Analysis of Hydro's Energy Supply Cost Variance Deferral Account

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

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Contents

I. Analysis of Hydro's Energy Supply Cost Variance Deferral Account

Newfoundland and Labrador Hydro's (Hydro) 2017 General Rate application seeks recovery of the balances in certain deferral accounts that have accrued from 2015 through 2017. Substantial increases in the use of standby generation significantly affected one of these accounts - the Energy Supply Cost Variance Deferral Account. At the direction of the Board of Commissioners of Public Utilities Newfoundland and Labrador (Board), The Liberty Consulting Group (Liberty) has analyzed the factors driving the balance in that account. These factors include new operating practices by Hydro and the operational philosophy underlying them. This report provides the results of that analysis, including an assessment of the costs and benefits of Hydro's new practices and the prudence of their implementation.

A. Executive Summary

Hydro's Energy Supply Cost Variance Deferral Account contains a balance of $58.8 million, covering the period from 2015 through 2017. Hydro's current rate filing seeks recovery of the full amount. Liberty has analyzed the factors that produced the balance, Hydro's role in managing those factors, and the prudence of related Hydro decisions.

The primary costs associated with the deferral balance arose from extended use of standby generation. The Holyrood GT, and the Hardwoods and Stephenville CTs, ran far more often than anticipated by the test year (2015) assumptions. The resulting increases in fuel costs nominally qualify as allowable charges to the Energy Supply Cost Variance Deferral Account.

The biggest reason for increased standby generation arose from Hydro's decision to require spinning reserve at all times to cover the loss of the largest generating unit - - typically an amount of about 170 MW. We have estimated the added fuel cost for the increased reserve at $32.7 million for the three-year period. In addition, forced outages at major units, primarily the Holyrood TGS, caused increased standby operation, producing an estimated cost of $13.2 million.

Liberty evaluated the circumstances around these added costs, finding some management actions that we determined were seriously deficient. With respect to the spinning reserve decision, we found that Hydro failed to consider costs at the time of the decision or at any reasonable time thereafter. Moreover, the benefits associated with the change appear minimal in relation to the high cost. Finally, Hydro afforded this important change very little visibility, with no dialog with stakeholders at all before the decision. Stakeholders remained unaware of the tens of millions of dollars of associated cost impact until nearly three years later, in October 2017.

Nevertheless, we did not find circumstances justifying the disallowance of costs associated with the spinning reserve decision and subsequent actions. Offsetting the management failings described above is the high degree of pressure upon Hydro in 2015 to improve reliability. After the major outages of 2013 and 2014, reliability became a much higher priority, and Hydro's adoption of N-1 and the higher spinning reserve requirement simply reflected a practice in near-universal use in the industry. It is difficult to challenge the prudence of a decision that simply aligns one's practices with the rest of the industry. While critical of the failure to address costs at the time, we simply could not conclude with a reasonable degree of certainty that doing so would have led to a different decision, and thus it is our opinion that the decision Hydro made fell within the range of alternatives a reasonable utility manger would consider.

Our analysis further revealed no evidence of imprudence in the incurring of standby generation costs to cover forced outages of large units. Liberty has frequently addressed the reliability problems of Hydro's thermal generation in general and the Holyrood TGS in particular. For many reasons, including some outside of management's control, forced outages will continue to become more frequent.

We have therefore not recommended any specific disallowances relating to the Energy Supply Cost Variance Deferral Account. We do, however, offer recommendations relating to the process, management practices, reliability planning and analysis, and cost analysis and estimation. We attach particular importance to the rapidly changing priorities relating to reliability and cost, with the balance now tilting in favor of mitigating cost. We also discuss some serious inconsistencies between the operating changes reported in the application and Hydro's governing operating instructions.

B. Background

1. The Energy Supply Cost Variance Deferral Account

Typical ratemaking practices generally transfer the risk associated with the variability of energy costs from utilities to their customers. This practice began and became widespread in the 1970s, an era of extreme fuel cost volatility. The practice remains in use today in the industry to cover a variety of uncertainties usually thought to be outside the control of utility managers. The treatment of costs works both ways, allowing the utility to seek recovery of higher costs, but crediting customers when costs fall.

Hydro's test-year (2015) energy supply cost variances from assumptions have received such pass-through treatment in the following categories"[1]

- Variations in both <u>price and volume</u> of selected thermal peaking units, including the Holyrood CT, and the Hardwoods and Stephenville GTs.
- Variation in <u>volume</u> of power purchases from selected sources.
- Fuel costs or savings from variances in Holyrood TGS <u>generation</u>.

Customer charges or credits result only to the extent that the sum of the three variations exceeds a deadband of $500,000. The next table summarizes the amounts accumulated in the energy supply deferral during 2015-17.

[1] Application, Schedule 1 – Appendix A

Energy Supply Deferral Summary
(Thousands of Dollars)

Category	2015[1]	2016[2]	2017[3]	Total
Standby Generation Costs	11,182	25,060	15,605	51,847
Power Purchase Savings	(1,526)	(1,780)	(1,080)	(4,386)
Holyrood TGS Fuel Costs	5,044	1,683	6,110	12,837
Deadband	(500)	(500)	(500)	(1,500)
Total	**14,200**	**24,463**	**20,135**	**58,798**

[1] Application – Table 5 [2] Application – Table 7 [3] Application – Table 9

2. Hydro's Operating Practices

Hydro's justification for these costs focuses on the adoption of new operating practices intended to improve reliability. Virtually all utility systems employ, at a minimum, the so-called N-1 criterion. This standard requires that the system be able to withstand the loss of the largest unit without experiencing any loss of load. This approach seeks to allow the system to maintain suitable reserves such that the loss of the largest unit can be quickly made up without unacceptable perturbation to the system.

Hydro's new reliability standard, implemented in 2015, is as follows:[2]

> *For events on the power system resulting in the loss of a single element (generator, transmission line or transformer) the power system shall remain stable, and both thermal and voltage limits shall be within applicable ratings, with no loss or curtailment of customer load.*[3]

It is well known that Hydro's system cannot achieve the full objectives of N-1 because of the system's inherent inability to withstand far smaller losses of generation. Specifically, automatic under-frequency load shedding (UFLS) results from generation losses as small as 50 MW, with such occurrences happening 5 to 10 times per year. Added reserves, including to meet the largest unit criterion, can reduce the recovery time from outages, but cannot prevent them.

Another key reliability shift in 2015 came with a new focus on the Avalon Peninsula. System Operating Instruction No. T-096, Avalon Capability and Reserves, recognized that a sole focus on the Island Interconnected System (IIS) as a whole was no longer appropriate. It also held that operating parameters on the Avalon, including load and reserves, must be actively managed as well. These two decisions (N-1 to minimize outage impacts and added focus on Avalon load and reserves) proved pivotal - - a very significant portion of the costs associated with the Energy Supply Cost Variance Deferral Account appear to flow from them.

