

MAAP-CANDU is an Industry Standard Toolset code. MAAP-CANDU version 4.0.7D was accepted by the CNSC for use in the Pickering NGS A PSAs.

There are five distinct roles for the code:

1. To establish accident progression for each plant damage state.
2. To support CET branch point quantification.
3. To estimate releases to the environment for those sequences in which containment fails.
4. To support systematic sensitivity and uncertainty analysis.
5. To provide information related to plant environmental conditions.

5.1.6 Integration of the Level 1 and 2 PSA

The purpose of integration is to link the Level 1 event trees with the PDSs via the Level 1/Level 2 bridging event tree and containment fault trees, and then with the RCs via the CET end-states using the results of the branch point quantification. The product is a complete set of sequences that contribute to each RC, from which the frequency of each RC can be determined.

Importance analysis is performed to identify the dominant contributors to each RC.

Sensitivity and uncertainty analysis is performed on both the frequency quantification and on the MAAP-CANDU consequence assessment.

5.2 Level 2 Outage Assessment for Internal Events

The Pickering NGS A Level 2 outage assessment for internal events was prepared following the methodology described in [R40]. This methodology was accepted by the CNSC in [R41].

Given the low SCDF for internal events occurring while a unit is in GSS (see Section 6.0 of this report), and given that less energy is available to challenge the containment envelope, a detailed Level 2 outage PSA for internal events was not prepared. Instead, a bounding assessment of the LRF was prepared for a unit in the GSS.

The bounding assessment was based on the following principles:

1. A large release can only occur if severe core damage has occurred. Therefore, the LRF for a unit in the GSS is bounded by the SCDF for a unit in the GSS.

2. Analysis using MAAP-CANDU [R39] demonstrated that accidents initiated in POS C do not progress to severe core damage within a 7-day analysis period. Therefore, transients initiated in POS C do not result in a large release.

   This outcome reflects the very low decay heat available approximately 70 days after shutdown.

3. Analysis using MAAP-CANDU [R39] demonstrated that accidents initiated in POSs A and B where Early Calandria Vessel Failure (ECVF) is postulated can progress to a large release. Based on the results of the PARA-L2P, only 13% of accidents that progress to severe core damage will progress to a large release as a result of ECVF. Therefore, the LRF due to early calandria failure is bounded by 13% of the SCDF.

   This is a conservative assessment as the MAAP-CANDU analysis only investigated sequences initiated early in an outage. It is likely that additional analysis could demonstrate that accidents with ECVF initiated later in an outage do not progress to a large release.

4. Analysis using MAAP-CANDU [R39] demonstrated that single or dual unit accidents without ECVF only progress from severe core damage to a large release in the first six days of an outage. That is, the LRF due to these sequences will be less than 10% of the SCDF.

5. Accidents that result in severe core damage and progress to a large release as a result of random failures of the containment envelope are a small contributor to LRF. This results from the high reliability of the containment envelope.

5.3 Level 2 Fire Assessment

The Pickering NGS A Level 2 fire assessment for internal events was prepared following the methodology described in [R6]. This methodology was accepted by the CNSC in [R7].

The Level 2 assessment of internal fire risk was built on the Level 1 internal fire model. The approach for Level 2 fire risk consisted of five steps:

1. Fire scenarios contributing a summed SCDF of 1 x 10^{-7} per reactor-year were screened from further analysis. The screening SCDF was carried forward as a direct contribution to LRF.

2. Fire scenarios that affect both units at Pickering NGS A, e.g. fires affecting the MCR, were identified. Scenarios that result in severe core damage at both units were assumed to progress directly to a large release.

3. The frequency of single unit fire scenarios that result in severe core damage and progress to a large release as a result of the consequential failure of the containment envelope was estimated. Based on the results of the PARA-L2P, this contribution to LRF was estimated as 13% of the single unit fire related SCDF.

4. Single unit fire scenarios that result in severe core damage where the fire also affects containment components were identified. These scenarios were assumed to progress to a large release. The PARA-L2P was used to identify the containment components of interest and the FSSA was used to identify and characterize the impact of fires upon the containment components.

5. Single unit fire scenarios that result in severe core damage and progress to a large release as a result of random failures of the containment envelope were identified. These scenarios were assumed to progress to a large release. The probability of random failure of containment components was taken from the PARA-L2P.

5.4 Level 2 Seismic Assessment

The Pickering NGS A Level 2 seismic assessment was prepared following the methodology described in [R24]. This methodology was accepted by the CNSC in [R25].

The Level 2 seismic assessment was limited to two main tasks:

- To estimate the seismic fragility of the containment boundary.

- To estimate the frequency of seismically induced containment failures.

Walkdowns and fragility calculations, using the same techniques as those described in Section 4.5.5, were used to assess the seismic fragility of containment components.

The plant level HCLPF for the containment boundary was determined by inspection of HCLPFs for the containment boundary components. The plant level HCLPF for the containment boundary was convolved with the mean seismic hazard curve to estimate the Seismically Induced Containment Failure Frequency (SCFF).

The seismically induced LRF was estimated by conservatively assuming that seismic events affect both Pickering NGS A units identically. If both Pickering NGS A units progress to severe core damage, then containment will fail consequentially and there will be a large release. Therefore, the seismically induced LRF was set equal to the seismically induced SCDF.

5.5 Level 2 Flood Assessment

The Level 2 at-power PSA for internal floods followed the methodology described in [R26]. This methodology was accepted by the CNSC in [R27].

The approach for Level 2 flood risk consisted of five steps:

1. Flood scenarios that affect both units at Pickering NGS A, e.g. floods affecting the MCR, were identified. Scenarios that result in severe core damage at both units were assumed to progress directly to a large release.

2. The frequency of single unit flood scenarios that result in severe core damage and progress to a large release as a result of the consequential failure of the containment envelope were estimated. Based on the results of the PARA-L2P, this contribution to LRF was estimated as 13% of the single unit flood related SCDF.

3. Single unit flood scenarios that result in severe core damage where the flood also affects containment components were identified. These scenarios were assumed to progress to a large release.

4. Single unit flood scenarios that result in severe core damage coupled with random failures of the containment envelope were assumed to progress to a large release. The probability of the random failure of containment components was taken from the PARA-L2P.

5. Sequences where the flood induces a forced shutdown in both units and there are random, independent failures of mitigating equipment on both units leading to severe core damage in both units were idetified and assumed to progress to a large release.

5.6 Level 2 High Wind Assessment

The Level 2 at-power PSA for high winds followed the methodology described in [R35]. This methodology was accepted by the CNSC in [R36].

The approach for Level 2 high wind risk consisted of four steps:

1. High wind scenarios that affect both units at Pickering NGS A were identified. Scenarios that result in severe core damage at both units were assumed to progress directly to a large release.

2. The frequency of single unit high wind scenarios that result in severe core damage and progress to a large release as a result of the consequential failure of the containment envelope was estimated. Based on the results of the PARA-L2P, this contribution to LRF was estimated as 13% of the single unit high wind related SCDF.

3. Single unit high wind scenarios that result in severe core damage coupled with random failures of the containment envelope were assumed to progress to a large release. The probability of the random failure of containment components was taken from the PARA-L2P.

4. Sequences where the high wind induces a forced shutdown in both units and there are random, independent failures of mitigating equipment on both units leading to severe core damage in both units were identified and assumed to progress to a large release.

6.0 SUMMARY OF RESULTS

This section presents the results of the following PSA studies that were completed as part of the PARA:

- Level 1 at-power PSA for internal events.
- Level 1 outage PSA for internal events.
- Level 2 at-power PSA for internal events.
- Level 2 outage for internal events.
- At-power PSA for internal fires.
- At-power PSA for internal floods.
- At-power PSA-based Seismic Margin Assessment.
- At-power PSA for high winds.

Table 8 presents the SCDF and LRF for each of the above studies.

OPG did not prepare PSAs for internal floods, internal fires, seismic events and high winds for a single shutdown unit. The risk from each of these hazards while a unit is shutdown was shown to be bounded by the risk from an operating unit.

Results for PARA-L1P

The Level 1 at-power PSA for internal events (PARA-L1P) estimated the frequency of two Fuel Damage Categories, FDC1 and FDC2. These FDCs represent severe core damage due to the failure to shutdown and due to the failure of all heat sinks, respectively. The frequencies of these FDCs are presented in Table 9.

The results in Tables 8 and 9 show that:

1. The overall SCDF is almost one order of magnitude below OPG's safety goal limit.
2. Sequences involving the failure to shutdown are a very small contributor to SCDF.

The PARA-L1P assumed that the reactor was at full power for 100% of the operating cycle. Therefore, there is a degree of double-counting of SCDF between the PARA-L1P and the PARA-L1O.

Results for PARA-L1O

The Level 1 outage PSA for internal events (PARA-L1O) estimated the frequency of Fuel Damage Category FDC2 only. This FDC represents severe core damage due to failure of all heat sinks. The frequency of FDC2 for each POS is presented in Table 10.

The contribution of FDC1 to SCDF for a shutdown unit is very low due to the provision of two very reliable lines of defence, the shutdown guarantee and the shutdown systems. Therefore, the frequency of FDC1 was not estimated in the PARA-L1O.

The results in Tables 8 and 10 show that:

1. The overall SCDF is more than one order of magnitude below OPG's safety goal limit.

2. Sequences occurring in POS C do not contribute to SCDF. Analysis demonstrated that there is insufficient decay heat to lead to severe core damage over the seven-day analysis period.

   It is likely that additional analysis for POSs A and B could demonstrate that accidents occurring in these POSs long after shutdown also do not result in severe core damage. This could result in a significant reduction in the SCDF.

Results for PARA-L2P

The Level 2 at-power PSA for internal events (PARA-L2P) estimated the frequency of five Plant Damage States (PDS). The frequencies of the five PDS are presented in Table 11.

The PDS analysis was used as an input to estimate the frequency of three Release Categories (RC). The frequencies of the three RCs are presented in Table 12.

The results presented in Tables 8 and 12 show that the LRF is well below OPG's safety goal limit.

Results for Level 2 Outage for Internal Events

The bounding assessment of Level 2 outage for internal events determined that the LRF is less than 1 x 10^{-6} per reactor-year.

Results for the PARA-FIRE

The at-power fire PSA (PARA-FIRE) estimated the SCDF and LRF resulting from internal fires. The SCDF and LRF are presented in Table 8.

The results in Table 8 show that:

1. The SCDF due to internal fires is well below OPG's safety goal limit.

2. The LRF due to internal fires is below OPG's safety goal limit.

Results for the PARA-FLOOD

The at-power flood PSA (PARA-FLOOD) estimated the SCDF and LRF resulting from internal floods. The SCDF and LRF are presented in Table 8.

The results in Table 8 show that:

1. The SCDF due to internal floods is almost one order of magnitude below OPG's safety goal limit.

2. The LRF due to internal floods is well below OPG's safety goal limit.

Results of the PARA-SEISMIC

The at-power PSA-based seismic margin assessment (PARA-SEISMIC) estimated the plant level HCLPF for heat sinks to be 0.22g. This is very marginally below the peak ground acceleration for an earthquake corresponding to a 10,000 year return period 84^{th} percentile UHRS.

The PARA-SEISMIC estimated the seismically induced SCDF by convolving the plant level HCLPF with the mean seismic hazard curve. The estimated seismically induced SCDF was 2×10^{-8} per reactor-year.

The total seismic SCDF was estimated by adding the seismically induced SCDF to the SCDF from non-seismically induced failures. The non-seismically induced failures represent random failures of equipment in response to the unit shutdown forced by the seismic event. The total SCDF was estimated to be 0.26×10^{-5} per reactor-year.

The total seismic SCDF is more than one order of magnitude below OPG's safety goal limit.

Random, non-seismically induced failures of SSCs contributed approximately 99% of the SCDF.

The PARA-SEISMIC estimated the plant level HCLPF of containment boundary components to be 0.23g. The PARA-SEISMIC estimated the Seismically Induced Containment Failure Frequency by convolving the plant level containment HCLPF with the mean seismic hazard curve. The estimated SCFF was 1.3×10^{-8} per reactor-year.

The PARA-SEISMIC estimated the LRF by assuming that seismic events affect both units identically. If both units simulataneously progress to severe core damage, the containment boundary will fail consequentially and there will be a large release. Therefore, the LRF is also 0.26×10^{-5} per reactor-year.

The total seismic LRF is well below OPG's safety goal limit.

Given that most of SCDF results from non-seismically induced failures, the assumption of perfect correlation between the units is very conservative. Therefore, the estimate of LRF is also very conservative.

Results for the PARA-WIND

The at-power PSA for high winds (PARA-WIND) estimated the SCDF and LRF resulting from high winds. The SCDF and LRF are presented in Table 8.

The results in Table 8 show that:

1. The SCDF due to high winds is well below OPG's safety goal limit.

2. The LRF due to high winds is below OPG's safety goal limit.

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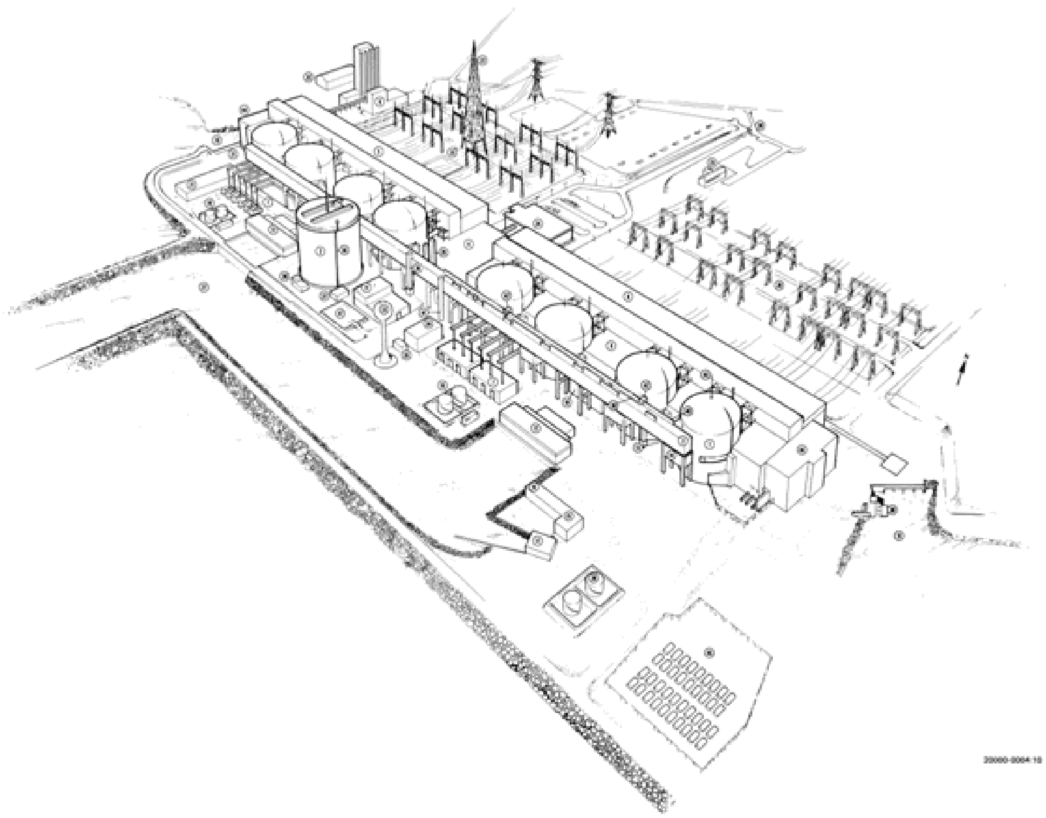
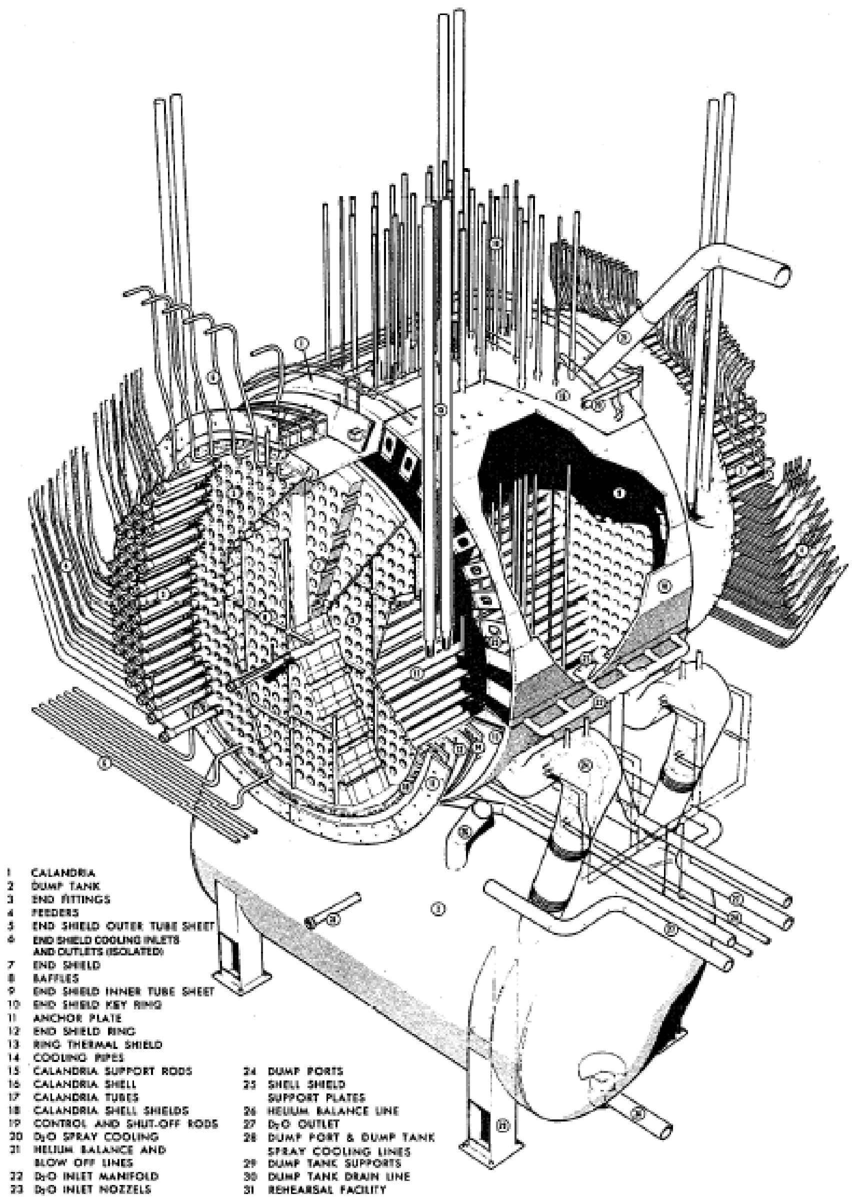
Figure 1: Pickering Site Layout



1. Reactor Building
2. Vacuum Building
3. Pressure Relief Duct
4. Service Wing
5. Turbine Hall (Units 1 to 4)
6. Turbine Hall (Units 5 to 8)
7. Standby Generators
8. Reactor Auxiliary Bay
9. Heavy Water Upgrading Plant
10. Cooling Water Outfall
11. Water Treatment Building
12. Screenhouses
13. Emergency Water Supply Valve Station (One Each for Units 5 to 8)
14. Unit Emergency Control Centre (One Each for Units 5 to 8)
15. Emergency Power Supply Generators
16. Emergency Water Supply Pumphouse
17. Tempering Water Pumphouse
18. Irradiated Fuel Bay (Units 5 to 8)
19. Oil Tanks for Standby Generators
20. Off-Gas Management Building
21. Auxiliary Irradiated Fuel Bay
22. Microwave Tower
23. Information Centre
24. Administration Building
25. Heavy Water Upgrading Towers
26. 230 kV Switchyard
27. Cooling Water Intake Channel
28. Emergency Power Generator Oil Tanks
29. Security Gatehouse
30. Small Craft Floating Dock
31. Component Dock
32. Warehouse
33. ECI Storage Tank
34. HPECI Pumphouse
35. ECIS Auxiliary Services Building
36. FAD Tower
37. FAD Stack Monitoring Buildings
38. FAD Stack
39. Emergency Cooling Injection System Piping
40. Emergency Cooling Injection System Valve Station (One Each for Units 5 to 8)
41. ECIS Concrete Tower
42. ECIS Steel Tower
43. Emergency Communications Antenna (Unit 8 Only)
44. West Annex Building
45. Dry Storage Module Yard
46. East Annex Building
47. Settling Basin

