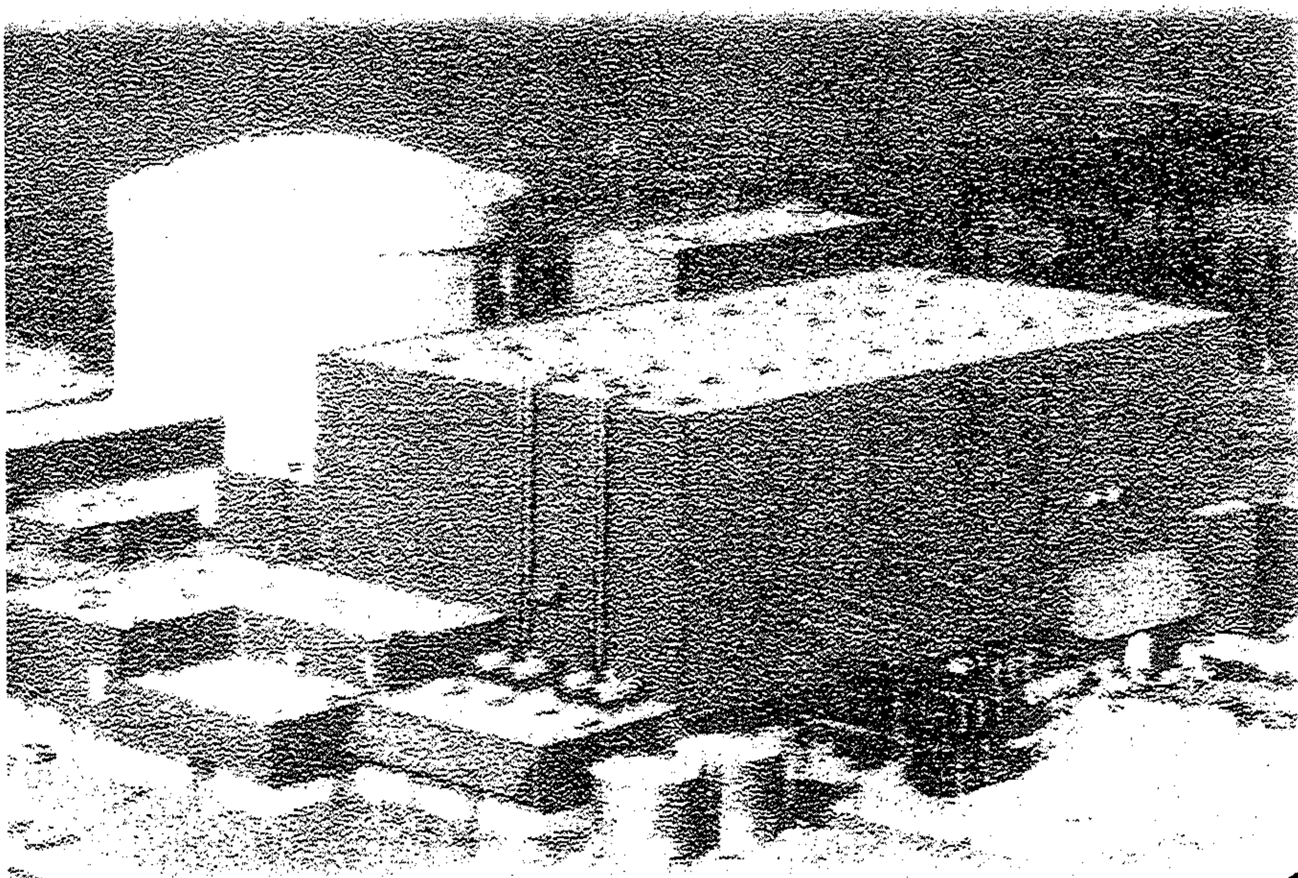

GENTILLY 2

STRATEGIC ASSESSMENT

Detailed Model Input
Final
September 2, 1998

Hagler Bailly

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Prepared for Hydro Quebec

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APPENDIX A
OPERATIONAL STRATEGIES

CONTENTS

APPENDIX A
OPERATIONAL STRATEGIES

The primary objective of this project is to compare the costs and outage time (replacement power costs). This appendix addresses the three operational scenarios, which are:

1. Operate, maintain, and refurbish the plant by conducting short, modular maintenance outages. In this strategy, a quarter of the pressure tubes and feeder pipes are replaced each year from 2005 to 2008. These dates were chosen because it is expected that at least some of the pressure tubes will need to be replaced by 2008. Thus, the most conservative analysis ensures all of the pressure tubes are replaced by 2008. After refurbishment, the station operates until 2033. This is based on the plant life extension program developed by AECL, which states that refurbishment will allow the plant to operate for 25 more years.[1] If this strategy is considered a suitable option, the feasibility issues must be addressed in detail.

2. Continue operation until major refurbishment of the plant is required. The base case for this scenario would be to operate until 2008 and then conduct a single refurbishment outage. As with the first strategy, after the refurbishment outage the plant will continue to operate until 2033 before permanent shutdown. In addition, we provide a cost per MWh value for operating the station until 2033 not including replacement power costs.

3. Provide a comparison with construction of a replacement Canadian Deuterium Uranium (CANDU) 6 nuclear station at the end of the design life or when a major pressure tube/feeder pipe replacement is required. In this strategy, Gentilly 2 is shut down in 2008 and is decommissioned. For comparison purposes, the all-in costs of the new station is included (cost of construction, financing, interest, operation, and decommissioning). Construction costs were obtained from AECL and operational and decommissioning costs were assumed to be similar to those for Gentilly 2. Costs of operating Gentilly 2 until 2008 and decommissioning Gentilly 2 were also included. These costs were converted to a cost per MWh value.

   This appendix addresses the details of each scenario. Please note that this information was provided by Atomic Energy of Canada, Limited (AECL) and should remain proprietary and confidential unless cleared with AECL.

1. "CANDU Plant Life Management and Plant Life Extension," B.A. Shalaby and E.G. Price, AECL, Mississauga, Ontario, Canada, 1997.

A.1 REQUIREMENT FOR FUEL CHANNEL REPLACEMENT

Since the intent of this appendix is to address three alternative scenarios after the fuel channels have exceeded their life, we discuss the reasons that the fuel channels need to be replaced and the associated life limiting factors.

The fuel channels in CANDU nuclear reactors have a limited lifetime because of a number of factors as summarized below.[2,3] Gentilly 2 addressed these issues with a detailed inspection and monitoring program that monitors for any degradation. This allows actions to be taken to correct any degradation before experiencing a limiting condition.

A.1.1 Pressure Tube Replacement

Sag. The pressure tubes and the calandria tubes in which they are contained sag over time because of irradiation induced creep, the operating temperature of the pressure tubes, and gravity. One consequence of this sagging of the pressure and calandria tubes is the potential that some pressure and calandria tubes may have to be replaced because of contact with the horizontal flux detector guide tubes and liquid injection safety system (LISS) nozzles. Possible replacement of a limited number of pressure and calandria tubes before a large-scale replacement is discussed in Appendix B. The pressure tube replacement tooling is currently qualified to insert new pressure tubes into a calandria tube with a maximum sag of 50 mm. With improved tooling, this could be increased to 75 mm. On a conservative basis, 50 mm could occur at 154K EFPH, whereas 75 mm will allow the pressure tubes to last their full lifetime. This could limit the pressure tube replacement to the 2005 time frame without improved tooling.

Diametrical creep. The pressure tubes also grow in diameter because of irradiation induced creep and the operating temperature. With a larger diameter, some coolant flow bypasses the fuel bundles in the increased gap between the fuel bundles and the pressure tube inner wall. This leads to higher fuel operating temperatures and reduced safety margins, which could require derating to control within acceptable limits. Two measured fuel channels at Gentilly 2, P16 and L09, are showing higher than anticipated diametrical expansion. The combination of flow bypass and reduced coolant flow rate from other heat transport system degradation factors have exceeded the current licensing margins at Gentilly 2. As a result, a derating of Gentilly 2 has occurred. Much of the reduction in the coolant flow rate has been recovered with the repair of the steam generator divider plates in 1995. The remaining reduction in the coolant flow is anticipated to be recovered by the primary side mechanical cleaning of the steam generator tubes planned for the 1999 outage. However, even if all of the coolant flow rate is recovered, it is

2. Programme De Suivi Des Tubes De Force — Mise A Jour 1997, Gentilly 2 Rapport Technique Interne, G2-RTI-97-54, 12/17/97.

3. Gentilly 2 Management of Pressure Tube Degradation Issues, AECL Report, 66-31100-655-005, October 1997.

likely that continued diametrical expansion will result in additional derating of the reactor in the future. If a new fuel design is licensed, it could defer this item as a life or reactor power level limiting item.

Axial creep. The pressure tubes also grow in the axial direction because of irradiation induced creep. One end of the pressure tube is fixed and the other end is allowed to grow for both axial creep and differential thermal expansion. During the 1998 planned outage, Gentilly 2 swapped the end of the pressure tubes that is fixed to the other end. The measured axial growth rates at Gentilly 2 appear to be very linear and linear extrapolation with the measured growth indicates that this would not be a problem until about 2013. If the more conservative growth model of CRNL 4003 is used, than a small number of pressure tubes at Gentilly 2 might reach the end of the available bearing in about 2007. It may be possible to demonstrate that the tubes will not hang up and will go back on bearing during cool down. It is also possible to change out a few limiting tubes or to operate for some time with the highest growth channels defueled. These options are costly in terms of direct costs, down time, or the need to derate the plant.

Deuterium pickup in pressure tubes. Deuterium pickup in the pressure tubes makes the pressure tubes more susceptible to failure by Delayed Hydride Cracking (DHC). AECL has recently developed a new "Design Equation" to predict the deuterium concentration in the pressure tubes as a function of time in service.[4] The rate at which the concentration increased was previously assumed to be constant (linear increase with time), whereas the new Design Equation has the rate increasing with time. Measurement of the scrapings done in the 1998 outage at Gentilly 2 revealed the potential for the Design Equation to be valid. These results need to be verified. If the new Design Equation is valid, the limiting deuterium concentration, TSS Threshold, of the Fitness-For-Service Guidelines[5] could be reached in late 2008.