[2] PUB-NLH-173, Attachment 1, Page 3 of 4, NLH 2017 GRA
[3] Does not include load loss for under-frequency load shedding events.

3. Prior Consideration of 2015-16 Deferrals

This 2018 rate case does not present the first occasion for considering these costs. On October 11, 2017, Hydro filed an application for approval to recover the 2015 and 2016 balances. The Board rejected this application in Order No. P.U. 39 (2017):

> *The Board is satisfied that Newfoundland Power has raised an issue which requires further review, given the magnitude of the costs and the fact that the information provided does not adequately address the costs and benefits of Hydro's approach to generation dispatch and the alternatives which may be available.*

4. Prudence Review Standards

In July 2015 Liberty completed for the Board a prudence review addressing eleven issues. Following this review, the Board, in Order No. P.U. 13(2016), determined that a no-hindsight approach of the conditions and circumstances existing at the time that decisions were made and costs were incurred was an appropriate approach for a prudence review of committed capital and operating costs. The Board stated at page 39:

> *In assessing whether particular costs are reasonable and prudent, the Board will therefore consider information that was known or ought to have been known by Hydro at the time of the decision or action, whether Hydro's decision or action was reasonable in the circumstances, and whether it was within the range of reasonable alternatives a utility would choose. Hindsight will not be used in determining the prudence of costs under review.*

Liberty conducted this review according to this standard.

This standard has special importance in the current matter. Our past prudence work has emphasized the need to evaluate the prudence of decisions based on the circumstances faced by the managers when they made those decisions, and not with the benefit of hindsight. Electric supply in Newfoundland has experienced massive change for several years and promises to continue to do so with the coming operational transformation of the IIS via Muskrat Falls and the Labrador Island Link (LIL), accompanying increases in financial pressures and rate growth, and most importantly for our purposes, changing perceptions on reliability. The changes have not been marginal but reflect significant quantum changes that have greatly shifted the demands on and priorities of management over a short duration. Management's operating philosophy and practices have changed, and will continue to change, as a direct result. A fair analysis of prudence must therefore reconstruct the decision framework at the time key decisions were made, in our case 2015, to determine whether Hydro's actions at that time were consistent with those expected of reasonable utility managers.

5. Principles Guiding Liberty's Prudence Review

Utility management must act with prudence in making decisions and taking (or deciding not to take) actions that involve or affect assets, personnel and operations related to the provision of service to customers. Their decisions and actions must be focused on promoting the delivery of safe, adequate, reliable and least cost service to their customers.

Prudent decisions and actions require that management:

- Identify all relevant information
- Identify a reasonable range of alternative solutions
- Test those solutions through the application of criteria and values consistent with such delivery of service
- Choose an option that falls within the range of those properly determined to be reasonable
- Act with the level of dispatch and care as is consistent with the timing needs for making a decision or effectuating actions.

In determining whether an action or decision was prudent, Liberty considered:

- Information that was known or ought to have been at the time of the decision or action (or inaction)
- Whether the utility applied reasonable foresight; perfect foresight is not required
- Whether the solution selected was within the range of reasonable alternatives.

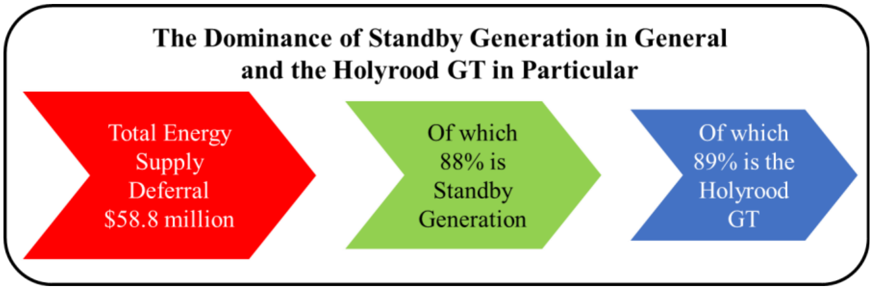
The questions of imprudence and customer impact are distinct. Because the future is unknown, imprudent actions can produce either higher or lower customer costs than would have occurred under a prudent course of action. Similarly, prudent actions can produce either higher or lower customer costs than would have occurred under an imprudent course of action. Where actions were found to be prudent by Liberty, no examination of resulting cost impacts was required to assess customer impacts. Where actions were found to be imprudent, Liberty examined where and by how much costs would have differed under a prudent course of action.

6. Analysis Framework

Liberty's analysis of the Energy Supply Cost Variance Deferral Account and the prudence of the related decisions followed this sequence:

- Analysis of Deferral Account Costs
- Reliability Considerations
  - Reliability Criteria – Industry Practices
  - Reliability Expectations in Newfoundland – A Moving Target
  - Improvement from Added Spinning Reserve
  - Balancing Cost and Reliability
- Prudence Analysis
  - Standby Generation
    - New spinning reserve requirement
    - Forced outage of large units
    - Planned outages of generation and transmission
- Other Considerations
- Recommendations

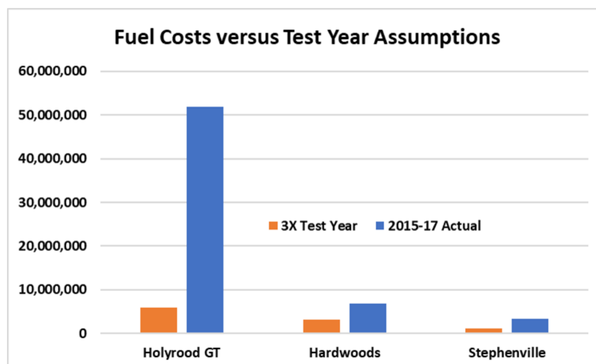
C. Analysis of Deferral Account Costs



Balances in the Energy Supply Cost Variance Deferral Account have largely resulted from standby generation costs, with high standby generation costs largely the result of the Holyrood GT. As a result, Hydro's application focuses significantly on analysis and justification of that category and that unit. Our analysis and report apply a similar focus.

1. Standby Generation

a. Test Year Assumptions



The variations that comprise the energy supply cost deferral balance are measured against the test year (2015) assumptions. We were not especially concerned here with how often standby generation ran, but rather with how often standby generation ran versus how often Hydro expected it to run at the time that rates were last set. One would normally expect relatively small variances in such an exercise, with fluctuations in both directions from the expected value. The accompanying chart, however, shows extremely high variances. This result suggests extraordinary circumstances in 2015-17 - - circumstances not anticipated when management prepared test-year assumptions.