Figure 2: Typical Pickering NGS A Reactor



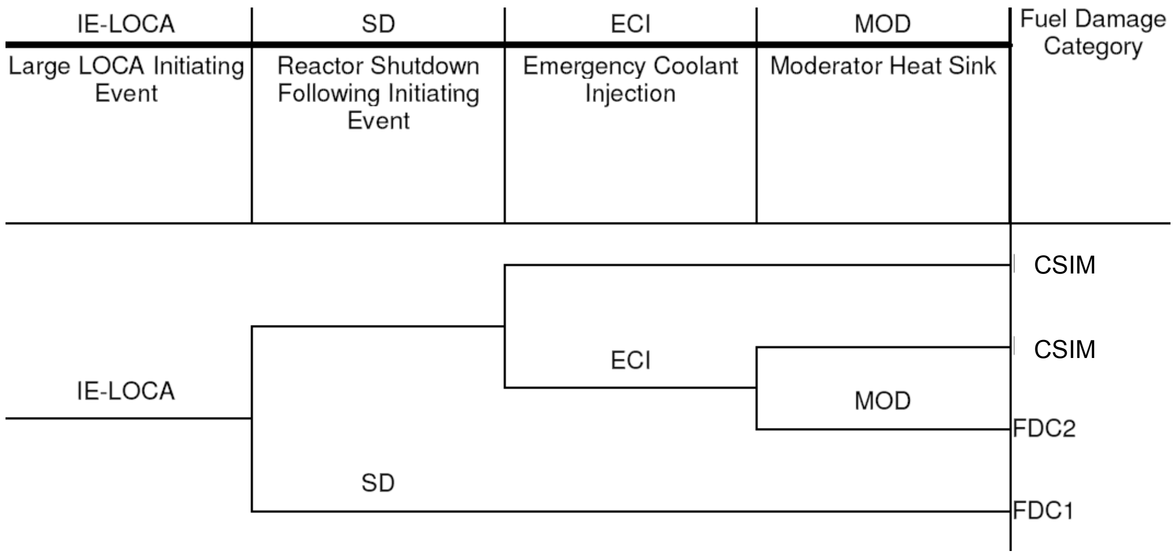


Figure 3: Example LOCA Event Tree

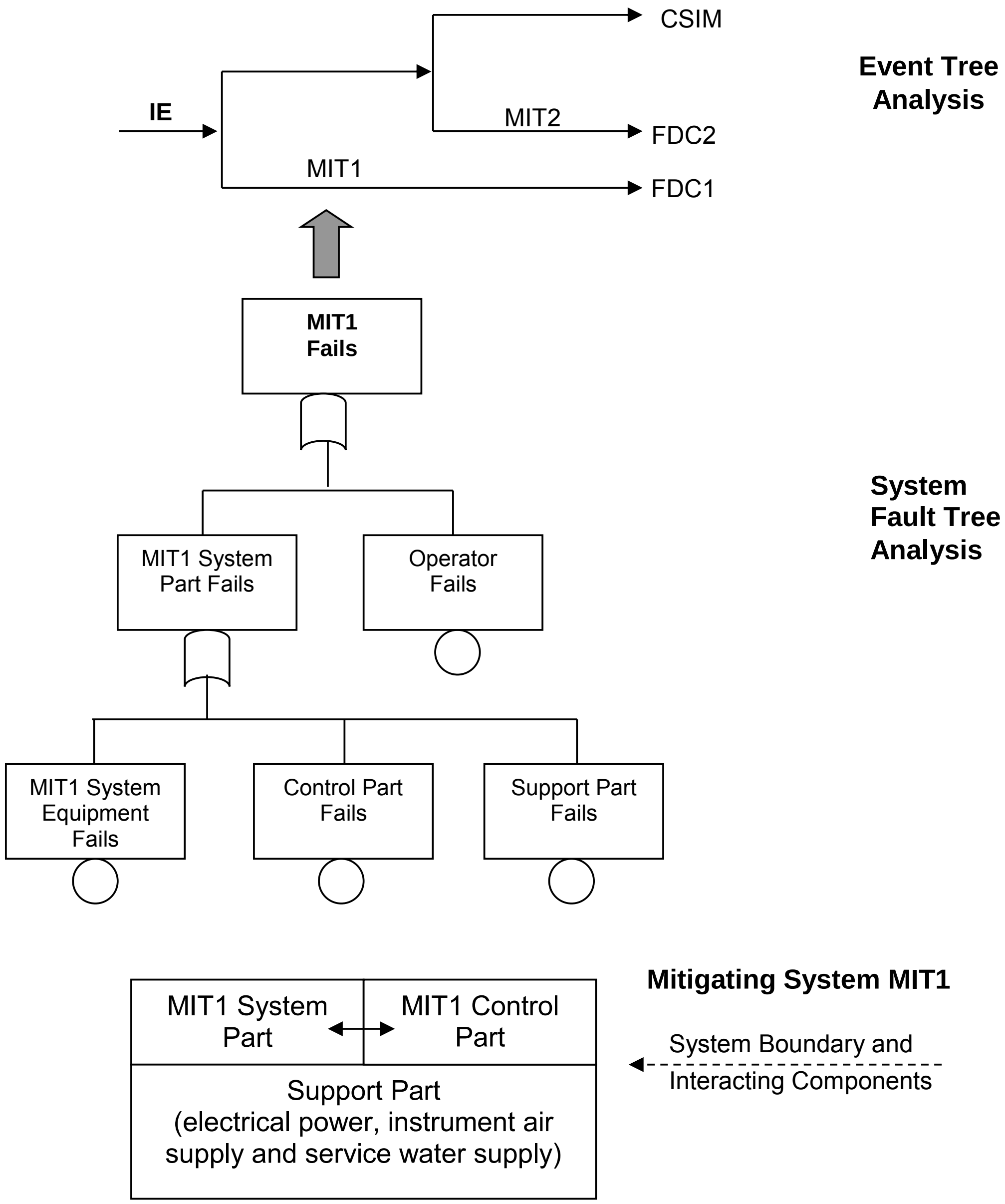


Figure 4: Fault Tree and Event Tree Integration

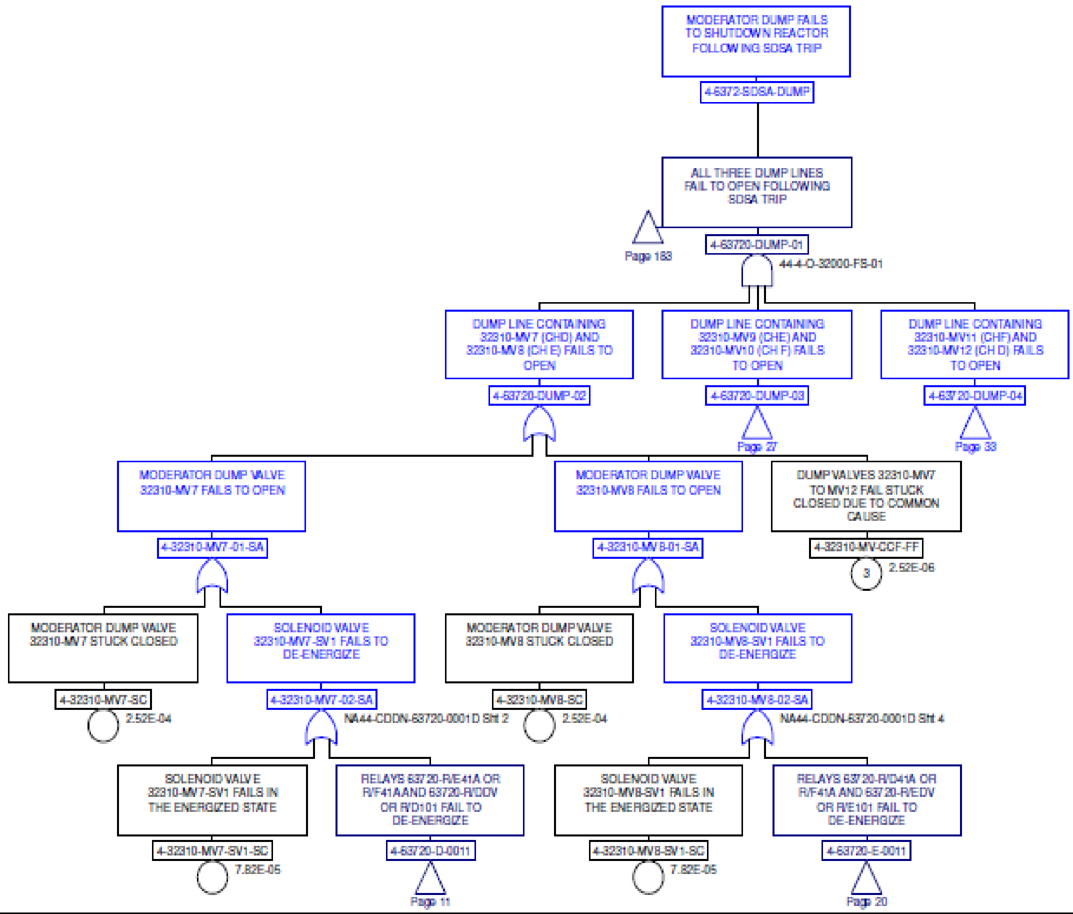
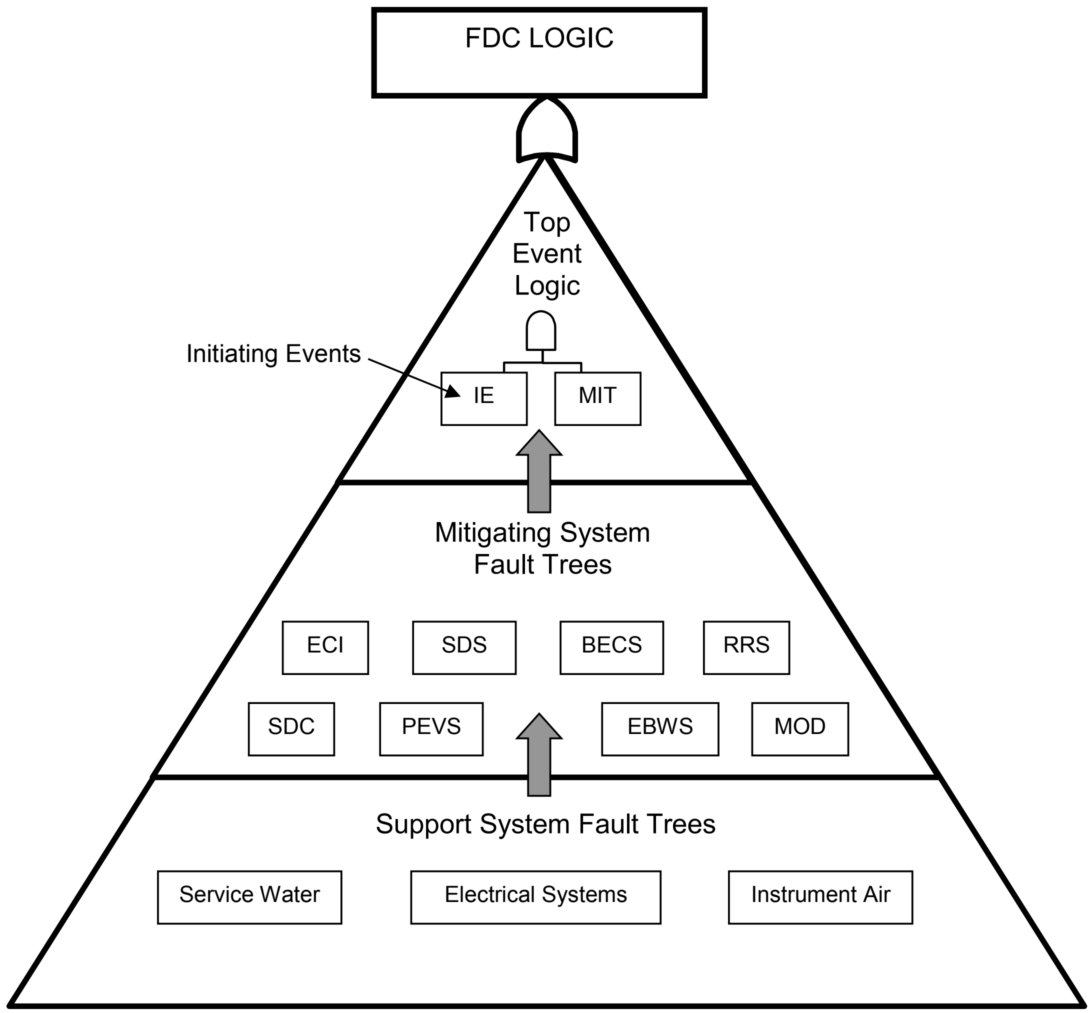


Figure 5: Example Fault Tree

Figure 6: Fault Tree Integration



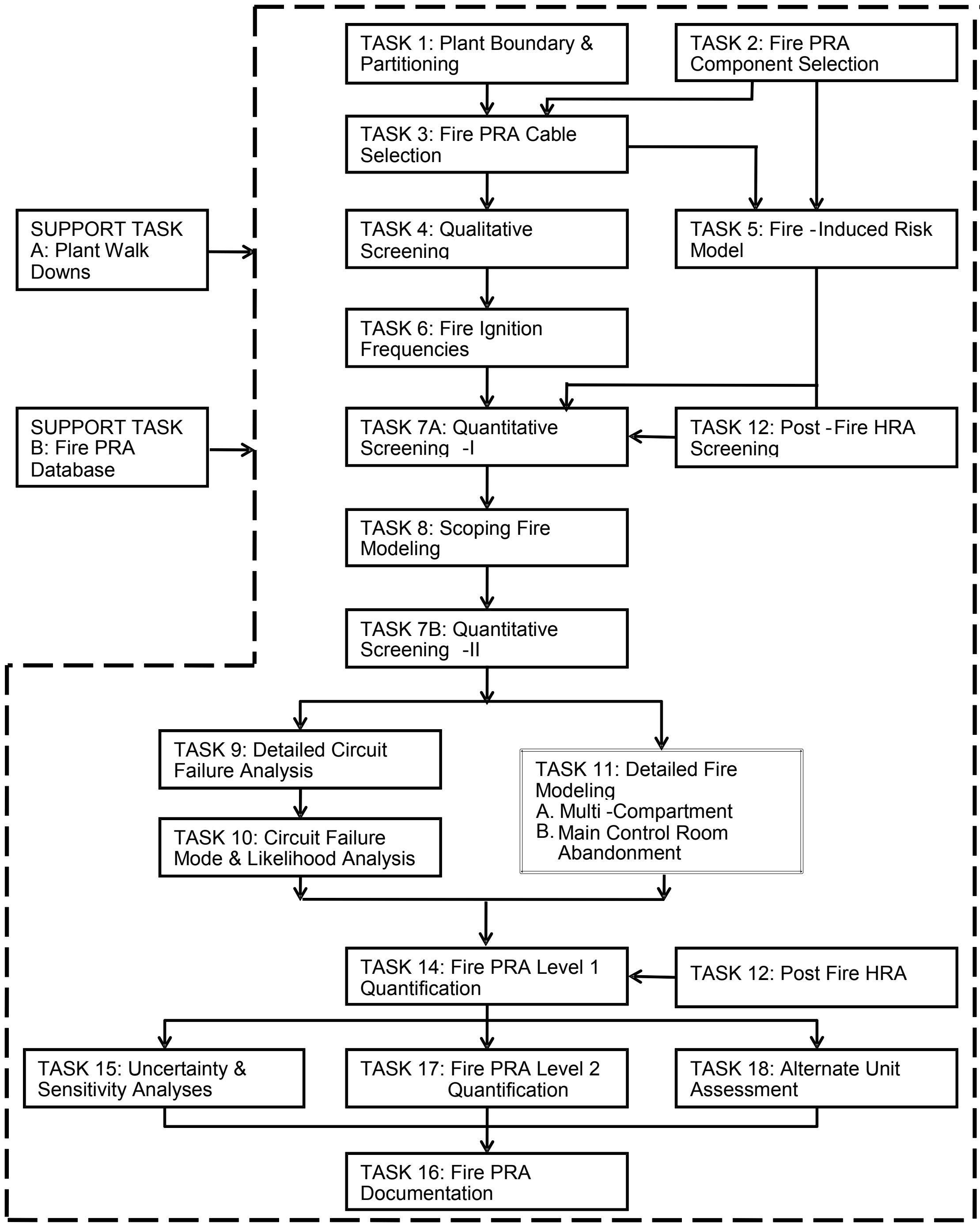


Figure 7: Fire PSA Tasks

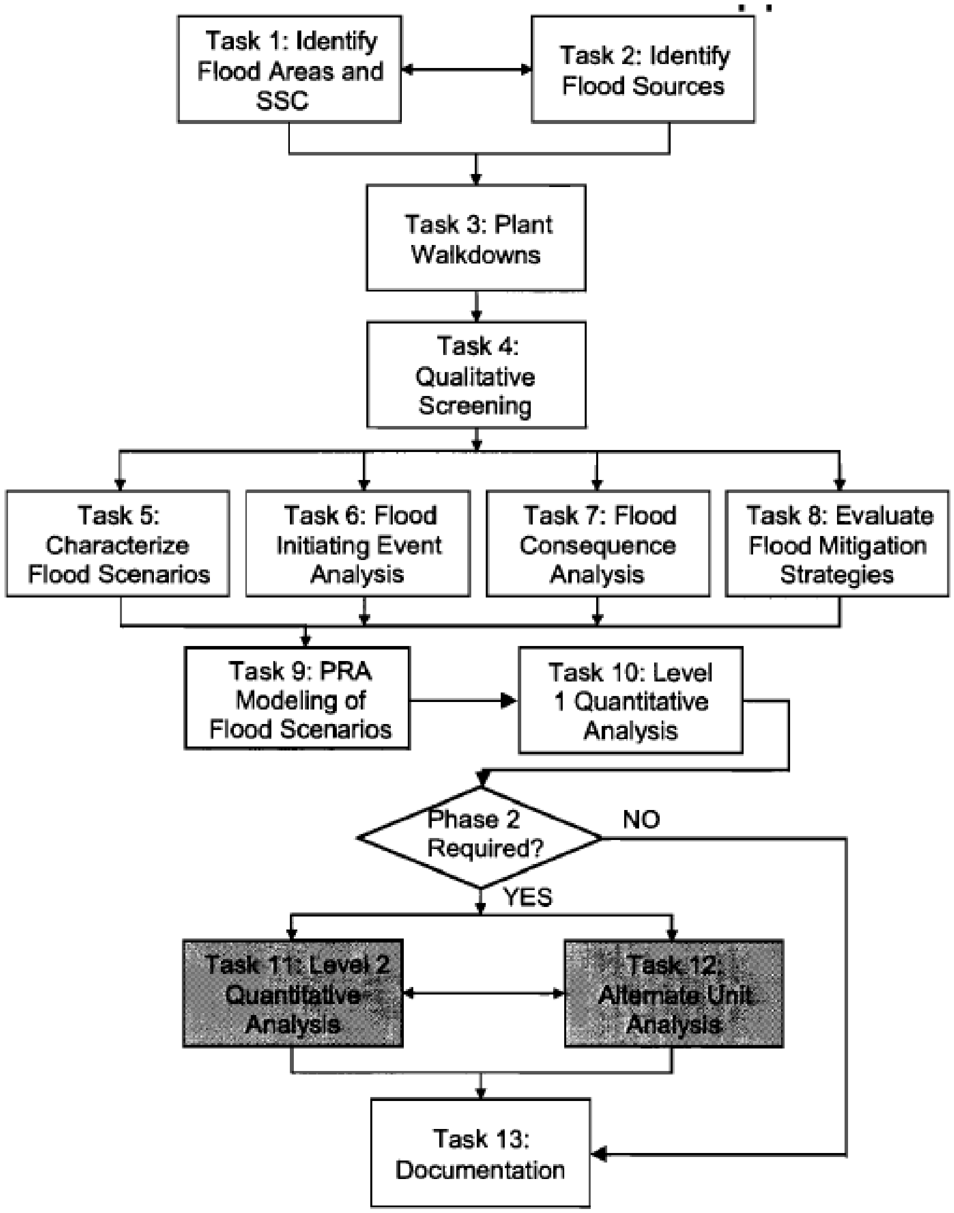


Figure 8: Internal Flood PSA Tasks

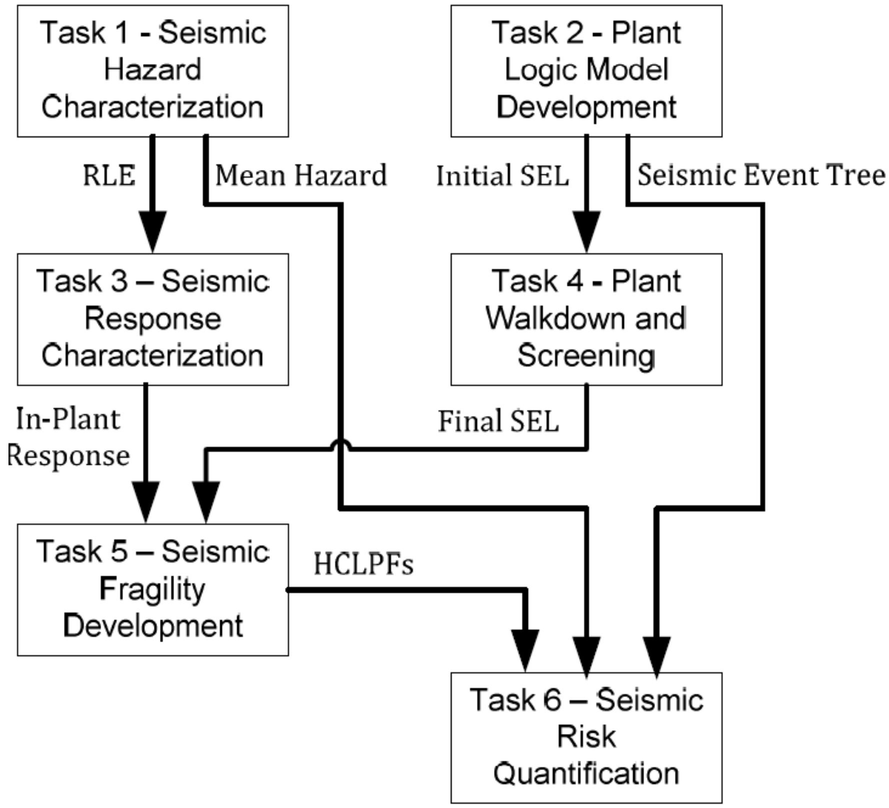


Figure 9: PSA-based SMA Tasks

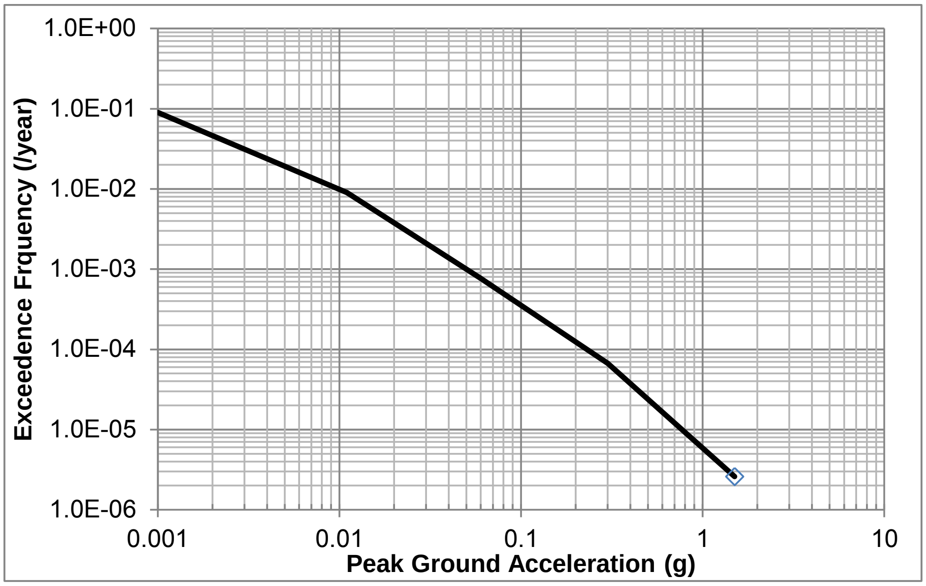


Figure 10: Example Seismic Hazard Curve

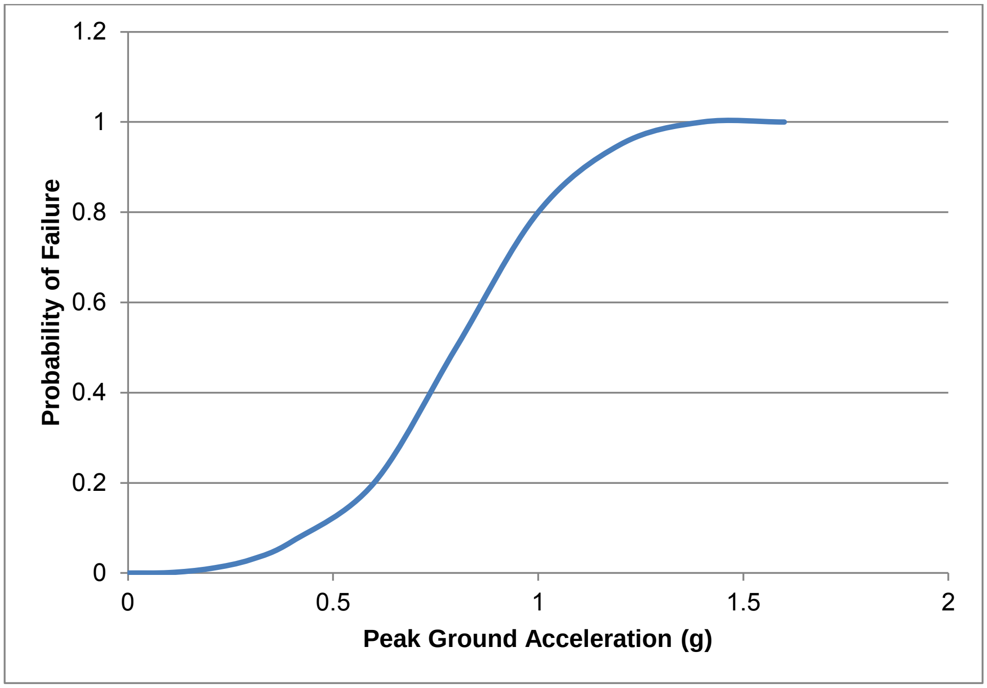


Figure 11: Example Fragility Curve

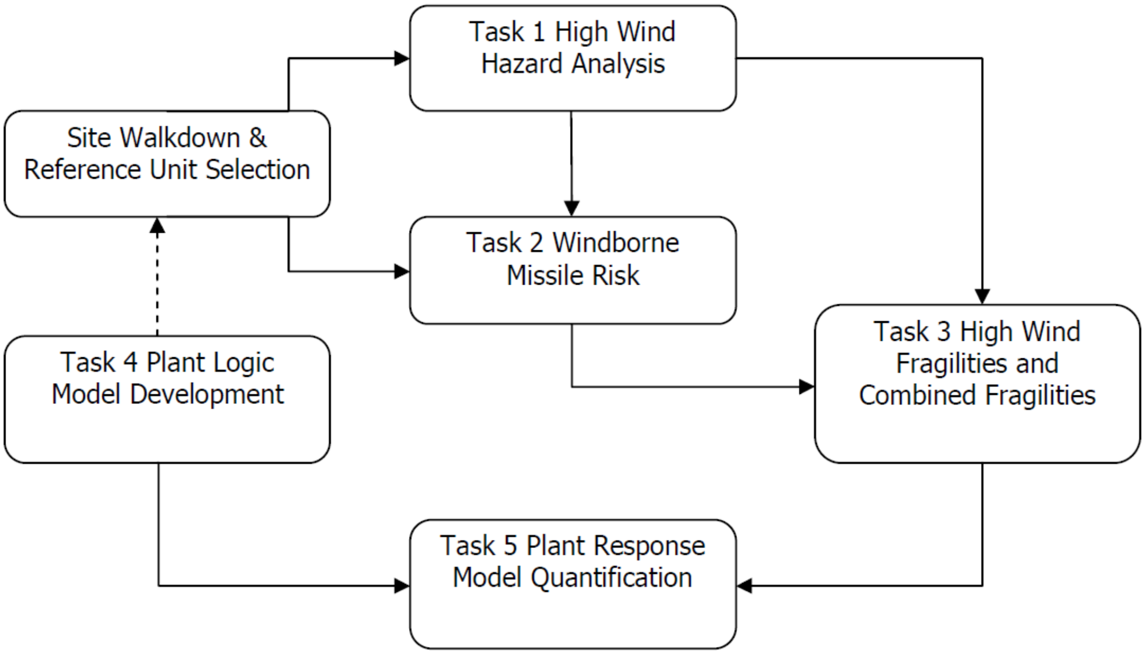
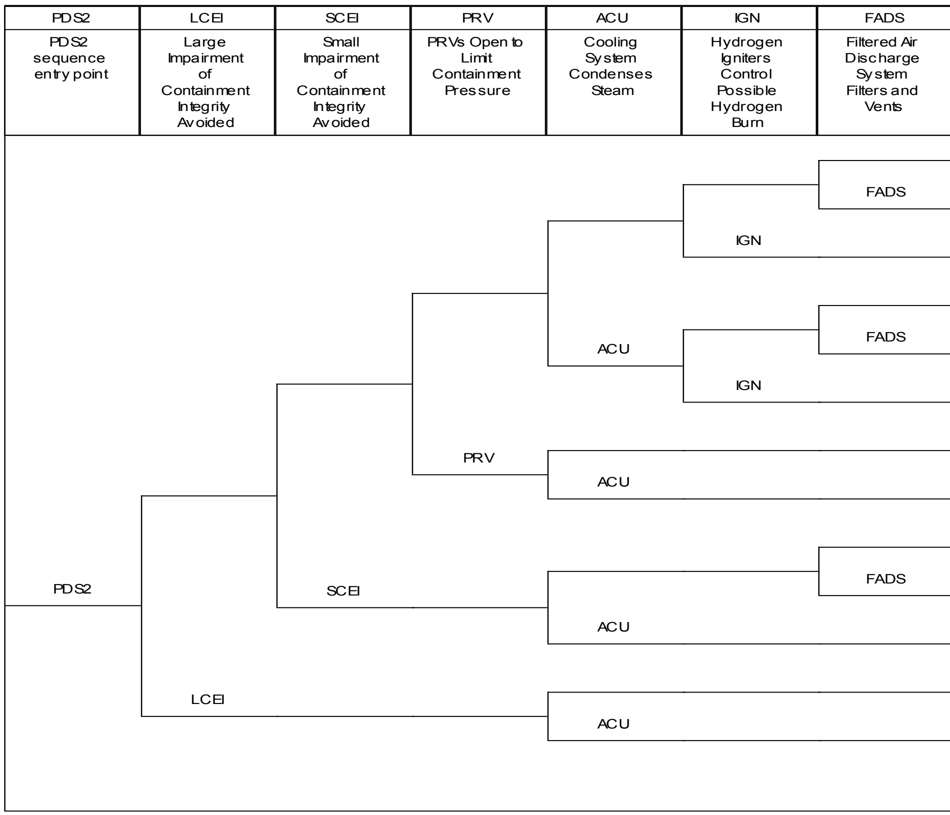