Pressure tube to calandria tube contact. The pressure tubes are held concentric with the calandria tubes by a number of "garter spring" spacers along the pressure tube. If the pressure tube comes in contact with the calandria tube, zirconium hydride blisters may form that can result in failure of the pressure tube. Gentilly 2 has used a number of short campaigns to reposition the garter springs for individual pressure tubes before reaching any limiting condition. Garter spring repositioning was performed in 1991, 1995, 1996, and 1997. The 1997 repositioning was done in the end of February rather than in May as originally planned because of new data on the formation of blisters. During the 1998 outage, pressure tube inspections to evaluate the amount of deuterium ingress showed an increase in the uptake rate. As a result, Gentilly 2 repositioned the remaining garter springs to ensure no calandria to pressure tube contact exists.

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4. Bahurmuz, A.A. et al., "A Design Equation for Predicting Corrosion and Deuterium Ingress in Pressure Tubes (Rev. 1.0)," AECL RC-1551, COG-95-596, September 1996.

5. AECL Memo, A.A. Bahurmuz and V.F. Urbanic to W.R. Clendening, "Deuterium Pickup in Bruce and CANDU 6 Pressure Tubes," RMR-97-239, 7/11/97.

Because of the above considerations, the basic analyses have assumed that a one-time pressure tube replacement would be required to be initiated in about 2008 to allow continued plant operation.

The pressure tube technology has improved since the original Gentilly 2 pressure tubes were manufactured. Improved performance will be obtained from the replacement pressure tubes.[6]

A.1.2 Feeder Pipe Replacement

The outlet feeder pipes are experiencing significant thinning due to Flow Assisted Corrosion (FAC) as described in Appendix B. The costs and outage time for a large-scale pressure tube replacement is not markedly increased if the feeders are also replaced at the same time. If the feeders are also replaced, their removal would greatly facilitate the access to, and the replacement of, the pressure tubes. It is assumed that the lower section of all of the feeders are replaced at the same time if a large-scale pressure tube replacement occurs.

A.1.3 Calandria Tube Replacement

When the pressure tubes are replaced, the relatively thin-walled calandria tubes are forced back into the original straight position with no sag because of the much stronger pressure tube is inserted inside of the calandria tubes. However, after about five years, the new pressure tubes and old calandria tubes will be sagged to a preretube condition.[7] This produces a number of potential problems.

1. The continued sagging of the calandria and pressure tubes will result in contact between the calandria tubes and the horizontal detector guide tubes and the LISS nozzles several years after the pressure tube replacement. To alleviate this problem, AECL has considered[8] that, as an option, the 38 calandria tubes in rows F and Q above these horizontal guide tubes and LISS nozzles be replaced during a large-scale pressure tube replacement.

2. The pressure tubes will exceed the sag limit for the tooling used to replace a pressure tube in a sagged calandria tube. As a result, replacement of single pressure tubes because of degradation after some years of operation may be much more difficult.

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6. Coleman, C.E. and B.A. Cheadle, "CANDU Fuel Channels," AECL-11755, January 1997.

7. Excerpts from "Ontario Hydro Nuclear Retube Breakthrough Initiative C Assessment of Expected OHN Unit Fuel Channel Lifetimes," 00-31100-600-025, Revision 1, April 1997.

8. Scott, D.A., "Point Lepreau Feeder & Pressure Tube Replacement — Outline Proposal," November 1997.

3. With increased sagging of the pressure and calandria tubes, additional stresses would be placed on the calandria tubes during a single pressure tube replacement. These increased stresses may increase the potential for a failure of a calandria tube.

4. Increased sagging may introduce problems with passing the fuel elements through a highly sagged pressure tube that has not experienced as much growth in the pressure tube diameter.[9]

5. There may be problems with the analysis of the core physics with highly sagged pressure tubes.[10]

In addition to the above issues, the ductility of the calandria tube weld for long-term operation is questioned. The AECL assessment of the calandria tube lifetime[11] states in the Abstract, "Although the ductility, especially of the weld, becomes very low, the data suggest that most of the changes to mechanical properties take place before one pressure tube lifetime. More information on this topic will be obtained from the current COG program." We are concerned that ductility of the weld material is very low, less than 1 percent burst strain, at 15 years of operation, and will become lower with continued operation. No data beyond 15 years are presented, and extrapolation to 50 to 60 years is tenuous at best.

Also, when the calandria tubes are replaced, there is a potential for discovery of problems with the calandria. Hydro Quebec staff estimates this as a 10 percent probability of costs between $1 million and $3 million.[12] Improved calandria tubes are under development, with the focus on strengthening the weld or eliminating it.[13] The replaced calandria tubes should therefore have better performance than the current calandria tubes.

A.2 MODULAR REPLACEMENT OPERATING STRATEGY

The vast majority of the generating capacity of Hydro Quebec is hydroelectric. The peak load on the system is during the four-month period of December through March. It is highly desirable that Gentilly 2 is operating near full load during this period. If the modular replacement of the feeders and pressure tubes can be performed in sequential years with durations of eight months

9. Excerpts from "Ontario Hydro Nuclear Retube Breakthrough Initiative C Assessment of Expected OHN Unit Fuel Channel Lifetimes," 00-31100-600-025, Revision 1, April 1997.

10. Personal communication, Stu Groom, NB Power.

11. Coleman, C.E. et al., "Assessment of the Lifetime of Calandria Tubes," AECL, RM-FCCB-50, December 1996.

12. Comments from René Pageau, August 20, 1998, transmitted to Eldridge from Aubray via e-mail.

13. Coleman, C.E. and B.A. Cheadle, "CANDU Fuel Channels," AECL-11755, January 1997.

or less during the spring, summer, and fall months, replacement power costs to the system will be lower.

The modular replacement scenario has not been explored any further than as an initial concept. This discussion is a preliminary report of the issues associated with the modular replacement. We met with representatives from AECL and requested a review of three different alternatives for the modular replacement. AECL provided an outline[14] of the modular replacement scope of work and addressed outage time, costs, and interfaces between AECL and Hydro Quebec. The alternatives include:

- half core retubing
- quarter core retubing
- multichannel replacement.

A.2.1 Methodology

To take advantage of the shorter outage times for the modular approach it will be necessary to minimize the preparatory stage of the process and cut down on the number of activities involved in the process.

For example, with the requirement of feeder replacement during the modular replacement, a more complex draining and drying process will be required than in normal retube work. The feeders and headers of the target channels will also be part of these activities. Because of this, it will be more prudent to deal will larger sections of the reactor for each stage of retubing to avoid having to repeat the draining, drying, and decontamination sequence on the same group of channels over several outages.

After shutting down the reactor, the preparatory work involves a number of tasks such as the removal of all fuel from the fuel channels (i.e., half core), supply and installation of electrical and pneumatic services, decontamination of one loop of the primary heat transport system (PHTS), draining and drying the fuel channels, installation of the shielding cabinets and services, setting up and commissioning the retube control center, and setting up equipment in the work area.

A.2.2 Feasibility

In addition to the technical issues that pertain to a standard one-time replacement of the fuel channels, the modular replacement has several additional feasibility issues. For example, between stages the operating reactor will consist of a combination of old fuel channels and feeders in adjacent positions to new fuel channels and feeders. To successfully complete a

14. AECL, "Overview Report for a Staged Retube of the Gentilly 2 Nuclear Generating Station," May 1998.

modular replacement, the process must be engineered to deal with issues such as the replacement fuel channel design, feeder clearances, fueling machine interference, channel isolation, and draining, as well as with general radiation fields that will be higher than during a full core retube.

Feeder Replacement, Positioning, and Clearances

Adequate feeder clearances must be maintained in order to allow for the axial growth of the pressure tubes during the life of the fuel channel after replacement.

For a one-time replacement, the feeder positions and clearances are set back to their nominal start of life conditions; however, for modular replacement of the channels, they will have to be grouped in sections that take into account their attached feeders. Feeders are grouped in "banks" of up to 10 lines with the feeders closest to the reactor face connecting to channels closest to the reactor centerlines. Because of this the installation process for replacement feeders will have to start from the center channels and work their way out to the periphery.

Feeder replacement will constrain the modular replacement options. Sections (or stages) will have to be grouped in accordance with header connections, and because of spatial constraints involved in cutting and rewelding new feeders, channels will have to be retubed in fairly large groups (i.e., eighth, quarter, or half core) to accommodate the feeder cutting and welding tools.

Fueling Machine Interference

New fuel channels will be installed to allow for maximum axial growth. They will be set to their original axial positions with the inboard journal ring sitting fully forward in the lattice tube bearing. Since new channels will be adjacent to original channels, some new end fittings will be as much as 3 inches further inboard than adjacent end fittings of channels whose replacement is left for a subsequent outage. With its current design, the fueling machine cannot accommodate this relative displacement between adjacent channels. This means that either the fueling machine snout will have to be redesigned, or the new end fitting must be lengthened.

Lengthening the end fitting will be a fairly straightforward exercise; however, there will be some constraints on the new design. The feeder port location will have to be set to its original plane to ensure that feeders do not become overstressed over the life of the fuel channel; and the closure plug must remain in its current axial position relative to the outboard end fitting face to accommodate the fuelling machine. The shield plug, however, can be moved up to 2.4 inches inboard of its current axial location (relative to the e-face) without modifying the fueling machine. This means the overall length of the fuel cavity will increase by about 1.2 inches. Given that the new channel will require a 1-inch longer cavity than that originally installed in Gentilly 2, the gap is only 0.2 inches longer than on the current new reactor installation. The longer gap is necessary to allow for thermal expansion of the fuel string in the event of a loss of coolant accident (LOCA) where all cooling to a new fuel channel is lost. In addition to this, the reactor will also require an extra 17 cubic feet of heavy water to fill the extra volume caused by the longer end fittings.

Isolation and Draining

An important factor in modular replacement will be the ability to isolate and drain individual, or groups of fuel channels, without resorting to feeder freezing, which is time consuming and dose intensive.