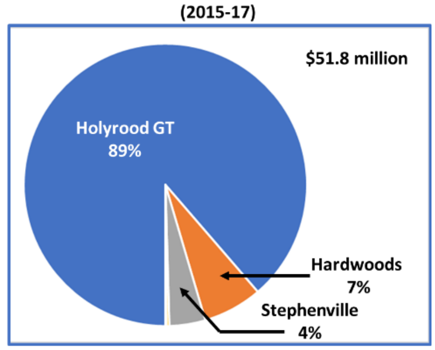
Clearly, deviations of this magnitude increase management's burden in fully explaining the unusual circumstances giving rise to such costs and in demonstrating that management acted responsibly. The content of Hydro's current application suggests that management now understands that burden and has sought to explain and justify its actions.

b. Holyrood, Hardwoods and Stephenville Variances

Fuel Costs versus Test Year Budget (2015-17)		
Holyrood GT	Hardwoods	Stephenville
775%	107%	174%

The standby generation units, primarily the Holyrood GT and the Hardwoods and Stephenville CTs, ran well above planned levels. The accompanying table shows that Hardwoods and Stephenville ran respectively at about double and triple their planned operating levels, while Holyrood GT costs were nearly nine times the planned level. Given these extreme operating variances and the high cost of fuel for these units, standby generation costs dominate the Energy Supply Cost Variance Deferral Account.

Added Fuel Costs for Standby Generation (2015-17)



Moreover, the accompanying pie chart shows that the costs associated with the Holyrood GT dominate the standby generation costs, accounting for 89 percent of the $51.8 million total. As a result, Hydro's supporting analysis understandably focuses primarily on the Holyrood GT and less so on the other units. Management's reasonableness in decision-making, and the recovery of the energy supply deferral balance, therefore centers around standby generation and the Holyrood GT.

We found no reason to question the accuracy of the added standby generating costs for each unit, but the level of usable detail ends there. The narrow scope of the data qualifies as a serious deficiency. With multiple drivers of the high energy supply deferral balance, each of those drivers deserves scrutiny and bears on examining prudence. Where associated costs cannot be credibly approximated, prudence analysis becomes more difficult. We discuss this data problem and potential ways around in the following sections.

c. Reasons for Holyrood GT Starts/Operations

Hydro has presented five operating functions intended to categorize the reasons for the starting and running of the Holyrood GT in the 2015-17 timeframe. The next table shows these categories and specific events influencing operations in them.

Function	2015	2016	2017
Support of spinning reserve	Operation in this area includes for Spinning and Avalon Reserves which are generally load driven and/or due to deratings of generating equipment.	Operation in this area includes for Spinning and Avalon Reserves which are generally load driven and/or due to deratings of generating equipment.	Operation in this area includes for Spinning and Avalon Reserves which are generally load driven and/or due to deratings of generating equipment.
Backup due to the loss of a major generating unit	The primary driver of operation in this area was outages to units at the HTGS and requirements for Avalon and Spinning reserves	The primary driver of operation in this area was the extended outages to HTGS Units 1 and 2 in January and February 2016 and the requirements for Avalon and Spinning reserves, as well as for reservoir support.	The primary drivers in this area were outages to Upper Salmon and Holyrood Units 1 and 2.
Planned generator outages	The primary driver of operation in this area was the planned Holyrood total plant outage, necessary for maintenance of common plant systems, in August 2015 and therefore operation for Avalon transmission support.	The primary driver of operation in this area was maintenance outages to the HTGS units and the requirements for Avalon and Spinning reserves.	The primary drivers in this area were planned outages to Holyrood units, including a total plant outage from July 30 to August 18.
Planned Avalon Peninsula transmission outages	The primary driver of operation in this area was the planned outage to transmission line TL201 in November 2015.	The primary driver of operation in this area was outages to transmission line TL237 in September 2016.	The primary drivers in this area were planned outages to TL206, TL217 and TL201.
Testing	Testing of the Holyrood GT primarily occurred in the months immediately following the commissioning and in-service date of the unit.	The primary driver of operation in this area was Holyrood GT compliance emissions testing in December 2016.	

In addition to providing the data shown in the table, Hydro has provided the number of unit starts and the total operating hours for each function. This information aids in understanding the duty that this machine experienced - - an average of 93 starts and 1,276 operating hours per year over the three-year period. The issue (function) to which the unit responded with each start is not clear, however, as there is considerable overlap among the functions. Note for example in the above table that "requirements for Avalon and spinning reserves" appears in multiple categories.

Management understands and explains this overlap of drivers in PUB-NLH-174. The cost impact of Hydro's new reliability standard comprises a key question for our analysis; however, this important question might remain unanswered, because, as management reported in the response to PUB-NLH-174, "Hydro has not tracked standby generation to this level of detail." It is therefore not possible to determine the cost associated with each function from the evidence. This gap significantly limits any analysis of prudence, because Hydro's evidence offers no direct relationship between decisions and actions and the resulting added Holyrood GT costs. Therefore, examining added costs and operating practices must employ an alternate analytical path.

d. The Cost Estimation and Attribution Dilemma

Hydro, and those seeking to evaluate its application for recovery of deferred costs relating to standby generation, face the dilemma of how to define and quantify the drivers of those costs. The method offered by Hydro, although inclusive of valuable data, does not provide an effective breakdown. Instead, Hydro uses categories that overlap with one another, precluding the ability to isolate unique drivers and the costs associated with those drivers. As a direct result, basic questions, such as the cost impact on standby generation from the new reliability standard, become impossible to answer from the evidence.