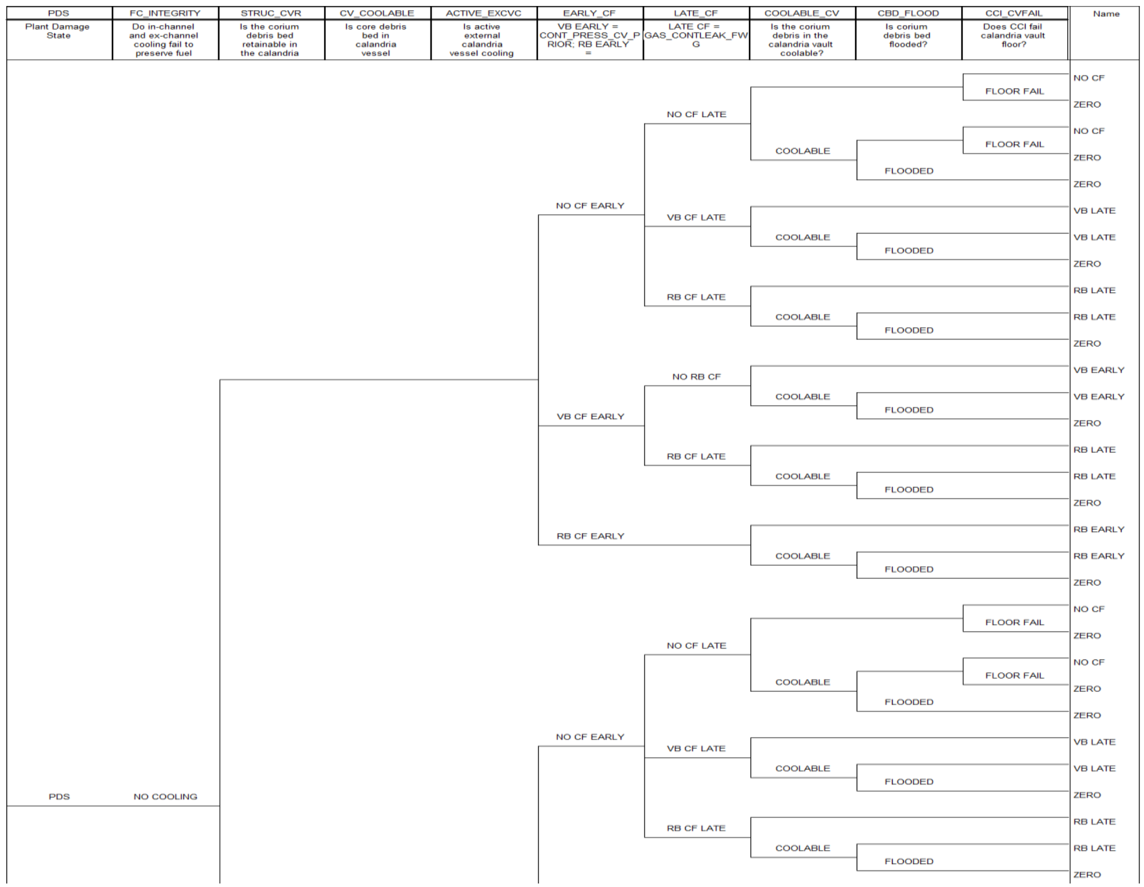
Figure 12: High Wind Hazard PSA Tasks

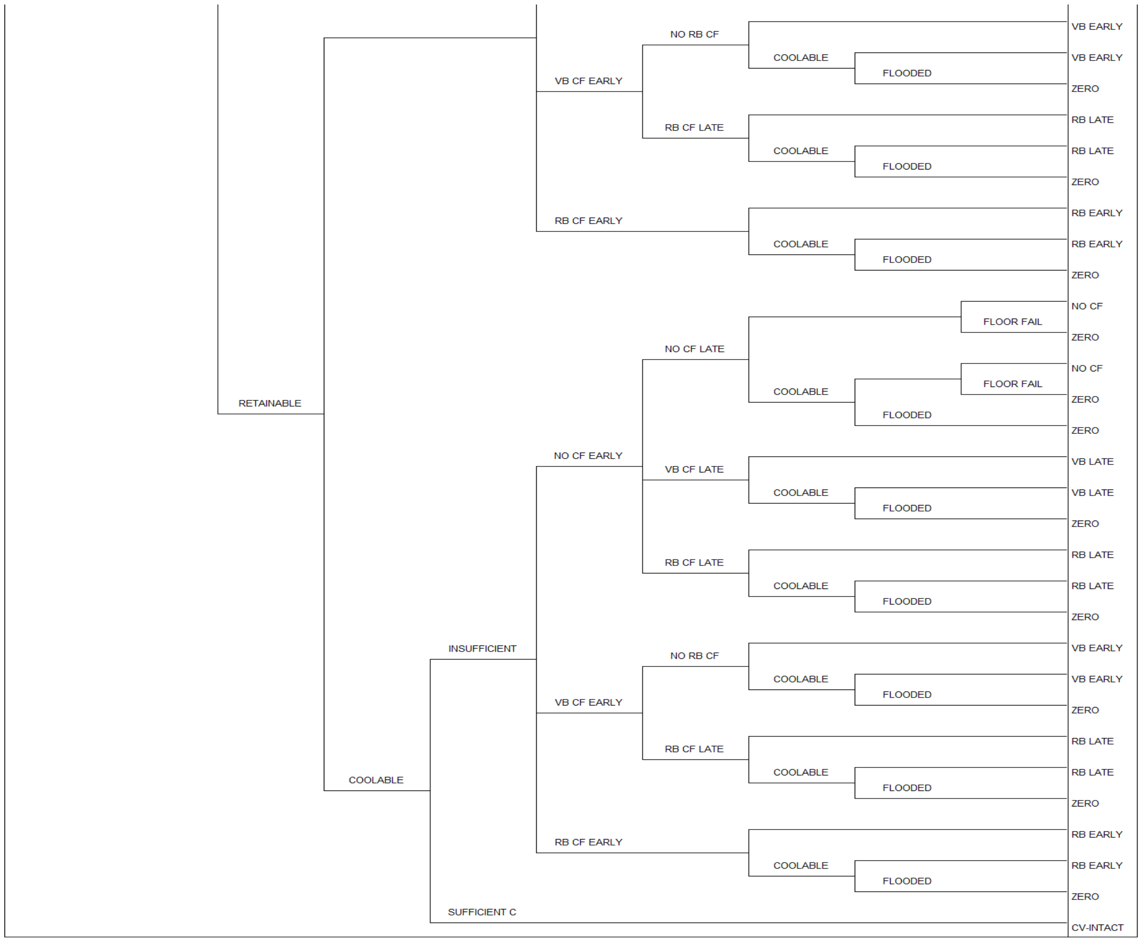
Figure 13: Pickering NGS A Bridging Event Tree



PDS	Sequence Description	Seq. Num
PDS2A	PDS2	BR-ET-001
PDS2B	PDS2,FADS	BR-ET-002
PDS2C	PDS2,IGN	BR-ET-003
PDS2D	PDS2,ACU	BR-ET-004
PDS2E	PDS2,ACU,FADS	BR-ET-005
PDS2F	PDS2,ACU,IGN	BR-ET-006
PDS2G	PDS2,PRV	BR-ET-007
PDS2H	PDS2,PRV,ACU	BR-ET-008
PDS2I	PDS2,SCEI	BR-ET-009
PDS2J	PDS2,SCEI,FADS	BR-ET-010
PDS2K	PDS2,SCEI,ACU	BR-ET-011
PDS2G	PDS2,LCEI	BR-ET-012
PDS2H	PDS2,LCEI,ACU	BR-ET-013

Figure 14: Generic Containment Event Tree




RETAINABLE
COOLABLE
INSUFFICIENT
SUFFICIENT C
VB CF EARLY
RB CF EARLY
NO CF EARLY
NO RB CF
RB CF LATE
NO CF LATE
VB CF LATE
COOLABLE
FLOODED
FLOOR FAIL
VB EARLY
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RB LATE
RB EARLY
NO CF
VB LATE
CV-INTACT

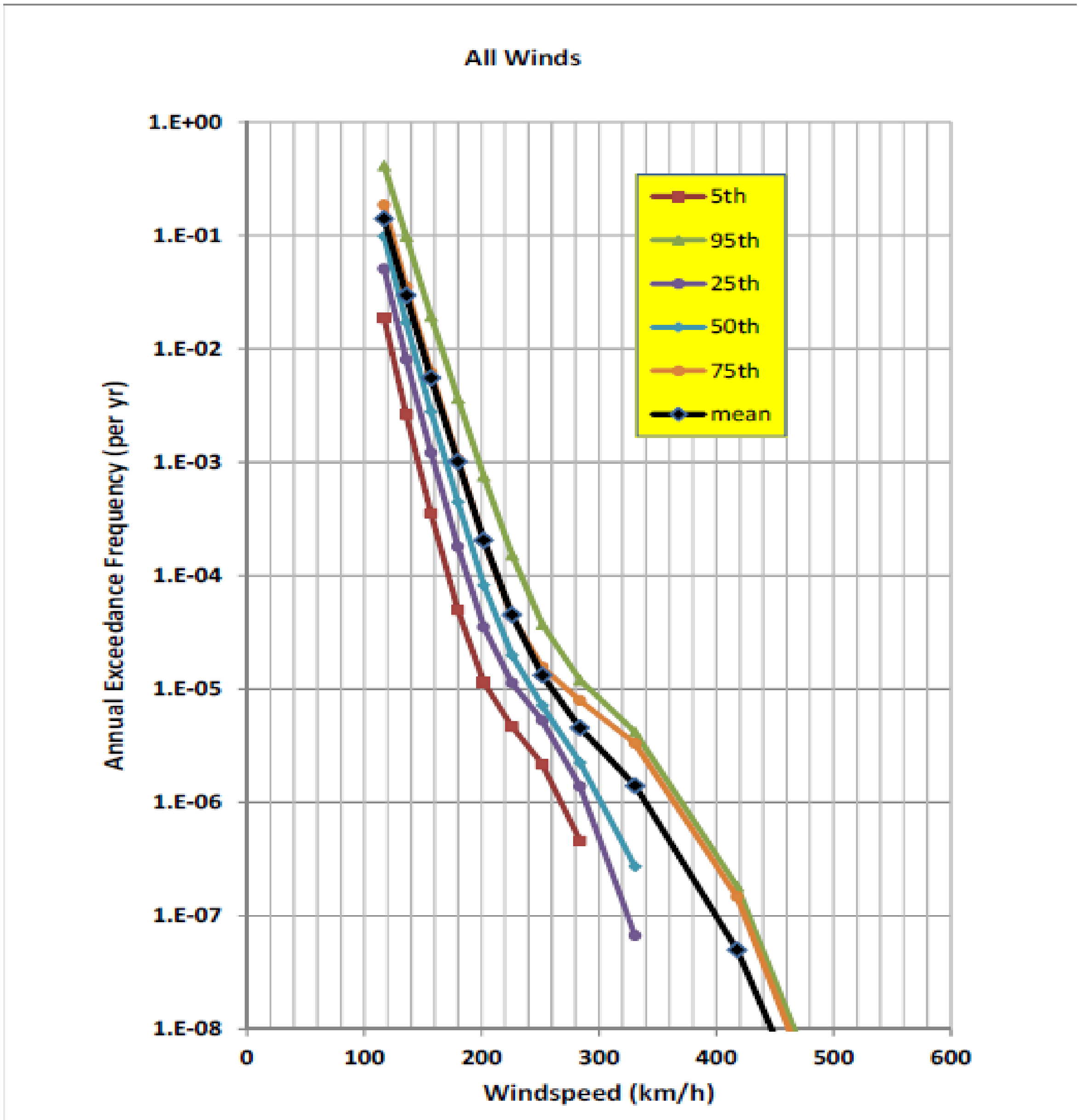

Figure 15: Pickering NGS A High Wind Hazard Curve

Table 1: OPG's Risk Based Safety Goals

RISK METRIC		AVERAGE RISK	
Title	**Definition**	**Target (per reactor year)**	**Safety Goal Limit (per reactor year)**
Severe Core Damage Frequency	Loss of core structural integrity	10^{-5}	10^{-4}
Large Release Frequency	Airborne release > 10^{14} Bq Cs-137	10^{-6}	10^{-5}

Table 2: Initiating Events in the PARA-L1P

Category	Label IE-44-	Description (PARA-L1P)
Forced Shutdown	FSD	All reactor shutdowns not included in other initiating events
LOCA	LOCA1	Small break within the capacity of two D_2O pressurizing pumps (initial discharge rate 1 - ~40 kg/s)
	LOCA2A	Small breaks which require ECIS for refilling and repressurization of the HTS (initial discharge rate ~40 - 100 kg/s)
	LOCA2B	Small breaks which require ECIS for refilling and repressurization of the HTS (initial discharge rate 100 - 1000 kg/s)
	LOCA3	Large breaks which require high and subsequently low pressure ECIS for refilling and do not result in flow stagnation into the core (initial discharge rate >1000 kg/s)
	LOCA4	Large breaks which require high and subsequently low pressure ECIS for refilling and lead to flow stagnation into the core (initial discharge rate >1000 kg/s)
	LOCA1-SF	Stagnation feeder break in LOCA1 range
	LOCA2-SF	Stagnation feeder break in LOCA2A range
Pressure Tube Rupture	PTL	Pressure tube failure resulting in an initial discharge rate of less than 1 kg/s
	PTF	Pressure tube failure resulting in an initial discharge rate in excess of 1 kg/s
End-fitting Failure	EFL2	End-fitting break of LOCA2-size outside annulus gas bellows in LOCA2 range (includes fuelling machine induced LOCAs)
Steam Generator Tube Rupture	SGTB1	Boiler tube break within the capacity of the D_2O feed system (initial discharge rate 1 - ~40 kg/s)
	SGTB2	Boiler tube break beyond the capacity of the D_2O feed system (initial discharge rate > ~40 kg/s)

Category	Label IE-44-	Description (PARA-L1P)
Loss of HTS Pressure Control (Low)	LRVO	One or more liquid relief valves fail open spuriously
	LBVO	A liquid bleed valve opens spuriously
	2LBVO	Both liquid bleed valves open spuriously
	FVFC	Both D_2O feed valves fail closed
	FPFO	Failure of in-service D_2O pressurizing pump
	XSPR	Bleed condenser spray valve 3332-CV113 opens spuriously
Loss of HTS Pressure Control (High)	BVFC	Both HTS bleed valves fail closed
	FVFO	Any or both D_2O feed valves fail open
	FP2S	Inadvertent start-up of standby D_2O pressurizing pump
	BCLCVFC	Bleed condenser level control valves fail closed
Loss of HTS Inventory Control	D2OFDL	Pipe break in D_2O feed system upstream of check valve 3331-NV1 or -NV2
HTS Pump Trip	HTPT	Any or up to four HTS pumps trip
Channel Flow Blockage	LFB	Channel flow reduced by 90 percent or more
	HTMV	Spurious closure of boiler isolating valve or HTS main pump discharge valve
Moderator Failure	LOMHS	Loss of moderator heat sink
	LOMF	Loss of moderator flow
	LOMI	Loss of moderator inventory
	DUMP	Spurious moderator dump
Loss of End Shield Cooling	LOESHS	Loss of end shield heat sink
	LOESF	Loss of end shield flow
	LOESI	Loss of end shield inventory

Category	Label IE-44-	Description (PARA-L1P)
Steam Line Break	SRV	One or more atmospheric steam rejection valves open spuriously
	SSLB-IC	Small steam line break inside containment
	SSLB-OC	Small steam line break outside containment
	LSLB-IC	Large steam line break inside containment
	LSLB-OC	Large steam line break outside containment
	U1LSLB-OC	Unit 1 large steam line break outside containment
	IE-30-LSLB-OC [1]	Unit 5 large steam line break outside containment at Pickering NGS B.
	IE-30-U678LSLB-OC	Unit 6/7/8 large steam line break outside containment at Pickering NGS B
Loss of Feedwater to One or More Boilers	TLOFW	Total loss of feedwater to all quadrants
	PLOFW	Partial loss of feedwater to all quadrants
	ALOFW	Asymmetric loss of feedwater (no feedwater flow to boilers in one quadrant)
Feedwater Line Break	SFLB-IC	Small feedline break inside containment
	SFLB-OC	Small feedline break outside containment
	LFLB	Large feedline break resulting in total loss of feedwater
	FLBCOND	Break in condensate system resulting in total loss of condensate flow to deaerator
	FWLB-CL1ROOM	Feedwater line break above Class I room
	U1LFLB	Unit1 large feedwater line break
Turbine Trip	TT	All turbine trips not included in other initiating events (includes loss of condenser vacuum events)
Loss of Condensate Flow	LOCONDA	Total loss of condensate flow to deaerator (excluding condensate pipe breaks)
	LOCONDB	Loss of main condensate flow to deaerator (excluding condensate pipe breaks)
Reheater Drains Line Break	RDLB	Breaks in reheater drains line between the boilers and the second check valve

[1] Note that events IE-30-LSLB-OC and IE-30-U678-LSLB-OC do not have the IE-44- prefix, since they originate in Pickering B.

Category	Label IE-44-	Description (PARA-L1P)
Unplanned Increase in Reactivity	FLOR	Fast rate of reactivity insertion
	SLOR	Slow rate of reactivity insertion
	LZCPMPFL	All liquid zone control system pumps fail
	URIR	Unplanned regional increase in reactivity
	SORD	Spurious shutoff rod drop resulting in a regional increase in reactivity
Loss of Computer Control	WDTOX	Controlling computer stall
	DCCF	Dual computer failure
	DCCUF	Unsafe failure of digital control computer leading to reactor power increase
	BPCF	Failure 'off' of boiler pressure control program on both computers
	FHCF	Failure 'off' of fuel handling system control program on digital control computer DCC2
	RRSF	Failure 'off' of reactor power control program on both computers
Loss of LPSW System	LOLPSW	Total loss of low pressure service water
Forebay event	FOREBAY	Adverse conditions in the forebay
Loss of HPSW System	LOHPSW	Total loss of high pressure service water
Loss of RCW System	LORCW	Total loss of recirculated cooling water system flow
Loss of Instrument Air	TLOIA	Total loss of instrument air
Loss of Bulk Electricity Supply	LOBES	Loss of bulk electricity supply
Loss of Switchyard	LOSWYD	Loss of switchyard
Loss of Power to Unit Class IV 4.16 kV Bus	LOCL4	Total loss of unit Class IV power
	LOSST	Loss of system service transformer or circuit breakers 5320-CB1A or -CB1C causing loss of power supply to Class IV 4.16 kV buses 5320-BUA or -BUC, respectively
	LO5320BUA	Loss of power to unit Class IV 4.16 kV bus BUA
	LO5320BUB	Loss of power to unit Class IV 4.16 kV bus BUB
	LO5320BUC	Loss of power to unit Class IV 4.16 kV bus BUC

Category	Label IE-44-	Description (PARA-L1P)
	LO5320BUD	Loss of power to unit Class IV 4.16 kV bus BUD
Loss of Unit Class IV 600 V Bus	LO5330BUA	Loss of power to unit Class IV 600 V bus BUA
	LO5330BUB	Loss of power to unit Class IV 600 V bus BUB
	LO5330BUC	Loss of power to unit Class IV 600 V bus BUC
	LO5330BUD	Loss of power to unit Class IV 600 V bus BUD
Loss of Power to Unit Class III 4.16 kV Bus	LO5412BUA	Loss of power to unit Class III 4.16 kV bus BUA
	LO5412BUB	Loss of power to unit Class III 4.16 kV bus BUB
Loss of Power to Unit Class III 600 V Bus	LO5413BUA	Loss of power to unit Class III 600 V bus BUA
	LO5413BUB	Loss of power to unit Class III 600 V bus BUB
	LO5413BUC	Loss of power to unit Class III 600 V bus BUC
	LO5413BUD	Loss of power to unit Class III 600 V bus BUD
Loss of Power to Unit Class II 600 V Bus	LO5423BUA	Loss of power to unit Class II 600 V bus BUA
	LO5423BUB	Loss of power to unit Class II 600 V bus BUB
Loss of Power to Unit Class II 120 V Bus	LO5440BUA	Loss of power to unit Class II 120 V ac bus BUA
	LO5440BUB	Loss of power to unit Class II 120 V ac bus BUB
	LO5450BUA	Loss of power to unit Class II 120 V ac bus BUA
	LO5450BUB	Loss of power to unit Class II 120 V ac bus BUB
	LO5450BUC	Loss of power to unit Class II 120 V ac bus BUC
	LO5450BUD	Loss of power to unit Class II 120 V ac bus BUD
	LO5450BUE	Loss of power to unit Class II 120 V ac bus BUE
	LO5450BUF	Loss of power to unit Class II 120 V ac bus BUF
	LO5440BUB1	Loss of power to unit Class II 120 V ac bus BUB1
Loss of Power to Unit Class II 48 V Bus	LO5520BU1 to LO5520BU22	Loss of power to unit Class II 48 V dc bus BU1 to BU22
	LO5520BU31 to LO5520BU52	Loss of power to unit Class II 48 V dc bus BU31 to BU52
Loss of Unit Class I 250 V Power	LO250	Total loss of unit Class I 250 V dc buses 55100-BUA1 and 55100-BUB1
Heat Transport Flow Diversion	SDCMV	Spurious opening of both shutdown cooling isolation valves in one or more quadrants
Powerhouse Freezing	PHFREEZE	Spurious opening of powerhouse venting during an extreme cold outside condition