To eliminate unnecessary efforts, it is essential to drain only the feeders and channels that are to be replaced, and their associated headers. For this reason the reactor face must be sectioned for retubing in groups of channels on the same header system. In the event that a header services a larger section of channels than those scheduled for retubing, the CANDECON process will require the use of heavy water, and all channels on the isolated header (including those not to be replaced) must be defueled to prevent the channels from overheating. Because of this, the portion of the outage before the actual retubing efforts will remain equal in duration for all options (half core, quarter core, and multichannel).

Radiation Fields

During a modular replacement, at least half of the reactor fuel channels will remain in place with fuel. Hence, general radiation fields are expected to be higher than would be in standard full reactor core retube. To cut down on the localized fields, a combination of modular shielding (such as lead blankets and patches) will be used in conjunction with shielding cabinets to keep radiation exposure to a minimum.

Calandria Tubes

It is AECL's position that the calandria tubes in operating CANDU 6 reactors are expected to have a life of 60 years of operation. As discussed previously in this report, this is not the Hagler Bailly position. We do agree, however, that because calandria tube to LISS nozzle contact cannot be prevented at Gentilly 2 for a 60-year calandria tube life, replacement of up to two rows of calandria tubes may be required. These are rows F (18 tubes) and Q (20 tubes).

During each retubing stage, when an F or Q row is being worked on, following removal of the fuel channels and before new channel installation, the calandria tubes will be replaced. Over the entire retube duration, all 38 calandria tubes will be replaced.

However, not all of the calandria tubes can be replaced, and we believe this to be a major flaw in this approach.

A.2.3 Advantages and Disadvantages of the Different Concepts

Half Core Retubing

Half core retubing entails replacing approximately half of the 380 fuel channels in the reactor core in a single outage. The main advantage is that it allows the job to be split over two outages.

From a feeder interference point of view, half core retubing can be performed using two different approaches:

1. replace the upper half of the core in one outage followed by the lower half in the next outage

2. replace the channels on one side of the vertical centerline of the reactor in one outage followed by the other side in the next outage.

However, from a decontamination point of view, only the second approach is practical.

Half core retubing will require the least total downtime of all the staged retubing options; however, it will also require the longest outage durations for each stage. The overall reactor downtime for channel replacement will be approximately 12 months, made up of two outages, each approximately 6 months long. This does not include Hydro Quebec's time to prepare the reactor for retubing and to recommission the reactor.

Quarter Core Retubing

Quarter core retubing divides the reactor into quadrants, and replaces all the fuel channels within a given quadrant (approximately 95 channels) in a single outage. The main advantage is that it divides the retubing portion of the outages into much smaller durations (approximately four months each) that can more easily fit into the existing outage cycle for the station. Note this includes only AECL's time and not Hydro Quebec's time.

Multichannel (≈50) Retubing

With this option, approximately 50 channels will be replaced during each retubing outage, requiring a total of eight outages to completely retube the entire reactor core. Multichannel staged retubing offers the most flexibility in terms of outage duration because it can be fit into approximately three month outages (including only AECL time); however, it will take many years to complete, with a total of 24 months required to retube the reactor plus preparatory and recommissioning time.

To provide a comparison of the three alternatives, we have included the AECL durations for each in Exhibit A-2-1. It should be remembered that this does not include the Hydro Quebec time required to unload and reload fuel or to recommission the reactor at start up.

Note:

1. The above estimates are averaged over the entire retube process; some sections of the reactor will take longer to retube than others.

2. The above durations do not include the defueling and PHT draining operations or refueling and system recommissioning operations to be performed by Hydro Quebec.

Exhibit A-2-1
AECL Modular Replacement Durations

Activity	Half Core (days)	Quarter Core (days)	50 Channels (days)
Vault Preps (includes decontam)	20	20	20
Isolate and Drain Channels	27	14	8
Remove Insulation, Feeders and P/A	21	15	10
Remove Fuel Channels	38	21	15
Replace Calandria Tubes	11	7	5
Install Fuel Channels	30	18	12
Install P/A, Feeders and Insulation	25	16	11
Remove Equipment and Clean Vault	7	7	7
Total	179	118	88

3. Because of the time required for a half core retube, it is not considered a suitable option. The amount of time required for the one-half core option is at least 11 months for two years in a row. The 11 month duration is obtained from six months for AECL work and five months for Hydro Quebec work. The goal of this project is to conduct outages in less than eight months, thus this option does not meet the criteria. The multichannel retubing effort does not show much time savings over the quarter core retube. Thus, for the purposes of this analysis we assume quarter core retube methodology is used.

A.2.4 Cost of a Modular Large-Scale Pressure Tube and Feeder Replacement

The estimated total costs for a modular large-scale pressure tube and feeder replacement are given in Exhibit A-2-2. These costs include both the Hydro Quebec costs as well as the AECL costs. AECL costs were estimated at $272 million. For the purposes of our analysis, it is assumed that 20 percent of these total costs are spent in each of the four sequential years of the modular replacement. It is recognized that some of these costs will be spent in earlier years for planning, materials, and tooling. We assume the following cost distribution:

2002	5%
2003	5%
2004	10%
2005	20%
2006	20%
2007	20%
2008	20%.

Exhibit A-2-2 provides the total costs.

Exhibit A-2-2 Minimum, Most Likely, and Maximum Costs (1998 $ million) for a Modular Large-Scale Pressure Tube and Feeder Replacement		
Minimum	**Most Likely**	**Maximum**
342.8	380.9	423.2

The standard deviation of the Ln is 0.30.

A.2.5 Outage Time for a Modular Large-Scale Pressure Tube and Feeder Replacement

The outage time for the modular outages was estimated to be eight months; however, the uncertainty of completion is quite high. Exhibit A-2-3 provides the total outage time for each of the four replacement outages.

Exhibit A-2-3 Minimum, Most Likely, and Maximum Outage Times (days/outage) for a Modular Large-Scale Pressure Tube and Feeder Replacement		
Minimum	**Most Likely**	**Maximum**
220	240	300.2

The standard deviation of the Ln is 0.30.

A.3 ONE-TIME FUEL CHANNEL REPLACEMENT AND POSSIBLE CALANDRIA TUBE REPLACEMENT

A.3.1 Background

The considerations for the large-scale replacement of the pressure tubes and feeders in a single long outage are similar to those described earlier in Section A.1. However, the technical uncertainties are fewer for the single outage approach since it has been done before at the Pickering CANDU station. For similar reasons, the costs and outage durations for the single outage approach are more certain than for the modular approach.

AECL provided an estimate of the costs and outage duration of a single large-scale replacement of the pressure tube and feeders using newer AECL developed Fast Channel Replacement (FCR) technology[15] for NB Power. The base costs for this estimate were significantly less than the estimate based on the Pickering experience. Subsequently, NB Power and AECL worked together to develop revised estimated costs and durations that included the fixed-price AECL work, and that could clearly identify the work to be done by AECL and the work to be done by PLGS personnel.[16] These modified AECL estimated costs and outage durations, along with the PLGS estimates for their work scope and costs for a single large-scale pressure tube and feeder replacement at Point Lepreau, have been used for Gentilly 2. We would suspect that these estimated values somewhat understate the costs and outage durations at Gentilly 2 because of the higher radiation levels at Gentilly 2.

A.3.2 Cost of a Single Large-Scale Pressure Tube and Feeder Replacement

The estimated minimum (10 percent), most likely (50 percent), and maximum (90 percent) total costs for a single large-scale pressure tube and feeder replacement are given in Exhibit A-3-1. For the purposes of our analysis it is assumed that these total costs are spread out over four years: 5 percent in year 1, 10 percent in year 2, 15 percent in year 3, and 70 percent in the year of the replacement.

Exhibit A-3-1
Minimum, Most Likely, and Maximum Costs (1998 $ million)
for a Large-Scale Pressure Tube and Feeder Replacement

Minimum	Most Likely	Maximum
271.1	286.0	301.0

The standard deviation of the Ln of the values for the lognormal distribution for the data of Exhibit A-3-1 is 0.040.

A.3.3 Additional Costs for Replacing the Calandria Tubes Concurrent with the Single Replacement of Pressure Tubes and Feeders

As discussed in Section A.1, we have assumed that there is a 90 percent probability that the calandria tubes will be replaced concurrent with a large-scale pressure tube and feeder replacement. The estimated minimum, most likely, and maximum total additional costs for replacing all of the calandria tubes concurrent with a single large-scale pressure tube and feeder

15. Scott, D.A., "Point Lepreau Feeder & Pressure Tube Replacement — Outline Proposal," November 1997.

16. Letter, Gary Kugler to R.M. White, "AECL Proposal for retubing of Point Lepreau," 2/19/98.

replacement are given in Exhibit A-3-2. For the purposes of our analysis it is assumed that these total costs are spent in the year of the replacement.

Exhibit A-3-2
Minimum, Most Likely, and Maximum Additional Costs (1998 $ million) for a Single Replacement of All Calandria Tubes

Minimum	Most Likely	Maximum
26.5	29.7	33.4

The standard deviation of the Ln of the values for the lognormal distribution for the data of Exhibit A-3-2 is 0.0904.

A.3.4 Outage Time for a Single Large-Scale Pressure Tube and Feeder Replacement

The estimated minimum, most likely, and maximum outage times for a single large-scale pressure tube and feeder replacement based on the PLGS study are given in Exhibit A-3-3. The time required by AECL is 217 days with the balance of time required for Hydro Quebec scope of work.

Exhibit A-3-3
Minimum, Most Likely, and Maximum Outage Times (days) for a Single Large-Scale Pressure Tube and Feeder Replacement

Minimum	Most Likely	Maximum
412.2	458.0	508.8

The standard deviation of the Ln of the values for the lognormal distribution for the data of Exhibit A-3-3 is 0.0822.

A.3.5 Additional Outage Time for a Single Replacement of the Calandria Tubes Concurrent with the Pressure Tubes and Feeders

The estimated minimum, most likely, and maximum additional outage times for replacing all of the calandria tubes during a single large-scale pressure tube and feeder replacement based on the PLGS study are given in Exhibit A-3-4.

Exhibit A-3-4
Minimum, Most Likely, and Maximum Additional Outage Time (days) for Replacement of All Calandria Tubes

Minimum	Most Likely	Maximum
44.5	50.0	56.1

The standard deviation of the Ln of the values for the lognormal distribution for the data of Exhibit A-3-4 is 0.09096.