Anticipating that identification of drivers and costs might become necessary, either in this proceeding or a future one, we have examined an alternate approach to cost attribution and a method for estimating those costs. Appendix A presents this revised approach.

e. Application for Prudence Analysis

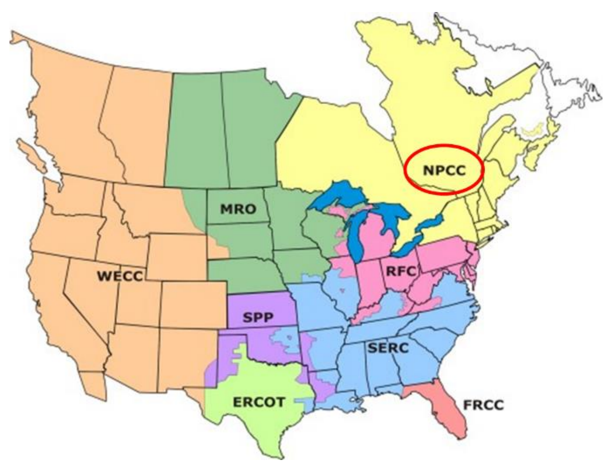
The Appendix A method offers a cost solution for Hydro's four scenarios of interest (its categories or functions) and provides an approximation of costs from different causal factors. For present purposes, however, we only use these estimates as a part of our prudence analysis, and then only as needed. Our prudence analysis will address two areas, which we cost out from Appendix A:

- New spinning reserve requirement: $32.7 million
- Forced outages of major units: $13.2 million

D. Reliability Considerations

1. Reliability Criteria – Industry Practices

a. Standards



In addressing reliability standards, we cite the North American Electric Reliability Corporation (NERC) as the North American authority, and NPCC as the regional authority. The Northeast Power Coordinating Council (NPCC) has responsibility for promoting and enhancing reliability of the international, interconnected bulk power system in Northeastern North America. The NPCC geographic region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Newfoundland and Labrador, not a member currently, may become one depending on pending decisions by the Government.

Overall, NPCC covers an area of nearly 1.2 million square miles, populated by more than 55 million people. In total, from a net energy for load perspective, NPCC is approximately 45 percent

U.S. and 55 percent Canadian. Approximately 70 percent of total Canadian net energy for load falls within the NPCC Region.

NPCC sets mandatory standards for the planning and operation of electrical systems in its region. NERC also publishes standards; NPCC standards must be at least as rigorous as those of NERC.

Newfoundland and Labrador's future obligations to NPCC, if any, have not been defined. The Government is preparing the province's reliability framework; it will define the relationship with NPCC and other reliability authorities. We present NPCC standards only as the regional approach, which the province may or may not choose to meet.

b. NPCC Operating Reserves

NPCC requirements for operational reliability center around ten-minute and thirty-minute reserves, meaning the backup supply must be available within those time limits. Each Balancing Authority must have available to it ten-minute reserve at least equal to its first contingency loss.[4] NPCC requirements allow some portion of the ten-minute reserve to be non-spinning, provided that the viability of the selected arrangement has been physically demonstrated. Otherwise, 100 percent of the ten-minute reserve must consist of synchronized capacity, which of course would be available in well under ten minutes.

The new standard that Hydro has chosen is similar, except that all of the ten-minute reserve must be made up of synchronized capacity (spinning reserve). Hydro's use of spinning reserve to cover a first contingency loss of the largest generating unit is therefore consistent with the NPCC requirement and, more broadly, consistent with the way virtually all utilities operate. In this regard, we found nothing remarkable or unusual in Hydro's decision to require spinning reserve to cover a first contingency loss.

2. Reliability Expectations in Newfoundland – A Moving Target

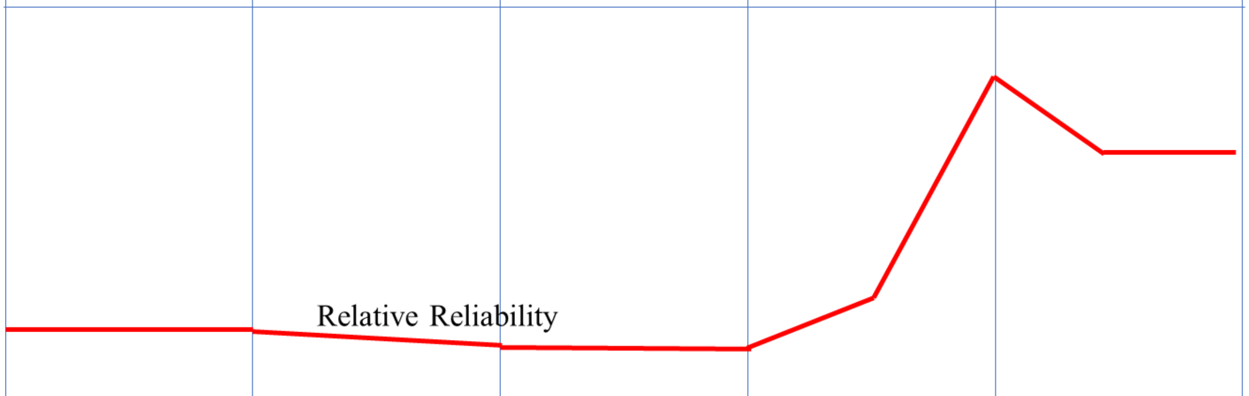
Reliability decision-making processes and criteria are rarely absolute, but instead subject to many intangibles including customer expectations and public pressures. Those intangibles tend to change with time, making it impossible to analyze a utility decision without a solid understanding of the factors present at the time of the decision that properly would have substantial influence on management. To be unaware of those factors, or to ignore them in favor of today's circumstances, would produce a flawed analysis.

The immediate case of the added costs associated with the N-1 decision and added spinning reserves, makes this question especially important. The subject of electric reliability was paramount at the time of the decision with both the thinking and expectations changing quickly. In considering Hydro's decisions vis-à-vis operational reliability, we must therefore establish a sound historical context. The expectations of Newfoundland's electrical stakeholders, including Hydro, the Board and customers, have changed considerably over the last decade and we consider

[4] NPCC Directory 5

those expectations likely to continue to change in the years ahead. The next illustration summarizes the recent evolution of power-supply reliability.

The Evolution of Power Supply Reliability in Newfoundland



← 2010	2011-12	2013-14	2015-17	2018 →
LOLP of 1 in 5 years versus 1 in 10 years in other systems UFLS of 5-10 events per year, versus none or 1 in <u>10 years</u> in other systems	Initial LIL design (pre-ML) trips the Avalon on loss of LIL	Major system-wide events during the winter of 2013 and 2014 with widespread blackouts and equipment damage	Changed expectations on the part of all stakeholders. Specific responses by Hydro	With: (1) low hanging fruit already exploited (2) recognition of post-MF reliability ceiling (3) affordability of electricity the major issue, It is time to revisit the reliability versus cost balance

a. The Past

It was long established that Newfoundland's electrical isolation tilted the cost versus reliability balance against reliability. Established power supply criteria were half those in general use throughout most of the rest of North America. In addition, the necessity for under-frequency load shedding (UFLS) upon certain perturbations was generally accepted. A loss of generation of perhaps 50 MW under certain circumstances produces a frequency reduction that triggers UFLS, with this occurring 5 to 10 times per year.

We have found this frequency of UFLS unusual in the extreme for a modern power system. We have previously presented statistics over an 11-year period, showing that two reliability regions had no incidents of UFLS, and three had only one. In four of the 11 years, no region experienced any incidents; in nine of the 11 years, no region experienced more than one.[5] UFLS remains a

[5] "Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls – Final Report", August 19, 2016.