Category	Label IE-44-	Description (PARA-L1P)
ECI Blowback	3335MV156	33350-MV156 opens spuriously
	3335MV156TS	33350-MV156 on test
ECI Blowback contd.	3335MV157	33350-MV157 opens spuriously
	3335MV157TS	33350-MV157 on test
	3335NV158	33350-NV158 opens spuriously
	3335NV159	33350-NV159 opens spuriously
	3335NV33	33350-NV33 opens spuriously
	3335NV34	33350-NV34 opens spuriously
	3335NV358	33350-NV358 opens spuriously
	3335NV47	33350-NV47 opens spuriously
	3335NV48	33350-NV48 opens spuriously
	3341MV1	33410-MV1 open spuriously
	3341MV10	33410-MV10 open spuriously
	3341MV10TS	33410-MV10 on test
	3341MV11	33410-MV11 open spuriously
	3341MV11TS	33410-MV11 on test
	3341MV1TS	33410-MV1 on test
	3341MV2	33410-MV2 open spuriously
	3341MV2TS	33410-MV2 on test
	3341MV4	33410-MV4 open spuriously
	3341MV4TS	33410-MV4 on test
	3341MV5	33410-MV5 open spuriously
	3341MV5TS	33410-MV5 on test
	3341MV7	33410-MV7 open spuriously
	3341MV7TS	33410-MV7 on test
	3341MV8	33410-MV8 open spuriously
	3341MV8TS	33410-MV8 on test
	BM-CHDTEST	LOCA conditioning logic on Test E-5 (Channel D)
	BM-CHETEST	LOCA conditioning logic on Test E-5 (Channel E)
	BM-CHFTEST	LOCA conditioning logic on Test E-5 (Channel F)
	BM-CHSTEST	LOCA conditioning logic on Test E-5 (Channel S)

Category	Label IE-44-	Description (PARA-L1P)
ECI Blowback contd.	SPBM-CHD	Spurious signal from LOCA conditioning logic (Channel D)
	SPBM-CHE	Spurious signal from LOCA conditioning logic (Channel E)
	SPBM-CHF	Spurious signal from LOCA conditioning logic (Channel F)
	SPBM-CHS	Spurious signal from LOCA conditioning logic (Channel S)
	SPHTPL-CHD	Spurious signal from LOCA HTS pressure low logic (Channel D)
	SPHTPL-CHE	Spurious signal from LOCA HTS pressure low logic (Channel E)
	SPHTPL-CHF	Spurious signal from LOCA HTS pressure low logic (Channel F)
	SPHTPL-CHS	Spurious signal from LOCA HTS pressure low logic (Channel S)
	SPHTPVL-CHD	Spurious signal from LOCA HTS pressure low logic (Channel D)
	SPHTPVL-CHE	Spurious signal from LOCA HTS pressure low logic (Channel E)
	SPHTPVL-CHF	Spurious signal from LOCA HTS pressure low logic (Channel F)
	SPHTPVL-CHS	Spurious signal from LOCA HTS pressure low logic (Channel S)
	BLR-CHDTEST	LOCA high boiler room pressure logic on test E-2 or E-6 (Channel D)
	BLR-CHETEST	LOCA high boiler room pressure logic on test E-2 or E-6 (Channel E)
	BLR-CHFTEST	LOCA high boiler room pressure logic on test E-2 or E-6 (Channel F)
	BLR-CHSTEST	LOCA high boiler room pressure logic on test E-2 or E-6 (Channel S)
	HTPLVL-CHDTEST	LOCA HTS pressure low / very low logic on test E-1 or E-6 (Channel D)
	HTPLVL-CHETEST	LOCA HTS pressure low / very low logic on test E-1 or E-6 (Channel E)
	HTPLVL-CHFTEST	LOCA HTS pressure low / very low logic on test E-1 or E-6 (Channel F)
	HTPLVL-CHSTEST	LOCA HTS pressure low / very low logic on test E-1 or E-6 (Channel S)
	MOD-CHDTEST	LOCA high moderator inventory logic on test E-3 or E-7 (Channel D)

Category	Label IE-44-	Description (PARA-L1P)
	MOD-CHETEST	LOCA high moderator inventory logic on test E-3 or E-7 (Channel E)
	MOD-CHFTEST	LOCA high moderator inventory logic on test E-3 or E-7 (Channel F)
	MOD-CHSTEST	LOCA high moderator inventory logic on test E-3 or E-7 (Channel S)

Table 3: List of Systems Modelled by Fault Trees in the Internal Events PSAs

System Name	L1 At-Power	L1 Outage	Level 2 At-Power
Heat Transport System Feed, Bleed, Relief and D_2O Storage and Transfer System	Y	Y	*
Heat Transport System D_2O Recovery System	Y	Y	*
Heat Transport Pump Gland Seal Supply and Gland Seal LOCA	Y	Y	*
Heat Transport Shutdown Cooling System	Y	Y	*
Moderator and ECI Recovery Systems	Y	Y	*
Boiler Feedwater System	Y	Y	*
Boiler Emergency Cooling System	Y	N	*
Steam Relief System	Y	Y	*
Class IV Power Supply System	Y	Y	*
Class III Power Supply System	Y	Y	*
Class II Power Supply System	Y	Y	*
Class I Power Supply System	Y	Y	*
Low Pressure Service Water System	Y	Y	*
Recirculated Cooling Water System	Y	Y	*
High Pressure Service Water System	Y	Y	*
Low Pressure Instrument Air System	Y	Y	*
High Pressure Instrument Air System	Y	Y	*
Emergency Coolant Injection System	Y	Y	*
Emergency Boiler Water Supply System	Y	Y	*
Standby Generator Fuel Oil System	Y	Y	*
Hostile Environment Events	Y	Y	*
Shutdown System A	Y	N	*
Shutdown System E	Y	N	*
Annulus Gas System	Y	Y	*
Digital Control Computer	Y	Y	*
Heating and Ventilation (Electrical Rooms, MCR, CER)	Y	Y	*
Reactivity Control System	Y	N	*
Condensate System	Y	Y	*
Emergency Coolant Injection System Blowback	Y	Y	*
Shutdown Heat Sinks	N	Y	*
Pressure Relief Valves	N	N	Y
Containment Isolation, Airlocks and Hydrogen Ignition System	N	N	Y
Boiler Room and Fuelling Machine Vault Air Cooling Units	N	N	Y
Hydrogen Ignition System	N	N	Y

* Included in Level 2 At-Power Model through integration with Level 1 At-Power Model.

Table 4: PARA-L1O Plant Operational States

Input Parameter	Plant Operational State (POS)		
	A	B	C
GSS	Dumped	Dumped	Dumped
HTS Inventory Level	Primary side of all boilers full	Primary side of some boilers drained and isolated	Primary side of all boilers full
HTS Boundary Configuration	Closed	Closed	Closed
Typical HTS Pressure (ROH)	HTS depressurized	HTS depressurized	HTS pressurized
Typical Primary Heat Sink (Circulation)	SDCS pumps	SDCS pumps	SDCS pumps
Typical Primary Heat Sink (Heat Removal)	SDCS HXs	SDCS HXs	Bleed cooler or boilers
Typical Backup Heat Sink (Circulation)	SDCS pumps	SDCS pumps	SDCS pumps
Typical Backup Heat Sink (Heat Removal)	SDCS HXs	SDCS HXs	Bleed cooler or boilers
Emergency Heat Sink	EBWS supply to boilers, heat rejection via SRVs	EBWS supply to boilers, heat rejection via SRVs	EBWS supply to boilers, heat rejection via SRVs
Time Average (days) - Duration per Unit per Year	34.6	41.5	3.3

Table 5: Initiating Events for PARA-L1O

IE-LABEL	DEFINITION	APPLICABLE POS		
		POS A	POS B	POS C
SDC-HX	Loss of SDCS heat removal	Y	Y	-
SDC-FLOW	Loss of SDCS flow	Y	Y	Y
BLDCLR	Loss of bleed cooling			Y
TLOFW	Total loss of feedwater			Y
BLOWDOWN	Loss of boiler blowdown			Y
LEAK1	HTS leak inside containment from depressurized HTS greater than capacity of D2O make-up	Y	Y	-
LLEAK	Small HTS leak inside containment from depressurized HTS within capacity of D2O make-up	Y	Y	-
LOCA1	Rupture of pressurized HTS within the capacity of D2O make-up	-	-	Y
LLOCA	Rupture of pressurized HTS beyond the capacity of D2O make-up	-	-	Y
LEAK-SDC	Rupture of SDCS piping	Y	Y	Y
SDCHXTB	Break of SDCS HX tube	Y	Y	Y
PTF	Pressure tube failure	-	-	Y
PTL	Pressure tube leak	Y	Y	Y
SGTB	Boiler tube leak	-	-	Y
BLOWBACK	Blowback outside containment through ECIS piping	-	-	Y
U1LSLB-OC	U1 large steamline break	Y	Y	Y
U5678-LSLB-OC	Large steamline break at Pickering NGS B	Y	Y	Y
U1LFLB	U1 large feedline break	Y	Y	Y
PHFREEZE	Spurious operation of powerhouse venting during cold weather	Y	Y	Y
U15678-BREAK-IC	High energy line break inside containment from any high power unit	Y	Y	Y
LOPIC-HIGH	Loss of HTS pressure & inventory control leading to high pressure	-	-	Y
LOPIC-LOW	Loss of HTS pressure & inventory control leading to low pressure	-	-	Y
SDC-INV	Loss of HTS inventory leads to failure of SDCS circulation	Y	Y	Y
LOBES	Loss of off-site power	Y	Y	Y
LOSWYD	Loss of switchyard	Y	Y	Y
LOSST	Loss of System Service Transformers or associated breakers	Y	Y	Y
LOCL4	Total loss of Class IV power	Y	Y	Y
LOCL4BU	Loss of one or several Class IV busses	Y	Y	Y
LOCL3BU	Loss of one or several Class III busses	Y	Y	Y
LOCL2BU	Loss of one or several Class II busses	Y	Y	Y
LOCL1BU	Loss of one or several Class I busses	Y	Y	Y
LOLPSW	Total loss of low pressure service water	Y	Y	Y
FOREBAY	Adverse conditions in forebay affects service water supply	Y	Y	Y
LOHPSW	Total loss of high pressure service water	Y	Y	Y
LORCW	Total loss of recirculated cooling water	Y	Y	Y
TLOIA	Total loss of instrument air	Y	Y	Y

Table 6: PARA-L2P Plant Damage States

PDS	Representative Accident Sequence
PDS1	No representative sequence required
PDS2A	Not used.
PDS2B	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, and FADS.
PDS2C	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, FADS, and igniters.
PDS2D	Not used.
PDS2E	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, ACUs in the accident unit, and FADS.
PDS2F	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, ACUs in the accident unit, igniters, and FADS.
PDS2G	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, igniters, and FADS, and a large containment envelope impairment.
PDS2H	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, ACUs in the accident unit, igniters, and FADS, and a large containment envelope impairment.
PDS2I	Not used.
PDS2J	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, FADS, igniters, and a small containment envelope impairment.
PDS2K	Out-of-core LOCA with failure of moderator cooling, ECIS injection and recovery, FADS, ACUs in the accident unit and igniters, and a small containment envelope impairment.
PDS3-2U	Secondary side line break with EBWS failure in Unit 4 and a total loss of heat sinks in Unit 1.
PDS3-6U	Total loss of heat sinks in all 6 Pickering units.
PDS4	Multiple steam generator tube rupture, failure of ECIS and moderator cooling.

Table 7: Pickering NGS A Release Categorization Scheme

Release Category #	Description
RC1	Large early release with potential for acute offsite radiation effects and/or widespread contamination (greater than 3% core inventory of I-131/Cs-137).
RC2	Release in excess of 10^{14} Bq of Cs-137 but less than RC1 occurring within 24 hours.
RC3	Release in excess of 10^{14} Bq of Cs-137 but less than RC1 occurring after 24 hours.

Table 8: Results for the Pickering NGS A PSA

PSA Element	SCDF (x 10^{-5} per r-year)	LRF (x 10^{-5} per r-year)
Internal Events At-Power	1.63	0.47
Internal Events Shutdown	0.66	< 0.1
Internal Fires At-Power	4.73	0.84
Internal Fires Shutdown	(Note 1)	(Note 1)
Internal Floods At-Power	1.02	0.20
Internal Floods Shutdown	(Note 1)	(Note 1)
Seismic Events At-Power	0.26 (Note 2)	0.26 (Note 2)
Seismic Events Shutdown	(Note 1)	(Note 1)
High Wind At-Power	2.69 (Note 2)	0.80 (Note 2)
High Wind Shutdown	(Note 1)	(Note 1)
OPG's Safety Goal Limit	10	1

Notes:

1. The risk for a shutdown unit was shown to be bounded by the risk for an at-power unit. The PSA conservatively assumed that the unit was continuously at-power.

2. The risk was estimated for seismic events / high winds with a return period up to and including 10 000 years.

Table 9: PARA-L1P Frequency of Fuel Damage Categories

Fuel Damage Category: Designation	Fuel Damage Category: Definition	Frequency (per r-yr)
FDC1	Rapid loss of core structural integrity	2.80×10^{-7}
FDC2	Slow loss of core structural integrity	1.60×10^{-5}
Severe Core Damage	(FDC1 + FDC2)	1.63×10^{-5}

Table 10: PARA-L1O Frequency of FDC2 by POS

Fuel Damage Category	Plant Operating State	Time-Average Frequency (per r-yr)
FDC2-SD	POS A	3.68×10^{-6}
	POS B	2.95×10^{-6}
	POS C	0
Severe Core Damage	All	6.63×10^{-6}

Table 11: PARA-L2P Plant Damage State Frequency

PDS	Frequency (/r-yr)
PDS1	2.80×10^{-7}
PDS2	1.28×10^{-5}
PDS3 – 2U	1.89×10^{-6}
PDS3 – 6U	1.30×10^{-6}
PDS4	7.20×10^{-8}

Table 12: PARA-L2P Release Category Frequency

Release Category	Frequency (/r-yr)
RC1	4.69×10^{-6}
RC2	(Note 1)
RC3	3.45×10^{-8}
LRF	4.72×10^{-6}

Notes:

1. No sequences were assigned to this RC.

Table 13: High Wind Hazard and Wind Speed Ranges

Sub-interval	Wind Speed [km/hr]		Wind Speed Frequency Distribution Parameters [per year]					
	Range	Mid Pt	5th	25th	50th	75th	95th	Mean
F1-1	117 - 137	127	1.61E-02	4.27E-02	8.15E-02	1.50E-01	3.15E-01	1.11E-01
F1-2	137 - 158	147	2.26E-03	6.78E-03	1.42E-02	2.90E-02	7.84E-02	2.41E-02
F1-3	158 - 180	169	3.02E-04	1.03E-03	2.33E-03	5.13E-03	1.57E-02	4.51E-03
F2-1	180 - 203	191	3.82E-05	1.45E-04	3.63E-04	8.65E-04	2.90E-03	8.08E-04
F2-2	203 - 227	215	6.75E-06	2.38E-05	6.25E-05	1.58E-04	5.96E-04	1.60E-04
F2-3	227 - 253	240	2.49E-06	5.98E-06	1.27E-05	2.83E-05	1.15E-04	3.18E-05
F3-1	253 - 285	269	1.71E-06	3.89E-06	4.89E-06	7.67E-06	2.50E-05	8.65E-06
F3-2	285 - 332	308	4.56E-07	1.31E-06	1.97E-06	4.61E-06	7.84E-06	3.13E-06
F4	332 - 418	375		6.67E-08	2.72E-07	3.16E-06	3.98E-06	1.35E-06
F5	>418			2.34E-13	2.08E-12	1.46E-07	1.81E-07	5.01E-08

Appendix A: Abbreviations and Acronyms

Acronym	Definition
ACU	Air Cooling Unit
BECS	Boiler Emergency Cooling System
Bq	Bequerels
CAFTA	Computer Aided Fault Tree Analysis System
CANDU	CANadian Deuterium Uranium
CCDP	Conditional Core Damage Probability
CER	Control Equipment Room
CET	Containment Event Tree
CNSC	Canadian Nuclear Safety Commission
CSIM	Core Structural Integrity Maintained
Cs-137	Cesium-137
D_2O	Deuterium Oxide (Heavy Water)
DCC	Digital Control Computer
EBWS	Emergency Boiler Water Supply System
ECIS	Emergency Coolant Injection System
ECVF	Early Calandria Vessel Failure
EME	Emergency Mitigating Equipment
ERO	Emergency Response Organization
ET	Event Tree
FADS	Filtered Air Discharge System
FDC	Fuel Damage Category
FHA	Fire Hazard Assessment
FIF	Fire Ignition Frequency
FSSA	Fire Safe Shutdown Assessment
FT	Fault Tree
FTREX	Fault Tree Reliability Evaluation eXpert
GSS	Guaranteed Shutdown State
HCLPF	High Confidence of Low Probability of Failure.
HGL	Hot Gas Layer
HPECI	High Pressure Emergency Coolant Injection
HPSW	High Pressure Service Water
HRA	Human Reliability Analysis
HTS	Heat Transport System
HX	Heat Exchanger
Hz	Hertz (1 Hz = 1 cycle per second)
IE	Initiating Event
IFB	Irradiated Fuel Bay
IGN	Hydrogen Igniters
ISTB	Inter-Station Transfer Bus
I-131	Iodine-131
kg/s	Kilograms per second
km/hr	Kilometres per hour
kV	Kilo-Volts
LCEI	Large Containment Envelope Impairment
LOCA	Loss-of-Coolant Accident

Acronym	Definition
LPSW	Low Pressure Service Water
LRF	Large Release Frequency
m	Metres
m^2	Metres squared
MAAP	Modular Accident Analysis Program
MCA	Multi-Compartment Analysis
MCR	Main Control Room
MPa	Mega Pascals (10^6 Pascals)
MPa(g)	Mega Pascals gauge
MWe	Megawatt electrical
NGS	Nuclear Generating Station
NPCS	Negative Pressure Containment System
NRC	U.S. Nuclear Regulatory Commission
occ/yr	Occurrences per year
OPG	Ontario Power Generation
PAU	Physical Analysis Unit
PARA	Pickering NGS A Probabilistic Safety Assessment
PARA-FIRE	Pickering NGS A At-Power Internal Fire PSA
PARA-FLOOD	Pickering NGS A At-Power Internal Flooding PSA
PARA-WIND	Pickering NGS A At-Power High Wind PSA
PARA-L1O	Pickering NGS A Level 1 Outage PSA for Internal Events
PARA-L1P	Pickering NGS A Level 1 At-Power PSA for Internal Events
PARA-L2P	Pickering NGS A Level 2 At-Power PSA for Internal Events
PARA-SEISMIC	Pickering NGS A At-Power PSA-Based Seismic Margin Assessment
PDS	Plant Damage State
PEVS	Powerhouse Emergency Venting System
POS	Plant Operational State
PSA	Probabilistic Safety Assessment
PRD	Pressure Relief Duct
PRV	Pressure Relief Valve
RC	Release Category
RCWS	Recirculating Cooling Water System
RLE	Review Level Earthquake
RRS	Reactor Regulating System
SCDF	Severe Core Damage Frequency
SCEI	Small Containment Envelope Impairment
SCFF	Seismically induced Containment Failure Frequency
SDCS	Shutdown Cooling System
SDS	Shutdown System
SDSE	Shutdown System Enhancement
SEL	Seismic Equipment List
SMA	Seismic Margin Assessment
SRV	Steam Reject Valve
SSC	Systems Structures and Components
THERP	Technique for Human Error Rate Prediction
UHRS	Uniform Hazard Response Spectrum

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Revision Summary

Revision Number	Date	Comments
R000	April 2014	Initial issue.

Executive Summary

OPG prepared Probabilistic Safety Assessments (PSA) for Pickering NGS A and Pickering NGS B to provide comprehensive assessments of the safety of the stations. These PSAs complied with the requirements of Canadian Nuclear Safety Commission Regulatory Standard S-294 *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants*.

The results of the Pickering S-294 compliant PSAs were reported in:

- NA44-REP-03611-00036-R000 *Pickering A Risk Assessment Summary Report.*
- NK30-REP-03611-00021-R000 *Pickering B Risk Assessment Summary Report.*

Pickering Power Reactor Operating Licence 48.00/2018 established a hold-point of 210,000 Effective Full Power Hours for the Pickering pressure tubes. Prior to removal of the hold point, OPG was required to update the Pickering S-294 compliant PSAs to take into account the enhancements required under the Canadian Nuclear Safety Commission's Fukushima Integrated Action Plan.

OPG updated only the Pickering S-294 compliant PSAs for hazards that were significant to risk. For example, the Pickering NGS B PSA for internal floods was not updated due to the very low risk from internal floods.

The most risk significant enhancement required under the Fukushima Integrated Action Plan was the Emergency Mitigating Equipment (EME). The EME was incorporated into all of the updated PSAs. The Pickering NGS A S-294 compliant PSAs for internal fires and high winds had already incorporated the EME.

OPG also incorporated some of the lessons learned in the preparation of the S-294 compliant PSAs into the updated PSAs. Only lessons that were likely to affect risk and were easily incorporated into the PSA were addressed.

The purpose of this report is to summarize the changes made to the S-294 compliant PSAs and to report the results of the updated PSAs.

OPG uses Severe Core Damage Frequency (SCDF) and Large Release Frequency (LRF) as safety goals. The intent of these safety goals is to ensure that the risk arising from nuclear accidents associated with the operation of OPG's nuclear power reactors is low in comparison to the risks to which the public is normally exposed.

The following tables summarize the SCDF and LRF for each of the hazards analysed in the PSA.

For Pickering NGS A, the updated SCDF for each hazard is at least one order of magnitude below OPG's safety goal limit and the updated LRF for each hazard is no more than 20% of OPG's safety goal limit.

For Pickering NGS B, the updated SCDF for each hazard is at least two orders of magnitude below OPG's safety goal limit and the updated LRF for each hazard at least one order of magnitude below OPG's safety goal limit.

OPG further updated the estimate of Pickering NGS A LRF to better take account of the risk associated with a shutdown unit. This further reduced the estimate of LRF for Pickering NGS A.

Results of the Pickering NGS A PSA

PSA Element	PSA Updated ?	Severe Core Damage Frequency ($x\ 10^{-5}$ per reactor-year)		Large Release Frequency ($x\ 10^{-5}$ per reactor-year)	
		Baseline	Updated	Baseline	Updated
Internal Events At-Power	Y	1.63	0.83	0.47	0.17
Internal Events Shutdown	N	0.66	n/a	< 0.1	n/a
Internal Fires At-Power	N	4.73	n/a	0.84	n/a
Internal Fires Shutdown	N	(Note 1)	n/a	(Note 1)	n/a
Internal Floods At-Power	Y	1.02	0.56	0.20	0.09
Internal Floods Shutdown	Y	(Note 1)	0.15	(Note 1)	0.02
Seismic Events At-Power	Y	0.26	0.18	0.26	0.04
Seismic Events Shutdown	Y	(Note 1)	0.05	(Note 1)	0.01
High Wind At-Power	Y	2.69	0.30	0.80	0.07
High Wind Shutdown	Y	(Note 1)	0.08	(Note 1)	0.02
OPG's Safety Goal Limit	-	10	10	1	1

Results of the Pickering NGS B PSA

PSA Element	PSA Updated ?	Severe Core Damage Frequency (x 10^{-5} per reactor-year)		Large Release Frequency (x 10^{-5} per reactor-year)	
		Baseline	Updated	Baseline	Updated
Internal Events At-Power	Y	0.42	0.08	0.39	0.03
Internal Events Shutdown	N	0.10	n/a	< 0.1	n/a
Internal Fires At-Power	Y	0.38	0.06	0.34	0.04
Internal Fires Shutdown	N	(Note 1)	n/a	(Note 1)	n/a
Internal Floods At-Power	N	0.07	n/a	< 0.07	n/a
Internal Floods Shutdown	N	(Note 1)	n/a	(Note 1)	n/a
Seismic Events At-Power	N	0.10	n/a	0.10	n/a
Seismic Events Shutdown	N	(Note 1)	n/a	(Note 1)	n/a
High Wind At-Power	Y	0.80	0.03	< 0.80	< 0.03
High Wind Shutdown	N	(Note 1)	n/a	(Note 1)	n/a
OPG's Safety Goal Limit	-	10	10	1	1

Pickering NGS A LRF with Improved Estimate of Risk

PSA Element	Large Release Frequency (x 10^{-5} per reactor-year)
Internal Events At-Power	0.17
Internal Events Shutdown	0
Internal Fires At-Power	0.66
Internal Fires Shutdown	0
Internal Floods At-Power	0.09
Internal Floods Shutdown	0
Seismic Events At-Power	0.04
Seismic Events Shutdown	0
High Wind At-Power	0.07
High Wind Shutdown	0
OPG's Safety Goal Limit	1.00

Notes:

1. The risk for a shutdown unit was shown to be bounded by the risk for an at-power unit. These results conservatively assume that all units are continuously at power.

n/a not applicable

1.0 INTRODUCTION

OPG prepared Probabilistic Safety Assessments (PSA) for Pickering NGS A and Pickering NGS B to provide comprehensive assessments of the safety of the stations. These PSAs complied with the requirements of Canadian Nuclear Safety Commission (CNSC) Regulatory Standard S-294 *Probabilistic Safety Assessment (PSA) for Nuclear Power Plants* [R1].