A.3.6 Cost per MWh Value

Upon request from Hydro Quebec, we estimated the cost per MWh for the one-time refurbishment outage strategy. The intent of developing this value is to provide a comparison to other alternatives not included in this report. As requested, we calculated a value of $27.7/MWh; however, there are many uncertainties associated with this value.

Difficulties in Determining Unit Cost

Determining a present value cost of Gentilly 2 electricity generation is straightforward. The model developed for Gentilly 2 provides present value costs for three different operating scenarios. The model includes relevant uncertainties and computes a distribution of present value cost, measured in 1998 dollars. Present value costs produced by the model include replacement and substitute power costs as well as the cost of electricity production from Gentilly 2. For Strategy 2 — one-time refurbishment — the present value cost is about $2,304 million. (This is a median.) Excluding replacement power, the present value cost of this scenario is about $1,800 million.

Converting total dollar cost into a cost per MWh is not straightforward. Both costs and generation quantities vary annually. In addition, significant costs associated with decommissioning and irradiated fuel management are incurred after electricity generation has stopped.

Variable costs are typically handled by levelizing, converting them into constant costs. The levelized annual cost is one that, as a discounted cost, yields the same present value as the variable annual costs. This method of levelization assumes capacity and generation do not vary over time. However, electricity generation from Gentilly 2 varies year by year. The model resolves this problem by including replacement and substitute power. Including replacement and substitute power makes it possible to fix the amount of net electricity generation at 635 MWh per hour for every hour over the 35-year timeframe. With annual electricity generation fixed at 5,563 GWh, a levelized annual cost and a levelized unit cost may be computed. For Gentilly 2, the levelized annual cost is $159 million; at annual generation of 5,563 GWh, the levelized unit cost is $28.60/MWh. (Again, these are median estimated costs of Strategy 2.) These costs include replacement power.

The levelized unit cost of $28.60/MWh assumes that a MWh is worth the same, regardless of when it is produced. Discounting cash flows reflects the preference for money today over money tomorrow. Similarly, preferences may exist for MWh. However, it is not so clear whether MWh are preferred today or tomorrow. With many commodities, it is preferable to have them today rather than tomorrow, because these commodities may be stored at nominal cost. Because electricity is not readily storable, MWh are clearly preferred during periods of high demand and scarce supply. Over the 35-year timeframe for possible Gentilly 2 operations, it is not obvious whether MWh are preferred sooner or later. While typical application of the economic theory of commodities would suggest MWh are more valuable now rather than later, impending environmental regulation may make MWh more valuable in 2010 than in 2000. Regardless, the levelized unit cost of $28.60/MWh assumes no time preference for generation.

Replacement power is included in the levelized unit cost of $28.60/MWh reported above. To calculate a cost per MWh for Gentilly 2 that excludes replacement and substitute power, we again focus on time preference for MWh. Gentilly 2 electricity production varies annually. How much more are 4,250 GWh (76 percent capacity factor) in 2000 worth, compared with 3,500 GWh (67 percent capacity factor) in 2010? An explicit discount rate for MWh is needed to determine this.

When an average capacity factor is used, a zero percent discount rate is implied for MWh, that is, a MWh is a MWh, regardless of when it is produced. The same assumed discount rate for MWh is embedded in the levelized cost of $28.60/MWh reported above.

With an assumption that MWh are discounted at zero percent, a levelized cents per MWh cost may be calculated by dividing the levelized annual cost by annual production at the average capacity factor. The model projects Gentilly 2 to have an average capacity factor of 81 percent, or electricity generation of about 4,506 GWh per year (again, at the median, or 50th percentile, for Strategy 2). As calculated above, the levelized annual cost, excluding replacement power, is $125 million. Dividing $125 million by 4,506 GWh yields a unit cost of about $27.7 per MWh.

It is important to note that the estimate of $27.7 per MWh does not rely on an assumed capacity factor. The model estimates a capacity factor from engineering detail, it does not assume a capacity factor. Major outage events such as refurbishment result in annual capacity factors varying greatly from the average. The key assumption in the estimate of $27.7 per MWh is that MWh are discounted at zero percent; hence, projected annual capacity factors that vary from the projected average do not matter.

Comparing Unit Costs of Different Generating Resources

The validity of the estimated cost of $27.7 per MWh for Gentilly 2 electricity production hinges on the assumptions discussed above. Using this number to compare with similar numbers for other generating resources causes other problems.

The generating resources that are compared should have equal capacities and lifetimes. If not, then present value costs for the different resources are difficult to compare directly. Accounting for one resource's economic life that has expired while another resource continues to economically generate electricity is difficult. Using levelized costs to compare resources implies that when each resource's useful economic lifespan is over, a new and identical resource is used to generate electricity. While such an assumption is appropriate for many equipment replacement decisions, it is clearly not appropriate for central-station electric power plants. Simply comparing levelized costs is generally not a good substitute for integrated resource planning or a decision analytic approach.

Second, the resources that are compared should have similar risk profiles. Outage rates, future costs, and other uncertainties should be similar for the different resources. If the risks are not similar, then preferences for risk are important. If risk-adjusted discount rates have been used in calculating the levelized costs, then it may be possible to compare generating resources. A more appropriate way to directly compare different generating resources, with different operating and financial characteristics, is decision analysis.

A.4 REPLACEMENT OF GENTILLY 2 WITH A NEW CANDU 6 UNIT

The third operating scenario requires building a new CANDU 6 unit (Gentilly 3) by 2008. It should be noted that Gentilly 2 may be able to operate past 2008; however, for the purposes of this analysis, we assume a shutdown date of 2008. We included the costs of operating Gentilly 2 until 2008 and then developed a cost per MWh and treated it as substitute power for 25 years at 80 percent capacity factor.

To develop a substitute power cost, the all-in costs of a new CANDU-6 had to be developed. We developed these costs for a new CANDU-6 that is expected to operate for 40 years at 80 percent capacity factor. We included construction, licensing, interest, financing, operating costs, fuel, and decommissioning. We developed a cost per MWh that could be used to calculate the substitute power costs for the 25 years that power is needed.

AECL was requested to provide a cost estimate for a new CANDU 6 unit for comparative purposes. Construction would begin in 2001.

A.4.1 AECL Costs

AECL provided the costs detailed in Exhibit A-4-1.

Exhibit A-4-1
Cost Estimates for a New CANDU 6 Unit
[millions of dollars (1998-CND)]

Task	$ Million
Engineering and Project Management	265
Equipment Supply (including procurement)	760
Construction/Installation	731
Initial Fuel Load (5,000 bundles)	21
Initial Heavy Water (465 mg)	44
Cost	**1,912**

The AECL costs do not include the following:

- financing and interest during construction
- licensing
- commissioning
- training
- traditional owner's scope (e.g., land, permits)
- common facilities (e.g., simulator, D_2O upgrade, river water, intake structure).

A.4.2 Financing and Interest

We calculated the financing costs during construction using a 7.7 percent discount rate with a 2.7 percent inflation rate and a seven-year period for construction. The total costs for construction financing are estimated to be $583 million.

We calculated the debt financing for the life of the project using a 50 percent debt to equity ratio, a 13.5 percent equity rate, and a 10.6 percent weighted cost of capital. The total cost for 40 years is estimated at $1,201 million.

A.4.3 Licensing and Commissioning Costs

In addition to the AECL costs, we included licensing and commissioning costs. We estimate these costs to be a lognormal distribution with a minimum of $40 million and a maximum of $70 million. The nominal costs were estimated at $50 million.

A.4.4 Additional Costs of Operating Gentilly 2 until 2008 and Gentilly 3 until 2048

All equipment, regulatory, and routine costs are adjusted to model a shutdown of Gentilly 2 in 2008. The decommissioning costs of Gentilly 2 are included in the model. Routine OM&A and capital costs assigned to Gentilly 2 were assumed to continue after 2008 adjusted for the operation of Gentilly 3. The spent fuel disposal and decommissioning costs for Gentilly 3 are included in the model in 2048. There are many unknowns and additional costs may also be needed to continue operation of Gentilly 3. To account for this, we assumed costs for major equipment replacement and repairs for Gentilly 3.

A.4.5 Cost per MWh

In order to obtain a cost per MWh, we assume that the new CANDU 6 will operate for 40 years. The AECL design is currently rated to this design life. We have not included costs for wholesale replacement of the pressure tubes. If Hydro Quebec chooses to pursue this strategy, we highly recommend that a contract guaranteeing the life of the pressure tubes is negotiated with AECL.

We only include 25 years of generation at 80 percent in order to compare the present value costs to the other strategies of operating Gentilly 2 until 2033.

The costs are estimated at $81.21 per MWh.

APPENDIX B
MODELING OF EQUIPMENT ISSUES

CONTENTS

APPENDIX B
MODELING OF EQUIPMENT ISSUES

This appendix addresses the equipment issues that were specifically addressed for Gentilly 2, including:

- feeder thinning input
- steam generator input
- main turbine
- main generator
- containment
- feedwater
- condenser.

Other issues that were specifically addressed for Point Lepreau and revised for Gentilly 2 include:

- calandria tube and pressure tube replacement due to sagging and contact with horizontal flux detector tubes or LISS nozzles

- individual pressure tube replacement

- feeder pipe cracking

- emergency diesel generators

- station computers

- cable replacement

- plant aging program.

Each of these 14 issues is detailed below.

B.1 FEEDER THINNING INPUT

B.1.1 Background

Much of the data in this section on the thinning of the outlet feeder pipes is taken from the work done for the Point Lepreau Generating Station (PLGS) and modified for the conditions of

Gentilly 2. During the fall 1997 planned outage at PLGS, detailed thickness measurements of 175 outlet feeders were made. In total, 214 of the 380 outlet feeders at PLGS have been measured, including those measured in previous years. The results of these PLGS measurements[1] were compared to the results of the Gentilly 2 million measurements made in 1996 and 1997.[2] The Gentilly 2 measurements appear to be totally consistent with the measurements at PLGS. The PLGS data, modified to Gentilly 2 conditions, were used because of the significantly larger number of measured feeders.