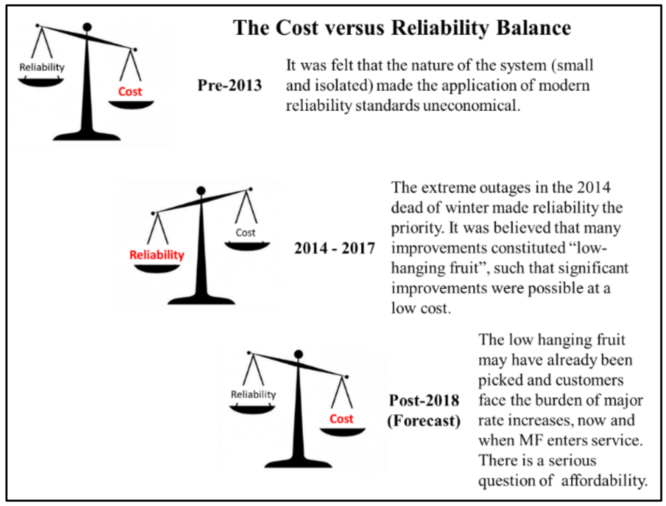
critical tool for system protection, but it should occur only rarely. The Newfoundland experience, while perhaps driven by the system's size and isolation, has nonetheless proven highly unusual.

These two factors, relaxed planning criteria and the UFLS events, firmly established that Newfoundland differed considerably from North American standards, resulting in acceptance of a lesser level of reliability. Perhaps most indicative of the tolerance for outages was the strategy accepted for Muskrat Falls when that project was first sanctioned. It was established that, upon loss of the LIL, the Avalon Peninsula would be automatically tripped and isolated from the system. Nalcor estimates that a LIL bipole trip will occur about once every three years. It was therefore considered acceptable that, by design, Newfoundland's predominant load center and the majority of its electric customers would suffer interruption. We emphasize this acceptance to illustrate the depth of the culture in place at that time, a culture that placed a comparatively lesser value on electric reliability - - accepting a much lower standard for electric service than expected elsewhere in North America.

The tolerance for outages, at least from a public perspective, began to change in 2013 and 2014, with widespread winter outages. We began our work here after the 2014 events, which have come to be known as DarkNL. First discussions with Hydro operators and management, made apparent the culture issue. Leading us to cite a "tolerance for outages" that had a great influence on the events of DarkNL.

There is room for debate on the degree to which this culture has shifted since 2014, but it has undoubtedly changed. Pre-2013 principles have eroded considerably in the minds of stakeholders. Acceptance of previously established beliefs that Newfoundland must settle for a materially lower quality of electric service and face periodic outages, sometimes widespread, has changed. Since 2015, Hydro has taken steps to improve power system reliability.

b. The Future



The Cost versus Reliability Balance

The reliability landscape has indeed changed in recent years, and Muskrat Falls, the LIL and the Maritime Link (ML) are producing further major changes in expectations. We would anticipate that the cost versus reliability balance, which has tilted towards reliability since 2014, may now tilt back in favor of cost. We base this expectation on the:

- Rising cost of incremental reliability improvements, with "low hanging fruit" already picked since 2014
- Declining value of incremental reliability improvements, as we approach a long-term "reliability ceiling" created by the LIL
- Fact that pending and future rate increases will create real customer burdens and affordability issues.

It has generally been felt that reliability improvements to date have come at an acceptable cost. This application and its high reliability costs underscores the issue of whether cost effective reliability improvements remain

Liberty concluded in its Phase 2 report that certain reliability risks are embedded in the very concept of the LIL, and this was emphasized in the original design scheme that required the Avalon be tripped upon loss of the bipole. That contingency will now be somewhat mitigated by the trip of the ML, assuming it is loaded outbound, but not to the extent that UFLS will be prevented under normal loading. Since a bipole outage is expected once or more every three years, a significant and potentially widespread outage is built in to the system. Although it is hoped that such an outage can be contained at hours, or at most a few days, the potential for far worse is possible. Consider, for example, one or more LIL tower failures in remote regions.

This built-in risk effectively establishes a ceiling on both expected and actual reliability. Post-2014 stakeholder expectations likely cannot be met in the future, with an inevitable reduction in those expectations. The question becomes whether customers should be asked to invest heavily in reliability when a certain and significant supply outage probability remains inevitable anyhow.

Significant affordability issues loom for the province. Rate increases from this and future rate cases, including the massive Muskrat Falls impact, will place a very large burden on an economy not forecasted to do well in the years ahead. Assuming added costs will produce higher reliability, the question remains just how high can rates be permitted to go. The answer is hard to quantify, but the need for close attention to affordability in the coming years of high rate escalation is patent.

c. Conclusion

The 2014-17 period, in which Hydro made the decision to improve reliability through enhanced spinning reserves, reflected a time when the decision-making balance tilted towards reliability.

Now, when evaluating Hydro's decision, the bias may be shifting in the other direction. The prudence analysis must be based on the historically relevant environment, not today's.

3. Reliability Improvement from Added Spinning Reserve

Utilities implement N-1 criterion to avoid loss of load upon occurrence of the single biggest contingency. Applying this criterion makes UFLS rare industry-wide, effectively requiring two nearly simultaneous large failures. As we have seen, however, Hydro's is not the typical case. Management's application of N-1 does not avoid loss of load. In fact, Hydro loses load on contingencies far smaller than the largest unit. These circumstances beg the question of why one chooses to maintain such standards when they do not produce the primary intended benefit.

Hydro maintains that its N-1 standard seeks to mitigate the impact of outages, not *per se* to prevent them. One therefore should measure any benefit from Hydro's expanded spinning reserves against that objective. In this regard, management states that:

> *Hydro has seen an improvement in reliability associated with its evolved operating philosophy, specifically in the restoration of customers following unit trips which typically result in under-frequency load shedding (UFLS).*[6]

A sampling of UFLS events, both before and after the implementation of expanded spinning reserves bears out this review. The data appear to indicate a measurable reliability benefit. The accompanying table indicates that the times to start and complete restoration both improved by about 50%. In absolute terms, however, the improvement in completion of restoration was only about six minutes.