The results of the Pickering S-294 compliant PSAs were reported in:

- NA44-REP-03611-00036 *Pickering A Risk Assessment Summary Report* [R2].
- NK30-REP-03611-00021 *Pickering B Risk Assessment Summary Report* [R3].

Pickering Power Reactor Operating Licence 48.00/2018 established a hold-point of 210,000 Effective Full Power Hours for the Pickering pressure tubes. Prior to removal of the hold point, OPG was required to update the Pickering S-294 compliant PSAs to take into account the enhancements required under the CNSC's Fukushima Integrated Action Plan [R4].

OPG also incorporated some of the lessons learned in the preparation of the S-294 compliant PSAs into the updated PSAs. Lessons were incorporated if they were likely to affect risk and were easily incorporated into the PSAs.

OPG also updated the estimate of Pickering NGS A LRF to better take account of the risk associated with a shutdown unit. This further reduced the estimate of LRF for Pickering NGS A.

The purpose of this report is to summarize the changes made to the S-294 compliant PSAs and to report the results of the updated PSAs

OPG updated only the S-294 compliant PSAs for hazards that were significant to risk. For example, the Pickering NGS B PSA for internal floods was not updated due to the very low risk from internal floods.

1.1 Objectives

The principal objectives of the updated Pickering PSAs were:

1. To update the S-294 compliant PSAs for risk significant hazards at Pickering NGS A to include both the enhancements required under the CNSC's Fukushima Integrated Action Plan [R4] and the lessons learned during the preparation of the S-294 compliant PSAs.

2. To update the S-294 compliant PSAs for risk significant hazards at Pickering NGS B to include both the enhancements required under the CNSC's Fukushima Integrated Action Plan [R4] and the lessons learned during the preparation of the S-294 compliant PSAs.

3. To update the LRF estimate for Pickering NGS A to better take account of the risk associated a shutdown unit.

1.2 Scope

The Pickering S-294 compliant PSAs addressed in detail the following hazards:

- Internal events, e.g. Loss of Coolant Accident or Main Steamline Break.
- Internal fires.
- Internal floods.
- Seismic events.
- High winds.

OPG updated only the S-294 PSAs for hazards that were significant to risk. Therefore, the scope of the Pickering PSA update was limited to the following:

- Internal events at-power at Pickering NGS A.
- Internal floods at Pickering NGS A.
- Seismic events at Pickering NGS A.
- High winds at Pickering NGS A.
- Internal events at-power at Pickering NGS B.
- Internal fires at-power at Pickering NGS B.
- High winds at-power at Pickering NGS B.

Neither the Pickering S-294 compliant PSAs nor the updated PSAs cover the following sources of risk:

- Fuelling machine accidents while the fuelling machine is in transit between the reactor face and the Irradiated Fuel Bay (IFB). Analysis demonstrated that fuelling machine accidents while in transit cannot result in a large release of radioactive material to the environment.
- Hazards from chemical materials used and stored at the plant.
- Other external initiating events such as external floods, airplane crashes, train derailment, etc.
- Other internal initiating events such as turbine missiles.

These types of hazards were addressed separately through screening studies or other deterministic hazard studies.

The Pickering S-294 compliant PSAs and the updated PSAs were limited to hazards affecting the reactors. Accidents affecting other sources of radioactive material such as the IFB are outside of the scope of this report.

1.3 Organization of Summary Report

This summary report includes:

- A brief summary of risk terminology and the PSA-related elements of the CNSC's Fukushima Integrated Action Plan (Section 2.0).
- A summary of the changes made to the Pickering NGS A S-294 compliant PSAs and the results of the updated PSAs (Section 3.0). This section includes the assessment of LRF at Pickering NGS A that better accounts for the risk associated with a shutdown unit.
- A summary of the changes made to the Pickering NGS B S-294 compliant PSAs and the results of the updated PSAs (Section 4.0).
- Conclusions (Section 5.0).

Appendix A contains a list of abbreviations and acronyms used in this report.

2.0 RISK AND THE FUKUSHIMA INTEGRATED ACTION PLAN

2.1 Risk Terminology

Risk is defined as the product of the frequency of a hazardous event and the consequences of the event. Risk is expressed in units of consequence per unit time.

Risk = Frequency x Consequences

Risk provides a means of quantifying the degree of safety associated with a potentially hazardous activity and provides a common basis for comparing the relative safety of different activities. One of the principles of risk assessment is that the larger the numerical value of risk for a particular event, the more important the event is to safety. Thus, measures taken to reduce risk improve the level of safety.

OPG uses PSA to quantify the risk associated with accidents at its nuclear generating stations. For a nuclear generating station, the events studied are those leading to fuel damage in the reactor core or airborne releases of radioisotopes into the environment.

OPG uses a two level approach to assess risk:

- A Level 1 PSA to assess the frequency of severe core damage. Events resulting in severe core damage release radioactive material from the fuel into containment.
- A Level 2 PSA to assess the frequency and magnitude of airborne releases of radioactive material from containment to the environment.

OPG has defined two risk parameters based upon the PSA approach: Severe Core Damage Frequency (SCDF) and Large Release Frequency (LRF). These parameters are estimated in the Level 1 PSA and the Level 2 PSA, respectively.

OPG has defined safety goals for both SCDF and LRF, see Table 1. The intent of these safety goals is to ensure that the radiological risk arising from nuclear accidents at OPG's nuclear power reactors is low in comparison to risks to which the public is normally exposed.

2.2 Fukushima Integrated Action Plan

In response to the accident at the Fukushima Daiichi Nucler Power Plant, the CNSC prepared an action plan [R4]. The Integrated Action Plan applied to all nuclear facilities and addressed:

- Strengthening defence in depth.
- Enhancing emergency response.
- Improving the regulatory framework.

- Enhancing international collaboration.
- Communications and public consultation.

The actions related to nuclear power plants were summarized in Annex A of the CNSC's Integrated Action Plan [R4].

Table 4 lists the actions in the Fukushima Integrated Action Plan that were potentially relevant to the updated PSAs and explains how these actions were addressed by OPG. In summary, the following changes were made in the updated PSAs:

1. The Emergency Mitigating Equipment (EME) was incorporated into all updated PSAs.
2. An improved model of calandria vault pressure relief was incorporated into the thermal hydraulic analysis in the updated Pickering NGS B Level 2 PSA for internal events (Section 4.2.2).
3. The Passive Autocatalytic Recombiners (PARS) were included in the updated thermal-hydraulic analysis in the updated Pickering NGS B Level 2 PSA for internal events (Section 4.2.2).

2.2.1 Emergency Mitigating Equipment at Pickering NGS A

The EME is stored in a light frame structure located north of the Brock Road security building. The EME building is not seismically robust; however, collapse of the building is not expected to damage the EME. The EME building is not robust with respect to wind damage; however, the EME itself will be tied down to prevent wind induced toppling or sliding. Provision has been made to clear the structure if it is damaged in an earthquake or wind storm, and so allow access to the EME.

Following an Initiating Event (IE), the EME is deployed to pre-determined locations in the plant and connected to the designated tie-in points. Deployment of the EME is initiated by the Shift Manager in the Main Control Room (MCR) and follows pre-approved procedures. EME deployment is routinely drilled.

Provision has been made to clear debris from the path between the EME building and the plant following an external event.

The EME is comprised of:

- Two portable uninterruptible power supplies per unit to provide short term power to the instrumentation necessary to monitor key plant parameters.
- One diesel generator per unit to provide long term power to the instrumentation necessary to monitor key plant parameters.
- One self powered pump for each unit that can be deployed either in the Reactor Auxiliary Bay or in the Turbine Auxiliary Bay. The pump draws lake water

through hose routed from the suction channel of the Condenser Cooling Water pumps, and can provide make-up to the secondary side of the boilers, to the Heat Transport System (HTS) and to the calandria.

2.2.2 Emergency Mitigating Equipment at Pickering NGS B

The EME for use at Pickering NGS B is stored in the same building as the EME for use at Pickering NGS A, see Section 2.2.1.

The EME is comprised of:

- One portable uninterruptible power supply per unit to provide short term power to the instrumentation necessary to monitor key plant parameters.
- One diesel generator per unit to provide long term power to the instrumentation necessary to monitor key plant parameters.
- One common self powered pump that is deployed to the west side of the Pickering NGS B screehouse. This pump can supply make-up to the secondary side of the boilers and the HTS for all four Pickering B units, and to the high pressure Emergency Coolant Injection System (ECIS) storage tank.
- One common self powered pump that is deployed to the east side of the Pickering NGS B screenhouse. This pump can supply make-up to the HTS and and calandria for all four Pickering B units, and to the IFB.
- One self powered pump for each unit that is deployed in the Reactor Auxiliary Bay or in the Turbine Auxiliary Bay, and can provide make-up to the secondary side of the boilers, to the HTS and to the calandria.

3.0 UPDATE OF THE PICKERING NGS A S-294 COMPLIANT PSAs

3.1 Level 1 At-Power PSA for Internal Events

3.1.1 Introduction

The goal of a Level 1 at-power PSA for internal events is to identify the initiating events at a plant that can challenge fuel cooling, to identify the systems that can mitigate the initiating events, to determine if the initiating events result in fuel damage should the mitigating systems fail, to determine the total frequency of events that result in fuel damage, and to identify the major contributors to fuel damage.

Internal events are those that occur within the station. In the Pickering NGS A PSAs:

- IEs may affect either a single Pickering NGS A unit or both Pickering NGS A units.
- IEs originating at Pickering NGS B that affect Pickering NGS A are also included.

The methodology for the S-294 compliant Level 1 at-power PSA for internal events was summarized in [R2]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated Level 1 at-power PSA for internal events generally followed the same methodology used in the S-294 compliant Level 1 at-power PSA for internal events. However:

- The methodology was revised to incorporate the EME. This included developing a methodology for estimating human error probabilities associated with EME deployment. The human error methodology was accepted by the CNSC.
- Only those elements of the methodology required to estimate the SCDF were completed. Elements of the methodology not required to estimate the SCDF, e.g. parametric uncertainty analysis, were not completed as part of the updated PSAs.

3.1.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS A Level 1 at-power PSA for internal events:

1. The S-294 compliant PSA used a single IE, label IE-44-LO250, to represent the simultaneous failure of both unit Class I 250 V dc busses 55100-BUA1 and BUB1. This simplification is conservative as the two busses are generally not connected and operate independently.

   In the updated PSA, the failure of the unit Class I 250 V dc supply was represented as two separate IEs, labelled IE-44-LO5510BUA1 and IE-44-LO5510BUB1.

A new Event Tree (ET) was prepared for each of these two new IEs.

2. In the S-294 compliant PSA, Pickering operating experience to the end of 2011 was used in the quantification of IE frequency.

   In the updated PSA, Pickering operating experience to the end of 2012 was used in the quantification of IE frequency. The use of the most up to date data set provides a more reliable assessment of risk and ensures consistency between the updated Pickering NGS A PSAs and the updated Pickering NGS B PSAs. However, this change had little impact upon overall risk.

3. In the S-294 compliant PSA, the units were assumed to be at full power for 100% of the operating cycle. This simplification results in overlap and double counting with the Level 1 outage PSA for internal events.

   In the updated PSA, the IE frequencies were scaled by the average time fraction that a reactor is not in the Guaranteed Shutdown State (GSS). That is, the at-power IE frequencies were multiplied by a factor of 0.78.

   IEs occurring while a reactor is in the GSS are covered in the Level 1 outage PSA for internal events.

4. The EME was not credited in the S-294 compliant Level 1 at-power PSA for internal events.

   The EME was incorporated into the updated PSA:

   - The ETs were revised to include EME make-up to the boilers, the ECIS and the calandria. However, not all accident sequences credit the EME, for example:

     - For some sequences, e.g. large Loss of Coolant Accident (LOCA) and failure of the ECIS, there is insufficient time to deploy the EME prior to the onset of severe core damage.

     - For some sequences, e.g. a total loss of feedwater, the IE may render an EME injection path unavailable.

   - The Fault Trees (FT) for the boiler feedwater system, the HTS and the moderator system were revised to include tie in points for the EME.

   - A new FT for the EME was prepared. This FT included failures of the EME equipment and human errors during EME deployment.

   - A methodology was developed to estimate human error probability for EME deployment. As EME deployment is initiated from the MCR by the Shift Manager, follows pre-approved procedures and is regularly drilled, the methodology is very similar to that used for post-accident actions in the S-294 compliant PSA. This methodology was accepted by the CNSC.

5. In a PSA, only equipment qualified to operate in a harsh environment is typically credited to mitigate an IE that causes a harsh environment. Non-qualified equipment located in a harsh environment is assumed to fail.

   In the S-294 compliant PSA, a large feedwater line break was assumed to cause a harsh environment in both the accident unit and the non-accident unit.

   Thermal-hydraulic analysis performed after completion of the S-294 compliant PSA showed that, following a large feedwater line break, a harsh environment does not occur in all areas of the non-accident unit. Therefore, non-qualified equipment in these areas can be credited to operate following a large feedwater line break.

   The system level FTs were revised to reflect the new thermal hydraulic analysis for large feedwater line breaks.

6. In the S-294 compliant Level 1 at-power PSA for internal events, the Class III motor control centres 54130-MCC101x and MCC102x were assumed to be supplied only from the inter-station transfer bus. The normal Class III power supply to the motor control centres was not credited as it is not environmentally qualified for all accident scenarios.

   Not all accident scenarios result in a harsh environment at the Class III power supplies; therefore, in the updated PSA, the conservative simplification was corrected. That is, in the updated PSA, it was assumed that the Class III motor control centres could be supplied from either the inter-station transfer bus or the normal Class III power supply unless the accident sequence caused a harsh environment.

7. In the S-294 compliant PSA, it was assumed that the Emergency Boiler Water Supply System (EBWS) can not supply water from Pickering NGS B to Pickering NGS A in the event of a loss of Class IV electrical power at Pickering NGS B. This assumption resulted from a contradiction between two documents.

   The contradictory documents were made consistent. The updated PSA credits make-up to the Pickering NGS A boilers from the EBWS even in the event of a loss of Class IV electrical power at Pickering NGS B.

8. In the S-294 compliant PSA, it was assumed that failure open of the EBWS test flowpath (6-73140-V853, V854 and V855) can divert sufficient flow to render the EBWS unavailable.

   Analysis preformed after completion of the S-294 compliant PSA demonstrated that failure open of the EBWS test flowpath will not divert sufficient flow to render the EBWS unavailable.

   In the updated PSA, failure open of the EBWS flowpath was removed from the feedwater FT.

9. In the S-294 compliant PSA, it was assumed that at least one moderator room air cooling unit is required to prevent moderator pump overheating following a LOCA. This assumption was a conservative simplification, moderator room cooling is not required for small LOCAs and single channel events.

   In the updated PSA, the moderator system FTs were revised to remove the requirement for moderator room cooling for small LOCAs and single channel events.

10. In the S-294 compliant PSA, Pickering operating experience to the end of 2011 was used in the quantification of component failure rates used in the mitigating system FTs.

    In the updated PSA, Pickering operating experience to the end of 2012 was used in the quantification of component failure rates. The use of the most up to date data set provides a more reliable assessment of risk and ensures consistency between the updated Pickering NGS A PSAs and the updated Pickering NGS B PSAs. However, this change had little impact upon overall risk.

11. Some systems at Pickering NGS B support accident mitigation at Pickering NGS A. For example, the Pickering NGS B High Pressure Water System supplies the Pickering NGS A EBWS. Therefore, the Pickering NGS A PSAs include FT models for some Pickering NGS-B systems.

    The FT models revised as part of the update of the Pickering NGS B PSA (Section 4.1.2 of this report) were incorporated into the updated Pickering NGS A PSA.

3.1.3 Results Summary

Table 2 summarizes the results of the updated Level 1 at-power PSA for internal events:

- The updated SCDF, 0.83 x 10^{-5} per reactor-year, is more than one order of magnitude below OPG's safety goal limit.

- The updated SCDF is approximately one half of the SCDF estimated in the S-294 compliant PSA.

- The updated SCDF due to sequences involving failure to shutdown (FDC1), 2.12 x 10^{-7} per reactor-year, is less than the frequency estimated in the S-294 compliant PSA. The reduction mainly results from weighting the IE frequency by the time fraction that the reactor is not in the GSS, item 3 in Section 3.1.2.

- The updated SCDF due to the failure of all heat sinks (FDC2), 0.81 x 10^{-5} per reactor-year, is approximately one half of the frequency estimated in the S-294 compliant PSA. The reduction mainly results from:

- Weighting the IE frequency by the time fraction that the reactor is not in the GSS, item 3 in Section 3.1.2.

- Credit for the EME to mitigate a total loss of heat sinks, item 4 in Section 3.1.2.

3.2 Level 2 At-Power PSA for Internal Events

3.2.1 Introduction

The goal of a Level 2 at-power PSA for internal events is to study the events at a plant that result in fuel damage to determine:

- How system failures and accident phenomena might result in an airborne release of radioactive material to the environment.

- The characteristics of the release, e.g. its magnitude and timing.

The above information is combined with the Level 1 PSA for internal events to quantify the frequency of releases. The frequency estimate includes:

- IEs that affect either a single Pickering NGS A unit or both Pickering NGS A units.

- IEs originating at Pickering NGS B that affect Pickering NGS A.

The methodology for the S-294 compliant Level 2 at-power PSA for internal events was summarized in [R2]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated Level 2 at-power PSA for internal events generally followed the same methodology used in the S-294 compliant Level 2 at-power PSA for internal events. However:

- The methodology was revised to incorporate the EME. This included developing a methodology for estimating human error probabilities associated with EME deployment. The human error methodology was accepted by the CNSC.

- Only those elements of the methodology required to estimate the LRF were completed.

3.2.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS A Level 2 at-power PSA for internal events:

1. Changes made in the Level 1 at-power PSA for internal events (Section 3.1.2) flowed through to the Level 2 at-power PSA for internal events during Level 1 / Level 2 integration.

2. In the S-294 compliant PSA, Pickering operating experience to the end of 2011 was used in the quantification of component failure rates used in the containment system fault trees.

   In the updated PSA, Pickering operating experience to the end of 2012 was used in the quantification of component failure rates used in the containment system fault trees. This change is the equivalent of item 10 in Section 3.1.2.

3. The Instrumented Pressure Relief Valves (IPRV) control containment pressure in the hold-up period following an accident. The IPRVs are normally controlled from the Pickering NGS A MCR but control can be transferred to the Pickering NGS B Unit 5 Unit Emergency Control Centre (UECC).

   In the S-294 compliant PSA, it was assumed that control could be transferred to the UECC for the full range of accident sequences.

   In the updated PSA, it was assumed that control cannot be transferred for LOCAs with an initial discharge rate of more than 100 kg/s. For LOCAs with an initial discharge rate of more than 100 kg/s, the UECC may become unihabitable due to the transport of fission products along the Pressure Relief Duct.

4. The estimate of LRF includes IEs originating at Pickering NGS B. Some of the sequences for these IEs result in a large release in the Pickering NGS B Level 2 PSA; therefore, counting these sequences in the Pickering NGS A PSA constitutes double counting.

   In the S-294 compliant PSA, sequences originating at Pickering B that result in a large release in the Pickering NGS B Level 2 PSA were maintained in the results of the Pickering NGS A Level 2 PSA.

   In the updated PSA, sequences originating at Pickering B that result in a large release in the Pickering NGS B Level 2 PSA were eliminated from the results of the Pickering NGS A Level 2 PSA. This reduced the frequency of RC1 and LRF by approximately 3×10^{-7} per reactor-year.

3.2.3 Results Summary

Table 3 summarizes the results of the updated Level 2 at-power PSA for internal events:

- The updated LRF, 1.72×10^{-6} per reactor-year, is almost one order of magnitude below OPG's safety goal limit.

- The updated LRF is approximately one third of the LRF estimated in the S-294 compliant PSA. The reduction mainly results from:

  - Weighting the IE frequency by the time fraction that the reactor is not in the GSS, item 3 in Section 3.1.2.

- Credit for the EME to mitigate a total loss of heat sinks, item 4 in Section 3.1.2.

3.3 Internal Flood At-Power PSA

3.3.1 Introduction

The goal of a PSA for internal floods is to:

- Study how floods originating within the station may affect fuel cooling and lead to severe core damage or large airborne releases of radioactive material to the environment.
- Estimate the flood-induced SCDF.
- Estimate the flood-induced LRF.

Internal floods are those occurring within the station. In the Pickering NGS A PSAs:

- Internal floods may affect either a single Pickering NGS A unit or both Pickering NGS A units.
- Floods originating at Pickering NGS B that affect Pickering NGS A are also included.

The methodology for the S-294 compliant at-power PSA for internal floods was summarized in [R2]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated at-power PSA for internal floods generally followed the same methodology used in the S-294 compliant at-power PSA for internal floods. However:

- The methodology was revised to incorporate the EME. This included developing a methodology for estimating human error probabilities associated with EME deployment. The human error methodology was accepted by the CNSC.
- Only those elements of the methodology required to estimate the SCDF and the LRF were completed.

3.3.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS A at-power PSA for internal floods:

1. Changes made in the Level 1 at-power PSA for internal events (Section 3.1.2), including credit for the EME, flowed through to the internal flood PSA through use of the forced shutdown event tree in the preparation of the Level 1 flood model.

2. In the S-294 compliant PSA, the units were assumed to be at full power for 100% of the operating cycle.

   In the updated PSA, the IE frequencies were scaled by the average time fraction that a reactor is not in the Guaranteed Shutdown State (GSS). That is, the estimated IE frequencies were multiplied by a factor of 0.78.

   IEs occurring while a reactor is in the GSS are covered in Section 3.6.

3. In the S-294 compliant Level 1 at-power PSA for internal events, the Class III motor control centres 54130-MCC101x and MCC102x were assumed to be supplied only from the inter-station transfer bus. The normal Class III power supply to the motor control centres was not credited as it is not environmentally qualified for all accident scenarios.

   Internal floods do not result in a harsh environment at the Class III power supplies; therefore, in the updated flood PSA, the conservative simplification was corrected. That is, in the updated flood PSA, it was assumed that the Class III motor control centres could be supplied from either the inter-station transfer bus or the normal Class III power supply.

3.3.3 Results Summary

Tables 5 and 6 summarize the results of the updated at-power PSA for internal floods:

1. The updated SCDF for internal floods, 0.56×10^{-5} per reactor-year, is:

   - More than one order of magnitude below OPG's safety goal limit limit.
   - Approximately one half of the SCDF estimated in the S-294 compliant flood PSA.

2. The updated LRF for internal floods at-power, 0.09×10^{-5} per reactor-year, is:

   - Approximately one order of magnitude below OPG's safety goal limit.
   - Approximately one half of the LRF estimated in the S-294 compliant flood PSA.

3. The reduction in the SCDF and the LRF mainly result from:

   - Weighting the IE frequency by the time fraction that the reactor is not in the GSS, item 3 in Section 3.1.2.
   - Credit for the EME to mitigate a total loss of heat sinks, item 4 in Section 3.1.2.