The feeder thickness measurements correlate very well with the CANDU Owners Group (COG) QV (flow rate x velocity) model of the feeder thinning. The COG QV model assumes a normal distribution for the initial thickness based on bend measurements of the available new spare feeders and inaugural measurements from other stations with the same type of bends.[3] In this model, the thinning rate is assumed to be proportional to the QV of the individual feeders.

B.1.2 Number of Feeders Requiring Replacement

The Gentilly 2 staff believes that the evidence for replacement of feeders before the refurbishment outage is not sufficient. The model will show no replacements of feeder pipes before the refurbishment outage. For future use, we provide the following information:

Based on the 1997 PLGS measurements, the PLGS system engineer calculated the number of feeders that would require replacement each year for the following three scenarios,[45]:

1. An Upper Bound (UB) Model, where the initial thickness of all of the feeders is assumed to be at the thick end of the normal distribution of the COG QV model. This UB Model is believed to be overly conservative, and the PLGS system engineer recommended that a thinning rate equal to 80 percent of that of the UB Model be used to calculate the maximum (90 percent probability) number of feeders that may be required to be replaced each year. This scenario is consistent with the conservative approach suggested by Gentilly 2.[6]

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1. E-Mail, John Slade to Ross Reid et al., "FW: Final Feeder Thickness Status Report," 1/7/98.

2. "Condition actuelle des tuyaux d'alimentation du reacteur," Gentilly 2 report, Revision 2, 12/10/97.

3. E-Mail, John Slade to Syd Turner, "RE: Feeder Thinning Methodology," 12/31/97.

4. E-Mail, Syd Turner to Ken Van Howe, "FW: Feeder Numbers for HB," 2/1/98.

5. E-Mail, John Slade to Ross Reid et al., "RE: Feeder Thinning Table," 2/3/98.

6. "Condition actuelle des tuyaux d'alimentation du reacteur," Gentilly 2 report, Revision 2, 12/10/97.

2. The COG QV Model, which is considered to yield the most likely scenario. The results from this model are used as the most likely number of feeders that would require replacement each year. This scenario is consistent with the second approach suggested by Gentilly 2.[7]

3. A modified result of the COG QV Model, where the thinning rate from the model is reduced to 67 percent of the measured rate after 1996 to account for the potential reduction in the historical thinning rate as described below. The PLGS system engineer believed that a greater (50 percent) reduction in the thinning rate would be more representative of the minimum (10 percent probability) number of feeders that would require replacement each year. The results of this scenario were modified to approximate a 50 percent reduction in the COG QV Model thinning rate. This scenario is consistent with the 50 percent reduction in the thinning rate suggested by Gentilly 2.[8]

The number of feeders that will require replacement using the COG QV model (scenario 2 above) assumes that no gain will come from the reduction in the pH of the primary system water, or from the potential of treating the inner surface of the feeders with selective Cr metal deposition to inhibit the feeder thinning. It is possible that these changes to the primary system water chemistry will significantly reduce the thinning rate of the feeders.

The currently accepted model is based on iron solubility at heat transport operating temperature and pH.[9] It is founded on long-established mild steel corrosion phenomena, i.e., the Uhlig Corrosion Handbook and refinements to this model by a peer-reviewed industry team. It is thus factual that a reduction in the pH to some optimal value below 10.6 will reduce the corrosion rate by some number. However, the degree of reduction to be achieved is not known. Gentilly 2 is now operating and controlling the pH at about 10.6, down from the previous value of about 10.9. It is therefore reasonable to conclude that some rate reduction is now underway. Of course, this is a theory that will require validation with long-term measurements using on-line thickness measurement technology. The evaluation of seven feeders that were measured in both 1996 and 1997 at PLGS did not provide any insight into a reduction in the thinning rate since the uncertainty in the measurement is approximately equal to the amount of thinning in a year.

It is accepted that flow-accelerated corrosion is the main feeder thinning mechanism at work. There are a number of influential variables affecting the rate of feeder thinning, namely fluid velocity, water chemistry (for which there are a number of elements), pipe geometry,

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7. "Condition actuelle des tuyaux d'alimentation du reacteur," Gentilly 2 report, Revision 2, 12/10/97.

8. "Condition actuelle des tuyaux d'alimentation du reacteur," Gentilly 2 report, Revision 2, 12/10/97.

9. Personal communication, Cyril MacNeil, NB Power.

temperature, and carbon-steel quality. It is not understood at this time what the weighting factors of influence are for each of the variables.[10]

To obtain an estimate of the minimum number of feeders that will require replacement (scenario 3 above), it was assumed that the feeder thinning rate could be reduced from the water chemistry changes to 50 percent of what has taken place before 1996 using the COG QV Model. Reducing the pH to the 10.2 to 10.4 range can reduce the thinning rate by 25 percent to 45 percent. Decreasing the pH to the 10.0 to 10.2 range can reduce the thinning rate by an additional 5 percent to 15 percent[11] so that a 50 percent reduction in the thinning rate is not impossible. As discussed above, the actual thinning rate that has been or can be achieved is unknown at this time because of uncertainties in weighting factors that influence the thinning rate.

At Gentilly 2, the primary system pH previously was at 10.9. It is now at about 10.6.[12] Gentilly 2 does not have sufficient capacity in the purification system to extract the lithium to a level sufficient to reduce the pH to very low levels. The height of the extraction columns has been increased by filling them to a maximum. A pH of about 10.4 could now be achieved. There is a level transmitter in the fuel handling system that uses conductivity to measure level. The conductivity of the primary system water decreases with decreasing pH and limits the current pH to about 10.6. The level transmitter was changed out in the 1998 outage allowing the pH to be lowered to about 10.4. In the future, the pH could be reduced to the 10.0 to 10.2 range, but this would require changes to the capacity of the purification system. If these changes could reduce the thinning rate to the assumed minimum value, they may be cost-effective.

The PLGS data were corrected to Gentilly 2 conditions. These corrections accommodated the shorter current operating duration of Gentilly 2 [about 1.5 fewer Equivalent Full Power Years (EFPY)] and a projected capacity factor of 80 percent (rather than the 90 percent used in the PLGS analysis). The minimum (10 percent probability), most likely (50 percent probability), and maximum (90 percent probability) values for the number of feeders that may require replacement each year from these analyses are given in Exhibit B-3-1.

Gentilly 2 performed a considerable number of measurements of the thickness of feeder bends in 1998. These measurements included a considerable number of bends that were measured in previous years. These measurements will provide additional data on the feeder thinning rate and allow confirmation of the validity of using the COG QV model for the Gentilly 2 feeder thinning. The analysis has not yet been completed. More precise information may be available about the number of feeders that may require replacement. Thus, we include our recommended approach to estimating the number of feeders that may require replacement. The assumed minimum, most likely, and maximum number of feeders that might require replacement as given

10. Personal communication, Cyril MacNeil, NB Power.

11. Personal communication, Marcel Bergeron, Gentilly 2.

12. Personal communication, Marcel Bergeron, Gentilly 2.

in Exhibit B-1-1 may require modification based on these Gentilly 2 measurements. However, for purposes of this report, we assume that no feeders require replacement because of the lack of information.

Exhibit B-1-1
Minimum, Most Likely, and Maximum Number of Feeders Requiring Replacement Each Year

Year	Minimum	Most Likely	Maximum
1998-2006	0	0	0
2007	0	1	1
2008	0	0	3
2009	0	2	7
2010	0	0	2
2011	0	1	2

B.1.3 Cost of Feeder Replacement

The cost to replace feeders because of thinning is based on an estimate obtained by NB Power for $9.9 million to replace 13 feeders or $0.76 million per feeder.[13] The cost to replace the feeders at Gentilly 2 were increased by 50 percent[14] to $1.14 million per feeder to account for the higher radiation field at Gentilly 2. These estimates are for feeders on the outer radius. These are the smaller diameter feeders that have a thinner initial wall thickness in the bend area and will be the first to require replacement. These feeders are easier to reach and are less expensive to replace than the feeders on the inside. These costs also assume that the feeder replacements are preplanned. Since the thinning of the feeders will be closely monitored, the need to replace any feeders will be known well in advance and preplanning is a valid assumption. The costs of replacing the minimum, most likely, and maximum number of feeders each year are given in Exhibit B-1-2.

13. E-mail, Allison Bull to Ken Van Howe, "RE: Pressure Tube, Calandria Tubes and Feeder Tube Replacement — Reply," 11/26/97.

14. Fax, Marc Aubray to Ken Van Howe, "Data for Pressure Tubes and Feeders replacement. Done by Pierre Gauthier et al.," 2/2/98.

Exhibit B-1-2
Costs (1998 $M Canadian) of Replacing the Minimum, Most Likely, and Maximum Number of Feeders Each Year

Year	Minimum	Most Likely	Maximum
1998-2006	0	0	0
2007	0	1.1	1.1
2008	0	0	3.4
2009	0	2.3	8.0
2010	0	0	2.3
2011	0	1.1	2.3

B.1.4 Outage Time for Feeder Replacement

If fewer than 16 feeders require replacement in a year at PLGS, it is assumed that 2.3 days are required per feeder based on an estimated 30 days to replace 13 feeders on a preplanned basis.[15] The outage time for Gentilly 2 was increased by 50 percent to 3.45 days per feeder to account for the higher radiation levels at Gentilly 2.[16] These times are for outer smaller-diameter feeders, which are easier to replace than feeders in the central section. The minimum, most likely, and maximum times required to replace feeders because of thinning are given in Exhibit B-1-3.

Exhibit B-1-3
Time (days) Required to Replace the Minimum, Most Likely, and Maximum Number of Feeders Each Year

Year	Minimum	Most Likely	Maximum
1998-2006	0	0	0
2007	0	3.5	3.5
2008	0	0	10.4
2009	0	6.9	24.2
2010	0	0	6.9
2011	3.5	3.5	6.9

15. E-mail, Ross Reid to Ken Van Howe, "FW: Hagler Bailly Info. on Feeders," 7/31/97.

16. Fax, Marc Aubray to Ken Van Howe, "Data for Pressure Tubes and Feeders replacement. Done by Pierre Gauthier et al.," 2/2/98.