Mitigation of Outage Impacts from Added Spinning Reserves

	Pre-2015			With New Standard		
	Restoration Started (Min)	Restoration Complete (Min)	Customers Impacted	Restoration Started (Min)	Restoration Complete (Min)	Customers Impacted
	3	33	19,012	2	7	4,655
	7	9	6,485		3	5,437
		11	36,836	7	14	18,498
		16	6,660	2	24	26,307
		15	4,309	3	6	6,951
		11	6,041	1	4	6,804
		11	13,744		6	12,381
					3	9,439
					9	11,669
Average	5	15	13,298	3	8	11,349
Median	5	11	6,660	2	6	9,439

Application, Table 2

Management suggests that these results understate improvement levels, citing changing system circumstances over the last few years - - changes that presumably would have made restoration times worse. Management states that:

> *This reduction in restoration time is in spite of load growth, concentration of load on the Avalon Peninsula, and higher unit unavailability through this period.*[7]

It is not clear to us why such factors would significantly affect restoration times and Hydro has offered no evidence to that effect. Further, we would not expect that such factors would substantively change our view that one should consider a six-minute improvement minimal.

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[6] Application, Schedule 1, Page 10, Line 17
[7] Application, Schedule 1, Page 14, Line 8

Hydro also believes that, had it not expanded the use of spinning reserve, and instead employed non-spinning reserve:

> *Customer restoration times would have increased by an additional 30-40 minutes and a greater number of customers would have been impacted*.[8]

This management observation assumes that enabling service restoration would require the start and loading of the Holyrood GT. This observation may well prove true under very specific circumstances. Note, however, that the preceding table shows only one pre-2015 event greater than 30 minutes. It also shows that the number of customers affected did not materially change with the new spinning reserve policy. Therefore, we continue to consider the six-minute improvement minimal.

4. Balancing Cost and Reliability

a. Industry Practice

Without doubt, utility management must strike a balance between electric reliability and the cost to achieve it - - with finding the right balance often a difficult challenge. It is much easier to quantify the level of reliability improvement than it is to quantify the *value* of any given level of reliability. Despite the impossibility of definitive cost benefit analysis, one nevertheless should expect an estimate of costs, combined with a subjective valuation of benefits as a minimum standard for guiding management decision-making.

b. Hydro's Balancing of Cost and Reliability

The degree to which Hydro balanced cost and reliability considerations in its use of standby generation in general and within the new operational philosophy in particular, frames a critical question in examining prudence. Hydro indicates that it has provided such a balance:

> *While the cost of the increased operation of gas turbines is material, Hydro believes that its operational philosophy and resulting operation and dispatch of gas turbines provides an appropriate balance of cost and reliability to customers.*[9]

No evidence exists here, however, that management analyzed or sought such a balance. It does not appear that management considered cost at all in establishing its new operational philosophy. Specifically,

> *Hydro did not prepare specific cost estimates or a cost benefit analysis in support of the decision to employ N-1 and added spinning reserve*.[10]

c. Finding a Reasonable Balance

We noted earlier our roughly $32.7 million estimate of the 2015-2017 costs of Hydro's new reliability criteria, reflected in higher standby generation costs (about $10.9 million per year). Hydro reported resulting benefits in the form of a 50 percent reduction in restoration times (about

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[8] Application, Schedule 1, Page 14, Line 17
[9] Application, Page 2, Line 8
[10] PUB-NLH-172

six minutes). Any evaluation seeking to balance cost and reliability will likely require subjectivity, given the difficulty in estimating the economic value of reliability benefits. That need is not necessarily bad - - the utility, key stakeholders, and the regulator have the best sense for that subjective value.

The judgement required involves valuing a trade-off of about $10.9 million per year against an approximately six-minute improvement in restoration times for 5-10 UFLS events per year, recognizing that Hydro argues the six-minute improvement is understated. A healthy discussion of such trade-offs among management and stakeholders will help to reach a defensible decision, which may well differ from ours. From our perspective, however, the six-minute benefit has come at too high a price, especially considering the limited number of customers affected and today's cost pressures. Whether such an opinion would have been different in 2015, however, is more pertinent.

E. Prudence Analysis

In examining prudence, we accept that a finding of prudence needs to be supported with facts and analysis. Further, we do not define prudence as demanding perfection, but rather simply requiring that the utility meet the "reasonable person", or more accurately the "reasonable utility manager" test. Finally, prudence does not require a successful outcome. Prudent decisions can produce unsuccessful outcomes just as imprudent ones can be followed by better results than prudent ones. The future can make good decisions look bad and bad ones good, depending on how uncertainties evolve.

We require a clear and convincing case to reach a conclusion of imprudence. Cases subject to material uncertainty do not support a conclusion of imprudence. This does not mean, of course, that weaknesses in decision making are irrelevant where a conclusion of imprudence does not follow. Even where a mediocre decision does not call for a finding of imprudence, using it as a model for identifying future improvements is sound.

The next illustration summarizes our structure for analyzing the Energy Supply Deferral Account.

Potential Prudence Issues			Associated Costs
New Spinning Reserve Requirement	→	Was adoption of the new requirement prudent and was it implemented properly?	$32.7 million
Forced Outages of Large Units	→	Were the outages outside of management's control and considered a part of normal operational variations?	$13.2 million

We decided to eliminate a number of areas from our analysis of prudence, for the reasons summarized below:

- Hydro reported energy supply deferral costs for the category of "planned outages of large generating units." This category included high costs associated with the new spinning reserve requirement, but those are evaluated elsewhere, under the spinning reserve issue. We did not identify any power replacement costs from standby units for this category; therefore, no such costs are subject to a possible imprudence determination.
- Hydro reported energy supply deferral costs for the category of "planned outages of Avalon Peninsula transmission facilities." We viewed the bulk of such costs as originating with the new focus on the Avalon which, as discussed below, we have found to be prudent.
- Hydro also reported costs resulting from variances in power purchases which we reviewed and found insufficient evidence to support an imprudence finding. We therefore excluded discussion of them from this report.

1. New Spinning Reserve Requirements

In early 2015, Hydro made pivotal decisions regarding its reliability standard and its treatment of reliability on the Avalon Peninsula. First, Hydro adopted a new requirement for spinning reserve, intended to meet the N-1 criterion. An amount of spinning reserve necessary to accommodate the loss of the largest on-line generator became an operating requirement. This adoption produced an increase in the required amount of on-line capability at any one time.

Second, Hydro implemented a new operating instruction (T-096), which defined stricter standards for the Avalon Peninsula. Management introduced this instruction in response to the March 4, 2015 voltage collapse. This collapse proved that a focus on IIS parameters was not enough to prevent certain instabilities. The result was a new focus on Avalon operating parameters, including load and reserves. Our analysis revealed no reason to question the renewed focus on the Avalon.

These changes resulted in a greatly expanded use of standby generation to support spinning reserves. The rough estimate of the effect on the supply deferral balance, which we presented earlier, is $32.7 million. The prudence question at issue here involves the reasonableness of management's decision to increase reliability requirements and management's prudence in implementing that decision.

a. What Really Changed?