3.4 Seismic Events At-Power

3.4.1 Introduction

The goal of a PSA based Seismic Margin Assessment (SMA) is to:

- Determine the seismic robustness of equipment required to shutdown the reactor, remove decay heat and contain radioactive material.
- Study how seismically induced failures of systems, structures and components may affect fuel cooling and lead to severe core damage or large airborne releases of radioactive material.
- Estimate the seismically induced SCDF.
- Estimate the seismically induced LRF.

Seismic events are external events that are assumed to affect both Pickering NGS A units at the same time.

The methodology for the S-294 compliant at-power PSA based SMA was summarized in [R2]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated at-power PSA based SMA generally followed the same methodology used in the S-294 compliant at-power PSA based SMA. However:

- The methodology was revised to include deployment of the EME supply to the boilers. This included developing a methodology for estimating human error probabilities associated with EME deployment. The human error methodology was accepted by the CNSC.
- Only those elements of the methodology required to estimate the SCDF and the LRF were completed.

3.4.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS A at-power PSA based SMA:

1. Changes made in the Level 1 at-power PSA for internal events (Section 3.1.2) flowed through to the PSA based SMA through use of the FTs in the Level 1 seismic model.
2. In the S-294 compliant PSA based SMA, the units were assumed to be at full power for 100% of the operating cycle.

   In the updated PSA based SMA, the IE frequencies were scaled by the average time fraction that a reactor is not in the Guaranteed Shutdown State (GSS). That is, the estimated IE frequencies were multiplied by a factor of 0.78.

IEs occurring while a reactor is in the GSS are covered in Section 3.6.

3. EME make-up to the boilers was incorporated into the Level 1 seismic model.

   EME make-up to the moderator was not incorporated into the Level 1 seismic model; there is insufficient time to refill the calandria and prevent severe core damage following a seismic event.

   EME make-up to the HTS was not incorporated into the Level 1 seismic model; the instrument air supplying valves in the EME flowpath is not seismically qualified and, therefore, the valves are assumed to fail closed following a seismic event.

4. The LRF was not explicitly estimated in the S-294 compliant PSA based SMA. Instead, the Pickering NGS A units were assumed to be perfectly correlated, i.e. the earthquake affects both units identically. If two units progress to severe core damage at the same time, containment will fail consequentially and there will be a large release of radioactive material to the environment. Therefore, the seismically induced SCDF was set equal to the seismically induced LRF.

   However, in the S-294 compliant PSA based SMA, it was determined that the dominant contributor to seismically induced SCDF was random, independent failures of unitized equipment, not seismically induced failures of equipment. Therefore, assuming that the Pickering NGS A units are perfectly correlated is overly conservative.

   In the updated PSA based SMA, the seismically induced LRF was estimated by:

   - Distinguishing between single unit sequences and two unit sequences in the results of the Level 1 seismic model.

     Two-unit sequences were assumed to progress from severe core damage to a large release.

   - For single unit sequences, the contribution to LRF was estimated by considering:

     i) Severe core damage on a single unit progressing to a large release as the result of early calandria vessel failure.

     ii) Severe core damage on a single unit coupled with random failures of the containment boundary.

     iii) Severe core damage on both units as the result of random, independent failures of heat sink components on both units.

3.4.3 Results Summary

Tables 5 and 6 summarize the results of the updated at-power PSA based SMA:

1. The plant level HCLPF increased from 0.22g to 0.23g. This reduced the contribution of seismically induced failures to both the SCDF and the LRF.

2. The updated at-power seismically induced SCDF, 0.18 x 10^{-5} per reactor-year, is more than one order of magnitude below OPG's safety goal limit.

3. The updated seismically induced SCDF is approximately 70% of the estimate in the S-294 compliant PSA based SMA, 0.26 x 10^{-5} per reactor-year.

4. The updated seismically induced LRF, 0.04 x 10^{-5} per reactor-year, is more than one order of magnitude below OPG's safety goal limit.

5. The updated seismically induced LRF is almost one order of magnitude below the estimate in the S-294 compliant PSA based SMA.

3.5 High Wind At-Power

3.5.1 Introduction

The goal of a PSA for high winds is to:

- Study how high winds may affect fuel cooling and lead to severe core damage or large airborne releases of radioactive material to the environment.
- Estimate the high wind-induced SCDF.
- Estimate the high wind-induced LRF.

The methodology for the S-294 compliant at-power PSA for high winds was summarized in [R2]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated at-power PSA for high winds generally followed the same methodology used in the S-294 compliant at-power PSA for high winds. However, only those elements of the methodology required to estimate the SCDF and LRF were completed.

3.5.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS A at-power PSA for high winds:

1. Changes made in the Level 1 at-power PSA for internal events (Section 3.1.2) flowed through to the Level 1 high wind PSA through use of the forced shutdown event tree in the preparation of the Level 1 wind model.

2. In the S-294 compliant PSA, the units were assumed to be at full power for 100% of the operating cycle.

   In the updated PSA, the IE frequencies were scaled by the average time fraction that a reactor is not in the Guaranteed Shutdown State (GSS). That is, the estimated IE frequencies were multiplied by a factor of 0.78.

   IEs occurring while a reactor is in the GSS are covered in Section 3.6.

3. Some systems at Pickering NGS-B support accident mitigation at Pickering NGS A. For example, the Pickering NGS B High Pressure Water System supplies the Pickering NGS A EBWS. Wind-induced failure of the siding on the Pickering NGS B powerhouse can, therefore, affect systems that mitigate a loss of heat sinks in Pickering NGS A.

   In the S-294 compliant Pickering NGS B high wind PSA, the wind fragility for the siding on the Pickering NGS B powerhouse was based on a simplified code based approach. In the updated Pickering NGS B high wind PSA (Section 4.4), a more detailed analysis of the fragility of the siding on the Pickering NGS B powerhouse was performed. This analysis matched the more detailed analysis completed in the Pickering NGS A S-294 compliant PSA [R2].

   The fragility analysis completed for the updated Pickering NGS B high wind PSA was incorporated into the updated Pickering NGS A high wind PSA.

4. In the Pickering NGS A and Pickering NGS B S-294 compliant high wind PSAs, it was conservatively assumed that there was a 95% correlation between the high wind induced failure of external building siding and rain induced failure of equipment contained in the building.

   A detailed assessment indicated that a more realistic value for the high wind / heavy rain correlation was 50%. The detailed assessment took account of the relatively short duration of a wind storm and the fact that the rain would have to “fall horiziontally” if it were to penetrate through wind damaged siding to equipment inside the powerhouse.

3.5.3 Results Summary

Tables 5 and 6 summarize the results of the updated at-power PSA for high winds:

1. The updated at-power wind-induced SCDF, 0.3×10^{-5} per reactor-year, is more than one order of magnitude below OPG’s safety goal limit.

2. The updated wind-induced SCDF is approximately one order of magnitude less than the SCDF estimated in the S-294 compliant PSA, 2.69×10^{-5} per reactor-year.

3. The updated at-power wind-induced LRF, 0.07×10^{-5} per reactor-year, is more than one order of magnitude below OPG’s safety goal limit.

4. The updated at-power wind-induced LRF is more than one order of magnitude less than the estimate in the S-294 compliant PSA, 0.80 x 10^{-5} per reactor-year.

3.6 Outage PSAs

In the S-294 compliant PSAs for internal floods, seismic events and high winds, it was shown that the risk for a shutdown unit was bounded by the risk for an at-power unit. The SCDF and LRF for internal floods, seismic events and high winds was conservatively reported on the basis that the reactor was at-power for 100% of the operating cycle.

In the updated at-power PSAs for internal floods, seismic events and high winds, the SCDF and LRF were scaled by the average amount of time that a reactor is not in the GSS. That is, the initiating event frequencies were multiplied by a factor of 0.78.

In order to account for the full operating cycle, the SCDF and LRF for an outage unit must be estimated and added to the reported risk data.

In the updated PSA, the contribution of the shutdown state to risk was estimated by:

1. Dividing the reported at-power risk estimate for the hazard by the time fraction that a unit is not in the GSS. This represents the risk if a reactor is at-power for 100% of the operating cycle.

2. Multiplying the risk calculated in 1, above by the time fraction that a unit is in the GSS, i.e. 0.22.

3. Multiplying the risk calculated in 2, above by the time fraction that a shutdown unit is not in Plant Operating State (POS) C, i.e. approximately 96%. It was shown in the Level 2 analysis for an outage unit (Section 5.2 in [R2]), that accidents initiated in POS C do not result in severe core damage or a large release of radioactive material to the environment.

Based on the above:

- The outage SCDF for internal floods is 0.15 x 10^{-5} per reactor-year and the outage LRF for internal floods is 0.02 x 10^{-5} per reactor-year.

- The outage SCDF for seismic events is 0.05 x 10^{-5} per reactor-year and the outage LRF for seismic events is 0.01 x 10^{-5} per reactor-year.

- The outage SCDF for high winds is 0.08 x 10^{-5} per reactor-year and the outage LRF for high winds is 0.02 x 10^{-5} per reactor-year.

It is likely that the estimates of outage risk remain conservative. It is likely that there is insufficient decay heat to result in severe core damage or large releases for much more of an outage than POS C, i.e. for much of POSs A and B.

3.7 Improved Assessment of LRF at Pickering NGS A

3.7.1 Introduction

In [R2], OPG estimated the LRF attributable to internal fires to be 0.84 x 10^{-5} per reactor-year. This estimate accounted for both at-power operation and outage operation.

As the estimate in [R2] included the EME, the Pickering NGS A fire PRA was not updated to include other enhancements required under the FAP.

As explained earlier in this report:

- The outage risk for internal events was not updated.
- The outage risk for internal floods, seismic events and high winds was updated. In particular, the contribution from POS C was eliminated; accidents initiated in POS C do not progress to severe core damage.

The estimate of LRF due to internal fires and the estimates of outage LRF due to internal events, seismic events, internal floods and high winds are conservative. In this section, a more realistic estimate of risk is derived.

3.7.2 Improved LRF Estimates

In [R2], OPG estimated the LRF attributable to internal fires to be 0.84 x 10^{-5} per reactor-year. This estimate accounted for both at-power operation and outage operation.

The total LRF attributable to internal fires can be distributed between at-power operation and outage operation by applying the time fraction that a unit is not in the GSS, i.e. 0.78. Therefore, the at-power LRF is 0.66 x 10^{-5} per reactor-year and the outage LRF is 0.18 x 10^{-5} per reactor-year.

The Level 2 thermal-hydraulic accident progression analysis for a shutdown unit at Pickering NGS A unit included:

- A Loss of Coolant Accident (LOCA) on the shutdown unit at the earliest possible time in each POS.
- A Total Loss of Heat Sinks (TLOHS) on the shutdown unit at the earliest possible time in each POS.
- A LOCA or a Main Steam Line Break on the adjacent at-power unit causing a LOCA in the shutdown unit in POSs A and B. The induced LOCA was assumed to be a double ended failure of a feeder ice plug; ice plugs are not possible in POS C.

The Level 2 analysis for a shutdown unit demonstrated that the only cases where a large release was possible were those in which there was early calandria vessel failure. Furthermore, the earliest time for calandria failure was estimated to be 12.5

hours after accident initiation. This provides more than sufficient time to deploy the EME, add water to the calandria and prevent calandria failure. Preventing calandria failure also prevents a large release.

The analysis described above assumed that the accident was initiated at the earliest possible time in each particular POS. As the time after shutdown increases, so the decay heat level falls, the likelihood of a large release falls, and the time at which a large release occurs, if at all, increases. For example, the time at which a large release occurs due to a TLOHS at the earliest possible entry into POS B is greater than 72 hours, the mission time in OPG's PRAs.

Given the time available for EME deployment and the likelihood of a large release at any time other than the earliest part of an outage, it is reasonable to reduce the outage LRF by more than one order of magnitude. The outage LRF effectively becomes zero.

Table 7 shows the revised LRF estimates based upon the above.

4.0 UPDATE OF THE PICKERING NGS B S-294 COMPLIANT PSAs

4.1 Level 1 At-Power PSA for Internal Events

4.1.1 Introduction

The goal of a Level 1 at-power PSA for internal events is to identify the initiating events at a plant that can challenge fuel cooling, to identify the systems that can mitigate the initiating events, to determine if the initiating events result in fuel damage should the mitigating systems fail, to determine the total frequency of events that result in fuel damage, and to identify the major contributors to fuel damage.

Internal events are those that occur within the station. In the Pickering NGS B PSAs, IEs may affect either a single Pickering NGS B unit or combinations of Pickering NGS B units.

The methodology for the S-294 compliant Level 1 at-power PSA for internal events was summarized in [R3]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated Level 1 at-power PSA for internal events generally followed the same methodology used in the S-294 compliant Level 1 at-power PSA for internal events. However:

- The methodology was revised to incorporate the EME. This included developing a methodology for estimating human error probabilities associated with EME deployment. The human error methodology was accepted by the CNSC.

- Only those elements of the methodology required to estimate the SCDF were completed.

4.1.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS B Level 1 at-power PSA for internal events:

1. In the S-294 compliant PSA, the SCDF due to failure to shutdown (FDC1) was estimated to be less than 1 x 10^{-9} per reactor-year.

   In the updated PSA, only the changes in IE frequency and component failure rates could affect the frequency of FDC1. The effect of these data changes was expected to be very small.

   In the updated PSA, the frequency of FDC1 was not updated.

2. In the S-294 compliant PSA, Pickering operating experience to the end of 2011 was used in the quantification of IE frequency.

   In the updated PSA, Pickering operating experience to the end of 2012 was used in the quantification of IE frequency. Use of the most up to date data set provides a more reliable assessment of risk and ensures consistency between the updated Pickering NGS A PSAs and the updated Pickering NGS B PSAs. However, this change had little impact upon overall risk.

3. In the S-294 compliant PSA, the units were assumed to be at full power for 100% of the operating cycle. This simplification results in overlap and double counting with the Level 1 outage PSA for internal events.

   In the updated PSA, the IE frequencies were scaled by the average time fraction that a reactor is not in the Guaranteed Shutdown State (GSS). That is, the at-power IE frequencies were multiplied by a factor of 0.895.

   IEs occurring while a reactor is in the GSS are covered in the Level 1 outage PSA for internal events.

4. The EME was not credited in the S-294 compliant PSA.

   The EME was incorporated into the updated PSA:

   - The ETs were revised to include EME make-up to the boilers, the HTS and the calandria.
   - The FTs for the boiler feedwater system, the ECIS and the Emergency Water System (EWS) were revised to include tie in points for the EME.
   - A new FT for the EME was prepared. This FT included failures of the EME equipment and human errors during EME deployment.
   - A methodology was developed to estimate human error probability for EME deployment. This methodology was accepted by the CNSC.

5. In the S-294 compliant PSA, the Auxiliary Power System (APS) was not credited for the full 72-hour mission assumed in OPG's PSAs.

   Following completion of the S-294 PSAs, changes to the procedures to allow online refuelling of the APS were initiated. These changes when implemented will allow the APS to fully support the 72-hour mission assumed in OPG's PSAs.

   In the updated PSA, the FT for the Class IV electrical power system was revised to credit online refuelling of the APS.

6. In the S-294 compliant PSA, the FT for the Emergency Power System (EPS) included only two Emergency Power Generators (EPG). The third EPG was not included as it was believed that the third EPG was about to be decommissioned.

   The third EPG remains in operation and there are no plans to decommission it.

   In the updated PSA, the EPS FT was revised to include all three EPGs.

7. In the S-294 compliant PSA, it was assumed that the power to the ECIS recovery panels 056/078-63335-PL403 to PL406 was provided from the Class II electrical system only.

   Power to the ECIS recovery panels can also be provided from the EPS.

   In the updated PSA, the ECIS FT was revised to include the EPS back-up supply to the ECIS recovery panels.

8. The S-294 compliant PSA used a single IE to represent the simultaneous failure of both unit Class I 250 V dc busses 55100-BUA1 and BUB1. This simplification is conservative as the two busses are generally not connected and operate independently.

   In the updated PSA, the Class I electrical power FT was revised to represent the separation of the two busses. This change is the equivalent of item 1 in Section 3.1.2.

9. In the S-294 compliant PSA, Pickering operating experience to the end of 2011 was used in the quantification of component failure rates used in the mitigating system FTs.

   In the updated PSA, Pickering operating experience to the end of 2012 was used in the quantification of component failure rates. Use of the most up to date data set provides a more reliable assessment of risk and ensures consistency between the updated Pickering NGS A PSAs and the updated Pickering NGS B PSAs. However, this change had little impact upon overall risk.

4.1.3 Results Summary

Table 5 summarizes the results of the updated Level 1 at-power PSA for internal events:

1. The updated SCDF, 7.53 x 10^{-7} per reactor-year, is more than two orders of magnitude below OPG's safety goal limit.

2. The updated SCDF is approximately one fifth of the SCDF estimated in the S-294 compliant PSA.

3. The reduction in the SCDF mainly results from credit for the EME to mitigate a total loss of heat sinks.

4.2 Level 2 At-Power PSA for Internal Events

4.2.1 Introduction

The goal of a Level 2 at-power PSA for internal events is to study the events at a plant that result in fuel damage to determine:

- How system failures and accident phenomena might result in an airborne release of radioactive material to the environment.

- The characteristics of the release, e.g. its magnitude and timing.

The above information is combined with the Level 1 PSA for internal events to quantify the frequency of releases. The frequency estimate includes IEs that affect either a single Pickering NGS B unit or a combination of Pickering NGS B units.

The methodology for the S-294 compliant Level 2 at-power PSA for internal events was summarized in [R3]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated Level 2 at-power PSA for internal events generally followed the same methodology used in the S-294 compliant Level 2 at-power PSA for internal events. However:

- The methodology was revised to include EME deployment.

- Only those elements of the methodology required to estimate the LRF were completed.

4.2.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS B Level 2 at-power PSA for internal events:

1. Changes made in the Level 1 at-power PSA for internal events (Section 4.1.2) flowed through to the Level 2 at-power PSA for internal events during Level 1 / Level 2 integration.

2. The EME was not credited in the S-294 compliant PSA.

   In the updated PSA, the EME was credited:

   - Through integration with the updated Level 1 PSA, item 3 in Section 4.1.2.

   - To arrest accident progression at in-vessel retention through the supply of EME to the calandria. Arresting accident progression at in-vessel retention precludes corium concrete interaction and so prevents the generation of large volumes of combustible gasses.

     This change required two revisions to the Containment Event Tree, Section 5.2 in [3]. The first change was the addition of a branch point for failure to arrest accident progression at in-vessel retention, the second change was the addition of a branch point for long-term over-pressure failure of containment due to sustained boil-off from the calandria.

3. In the S-294 PSA, the Filtered Air Discharge System (FADS) was credited as a mitigating system in the Containment Bridging Tree, Figure 13 in [3].

   The credit for FADS was removed in the updated PSA. It was determined that FADS may be initiated many hours into a transient when command and control of the plant has been transferred to the Emergency Response Organization (ERO). OPG's current methodology for human reliability analysis does not include actions initiated by the ERO.

   This change aligns the updated Pickering NGS B PSA with the Pickering NGS A PSA, see Section 5.1.1 of [R2].

4. MAAP-CANDU is an Industry Standard Toolset code used to simulate the thermal-hydraulic aspects of severe accident progression, e.g. core melt, HTS failure, calandria vessel failure, shield tank failure and containment failure. It is also used to estimate the magnitude and timing of airborne releases of radioactive material to the environment.

   Version 4.0.7C of MAAP-CANDU was used in the S-294 compliant PSA.

   Version 4.0.7D of MAAP-CANDU was used in the updated PSA:

   - The changes between versions 4.0.7C and 4.0.7D do not significantly affect the outcome of the thermal-hydraulic analysis.

   - Version 4.0.7D was used in the Pickering NGS A Level 2 PSA; therefore, using version 4.0.7D in the Pickering NGS B analysis ensured alignment between the two stations.

   The Pickering NGS B parameter file for MAAP-CANDU version 4.0.7D was revised to include an improved model of calandria vault pressure relief and the PARS.

5. In the S-294 compliant PSA, Pickering operating experience to the end of 2011 was used in the quantification of component failure rates used in the containment system fault trees.

   In the updated PSA, Pickering operating experience to the end of 2012 was used in the quantification of component failure rates used in the containment system fault trees. This change is the equivalent of item 9 in Section 4.1.2.

4.2.3 Results Summary

Table 6 summarizes the results of the updated Level 2 at-power PSA for internal events:

1. The updated LRF, 3.4 x 10^{-7} per reactor-year, is more than one order of magnitude below OPG's safety goal limit.

2. The updated LRF is more than one order of magnitude less than the LRF estimated in the S-294 compliant PSA, 0.39 x 10^{-5} per reactor-year.

3. The reduction in the LRF mainly results from credit for the EME to mitigate a total loss of heat sinks.

4.3 Internal Fire PSA

4.3.1 Introduction

The goal of a PSA for internal fires is to:

- Study how fires originating within the station may affect fuel cooling and lead to severe core damage or large airborne releases of radioactive material to the environment.
- Estimate the fire-induced SCDF.
- Estimate the fire-induced LRF.

Internal fires are those occurring within the station. In the Pickering NGS B PSA, internal fires may affect either a single Pickering NGS B unit or multiple Pickering NGS B units.

The methodology for the S-294 compliant at-power PSA for internal fires was summarized in [R3]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated at-power PSA for internal fires generally followed the same methodology used in the S-294 compliant at-power PSA for internal fires. However:

- The methodology was revised to include EME deployment.
- Only those elements of the methodology required to estimate the SCDF and LRF were completed.

4.3.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS B at-power PSA for internal fires:

1. Changes made in the Level 1 at-power PSA for internal events (Section 4.1.2) flowed through to the fire PSA through use of the forced shutdown event tree and associated fault trees in the preparation of the Level 1 fire model.

2. The EME was not credited in the S-294 compliant PSA.

   In the updated PSA, the EME was credited:

- Through use of the Level 1 forced shutdown event tree in the preparation of the Level 1 fire model.

- Through a revision to the Level 2 fire model to take account of in-vessel retention, see item 2 in Section 4.2.2.

4.3.3 Results Summary

Tables 5 and 6 summarize the results of the updated at-power PSA for internal fires:

1. The updated SCDF, 5.62×10^{-7} per reactor-year, is more than two orders of magnitude below OPG's safety goal limit.

2. The updated SCDF is approximately one seventh of the SCDF estimated in the S-294 compliant PSA, 0.38×10^{-5} per reactor-year.

3. The reduction in the SCDF mainly results from credit for the EME to mitigate a total loss of heat sinks.

4. The updated LRF, 4.1×10^{-7} per reactor-year, is more than one order of magnitude below OPG's safety goal limit.

5. The updated LRF is almost one order of magnitude below the LRF estimated in the S-294 compliant PSA, 0.34×10^{-5} per reactor-year.

6. The reduction in the LRF mainly results from credit for the EME to mitigate a total loss of heat sinks.

4.4 High Wind PSA

4.4.1 Introduction

The goal of a PSA for high winds is to:

- Study how high winds may affect fuel cooling and lead to severe core damage or large airborne releases of radioactive material to the environment.

- Estimate the high wind-induced SCDF.

- Estimate the high wind-induced LRF.

The methodology for the S-294 compliant at-power PSA for high winds was summarized in [R3]. The methodology is consistent with the current state of practice and was accepted by the CNSC.

The updated at-power PSA for high winds generally followed the same methodology used in the S-294 compliant at-power PSA for high winds. However:

- The methodology was revised to include EME deployment.

- Only those elements of the methodology required to estimate the SCDF and LRF were completed.

4.4.2 Summary of Changes

The following summarizes the changes that were incorporated into the updated Pickering NGS B PSA for high winds:

1. Changes made in the Level 1 at-power PSA for internal events (Section 4.1.2) flowed through to the high wind PSA through use of the forced shutdown event tree and associated fault trees in the preparation of the Level 1 high wind model.

2. In the S-294 compliant PSA, the units were assumed to be at full power for 100% of the operating cycle. This simplification results in overlap and double counting with the Level 1 outage PSA for internal events.

   In the updated PSA, the IE frequencies were scaled by the average time fraction that a reactor is not in the Guaranteed Shutdown State (GSS). That is, the at-power IE frequencies were multiplied by a factor of 0.895.

   IEs occurring while a reactor is in the GSS are covered in the Level 1 outage PSA for internal events.

3. A wind hazard analysis was completed for the S-294 compliant Pickering NGS B Level 1 at-power high wind PSA. The Pickering NGS B high wind hazard curve was enhanced for use in the S-294 compliant Pickering NGS A Level 1 at-power high wind PSA:

   - The tornado hazard was improved through the use of a more complete data set provided by Environment Canada.