In applying these data, only the outage time that is greater than the normal planned outage time for the year will be counted as critical path time. This assumes that the feeders that will have to be replaced in each year will be identified by the measurements made in the previous year's planned outage, or that the outage time for feeder replacement is small relative to the normal planned outage duration.

B.1.5 Probability Distributions

The various probability values represent differing assumptions in the modeling or differing degrees of success in reducing the thinning rate by water chemistry or feeder surface treatment modifications. The number of feeders requiring replacement each year depends on the probability. Therefore, the same probability value is used for each of the years to give the number of feeders that are required to be replaced each year at that probability value.

For the years before 2012, the relatively simple probability distributions of Exhibit B-1-4 can be used to represent the number of feeders that require replacement each year.

Exhibit B-1-4
Probability Distributions for Number of Feeders Requiring Replacement

Year	$p < 0.2$	$0.2 > p < 0.8$	$p > 0.8$
2007	0	1	1
2008	0	0	3
2009	0	2	7
2010	0	0	2
2011	0	1	2

B.2 STEAM GENERATOR REPLACEMENT

B.2.1 Background

The Gentilly 2 steam generators are currently in very good condition. The Gentilly 2 steam generator materials and design and the unique steam generator water chemistry used at Gentilly 2 contribute to the good condition and the likelihood that the steam generators will be able to operate for an extensive period of time without requiring replacement. The steam generators employ Incoloy alloy 800 TT tubes with trefoil broached stainless steel support plates. The tubes have stress relief in the U-bends, and stainless steel staggered scallop antivibration bars (AVBs) are used in the U-bend area. The tubes were hydraulically expanded in the tube sheet with flush tube-to-tubesheet welds so that no crevices are present. These features are consistent with the best design features of nuclear steam generators, with the possible exception of the use of alloy

800 lattice supports being somewhat preferable to the trefoil broached stainless steel support plates at Gentilly 2.

The steam generators have been well maintained. In 1993 the sludge pile on the tube sheet was measured to be about 3 inches high. Water lancing to remove the sludge was attempted, but the success was difficult to clearly demonstrate. The sludge was broken and only a small quantity remained even though only four kilograms were collected from four steam generators. It is suspected that the major portion of the sludge was removed through the purge.[17] In 1996 a visual inspection of the tubesheet area of one steam generator was performed and in 1997 the remaining three steam generators were inspected.[18] The maximum sludge pile height was 5.7 inches in the GV-4 steam generator. The other two steam generators inspected in 1997 had sludge pile heights of 4.9 and 3.2 inches. The bottom surface of the first hot leg tube support was also visually inspected in 1997. This tube support plate was clean with only small deposits observed within the trefoil broached flow holes in some local areas. Based on these inspections, regular water lance cleaning was recommended. It is planned to water lance the steam generators in the 1999 planned outage.[19] Periodic sludge lancing beyond 1999 at a frequency of every four to five years if requested because of sludge thickness, will contribute to maintaining a long lifetime for the steam generators.

The divider plate in the inlet-outlet plenum was replaced in 1995.[20] The reactor inlet temperature went down to 265°C, returning to near its initial value of 262°C, as a result of these modifications. The primary side of the steam generator tubes has a high level of deposits, about 4 microns in the hot legs and 150 microns in the cold legs. Atomic Energy of Canada Limited (AECL) has estimated that cleaning of the primary side tubes could pick up about 2°C on the inlet temperature and about a 2 percent increase in the primary system flow.[21] Gentilly 2 is planning on mechanically cleaning the primary side of all four steam generators during the 1998 planned outage.[22] The cost for this work is estimated to be $4 million.

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17. Personal communication, Steve Plante, Gentilly 2.

18. Foster-Miller Report, "Hydro Quebec, Centrale Nucleaire Gentilly-2, CECIL Systeme Inspection Visuelle de 3 Generateurs de Vapeur Cote Secondaire," HYQ-97552, 97-05-25.

19. Gentilly 2 Report, Programme d'entretien des generateurs de vapeur a Gentilly-2 Annees 1997-1998," G2 — RTI-97-39, 97-06-12.

20. Gentilly 2 Report, Programme d'entretien des generateurs de vapeur a Gentilly-2 Annees 1997-1998," G2 — RTI-97-39, 97-06-12.

21. Personal communication, Steve Plante, Gentilly 2. 1998.

22. Gentilly 2 Report, Programme d'entretien des generateurs de vapeur a Gentilly-2 Annees 1997-1998," G2 — RTI-97-39, 97-06-12.

The Gentilly 2 secondary system has a condenser with admiralty brass tubes. The high-pressure feedwater heaters have carbon steel tubes, and the low-pressure feedwater heaters have stainless steel tubes. The plant started up using all volatile treatment (AVT) for the steam generators using both hydrazine and morpholine for water treatment. They had difficulties maintaining the specified pH and ammonia levels. They reduced the hydrazine level and in April 1984 went to zero hydrazine.[23] The plant also operates with maximum steam generator blow down flow at 0.5 percent of full steam flow. Samples of the crud level in the system are measured each month. It is estimated that about 25 kg of crud are produced in each year of operation. About half of this or 12 to 13 kg of crud per year is removed by the blow-down system. The plant chemistry staff believes that morpholine reduces both erosion and corrosion better than ammonia.

The combination of the steam generator design and the water chemistry used has been very successful in preventing any major degradation of the steam generator tubes. Of the 14,200 tubes in the four steam generators (3,550 tubes per steam generator) only three tubes have been plugged because they were voluntarily extracted to permit metallurgical analysis and no tube leaks have occurred.[24] Fretting indications in the U-bend area at the AVBs are limited. Only one tube has been found with an indication of fretting wear. This tube showed a 16 percent through wall imperfection in the 1993 inspection. The imperfection grew to about 20 percent through wall in 1996.

Eddy current testing (ECT) of a representative number of the boiler tubes has been performed in the past. An ECT inspection of a significant portion of the steam generator tubes is under planning for the 1999 inspection.[25] We agree that a 100 percent ECT is required before any decision to initiate either a modular or a single large-scale pressure tube and feeder replacement.

B.2.2 Probability of Requiring a Steam Generator Replacement

As demonstrated in the previous section, the steam generators at Gentilly 2 are in very good condition. Assuming that the fretting or wear damage does not become worse, with a continuing aggressive program to maintain tight control on the steam generator water chemistry and to maintain the steam generators through periodic sludge lancing and tube inspections, the steam generators should last well beyond their design life of 30 years at an 80 percent capacity factor. It is therefore very unlikely that the steam generators should require replacement during the

23. Personal communication, Marcel Bergeron, Gentilly 2. 1998.

24. Personal communication, Steve Plante, Gentilly 2. 1998.

25. Personal communication, Marc Aubray, Gentilly 2. 7/10/98.

feeder/pressure tube outage in the 2008 to 2011 time frame. We estimate that there is zero probability that the steam generators will require replacement during the refurbishment outage.[26]

However, it is questionable if the steam generators could last for the entire plant lifetime if operations are extended to 2033. For the purpose of our analysis, it is assumed that there is a 10 percent probability that the steam generator will require replacement in 2023.

B.2.3 Outage Time for Steam Generator Replacement

In the last 10 years, 12 steam generator replacements have been completed and one is currently in progress in the United States. For this analysis, the experience in the last 10 years has been used since there have been some improvements in the outage durations and costs required for replacing the steam generators. It is assumed that the outage durations of the 12 steam generator replacements completed in the last 10 years in the United States are representative of the steam generator outage duration that may be achieved at Gentilly 2 to replace all four steam generators.

The U.S. steam generator replacement outage durations[27] were fit to a lognormal distribution with a Ln of the mean of 4.863 and a standard deviation of the Ln of the values of 0.536. The resulting minimum (10 percent), most likely, and maximum (90 percent) values are given in Exhibit B-2-1.

Exhibit B-2-1
Minimum, Most Likely, and Maximum Time (days)
Required to Replace the Four Steam Generators

Minimum	Most Likely	Maximum
65	129	257

B.2.4 Cost of Steam Generator Replacement

B&W Canada has supplied a cost for four new steam generators of $45 million to $50 million. These costs include engineering, licensing, manufacturing, and delivery to the site. They do not include installation costs, which are a major cost item.

Of the 12 completed steam generator replacements, valid data on the capital additions costs incurred in the replacements were available for 9.[28] The costs for these nine steam generator

26. Personal communication, Steve Plante, Gentilly 2. 1998.

27. Hagler Bailly Nuclear Data Base.

28. Hagler Bailly Nuclear Data Base.

replacements were converted to 1998 Canadian dollars using the U.S. CPI and the current U.S.-to-Canadian conversion rate. Linear regression techniques were used to fit the 1998 Canadian dollar cost data to a fixed cost component and a variable cost component. The fixed component is $157.8 million (includes four steam generator materials costs and other fixed costs) and the variable component is $0.334 million per outage day. This variable cost includes costs that are dependent on how long the steam generator replacement outage takes and does not include any replacement power costs. Using the minimum, most likely, and maximum outage durations developed in the previous section, the corresponding steam generator replacement costs are given in Exhibit B-2-2.

Exhibit B-2-2
Cost of Replacing Four Steam Generators — 1998 $M Canadian

Minimum	Most Likely	Maximum
180	201	244

B.3 MAIN TURBINE

B.3.1 Background

The Gentilly 2 main turbine and generator is a General Electric M-7 design unit. The turbine has a double-flow high-pressure section and two double-flow low-pressure sections. The rotor is constructed of a solid forging, with wheels and shaft integral for HP turbine and build up wheels for the LPS. The turbine bypass system allows for bypassing of up to 80 percent of the design steam flow. The turbine and generator alignment has been difficult to maintain because of growth in the turbine pedestal due to aggregate-alkali-reaction (AAR). These alignment problems were directly responsible for the planned outages in 1983, 1985, 1987, 1991, and 1998. The durations of these outage ranged from 6 to 20 weeks. The duration of many of the other planned outages have been extended for about a week to correct misalignment problems. The growth rate of the turbine pedestal is slowing down and the 1998 outage will probably be the last one dedicated to correct misalignment problems. However, future annual planned outages will each require about one week to correct misalignment.[29]

Two turbine wheel ultrasonic inspections have been performed on the high-pressure and low-pressure “A” turbines in 1991 and 1998. Similar inspections were performed for the low-pressure “B” turbine in 1990, 1995, and 1998. The 1998 inspection also included magnetic particle inspection and inspection of all diaphragms in all three turbine sections. There have been a few

29. Main Turbine Data Request, response prepared by Andre Babin, Gentilly 2. 1998.

repairs performed, including replacement of the 10th stage buckets of LP "B" in 1983 due to a rub, steam chest repairs in 1987, and a casing erosion repair in 1995.[30]

The main turbine appears to be in very good condition and with continued careful preventative maintenance should be able to operate well beyond its initial planned life of 30 years at 80 percent capacity factor. The draft plant life extension planning (PIME) document identified the potential replacement of the turbine MK II EHC with a Speedtronic MK V in about 2008 if the life of Gentilly 2 is to be extended beyond the initial planned life. The direct costs for this change are estimated to be $1.36 million.[31] These costs are included in the miscellaneous costs for the outages where the pressure tubes and feeders are replaced.