Hydro's application makes clear that major operational changes with respect to an N-1 approach and associated spinning reserve requirements took place in 2015.[11] A review of operating procedures, however, indicates that those changes are not reflected in the written procedures. For purposes of our analysis, we will take the application at face value. The lack of verification nonetheless has negative implications. We discuss further below the inconsistencies between the application and Hydro's procedures (T-001).

[11] Application, Page 6, Line 10

b. Elements of Hydro's Support for a Conclusion of Prudence

Our examination of Hydro's attempted reliability improvements found nothing unusual or out-of-the-ordinary in the new standards and practices adopted. N-1 incorporates a universal minimum requirement that Hydro had previously rejected due to the isolation of the system and the resulting higher cost to provide added reserves of any kind. It therefore becomes difficult to criticize Hydro for simply moving to a standard that the rest of the industry had long ago adopted. Regarding the new Avalon focus, this change corrected an important operational weakness exposed on March 4, 2015.

Considerable pressure existed at the time of these decisions for tangible improvements in reliability. Reliability was a high stakeholder priority, with Hydro expected to act aggressively in implementing a materially healthier attitude on the prevention and mitigation of customer outages. In its application, Hydro justifies its enhanced spinning reserve initiative, at least in part, by citing the encouragement of others. Such encouragement towards improved reliability certainly existed. Consider for example:

> *Since the power system outages in 2013, 2014, and 2015, Hydro has considered inputs from the Board and intervenors and adjusted its operations in response.*[12]
>
> *. . . Hydro understood that outside parties' position was that Hydro had not been placing an appropriate focus on customer reliability and that a reexamination of the balance between cost and reliability was needed.*[13]
>
> *In response to the events [of 2014 and 2015], the Board, its consultants, and intervenors have provided significant commentary and opinion on how Hydro should adjust its operations to increase its focus on customer reliability.*[14]
>
> *It was clear to Hydro based on Liberty's report [on the March 4, 2015 outage], the comments from Newfoundland Power, the Consumer Advocate and the decisions of the Board, that reliability required an increased focus.*[15]

These represent just a few of the citations in the application. Hydro appears to imply that the subject changes may never have happened if not for the opinions and recommendations of stakeholders. If such an implication is intended, it is not appropriate, because:

- Hydro bears responsibility for its decisions, even if recommended by others; would Hydro concede impropriety if its decisions were not in accord with stakeholder suggestions?
- Others did encourage reliability improvements in general, but we know of no outside suggestions for the specific improvements in question.

[12] Application, Page 2, Line 2
[13] Application, Page 2, Line 13
[14] Application, Page 3, Line 12
[15] Application, Page 6, Line 7

Nevertheless, stakeholder expectations did support reliability improvement, and we do not criticize Hydro for sharing the belief that reliability improvement should have been an important element of management's thinking at the time.

Hydro has also observed that, until recently, no one offered any objection to these reliability initiatives. The implication appears to be that, given implementation of the changes three years ago, if they were not justifiable, objection would have been made before now. We do not place significant value on this view, even before recognizing that Hydro failed to make the implications of the spinning reserve initiative known to stakeholders until at least October 2017.

c. Countervailing Prudence Factors

Several observations run counter to those, such as the ones highlighted above, that tend to support prudence.

Failure to Consider Costs at the Time: Even with strong agreement on the need for enhanced reliability, no one would suggest that improvements "at any cost" were appropriate. We have found no evidence that Hydro estimated the cost impact of the spinning reserve change. Hydro in fact acknowledges that management conducted no cost benefit analysis or estimate. We find the failure to do so before making the change a serious omission. It raises the real possibility that Hydro was, at the time of the decision and for quite some time afterwards, unaware of the magnitude of the resulting costs or, at the least, insensitive to those costs. If management were aware then, no evidence supports that conclusion. Surely, had management understood the potential magnitude of the cost impact, that understanding would have formed a clear and explicit part of its decision-making process.

The failure to consider cost of a change that is known or knowable to have material cost consequences does not comport with prudent decision-making. However, the next and equally relevant question becomes whether a process that did appropriately consider costs would have led to a different decision. Given the high priority given to reliability in early 2015, we cannot conclude that Hydro's decision clearly would have been different had cost been properly considered.

Continuing Failure to Consider Costs: Even today, cost appears to remain as a non-consideration for Hydro. Management lacks any meaningful method for estimating the cost impacts and has no mechanism or process to track and monitor cost impacts. Management did not consider cost in its decision-making process and continues to fail to consider cost in managing ongoing implementation of its decision.

A disregard for cost also shows in management's lack of any reconsideration of this decision, now that key factors have changed. Those changed factors include the reduced priority of reliability versus cost, the realization that benefits are minimal, and most importantly, the revelation of the magnitude of the cost impact. Hydro's application offers no suggestion that the decision and alternatives should or will be reevaluated in the months ahead.

Cost/Benefit Imbalance: The spinning reserve change, as shown above, has produced limited benefits. First, it does not provide customers the fundamental benefit of N-1 (prevention of loss of customer load) - - UFLS is inevitable. Second, Hydro's primary benefit, mitigation of outage impact through accelerated restoration times, amounts only to six minutes per outage. We have seen no evidence that management evaluated these realities in the decision-making process or tried to quantify benefits in any way.

What is particularly material here is by what process and through what methods did management measure the magnitude and assess the resulting value of the dollars spent and the minutes saved. Hydro does now seek to justify the cost and reliability balance in the application, but the data does not support Hydro's position on the value of the improvement for the costs incurred.

Lack of Change and Costs Transparency: Management provided limited visibility on the institution of reliability changes and their impact. Having made the changes in early 2015, Hydro acknowledges that its October 2017 application for recovery "was the first time that parties had been presented with the exact cost of this approach."[16] We found the qualifier "exact cost" inapt, in that it implies that Hydro had somehow presented approximate cost at some earlier time. It did not.

Hydro suggests that the parties should have been aware of such costs far sooner because of several filings *"that provided information regarding the magnitude of gas turbine generation"*.[17] We do not find it reasonable to expect that stakeholders will spot such operating variations and intuitively arrive at a cost impact of tens of millions of dollars. In fact, it is far from clear that Hydro itself was able to identify such an impact before October 2017.