   - The straight line wind hazard was improved by using all data available in the database rather than a single annual extreme. This provides more accurate extraploations for rare events and a more accurate assessment of uncertainties.

   - The number of wind speed intervals used in the Level 1 quantification was increased to capture the rapid change in the wind hazard curve. This produced a more refined estimate of risk.

   The enhanced wind hazard curve developed for the S-294 compliant Pickering NGS A Level 1 at-power PSA for high winds was used in the updated Pickering NGS B high wind PSA.

4. In the S-294 compliant PSA, the fragility of the metal cladding on the Turbine Hall, Turbine Auxiliary Bay, and Class I and II structures inside the turbine building was calculated using a simplified code based approach.

In the updated PSA, a refined fragility analysis was prepared for the metal cladding on the Turbine Hall, Turbine Auxiliary Bay, and Class I and II structures inside the turbine building. This provided a more accurate assessment of the cladding fragility and an assessment of the portion of the cladding over the whole building that might fail.

5. In the Pickering NGS A and Pickering NGS B S-294 compliant high wind PSAs, it was conservatively assumed that there was a 95% correlation between the high wind induced failure of external building siding and rain induced failure of equipment contained in the building.

   A detailed assessment indicated that a more realistic value for the high wind / heavy rain correlation was 50%. The detailed assessment took account of the relatively short duration of a wind storm and the fact that the rain would have to "fall horiziontally" if it were to penetrate through wind damaged siding to equipment inside the powerhouse.

6. In the S-294 compliant PSA, make-up from the Emergency Water Storage Tank (EWST) to the calandria was credited as an interim source only.

   In the updated PSA, the EWST was credited as a long-term make-up source to the calandria. Make-up to the EWST is provided from the Pickering NGS A service water systems. The ability of the Pickering NGS A service water systems to survive high winds was derived from the Pickering NGS high wind PSA.

7. The EME was not credited in the S-294 compliant PSA.

   In the updated PSA, EME make-up to the boilers, HTS and calandria was credited. This included an assessment of the fragility of the EME with respect to straight line winds and missiles.

4.4.3 Results Summary

Tables 5 and 6 summarize the results of the updated at-power PSA for high winds:

1. The updated SCDF, 2.9×10^{-7} per reactor-year, is more than two orders of magnitude below OPG's safety goal limit.

2. The updated SCDF is more than one order of magnitude less than the SCDF estimated in the S-294 compliant PSA, 0.80×10^{-5} per reactor-year.

3. The updated LRF, 2.9×10^{-7} per reactor-year, is more than one order of magnitude below OPG's safety goal limit.

4. The updated LRF is more than one order of magnitude less than the LRF estimated in the S-294 compliant PSA, 0.80×10^{-5} per reactor-year.

5.0 CONCLUSIONS

The results of the updated Level 1 and Level 2 PSAs are presented in Tables 5 and 6, respectively.

For Pickering NGS A:

1. The total updated SCDF for each hazard, at-power plus shutdown, is at least one order of magnitude below OPG's safety goal limit.

2. The total updated SCDF for each hazard, at-power plus shutdown, is less than the SCDF estimated in the S-294 compliant PSAs. The largest reduction in SCDF is 96% for high winds and the smallest reduction in SCDF is 12% for seismic events.

3. The updated estimates of SCDF for internal floods, seismic events and high winds for a shutdown unit are likely conservative.

4. The total updated LRF for each hazard, at-power plus shutdown, is well below OPG's safety goal limit. The highest updated LRF is for internal events; the LRF for internal events is approximately 20% of OPG's safety goal limit.

5. The total updated LRF for each hazard, at-power and shutdown, is less than the LRF estimated in the S-294 compliant PSAs. The largest reduction in LRF is 89% for high wind and the smallest reduction in LRF is 45% for internal floods.

For Pickering NGS B:

1. The updated SCDF for each hazard is at least two orders of magnitude below OPG's safety goal limit.

2. The updated SCDF for each hazard is less than the SCDF estimated in the S-294 compliant PSAs. The largest reduction in SCDF is 96% for high winds and the smallest reduction in SCDF is 81% for internal events.

3. The updated LRF for each hazard is at least one order of magnutude below OPG's safety goal limit.

4. The updated LRF for each hazard, is less than the LRF estimated in the S-294 compliant PSAs. The largest reduction in LRF is 96% for high winds and the smallest reduction in LRF is 88% for internal fires.

6.0 REFERENCES

[R1] Canadian Nuclear Safety Commission, Regulatory Standard S-294, Probabilistic Safety Assessment (PSA) for Nuclear Power Plants, April 2005.

[R2] Ontario Power Generation, Report, Pickering A Risk Assessment Summary Report, NA44-REP-03611-00036-R000, April 2014.

[R3] Ontario Power Generation, Report, Pickering B Risk Assessment Summary Report, NK30-REP-03611-00021-R000, February 2013.

[R4] Canadian Nuclear Safety Commission, CNSC Integrated Action Plan, On the Lessons Learned From the Fukushima Daiichi Nuclear Accident, August 2013.

Table 1: OPG's Risk Based Safety goals

RISK METRIC		AVERAGE RISK	
Title	Definition	Target (per reactor-year)	Safety Goal Limit (per reactor-year)
Severe Core Damage Frequency	Loss of core structural integrity	10^{-5}	10^{-4}
Large Release Frequency	Airborne release > 10^{14} Bq Cs-137	10^{-6}	10^{-5}

Table 2: Results of the Pickering NGS A Level 1 At-Power PSA for Internal Events

Fuel Damage Category		Frequency (per reactor-year)	
Designation	Definition	S-294 Compliant PSA	Updated PSA
FDC1	Severe core damage due to failure to shutdown.	2.80×10^{-7}	2.12×10^{-7}
FDC2	Severe core damage due to failure of all heat sinks.	1.60×10^{-5}	0.81×10^{-5}
Severe Core Damage	(FDC1 + FDC2)	1.63×10^{-5}	0.83×10^{-5}

Table 3: Results of the Pickering NGS A Level 2 At-Power PSA for Internal Events

Release Category	Definition	Frequency (per reactor-year)	
		S-294 Compliant PSA	Updated PSA
RC1	Large early release with the potential for acute off-site radiation effects and/or widespread contamination (greater than 3% core inventory of I-131/Cs-137).	4.69×10^{-6}	1.71×10^{-6}
RC2	Release in excess of 10^{14} Bq of Cs-137 but less than RC1 occurring within 24 hours.	(Note 1)	(Note 1)
RC3	Release in excess of 10^{14} Bq of Cs-137 but less than RC1 occurring after 24 hours.	3.45×10^{-8}	2.59×10^{-8}
LRF	(RC1 + RC2 + RC3)	4.72×10^{-6}	1.72×10^{-6}

Notes:

1. No sequences were assigned to this RC.

Table 4: Applicability of Actions in the Fukushima integrated action plan

Action Item	Description	Application in Updated PSAs
A.1.2	Licensees should re-examine the capability of the shield tank/calandria vault to discharge steam produced in a severe accident. The benefits of sustainability of shield tank heat sink during accident conditions should be re-examined.	OPG separately addressed this action as part of its response to the CNSC's Integrated Action Plan. This action does not apply to Pickering NGS A; the Pickering NGS A calandria vault is air filled. An improved model of calandria vault pressure relief was developed for Pickering NGS B. This model was incorporated into the MAAP-CANDU analysis performed as part of the updated Pickering NGS B Level 2 PSA for internal events.
A.1.3	Licensees should evaluate the means to prevent the failure of containment systems and, to the extent practicable, unfiltered releases of radioactive products in beyond-design-basis accidents including severe accidents. If unfiltered releases of radioactive products in beyond-design-basis accidents including severe accidents cannot be precluded, then additional mitigation should be provided.	OPG separately addressed this action as part of its response to the CNSC's Integrated Action Plan. As no changes had been made to the operation and design of the Pickering containment system, the PSA was not updated in response to this action.
A.1.4	Licensees should complete the installation of passive autocatalytic recombiners (PARs) as quickly as possible.	OPG separately addressed the installation of PARS as part of its response to the CNSC's Integrated Action Plan. The Pickering NGS A S-294 compliant PSA did not include the PARS. As no additional thermal-hydraulic analysis was prepared as part of the PSA update, the PARS were not included in the updated Pickering NGS A PSA. The PARS were included in the thermal hydraulic analysis that was completed to support the updated Pickering NGS B PSA.

Action Item	Description	Application in Updated PSAs
A.1.7	Licensees should evaluate means to provide coolant make-up to the primary heat transport system, moderator, shield tank/calandria vault, spent fuel pools and dousing tank where applicable. Means include: 1. Coolant make-up to prevent severe core damage. 2. If severe core damage cannot be precluded, then the make-up coolant should be used in severe accident management guidelines (SAMG) to mitigate the severe accident.	The updated Pickering PSAs incorporated the EME. The currently installed EME has the capability to make-up to the primary heat transport system, the moderator and the secondary side of the boilers. The updated Pickering PSAs did not include SAMG; recognized means of incorporating SAMG into PSAs, including estimating human error probabilities, have not yet been developed.
A.1.9	Licensees should ensure the habitability of control facilities under conditions arising from beyond-design-basis and severe accidents. This assessment should consider elements of HOP under accident conditions.	As part of its response to this action, OPG assessed the habitability the MCR, the UECC and areas of the plant required to deploy the EME: • For accidents in which the containment boundary is intact prior to the IE, habitability is generally only an issue for events that already result in a large release. Therefore, habitability generally does not affect LRF. • For accidents in which the containment boundary has been breached prior to the IE, habitability may be an issue depending upon the location and size of the breach. However, as the likelihood of a prior breach of containment is very low, i.e. 10-4 or less, then these events are not a significant contributor to risk and were not included in the updated PSAs.

Action Item	Description	Application in Updated PSAs
A.3.1	1. Licensees should develop/finalize and fully implement severe accident management guidelines (SAMG) at each station. 2. Licensees should expand the scope of SAMGs to include multi-unit events and IFB events. 3. Licensees should demonstrate effectiveness of SAMGs.	OPG separately addressed the preparation of SAMG as part of its response to the CNSC's Integrated Action Plan. The updated Pickering PSAs did not include SAMG; recognized means of incorporating SAMG into PSAs, including estimating human error probabilities, have not yet been developed.
A.3.2.1	An evaluation of the adequacy of existing modelling of severe accidents in multi-unit stations. The evaluation should provide a functional specification of any necessary improved models.	OPG separately addressed the adequacy of severe accident modelling as part of its response to the CNSC's Integrated Action Plan. MAAP-CANDU is an Industry Standard Toolset code that is the best available tool to model severe accident progression. OPG investigated two modes of using MAAP-CANDU to assess the timing of accident progression, containment response and the timing and magnitude of radioactive releases to the environment. Both were found to provide similar results. Both were considered to reasonably reflect severe accident progression within the uncertainties associated with this type of analysis. MAAP-CANDU was used in both the S-294 compliant PSAs and in the updated PSAs.

Table 5: Results of the Updated Level 1 Pickering NGS PSAs

STATION	PSA ELEMENT	SCDF (x 10^{-5} per reactor year)	
		S-294	Updated
Pickering NGS A	Internal Events At-Power	1.63	0.83
	Internal Floods At-Power	1.02	0.56
	Internal Floods Shutdown	- (Note 1)	0.15
	Seismic Events At-Power	0.26 (Note 2)	0.18 (Note 2)
	Seismic Events Shutdown	- (Note 1)	0.05 (Note 2)
	High Wind At-Power	2.69 (Note 2)	0.30 (Note 2)
	High Wind Shutdown	- (Note 1)	0.08 (Note 2)
Pickering NGS B	Internal Events At-Power	0.42	0.08
	Internal Fires At-Power	0.38	0.06
	High Wind At-Power	0.80 (Note 2)	0.03 (Note 2)

Notes:

1. The risk for a shutdown unit was shown to be bounded by the risk for an at-power unit. These results conservatively assume that all units are continuously at power.

2. The risk was estimated for seismic events/high winds with a return period up to and including 10,000 years.

Table 6: Results of the Updated Level 2 Pickering NGS PSAs

STATION	PSA ELEMENT	LRF (x 10^{-5} per reactor year)	
		S-294	Updated
Pickering NGS A	Internal Events At-Power	0.47	0.17
	Internal Floods At-Power	0.20	0.09
	Internal Floods Shutdown	- (Note 1)	0.02
	Seismic Events At-Power	0.26 (Note 2)	0.04 (Note 2)
	Seismic Events Shutdown	- (Note 1)	0.01 (Note 2)
	High Wind At-Power	0.80 (Note 2)	0.07 (Note 2)
	High Wind Shutdown	- (Note 1)	0.02 (Note 2)
Pickering NGS B	Internal Events At-Power	0.39	0.03
	Internal Fires At-Power	0.34	0.04
	High Wind At-Power	< 0.80 (Note 2)	< 0.03 (Note 2)

Notes:

1. The risk for a shutdown unit was shown to be bounded by the risk for an at-power unit. These results conservatively assume that all units are continuously at power.

2. The risk was estimated for seismic events/high winds with a return period up to and including 10,000 years.

Table 7: Improved Estimate of LRF at Pickering NGS A

PSA Element	Large Release Frequency (x 10^{-5} per reactor-year)
Internal Events At-Power	0.17
Internal Events Shutdown	0
Internal Fires At-Power	0.66
Internal Fires Shutdown	0
Internal Floods At-Power	0.09
Internal Floods Shutdown	0
Seismic Events At-Power	0.04
Seismic Events Shutdown	0
High Wind At-Power	0.07
High Wind Shutdown	0
OPG's Safety Goal Limit	1.00

Appendix A: Abbreviations and Acronyms

Acronym	Definition
Bq	Bequerels
CNSC	Canadian Nuclear Safety Commission
Cs-137	Cesium-137
EBWS	Emergency Boiler Water Supply System
ECIS	Emergency Coolant Injection System
EME	Emergency Mitigating Equipment
EPG	Emergency Power Generator
EPS	Emergency Power System
ERO	Emergency Response Organization
ET	Event Tree
EWS	Emergency Water System
EWST	Emergency Water Storage Tank
FADS	Filtered Air Discharge System
FT	Fault Tree
GSS	Guaranteed Shutdown State
HOP	Human and Organizational Performance
HTS	Heat Transport System
I-131	Iodine-131
IE	Initiating Event
IFB	Irradiated Fuel Bay
kg/s	Kilograms per second
LOCA	Loss of Coolant Accident
LRF	Large Release Frequency
MCR	Main Control Room
NPP	Nuclear Power Plant
n/a	Not applicable
OPG	Ontario Power Generation Inc.
PARS	Passive Autocatalytic Recombiners
POS	Plant Operating State
PSA	Probabilistic Safety Assessment
/r-yr	Per reactor year
SAMG	Severe Accident Management Guidance
SCDF	Severe Core Damage Frequency
SMA	Seismic Margin Assessment
UECC	Unit Emergency Control Centre
V dc	Volts, direct current

UNDERTAKING JT1.16

Undertaking

To provide any documentation available that sets out in writing the approach in respect of safety upgrades.

Response

In its response to Ex. L-6.6-6 GEC-010, OPG provided a summary of its policy for determining if safety upgrades are required based on Safety Goals established by reference to Probabilistic Risk Assessments.

This summary is based on an OPG document entitled “Risk and Reliability Program, N-PROG-RA-0016” (Attachment 1). OPG’s Safety Goals are provided in Subsection 1.1.1 and activities to be followed to manage safety goal limits and targets are provided in Subsection 1.1.2.

Nuclear Program

TITLE
RISK AND RELIABILITY PROGRAM

AUTHORIZATION	
OWNER:	C. Lorencez Director, Nuclear Safety
APPROVAL FOR ISSUE:	R. J. MacEacheron Director, Nuclear Regulatory Affairs
AUTHORIZATION AUTHORITY:	M. Elliott Senior Vice President, Nuclear Engineering and Chief Nuclear Engineer
COMPLIANCE DATE:	Immediate

PURPOSE

The purpose of the Program is to provide organizational accountabilities, interfaces, and key program elements to ensure that *risks* from nuclear accidents are identified, monitored and controlled across Ontario Power Generation, Nuclear (hereafter referred to as Nuclear) and that N-PROG-RA-0016 is consistent with OPG Nuclear Safety Policy, Nuclear Management System and best practice in the industry **[B-1] [B-2] [B-3] [B-4] [B-5] [B-6]**.

SCOPE

Probabilistic Risk Assessment (PRA) shall be used to assess the magnitude of radiological *risks* to the public from accidents due to operation of Nuclear reactors, and shall be applied in a consistent manner across Nuclear. Operational *reliability* monitoring and reporting should ensure that *risks* during operation are monitored and managed.

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1.0 DIRECTION

The purpose of the program is to establish a framework for the development and use of *PRA* at Nuclear as a means to manage radiological *risks* from nuclear accidents and to contribute to safe operation of Nuclear reactors. Program elements have been developed to meet the intent of OPG Nuclear Safety Policy and the applicable CNSC regulatory requirements in S99, S98, RD/GD-98, and S294. **[B-1] [B-2] [B-3] [B-4]** Specifically, the program elements are:

- *PRA* be developed and maintained current for each operating station. *PRA* be updated at a frequency required to satisfy regulatory requirements, or when warranted, such as by a major design change.
- *PRA* be used to support conduct of engineering, *maintenance* and operations as follows:
  - Proposed changes to plant operation, configuration or procedures that may significantly increase *risks* be reviewed to quantify impact on *risk* and assess its acceptability.
  - Proposed changes to plant operation, configuration or procedures that may significantly decrease *risks* be reviewed to quantify the benefits in terms of impact on *risk* as an input to decision-making.
  - *Systems important to safety* be identified and their *performance measures* and targets established with PRA insights used in this process.
  - *PRA* assumptions important to safety regarding surveillance, testing, and *maintenance* activities be identified and incorporated into operating and *maintenance* procedures.
- The operational performance of *systems important to safety* be monitored, assessed and reported.
- Component *reliability* data be compiled, analyzed, and applied to maintain *risk* and *unavailability models*.
- *PRA* be used to identify accident scenarios with the potential for significant core degradation.
- Identify weaknesses in the design and operation of plants and those design improvements or modifications to operating procedures that could reduce the probability of severe accidents or mitigate their consequences.
- *PRA* be used to support in-plant and ex-plant consequence analyses for event sequences beyond the design basis for use in understanding severe accident progression and management, as allowed by the scope and limitations of the *PRA*.
- *Risk* information used in safety decision-making should be based to the extent practical on data and models that reflect the characteristics of the facility concerned.

- An annual *reliability* report be prepared in accordance with guidelines specified in Appendix A, Guidelines for Contents of Annual Reliability Report.

N-PROG-RA-0016 consists of *Safety Goals,* station-specific *PRAs,* associated *risk models, unavailability models* of *systems important to safety* and software applications, and Nuclear governing documents. Refer to Figure 1, Risk and Reliability Governing Document Framework.

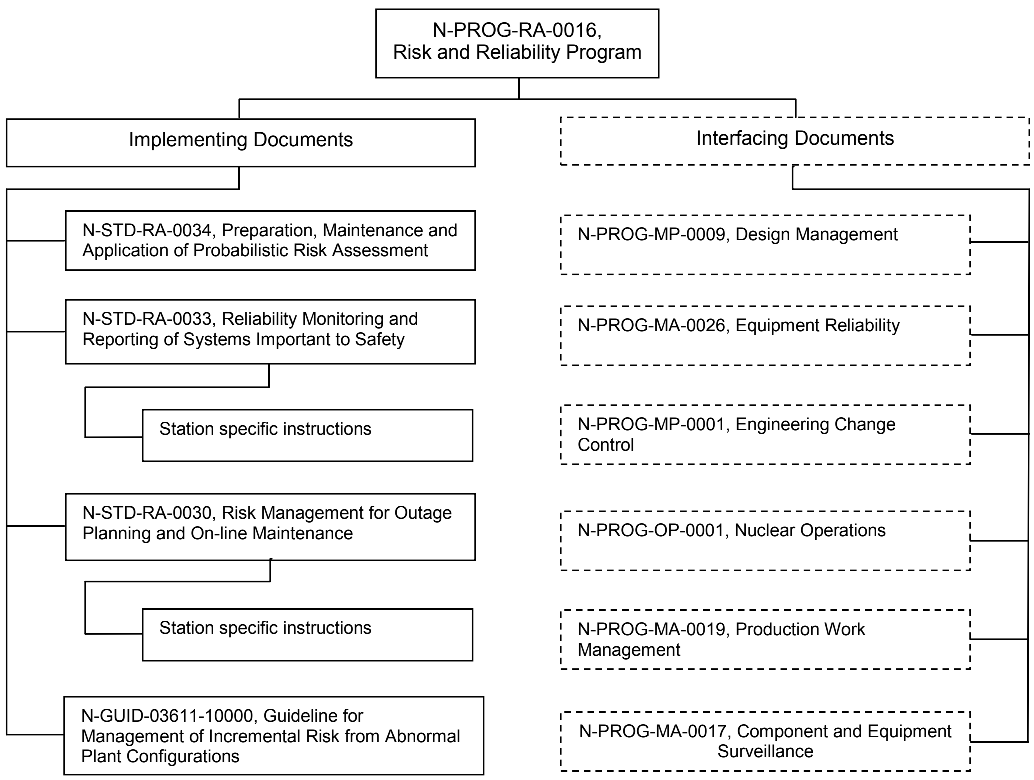

Figure 1. Risk and Reliability Governing Document Framework

1.1 Safety Goals

1.1.1 *Safety goals* are numerical safety criteria to be used in association with *PRA* applications and against which the safety of nuclear reactors can be judged. The intent is to ensure the radiological *risks* arising from nuclear accidents associated with operation of nuclear reactors should be low in comparison to *risks* to which the public is normally exposed. The *safety goals* outlined in Table 1 are comparable to industry best practice.

Table 1 Safety Goals

Safety Goal	Average Risk (per year)		Instantaneous Risk (per year)
	Target	Limit	Limit
Large Off-Site Release (per unit)	10^{-6}	10^{-5}	3×10^{-5}
Severe Core Damage (per unit)	10^{-5}	10^{-4}	3×10^{-4}

1.1.2 The *safety goal* limit represents the limit of tolerability of *risk* exposure above which action shall be taken to reduce *risk*. The *safety goal* target represents the desired objective towards which the facility should strive, provided that measures to further reduce *risk* are cost-effective, such as when benefits are comparable to, or greater than, the cost of implementing the measure. It is unlikely that *risk* reduction better than target would be cost effective, so further measures to reduce *risk* are not required.

1.1.3 The *safety goals* pertaining to *Severe Core Damage* are intended to help the station make routine decisions relating to changes in plant operation, configuration or procedures. For proposed changes significantly affecting the integrity of containment, either directly or through crosslink, a further assessment against *the Large Off-Site Release* is required.

1.1.4 *Risk base*d *safety goals* apply to estimated *risk* averaged over time, typically one year. This implies that it is permissible for the *risk* to exceed the limit for a short period of time provided that the average *risk* remains below the limit. To ensure that reasonable bounds are placed on the allowable short-term *risk*, an instantaneous limit has been defined. As there is no strong international consensus for instantaneous *risk* limits, engineering judgment is integral to their application: where instantaneous *risk* limits are exceeded, the acceptability of the *risk* should be demonstrated using other considerations, such as whether the benefit of the activity is comparable to, or exceeds, the *risk*.

1.1.5 When any *safety goal* instantaneous *risk* limit is exceeded, continued operation of the plant shall be approved by the Chief Nuclear Engineer and the Director of Operations and Maintenance.

1.1.6 Where either *Severe Core Damage* or *Large Off-Site Release safety goal* average *risk* limit is exceeded, action shall be taken to reduce the *risk*. If the *risk* cannot be returned to an acceptable level, the Chief Nuclear Engineer and the Director, Operations and Maintenance shall direct the immediate and orderly shutdown of the affected units or stations.

1.2 Implementing Documents

N-PROG-RA-0016 and implementing procedures and standards provide guidance for the *PRA* functions and *reliability* monitoring as follows.

1.2.1 N-STD-RA-0034, Preparation, Maintenance and Application of Probabilistic Risk Assessment,

This standard provides requirements for the preparation, *revision* and *maintenance* of *PRAs* to reflect current design, operation basis and *reliability* data, and application of *PRA* insights in operation. This also includes facility feedback on radiological *risk*.