B.3.2 Probability of a Major Main Turbine Outage

To obtain an estimate of the probability of a major outage due to a problem with the main turbine, the U.S. data base[32] was searched for main turbine caused outages with durations greater that one month. The time frame of this search was U.S. experience from January 1989 through September 1997, representing 942 unit years of experience. During this period there were nine main turbine events with durations greater than one month. The probability of a major main turbine outage is therefore 9/942, or a probability of 0.0096 of an event each unit-year.

B.3.3 Outage Time for a Major Turbine Outage

The total time that the main turbine was out of service for the nine U.S. nuclear events ranged from 30 to 359 days. However, some portion of the total equipment outage time can often be shadowed by other events such as the yearly planned outage. That is, if a major unplanned event takes place that will have a long duration, the yearly planned outage can often be moved forward in time so as to reduce the total outage impact of the unplanned event. In other cases, the opportunity is taken to do other critical path work concurrent with the overall outage. To account for the potential of some shadowing of the impact of these major events, outage durations equal to the unshadowed equivalent full power days (EFPDs) were used in this analysis. The use of the unshadowed EFPDs from the U.S. data for Gentilly 2 somewhat understates the net shadowed outage time for Gentilly 2. This results from the increased ability of U.S. units to shadow unplanned outage work with planned refueling outage work. At the U.S. units, the planned outages are generally longer than those at CANDU units because of the refueling activities. With longer planned outages at U.S. units, there is a potential that more of the work for a major turbine outage can be done in the shadow of planned outage work. We recognize this deficiency

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30. Main Turbine Data Request, response prepared by Andre Babin, Gentilly 2. 1998.

31. E-Mail, Marc Aubray to Ken Van Howe, TR: Change of EMC MK II for Speedtronic, 2/6/98.

32. Hagler Bailly nuclear unit data base Operating Plant Evaluation Code — OPEC.

in applying U.S. data to the CANDU units, which have on-line refueling. We do not feel that this is a major deficiency in our analysis.

The EFPDs of the nine main turbine events ranged from 17 days to 266 days. These outage durations were fit to both normal and lognormal distributions. In this case, the outage duration data were best represented by a lognormal distribution with a mean of 61 days and a standard deviation of the Ln of the values equal to 0.730. The minimum (10 percent), most likely, and maximum (90 percent) outage durations for the low-frequency high-impact main turbine events from this lognormal distribution are given in Exhibit B-3-1.

Exhibit B-3-1
Outage Time (days) for a Major Main Turbine Event

Minimum	Most Likely	Maximum
24	61	154

B.3.4 Costs of a Major Turbine Outage

An approximate estimate of the material and additional labor costs for a major turbine event was made as follows:

To obtain an estimate of the material and additional labor costs associated with a major outage due to a problem with the main turbine, the system engineer provided data on labor costs and developed material costs that might be representative of events with unshadowed durations approximating the minimum, most likely, and maximum durations given above.[33] For the minimum duration event, the material cost of $0.06 million for the replacement of a couple of L-0 blades was used. Twenty working days on a two 12-hour shift basis were assumed for an additional labor cost of $0.25 million for labor and per diem for Original Equipment Manufacturer (OEM) personnel and $0.27 million for overtime costs for the Gentilly 2 personnel. The total additional labor and materials cost was $0.58 million. In calculating the additional labor costs only the overtime costs for the Gentilly 2 personnel were included since the normal costs are included in the normal OM&A costs.

For the most likely duration event the material cost of $1.01 million for the replacement of a row of L-0 buckets was used. Thirty working days on a two 12-hour shift basis were assumed for an additional labor cost of $0.38 million for labor and per diem for OEM personnel and $0.40 million for overtime costs for the Gentilly 2 personnel. The total additional labor and materials cost was $1.78 million.

33. E-mail, Marc Aubray to Ken Van Howe, "TR: Turbine & Generator Forced Outages," 2/2/98.

For the maximum duration event the material cost of $11.91 million for the replacement of a LP rotor was used. Fifty work days on a two 12-hour shift basis were assumed for an additional labor cost of $0.19 million for labor and per diem for OEM personnel and $0.65 million for overtime costs for the Gentilly 2 personnel. The total additional labor and materials cost was $12.75 million.

These cost estimates do not require any cost adjustments for corporate overhead, interest costs, and contingency.[34] These estimated total costs are summarized in the Data row of Exhibit B-3-2.

Exhibit B-3-2
Additional Labor and Materials Costs
(1998 $M Canadian) for Major Turbine Event

	Minimum	Most Likely	Maximum
Data	0.58	1.78	12.75
Lognormal Fit	0.50	2.36	11.07

These data were used in a regression analysis to obtain a lognormal distribution representing the additional labor and materials costs for a major main turbine event. The results of this analysis are given in the Lognormal Fit row of Exhibit B-3-2. The lognormal distribution had a standard deviation of the Ln of the values equal to 1.2056.

The additional labor and materials costs for a major turbine event are interrelated to the outage durations. Therefore, the same probability value will be used in the model to obtain values from the outage time and additional labor and materials costs.

B.4 MAIN GENERATOR

B.4.1 Background

The problems with maintaining alignment due to growth of the turbine-generator pedestal, as described in Section B.3, have also affected maintaining the alignment of the generator to the turbine. These problems should reduce in the future. A copper dust inspection and vacuuming of the rotor was performed in 1991, but the rotor remained contaminated. In 1992 a forced outage occurred due to copper dust contamination. During the outage, the rotor was rewedged and modified to include a layer separator between the bars. A visual inspection of the generator internals and a stator bar leak test were performed in 1996. The stator was pressure tested and

34. E-mail, Marc Aubray to Ken Van Howe, "Possible costs of change of HX, Condenser," 2/20/98.

rewedged in 1997.[35] The rotor end retaining rings were replaced with rings that are not susceptible to stress corrosion cracking.

The main generator appears to be in very good condition and with continued careful preventative maintenance should be able to operate well beyond its initial planned life of 30 years at an 80 percent capacity factor.

B.4.2 Probability of a Major Main Generator Outage

To obtain an estimate of the probability of a major outage due to a problem with the main generator, the U.S. data base[36] was searched for main generator caused outages with durations greater that one month. The time frame of this search was U.S. experience from January 1989 through September 1997, representing 942 unit years of experience. During this period there were 12 main generator events with durations greater that one month. The probability of a major main generator outage is therefore, 12/942, or a probability of 0.013 of an event each unit-year.

B.4.3 Outage Time for a Major Generator Outage

The total time that the main generator was out-of-service for the 12 U.S. nuclear events ranged from 36 to 267 days. However, some portion of the total equipment outage time can often be shadowed by other events such as the yearly planned outage. That is, if a major unplanned event takes place that will have a long duration, the yearly planned outage can often be moved forward in time so as to reduce the total outage impact of the unplanned event. In other cases, the opportunity is taken to do other critical path work concurrent with the overall outage. To account for the potential of some shadowing of the impact of these major events, outage durations equal to the unshadowed EFPDs were used in this analysis. The use of the unshadowed EFPDs from the U.S. data for Gentilly 2 somewhat understates the net shadowed outage time for Gentilly 2. This results from an increased ability of U.S. units to shadow unplanned outage work with the planned outage work. At the U.S. units, the planned outages are generally longer than those at CANDU units because of the refueling activities. With longer planned outages at U.S. units, there is a potential that more of the outage time for a major generator outage can be done in the shadow of planned outage work. We recognize this deficiency in applying U.S. data to the CANDU units, which have on-line refueling. We do not feel that this is a major deficiency in our analysis.

The EFPDs of the 12 main generator events ranged from 12 to 94 days. These outage durations were fit to both normal and lognormal distributions. In this case, the outage duration data were best represented by a normal distribution with a mean of 56 days and a standard deviation of

35. Main Turbine Data Request, response prepared by Andre Babin, Gentilly 2. 1998.

36. Hagler Bailly nuclear unit data base Operating Plant Evaluation Code — OPEC. 1998.

20 days. The minimum (10 percent), most likely, and maximum (90 percent) outage durations for the low-frequency high-impact main generator events is given in Exhibit B-4-1.

Exhibit B-4-1
Outage Time (days) for a Major Main Generator Event

Minimum	Most Likely	Maximum
30	56	82

B.4.4 Costs of a Major Generator Outage

The value of the lost generation during the outage time above is generally the largest cost of a major generator outage. However, an approximate estimate of the material and additional labor costs for a major generator event was made as follows:

To obtain an estimate of the material and additional labor costs associated with a major generator outage, the system engineer provided data on labor costs and developed material costs that might be representative of events with unshadowed durations approximating the minimum, most likely, and maximum durations given above.[37] For the minimum duration event the material cost of $0.31 million for a replacement of one stator water cooling header was used. Twenty work days on a two 12-hour shift basis were assumed for an additional labor cost of $0.48 million. The total additional labor and materials cost is $0.79 million. In calculating the additional labor costs only the overtime costs for Gentilly 2 personnel were included since the normal costs are included in the normal O&M costs.

For the most likely duration event, the material cost of $0.37 million for a rewind of the field because of cooper dust contamination based on the event in 1991/1992 was used. Thirty working days on a two 12-hour shift basis were assumed for an additional labor cost of $1.32 million. The total addition labor and materials cost was $1.69 million.

For the maximum duration event, the materials cost of $7.0 million for a total stator rewind with new bars was used. Fifty working days on a two 12-hour shift basis were assumed for an additional labor cost of $2.81 million. The total additional labor and materials cost was $7.01 million.

It is not required to adjust these estimated costs for corporate overhead, interest costs, and contingency.[38] The estimated minimum (10 percent), most likely (50 percent) and maximum (90 percent) costs are summarized in the row labeled Data in Exhibit B-4-2.

37. E-mail, Marc Aubray to Ken Van Howe, "TR: Turbine & Generator Forced Outages," 2/2/98.

38. E-mail, Marc Aubray to Ken Van Howe, "Possible costs of change of HX, Condenser," 2/20/98.

Exhibit B-4-2
Additional Labor and Materials Costs
(1998 $M Canadian) for Major Generator Event

	Minimum	Most Likely	Maximum
Data	0.79	1.69	7.01
Lognormal Fit	0.71	2.11	6.28

These data were used in a regression analysis to obtain a lognormal distribution representing the additional labor and materials costs for a major generator event. The minimum, most likely, and maximum values from this lognormal distribution are given in the row labeled Lognormal Fit in Exhibit B-4-2. The lognormal distribution had a standard deviation of the Ln of the values equal to 0.8517.

The additional labor and materials costs are interrelated with the outage durations. Therefore, the same probability value will be used in the calculational model to obtain values from the normal outage distribution and the lognormal additional labor and materials costs distribution.

B.5 CONTAINMENT STRUCTURE

B.5.1 Background

The containment structure at Gentilly 2 represents one of the most significant unknowns with regard to the viability of operating the plant beyond its original lifetime. Little has been done to monitor the condition and the potential degradation of the containment building structure beyond the periodic integrated leak rate test at design and reduced pressure loading conditions, and inspection and repair/replacement of the containment liner. These measures demonstrate the ability of the containment to perform its design function at the current time, but yield little insight into its ability to provide this function for an additional 40 or 50 years.

The original plan was to perform an integrated leak rate test every five years. The original test in 1979 had a leak rate of 0.29 percent vol./day. The 1981 test had a measured leak rate of 0.16 percent vol./day. Both of these were below the 0.5 percent vol./day design leak rate limit. However, the 1985 test was slightly over the limit as shown in Exhibit B-5-1.[39]

Because the 1985 reactor building leak rate was higher than the design limit leak rate, the AECB required a more frequent test interval. The data in the second column of Exhibit B-5-1 is the total

39. Letter, Marc Aubray to Ken Van Howe, Containment Data (ref: your January 19, 1998 E-mail to Marc Aubray), 1/28/98.

Exhibit B-5-1
Results of Reactor Building Pressure Tests

Year	Total Leak Rate* with R2-001 %vol./day	Reactor Building Leak Rate %vol./day
1979	0.29	0.29
1981	0.16	0.16
1985	0.60	0.52
1987	0.84	0.63
1990	0.78	0.37
1993	0.79	0.41
1997	0.78	0.39

* Includes leakage into the spent-fuel discharge bay (room R2-001).

measured leak rate and includes leakage from the reactor building through the walls of the spent fuel discharge bay (room R2-001). The last column is the leakage from the reactor building less the leakage into the spent fuel discharge bay inside of the reactor building. This is the value that is compared to the 0.5 percent reactor building design leak rate limit. If there is a Loss-Of-Coolant Accident (LOCA), the pressure inside this room will never exceed 35 kPa(g), which is the height of the available water column in this room, which prevents the room atmosphere from venting to the exterior of the reactor building.[40]

The higher-than-design reactor building leak rates were due to the deterioration of the epoxy liner. Eighty percent of the liner has now been replaced with a polyurethane-based material (Normac), which is more flexible and bridges gaps better. The new liner material was installed starting in 1989. The tests results in 1990 and 1993 (with 54 percent of the liner replaced) and in 1997 (with 80 percent of the liner replaced) were below the leak rate limit. The walls of the spent fuel discharge bay were repaired in 1991. Both the total leak rate with the leakage into this room and the reactor building leak rate appear to have stabilized at this time.

Gentilly 2 has developed, installed, and is using equipment that allows an on-line measurement of the reactor building leak rate not only at the normal reactor building test pressure of 124 kPa(g) but also at reduced pressures with the plant at 100 percent load.[41,42] Extensive testing

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40. E-mail, Marc Aubray to Ken Van Howe, Containment Data, 2/6/98.

41. Collins, Normand and Paul Lafreniere, "On-line Reactor Building Integrity Testing at Gentilly-2" (Summary of Results 1987-1994) Rev. 1, October 1994.

at 3.0 kPa(g) has been done that also demonstrates that the reactor building leakage rate has stabilized. Hopefully, the combination of the three tests at full pressure with the reactor building leakage less that the design limit of 0.5 percent vol./day and the results of the frequent tests at 3.0 kPa(g) will allow the full-pressure test frequency to be extended to at least every five years. Returning to a five-year test would be desirable for retaining the long-term condition of the containment. Each full-pressure test of the containment most likely results in some degradation from opening cracks on the outer surface of the containment. With time, these outer surface cracks could increase the potential for corrosion of the rebar and prestressing tendons. With low leakage rates during the full-pressure tests it might be possible to obtain approval from the AECB to extend the five-year period with intermediate partial pressure tests. This would be desirable from a containment longevity aspect. COG performed a preliminary analysis of this issue.[43] The referenced report states that "final conclusions and recommendations will be provided in the final report due in 1996 April." The Gentilly 2 engineer providing input to us for the containment did not receive the final report and is not aware of it being issued.[44]

AECL has done a study on aging of containment structures at the Gentilly-2 and Point Lepreau plants. A preliminary draft report was reviewed.[45] This report indicates that there may be some age-limiting problems with the Gentilly 2 containment, primarily due to alkali aggregate reaction (AAR). The concrete used in the construction of the reactor building and other concrete structures at Gentilly 2 used St. Maurice quarry aggregates, without any addition of fly ash, which eventually resulted in cracks developing in the concrete due to AAR. To protect the concrete from exterior wetting, which facilitates the development of AAR and the formation of cracks, the exterior of the concrete was coated with Strescote 409 in 1982. Because of aging, the Strescote was replaced with Colorflex, which has a much higher coefficient of expansion, in 1987. Although this coating on the exterior of the concrete is appropriate to help stabilized the AAR reaction, it does make it more difficult to monitor the development of cracks on the exterior of the concrete as part of a reactor building aging program.

The Gentilly 2 reactor building has a significant number of strain gauges embedded in the concrete. Even though their use in monitoring the long-term changes in the concrete may have some uncertainty because of decalibration concerns, they can certainly be used to monitor the

42. Letter, Marc Aubray to Ken Van Howe, Containment Data (ref: your January 19, 1998 E-mail to Marc Aubray), 1/28/98.

43. Philipose, K.E., "Preliminary Report on 'Structural/Functional Issues Associated with Leakage Rate Testing of Reactor Building Containments' — COG 0157 Annual Report," AECL Report, COG-95-175, 1995 April.

44. Letter, Marc Aubray to Ken Van Howe, Containment Data (ref: your January 19, 1998 E-mail to Marc Aubray), 01/28/98.

45. Draft containment aging report for Gentilly-2 and Point Lepreau — unpublished, AECL.

strain response of the concrete during the periodic full-pressure tests. Gentilly 2 has collected a substantial amount of data from these strain gauges. However, it is not clear that an extensive analysis of the data collected has been made in regard to assessing if the reactor building has a good chance of remaining in a good condition beyond its original design life of 30 years. Based on an analysis of some of the data as part of the COG 0157 work,[46] it was observed that most of the instruments are in good working condition and are providing valid readings.

Gentilly 2 initially had 10 test beams of 10 feet and two test beams of 20 feet poured in July 1976 to allow testing for any relaxation or corrosion of the prestressing tendons. The 10-foot beams were made for destructive test and corrosion inspections. The 20-foot beams are available to measure any relaxation of the prestressing tendons. It was originally planned to perform the tests at 1, 2, 5, 10, 15, 20, and 25 years. As of February 1994, three tests had been performed at about 1, 6, and 14 years (relative to 1979). All of the test results were acceptable.[47] However, as pointed out in the preliminary draft of the AECL containment aging study for Gentilly 2 and Point Lepreau, the presence of AAR at Gentilly 2 and the resulting expansion of the concrete may be masking a loss of prestressing in the tendons. If the AAR in the test beams is progressing at a different rate than in the coated reactor building, the test results may not be fully indicative of the prestressing tendons of the reactor building. Because of the limited number of test beams available for long- term destructive testing, the frequency of testing will need to be reduced to allow tests after 30 years if the life of the plant is extended beyond its original 30-year life.

The preliminary draft of the AECL containment aging study for Gentilly 2 and Point Lepreau summarized the highlights from a 1992-1993 study of the status of the concrete of the Gentilly 1 containment as follows:

- The concrete quality was rated good to excellent, based upon its physical properties.
- AAR is present and continues (the G-1 concrete does not have any exterior protection).
- The depth of concrete carbonization was 4 mm, which is below the average of 1 mm/yr.
- The chloride concentration was 0.03 percent by mass of cement, which is well below the limit of 0.06 percent allowed by the applicable standards. According to the Ministry of Transportation of Ontario and the American Concrete Institute, the threshold of rebar corrosion initiation is 0.15 percent.

Based on these results, one could infer that carbonation and chloride corrosion should not be a major issue with the Gentilly 2 reactor building structure.

The preliminary draft of the AECL containment aging study for Gentilly 2 and Point Lepreau also concludes that based on the concrete air content and the water-to-cement ratio (W/C), it

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46. Philipose, K.E., "Preliminary Report on 'Structural/Functional Issues Associated with Leakage Rate Testing of Reactor Building Containments' — COG 0157 Annual Report," AECL Report, COG-95-175, 1995 April.

47. Letter, Julie Drouin and Nelson Garceau to David Kwong AECL, 2/23/94.