1.2.2 N-STD-RA-0033, Reliability Monitoring and Reporting of Systems Important to Safety

This standard provides requirements for *reliability* monitoring and reporting of *systems important to safety*. The document is consistent with the applicable CNSC regulatory requirements in S-98, Reliability Programs for Nuclear Power Plants, RD/GD-98, Reliability Programs for Nuclear Power Plants, and S-99, Reporting Requirements for Operating Nuclear Power Plants.

1.2.3 N-STD-RA-0030, Risk Management for Outage Planning and On-Line Maintenance

This standard describes the deterministic and *PRA*-based processes of assessing and managing nuclear safety *risk* that results from *maintenance* during planned outages (outage *risk*) and during reactor operation (on-line *risk*).

1.2.4 N-GUID-03611-10000, Guideline for Management of Incremental Risk from Abnormal Plant Configurations

This guide provides guidelines for managing incremental *risk* from abnormal plant configurations.

1.3 Interfacing Documents

N-PROG-RA-0016 interfaces with several Nuclear programs to ensure Nuclear public *safety goals* are met.

1.3.1 N-PROG-MP-0009, Design Management

This program ensures that *PRA* is used as design input.

1.3.2 N-PROG-MA-0026, Equipment Reliability

This program provides input to component *reliability* data for *PRAs* based on changes resulting from system *reliability* performance, and other *reliability* and maintainability assessments.

1.3.3 N-PROG-MP-0001, Engineering Change Control

This program ensures that effect of modification on *PRA* is assessed.

1.3.4 N-PROG-OP-0001, Nuclear Operations

This program provides input for evaluation of *risk* significance of operational configurations.

1.3.5 N-PROG-MA-0019, Production Work Management

This program provides input for evaluation of *risk* significance of outage and on-line *maintenance risk* assessment and provides input to outage and on-line *maintenance* planning.

1.3.6 N-PROG-MA-0017, Component and Equipment Surveillance

This program provides input to component *reliability* data for *PRAs* based on changes resulting from equipment *reliability* performance, and other *reliability* and maintainability assessments.

1.4 Training Qualifications

Staff preparing, applying or interpreting *risk models* and implementing *reliability* program shall be appropriately trained and qualified.

1.5 Performance Indicators and Review

1.5.1 Compliance with N-PROG-RA-0016 should be measured by monitoring performance against the *safety goals* described in Section 1.1, where applicable, and by self-assessment and internal audit of the program elements at regular intervals.

1.5.2 Program shall be reviewed and reported in accordance with N-PROC-RA-0023, Fleetview Program Health and Performance Reporting.

1.5.3 Self-assessments shall be conducted periodically in accordance with N-PROC-RA-0097, Self-assessment and Benchmarking.

2.0 ROLES AND ACCOUNTABILITIES

2.1 Senior Vice President, Nuclear Engineering and Chief Nuclear Engineer

2.1.1 Approves Public *Safety Goals* for use and application.

2.1.2 Approves continued operation of the facility where either the *Severe Core Damage* or *Large Off-Site Release safety goal* limit is exceeded.

2.1.3 Concurs with the final lists of *Systems Important to Safety*.

2.1.4 Ensures resource needs for N-PROG-RA-0016 are integrated into the program oversight and execution organizations business planning, as appropriate.

2.2 Manager, Nuclear Safety and Technology

2.2.1 Prepares and maintains *safety goals*.

2.2.2 Communicates corporate and regulatory requirements for N-PROG-RA-0016 application across Nuclear.

2.2.3 Coordinates and maintains N-PROG-RA-0016, that includes standards, procedures, instructions and performance metrics.

2.2.4 Provides in-plant and ex-plant consequence analyses for event sequences beyond the design basis, for use in understanding severe accident progression and management.

2.2.5 Supports the Manager, Reactor Safety Engineering in the preparation of facility *PRAs* and the *revision* of *risk models* and *unavailability* models of *systems important to safety*.

2.3 Site Senior Vice President

Ensures resource needs for N-PROG-RA-0016 are integrated into facility business planning.

2.4 Director, Nuclear Safety

2.4.1 Carries out roles and accountabilituies of N-PROG-RA-0016 owner in accordance with N-PROC-AS-0001, Program Management of Administrative Governance.

2.5 Director, Station Engineering

2.5.1 Approves the final list of *Systems Important to Safety*.

2.5.2 Monitors effectiveness of the N-PROG-RA-0016 at facility.

2.6 Director, Operations and Maintenance

Reviews continued operation of the facility where any *safety goal* limit is exceeded and takes appropriate action if it is necessary.

2.7 Manager, Reactor Safety Engineering

2.7.1 Ensures resource requirements for N-PROG-RA-0016 are identified as part of facility business planning.

2.7.2 Uses *PRA* to support assessment of radiological *risk* impact and significance of on-line *maintenance*, outage *maintenance*, abnormal plant configurations, and operational events against the appropriate *safety goals*.

2.7.3 Uses *PRA* to support assessment of proposed changes to plant configuration, equipment or procedures that may significantly alter radiological *risks* against *safety goals.*

2.7.4 Assesses reactor safety issues using *risk models* and provides basis for *risk*-informed decisions, such as, *risk* input to Technical Operability Evaluations.

2.7.5 Identifies safety-related back-fit modifications that contribute significantly to overall radiological *risk* and assesses whether impact on radiological *risk* justifies the cost.

2.7.6 Compiles and assesses component *reliability* data.

2.7.7 Prepares the final list of *Systems Important to Safety*.

2.7.8 Evaluates and reports on *reliability* of *systems important to safety* consistent with regulatory requirements.

2.7.9 Prepares, revises, and maintains *risk* and *unavailability models*.

2.7.10 Assesses performance of *systems important to safety*.

2.7.11 Updates site performance metrics for N-PROG-RA-0016.

3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Large Off-Site Release frequency is the sum of the mean frequencies of events that can lead to the release of greater than 1 percent of the core inventory of Cs-137 to the environment due to the operation of a nuclear reactor when averaged over a one year period. Large Release requires *Severe Core Damage* with coincident failure of containment.

Maintenance of the *risk models* refers to updates which capture current *reliability* data. Update of the *risk models* to capture design changes is referred to as *revision.*

Probabilistic Risk Assessment (PRA) is a systematic process of radiological hazard identification and *risk* estimation using quantitative methods. Implicit in the concept of *risk*, as applied in PRA, is an evaluation of a hazard both in terms of its frequency of occurrence and its consequence. PRA is a unique technology that combines knowledge about plant behaviour from a wide range of sources into a unified *risk model* based on data drawn from observed plant performance.

Reliability is the probability that a system or component shall perform its specified function when called upon to do so.

Revision of *risk models* refers to structural changes of the model due to design changes. Update of the *risk models* to capture current *reliability* data is referred to as *maintenance*.

Risk is broadly understood to mean the chance of injury, damage, or loss arising from a specific activity or source. In the nuclear industry, *risk* is quantified as the frequency of an undesired event multiplied by its consequences.

Risk Model(s) is an integrated set of plant system *reliability* models and consequence analyses representing the likelihood and consequences of all accidents within a defined scope, used to generate estimates of the overall *risk* from the operation of the plant concerned.

Safety Goals are a set of numerical values, expressed in terms of human health *risk* or frequency of core damage, which establish targets and limits for station design and operation. The goals are intended to represent the high standards of safety and *reliability* necessary to maintain public and regulatory acceptance of nuclear power.

Severe Core Damage Frequency is the sum of the mean frequencies of events due to operation of a nuclear reactor that can lead to failure of both fuel and fuel channels when averaged over one year.

Systems Important to Safety are those structures, systems and components (SSC) of the power plant which contribute significantly to the initiation, prevention, detection or mitigation of any failure sequence which could lead to damage of fuel or associated release of radionuclide or both.

Unavailability is the fraction of time, usually integrated over a period of 1 year, that a system or component is not available to perform its specified function.

3.2 Abbreviations and Acronyms

PRA Probabilistic Risk Assessment
SSC Structures, Systems and Components

4.0 BASES AND REFERENCES

4.1 Bases

[B-1] CNSC Regulatory Standard S-99, Reporting Requirements for Operating Nuclear Power Plants, 2003-03-01.

[B-2] CNSC Regulatory Standard S-98 Rev.1, Reliability Programs for Nuclear Power Plants, July 2005.

[B-3] CNSC Regulatory Standard RD/GD-98, Reliability Programs for Nuclear Power Plants, June 2012.

[B-4] CNSC Regulatory Standard S-294, Probabilistic Safety Assessments (PSA) for Nuclear Power Plants, April 2005.

[B-5] CSA-N286.7-99: Quality Assurance of Analytical, Scientific, and Design Computer Programs for Nuclear Power Plants.

[B-6] CSA N286-05: Management System Requirements for Nuclear Power Plants.

4.2 References

4.2.1 Performance References

N-GUID-03611-10000, Guideline for Management of Incremental Risk from Abnormal Plant Configurations

N-PROC-AS-0001, Program Management of Administrative Governance

N-PROC-RA-0023, Fleetview Program Health and Performance Reporting

N-PROC-RA-0097, Self-assessment and Benchmarking

N-PROG-MA-0017, Component and Equipment Surveillance

N-PROG-MA-0019, Production Work Management

N-PROG-MA-0026, Equipment Reliability

N-PROG-MP-0001, Engineering Change Control

N-PROG-MP-0009, Design Management

N-PROG-OP-0001, Nuclear Operations

N-STD-RA-0030, Risk Management for Outage Planning and On-Line Maintenance

N-STD-RA-0033, Reliability Monitoring and Reporting of Systems Important to Safety

N-STD-RA-0034, Preparation, Maintenance and Application of Probabilistic Risk Assessment

4.2.2 Developmental References

F.K. King, Risk Based Safety Goals for Ontario Hydro Nuclear Generating Stations D&D Report 89412, April 1990.

International Atomic Energy Agency, Basic Safety Principles for Nuclear Power Plants, INSAG-3 Rev. 1, Vienna, 1988.

K.S. Dinnie, A Review of Quantitative Criteria for Demonstrating Nuclear Power Plant Design Adequacy, Paper presented at the Canadian Nuclear Society 9th Annual Conference, June 12-15, 1988, Winnipeg, Manitoba.

"Probabilistic Risk Criteria and Safety Goals", NEA/CSNI/R(2009)16, 17-December 2009

N-CHAR-AS-0002, Nuclear Management System

N-POL-0001, OPG Nuclear Safety Policy

5.0 REVISION SUMMARY

This is an Intent revision.

- Updated section 1.0 to reflect roles of PRA identified in the Darlington Licence Conditions Handbook
- Updated Program Owner, Approval for Issue and Authorization Authority.
- Updated titles to reflect Business Transformation.
- Revised roles and accountabilities of Senior Vice President, Nuclear Engineering and Chief Nuclear Engineer to reflect Business Transformation.
- Added Director, Nuclear Safety to roles and accountabilities to reflect Business Transformation.
- Revised wording around *safety goals* consistent with S-294 requirements. In particular, the Latent Effects safety goal target and limit were removed as there is no requirement (explicit or implicit) derived from S-294 that necessitates the calculation of this safety goal. Also, this safety goal is not very useful in day-to-day decision making with respect to station operation. Moreover, the Latent Effects safety goal has not been widely adopted by nuclear safety organizations around the world, by regulators and utilities (see "Probabilistic Risk Criteria and Safety Goals", NEA/CSNI/R(2009)16, 17-December 2009). Broader industry/regulatory discussions are being planned on the subject of

safety goals, in general (e.g. via the IAEA); OPG will consider the output of such activities during its periodic review and revision of the present Program document.

- Updated Figure 1 to reflect the Interfacing Documents and References in Sections 1.3, 4.2.

- Revised section 1.5, Performance Indicators and Review.

- Added references to self-assessment and Benchmarking procedure and program health reporting procedure in section 4.2.

- Removed references to Pickering B Risk Assessment, Pickering A Risk Assessment and Darlington Probabilistic Safety Evaluation in Section 4.2.

- Removed references to CSA N286.2-00 and CSA N286.5-95.

- Added references to CSA N286-05 and RD/GD-98.

- Editorial and formatting changes performed throughout the document.

Appendix A: Guidelines for Contents of Annual Reliability Report

Annual Reliability Report should include the following:

- List identified *systems important to safety* and assigned *reliability* targets;
- Predict, using current *reliability* data, the probability that each system important to safety of the nuclear power plant will perform as intended when it is required to do so;
- Identify, and briefly describe, any incidents over the calendar year where a system important to safety of the nuclear power plant failed to meet its design and performance specifications;
- Identify, and briefly describe, any situation over the calendar year where, as a consequence of the failure or removal from service of a component of the nuclear power plant, there was an increase in the probability that a system important to safety of the nuclear power plant might fail to perform as intended;
- Include, for each system important to safety of the nuclear power plant, a comparative assessment of the *reliability* target for the system, the predicted *reliability* of the system, and the observed *reliability* of the system over the calendar year;
- Describe, for each system important to safety of the nuclear power plant, the occurrence, nature, duration of any impairment of the system over the calendar year, and the effect of the impairment on the *reliability* of the system;
- Describe any “initiating event” that occurred over the calendar year at the nuclear power plant;
- Describe any significant change over the calendar year to the design of a system important to safety, or to an operating practice or a *maintenance* practice for a system important to safety;
- Describe any changes made over the calendar year to any model used to assess the *reliability* of a system important to safety of the nuclear power plant;
- List any scheduled activities to inspect, monitor, test or verify the *reliability* of a system important to safety of the nuclear power plant that were not completed on schedule during the calendar year;
- Contain the *reliability* data that supports the assessments over the calendar year of the *reliability* of the *systems important to safety* of the nuclear power plant, including the assumed rates of failure of system components, the input data regarding human performance, the data regarding the impairment (failure, incipient failure, or degraded ability) of one or more system components as a direct result of a shared, or common cause, and any other relevant plant-specific data.

UNDERTAKING JT1.17

Undertaking

To explain why a containment filter venting system is required for Darlington but not for Pickering.

Response

OPG has weighed the benefits and costs associated with the installation of a Containment Filtered Venting System ("CFVS") at Pickering NGS. The existing containment integrity protection provisions, including the emergency Filtered Air Discharge System, combined with the additional protection provided through the post-Fukushima Emergency Measures Equipment and Severe Accident Management Guideline ("SAMG") capabilities, are sufficient to provide a robust means to protect OPG's employees and the public.

Darlington NGS identified CFVS installation as part of its nuclear refurbishment and continued operation plans. The decision to install CFVS at Darlington was a commitment in the Refurbishment Project Environmental Assessment. This Safety Improvement Opportunity was identified prior to the Fukushima accident. Darlington's containment design is different than Pickering's. Darlington's design pressure is higher and the containment volume is also smaller - hence the need for the CFVS.

UNDERTAKING JT1.19

Undertaking

To explain the value used, if any, for carbon emissions in OPG and OPA's assessments of net present value of the Pickering life extensions.

Response

In OPG's assessment of the net present value of Pickering Continued Operations of $520M, as summarized in Ex. F2-2-3, Attachment 1, the valuation of carbon costs ranged from $0/tonne in 2014 to $20/tonne in 2020.

The OPA has advised OPG that in its assessment of Pickering Continued Operations, the OPA considered a range of scenarios/sensitivities for carbon costs. One of the scenarios assumed a $0/tonne cost of carbon in 2014, increasing to approximately $27/tonne (2012$) by 2020; all other scenarios assumed a $0/tonne cost of carbon. The expected net benefit in the order of approximately $100M that the OPA referenced in its August 15, 2012 letter (Ex. F2-2-3, Attachment 2) is based on a scenario that assumes a carbon cost of $0/tonne.

UNDERTAKING JT1.20

Undertaking

To advise whether there was an ability to terminate short of breaching the contract, and if not, to provide the particulars of the provisions.

Response

As stated in Ex. L-6.5-3 CME-008, OPG's uranium concentrate contracts do not have termination for convenience provisions and therefore OPG would be in breach of contract if it failed to take delivery of uranium in accordance with the contract provisions.

However, there are two provisions within OPG's uranium contracts which could allow OPG to suspend/terminate uranium deliveries without being in breach of contract. The first is a standard force majeure provision which would allow OPG to avoid fulfilling its obligations to take delivery of uranium due to unanticipated events or events beyond its control (e.g., Acts of God). There have been no events that would have allowed OPG to claim force majeure.

The second provision addresses "Delivery Defaults". In commodity contracts this is often referred to as "Liquidated Damages" and these provisions address payments by one party to the contract in lieu of the other party not taking/making delivery of contract quantities. Relying upon Delivery Default provisions to reduce contract quantities in order to manage inventory levels is not a viable option for OPG for two reasons.

First the provisions would compensate the seller for the difference between contract price and prevailing market price in the event of default or termination, thus potentially offsetting any benefit to OPG of reduced inventory carrying cost.

Second, liquidated damages are a measure of compensation given to a party who suffered economic harm due to the other party failing to fulfill their contract obligations. OPG does not believe it would be prudent to pursue a policy of deliberately failing to fulfill contract obligations. OPG would suffer significant damage to its commercial reputation in the uranium supply industry if it was perceived to be an unreliable buyer who takes lightly its contract obligations. Given the limited supplier base, the potential negative impact would be fewer counterparties willing to supply OPG and at a higher cost to reflect a risk premium associated with being an unreliable buyer.

UNDERTAKING JT1.21

Undertaking

To provide an explanation of how the contingency is flowed through and what makes up the numbers.

Response

As stated in Ex. D2-T1-S1, page 3 and Ex. L-4.7-17 SEC-049, while a contingency is included in the cost estimate when a project business case is approved, those contingencies are not included in the test period nuclear operations project portfolio budget for capital and OM&A projects.

OPG bases its total nuclear operations project portfolio budget (i.e., annual capital expenditures and project OM&A) on OPG's historical investment patterns, project execution capabilities, and high-level comparative benchmark data from other nuclear utilities. In the 2013 - 2015 Business Plan, OPG's nuclear operations test period project portfolio budget is $276.1M in 2014 and $228M in 2015, <u>and those figures do not include any contingency amount.</u>

Once the nuclear operations project portfolio budget for a year is set, OPG's objective is to progress all of the required projects for that year through the portfolio while ensuring that the total amount of expenditures do not exceed the total project portfolio budget. Therefore, if an individual project needs to utilize contingency, OPG will find offsetting amounts elsewhere, either from another project that has expenditures below budget, or by deferring the start date of a project, or by slowing expenditures on other projects. Hence while individual projects may have a contingency amount, the overall project portfolio budget does not need to include any contingency amounts.

UNDERTAKING JT1.22

Undertaking

Provide updated closing rate base to 2013.

Response

The undertaking is a request to provide the 2013 actual rate base in Ex. B1-1-1, Table 2. See attached table.

Table 1
Prescribed Facility Rate Base - Nuclear ($M)
Update to Ex B1-1-1 Table 2 for 2013 Actual Amounts[1]

Line No.	Rate Base Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual[2]	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Gross Plant at Cost**	5,391.1	5,563.9	6,098.6	6,042.7	6,262.8	6,510.7
2	**Accumulated Depreciation and Amortization**	2,286.8	2,498.5	2,751.7	3,038.9	3,299.0	3,580.1
3	**Net Plant**	3,104.3	3,065.4	3,347.0	3,003.8	2,963.8	2,930.6
4	**Cash Working Capital**[3]	14.3	25.9	32.0	32.0	32.0	32.0
5	**Fuel Inventory**	335.0	345.4	340.7	330.6	283.6	274.4
6	**Materials & Supplies**	441.8	421.9	413.3	413.5	427.2	422.0
7	**Total**	3,895.3	3,858.6	4,132.9	3,779.8	3,706.7	3,659.0

Notes:
1 Amounts in cols. (a) - (c) and (e) - (f) are as shown in respective columns at Ex. B1-1-1, Table 2
2 Amounts are as shown as follows: line 1 from Ex. L-1.0-1 Staff-002, Table 2, line 16, col. (f); line 2 from Ex. L-1.0-1 Staff-002, Table 3, line 16, col. (e); line 4 from Ex. L-1.0-1 Staff-002, Table 1, line 3, col. (i); lines 5 and 6 from Ex. L-1.0-1 Staff-002, Table 4, col. (c), lines 8 and 9, respectively.
3 As noted at Ex. L-1.0-1 Staff-002, Table 4, Note 1, the 2013 budget information is provided in col. (d), as the 2013 actual cash working capital amounts have not been finalized. The $32M cash working capital used is the same as used in Ex. L-1.0-1 Staff-002, Table 4, col. (c) , line 7.

UNDERTAKING JT1.23

Undertaking

To advise whether an allocation can be made between nuclear support division projects that benefit Darlington and projects that benefit Pickering, and if so, provide details. And to provide the same information for minor fixed assets, to the extent possible.

Response

The table below allocates Nuclear Support Division (allocated) project costs and minor fixed assets to Pickering and Darlington. For the period 2010 - 2015, the majority of expenditures consist of Security-related requirements, Inspection & Maintenance Tooling/Equipment and common Fukushima-related commitments.

Capital Expenditures Summary - Nuclear Support Divisions ($M)

Line No.	Category	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(d)	(e)	(g)
	Portfolio Projects (Allocated)							
1	**Darlington NGS**	8.8	12.4	8.7	7.3	15.7	2.1	0.5
2	**Pickering NGS**	21.3	18.8	8.0	5.6	8.4	2.1	0.8
3	**Nuclear Support Division Capital (Allocated)**	30.1	31.2	16.7	13.0	24.1	4.2	1.3
4	**Minor Fixed Asets**							
5	**Darlington**	6.0	7.1	8.1	8.4	4.2	11.8	15.9
6	**Pickering**	9.5	5.8	7.4	11.5	6.1	9.5	5.8
7	**Total Minor Fixed Assets**	15.4	12.9	15.5	19.9	10.2	21.3	21.7

Numbers may not add due to rounding.

UNDERTAKING JT1.25

Undertaking

To advise whether or not the error in planned outage days and change in terawatt-hours impacted the revenue requirement for Darlington and Pickering.

Response

No, the error in planned outage days and change in terawatt-hours for Darlington and Pickering does not impact the revenue requirement.

UNDERTAKING JT1.26

Undertaking

To advise what each of the drivers are contributing to the bottom line.

Response

A breakdown of the year-over-year percentage changes pertaining to labour cost (salary and wages) per FTE is provided in Table 2 below. Numbers may not add up due to rounding.

Table 2

	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
Driver Percentage Change					
Salary and Wages	1.7%	0.8%	3.0%	2.0%	1.3%
Overtime	-1.7%	0.6%	-1.2%	-1.2%	1.4%
Incentive Pay	-0.5%	-0.6%	0.1%	0.1%	0.0%
Fiscal year Adjustment	-0.3%	-1.6%	2.0%	0.0%	0.0%
Total Percentage Change	-0.7%	-0.7%	3.8%	0.9%	2.7%

Annual changes in salary and wages are largely driven by the terms of the OPG's collective agreements. For example, labour cost escalation was approximately 3% - 4% from 2011 to 2014 for PWU-represented employees.

The labour cost per FTE for overtime is tied to outage campaigns. In 2011, overtime decreases from 2010 which included extensive work in support of the Pickering Vacuum Building Outage ("VBO"). The same principle applies to the year-over-year overtime increase in 2015 driven by a Darlington VBO. Also the amount of overtime in any year will reflect the selection of which incremental labour resource option (non regular labour versus overtime versus augmented staff) is employed during an outage. This is an ongoing resource optimization and balancing process and the result will depend on the specific circumstances at the time, as discussed at Ex. L-6.3.2 AMPCO-044.

Year-over-year variations in incentive pay reflect differing performance levels.

Year-over-year fiscal year adjustments reflect a 53-week year in 2012 which has been normalized to a calendar year.

UNDERTAKING JT1.27

Undertaking

To provide the 2013 actuals according to the table for nuclear operations and nuclear projects analogous to how it is shown in the second table.

Response

The attached table provided in Ex. L-6.3-17 SEC-087 has been updated to include 2013 actual results.

2014-2016 Business Plan (Reference N1-1-1 - Attachment 4)

	Actual	Forecast	Business Plan	
	2013	2013	2014	2015
Nuclear Operations Headcount (at year-end)	5,681	5,722	5,663	5,558
Nuclear Projects Headcount (at year-end)	305	305	319	319
Total	5,986	6,027	5,982	5,877