Each of these factors represents a significant failure on the part of management in the decision-making and implementation of these reliability initiatives, and hence represents compelling evidence in support of a finding of imprudence.

d. Conclusion

Management did not act reasonably in deciding to make the 2015 change without considering, in a robust and quantified way, its costs and its resulting benefits. Its decision process in that sense was seriously deficient and not good utility practice; nevertheless, it is not clear that a different decision would have resulted from a process that measured and balanced costs and benefits as it should have. There was considerable pressure at the time to implement reliability improvements, and the decision may indeed have been the same if Hydro had done a better job of considering costs. Further, the "loss of largest unit" criterion, which is the underlying concept behind the decision, is nearly universal. We cannot conclude that Hydro's decision in 2015 was imprudent even though its decision-making process was not reasonable and therefore we do not find it appropriate to exclude the resulting costs.

This conclusion leaves open the issue of management's *continuing* failure to consider costs and benefits in a robust and quantified way. Perhaps cost containment should have become a more

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[16] Application, Page 3, Line 2
[17] Application, Page 2, Line 3

acute focus of management, as cost pressures elsewhere have become more pressing; but there is no clear way to draw a bright line identifying the last date by which management should be held accountable (in a cost responsibility sense) for its continuing failure to do the analysis required. From a cost-recovery perspective, we know of no defining moment in which the cost-benefit balance, and the changing priority of cost, should have triggered a management response. It is clear, however, as we recommend later, that the decision should be reassessed now.

2. Forced Outages of Large Generating Units

Hydro incurred significant standby generation costs as a result of forced outages at large generating units. We estimate that the Energy Supply Cost Variance Deferral Account includes about $13.2 million in added fuel costs due to the need for standby generation to replace some of the energy lost through these outages. The units accounting for essentially all of these costs were Holyrood Units 1 and 2. In addition, Upper Salmon made a contribution in 2017. The bulk of the costs resulted in January and February 2016 in extended outages at Holyrood Units 1 and 2.

a. Prudence Considerations

The replacement power costs are significant, but the only basis for questioning their prudence is indirect and lies in the reasons for the unit outages in the first place. To the extent that the outages resulted from management failures, one could evaluate the propriety of a disallowance of the underlying outage costs, which should include replacement power costs. We, however, have not reviewed each outage and therefore have no basis upon which to question their appropriateness.

Forced outages are a normal part of utility operations, with prudence becoming an issue when the outage is both substantial and a result of a management failure. Prudence also can merit investigation when overall forced outage rates significantly exceed typical values. Some may be tempted to point to these poor levels of reliability as a management failure, especially because these units (Holyrood Units 1 and 2) have a well-documented propensity to fail at the wrong time. Liberty's past analysis of the Holyrood units, and our expectations for future performance, however, have been very clear. Our past assessments have consistently predicted poor and declining reliability at Holyrood because of aging and the inevitable decline of the assets. Given those factors, one cannot presume now that management failures are the real cause.

Liberty has repeatedly evaluated the asset management practices applicable to Holyrood TGS. We have recommended improvements, including the need for added asset management skills and capabilities, but we have never concluded that imprudence existed. With the question becoming whether any of the individual Holyrood forced outages in question would fail the prudence test, we found nothing in the record to suggest as much.

b. Conclusion

In summary, we have no reason to question the prudence of the $13.2 million in replacement costs that was incurred due to large forced outages. If any of those outages are subsequently proven to be imprudent, then the associated outage costs, including the proportional part of the $13.2 million in replacement costs, would presumably be recovered for the benefit of customers.

F. Other Considerations

Our analysis of the Energy Supply Cost Variance Deferral Account, although finding no firm basis for disallowances, nonetheless has surfaced a number of non-prudence questions that should be brought forth and addressed by Hydro.

1. Management of the Deferral Account

The fact that so many elements of the Energy Supply Cost Variance Deferral Account came as such a surprise to so many stakeholders evidences a serious management failing. The magnitude of the account was not understood, perhaps even by Hydro management itself, until October 2017. In addition, management did not communicate the drivers of the balance well. Finally, Hydro made major policy decisions involving cost and reliability trade-offs without stakeholder dialog and those decisions had a major impact on the account balance.

Improvements are needed in how this account is managed, and those improvements should include scope of acceptable items, requirements for cost estimation and monitoring, and periodic reporting.

2. Supply Planning Considerations

In 2015, Hydro made a major change in how it operates its power supply portfolio. That change required a much higher level of spinning reserve to be maintained at all times. It is incumbent on management, when a major new change in operations is imposed on the supply system, to consider how the system can be optimized for its new demands. In other words, as Hydro evaluates its long-term power supply needs, the future portfolio should reflect the new requirement and its design should seek to provide for that reserve at least cost. In addition, the new reserve requirement should be included in analysis of the adequacy of margins.

It is not clear that the new spinning reserve requirements have been included in power supply evaluations over the three years or are planned to be included in future assessments.

3. The October 2017 Criteria

In response to Hydro's October 2017 recovery application, the Board noted that "the information provided does not adequately address the costs and benefits of Hydro's approach to generation dispatch and the alternatives which may be available." While the current application addresses costs, the adequacy of that information continues in question. The categories of cost drivers contain significant overlap, which precludes effective analysis. The benefits discussion offers more clarity, but the value of those benefits is less clear and limited to a six-minute improvement in restoration times for 5-10 outages per year affecting perhaps 10,000 customers.

We believe that Hydro made a good effort to answer the Board's requirement for more information but is limited by its own cost methodology. We have suggested an alternate methodology that, by estimation, direct tracking, or simulation, can provide better results. Implementation of such new capability will assure better information for the Board and more prompt cost recovery for Hydro.

4. Policy and Procedure Inconsistencies

We discussed above the confusion in just what changes Hydro really implemented with respect to spinning reserve requirements since no such changes are reflected in the appropriate System Operating Instructions (T-001). We examined System Operating Instruction T-001 (Generation Reserves), which we understand to be the governing document which directs the requirements for system operators. From that examination, we observed that there appears to have been no change at all between 2014 and 2016. Consider the following language that appears identically in both Version 11 (12/19/14) and Version 13[18] (12/22/16) of T-001:

- "Sufficient generation reserve is required to meet current and forecasted demands under a contingency of the largest generating unit." Page 1
    - This suggests that an N-1 policy was in place in 2014. But the definitions that follow indicate that the contingency can be met by both spinning and non-spinning (20 minute) reserves.

- "Generation reserve is defined as the quantity of available generation supply that is in excess of demand, and includes spinning reserve. It is equal to Available Generation Supply less Current / Forecast Demand." Page 1, Footnote 1
    - This presumably means that generation reserve includes, but is not limited to, spinning reserve, which is confirmed below.

- "Available Generation Reserve is associated with generation that is in service or standby generation that can be placed in service within 20 minutes," Page 1, Footnote 2
    - This confirms that the reserve requirement applies to spinning and non-spinning reserves, with non-spinning defined as less than 20 minutes.

- "The ECC shall maintain sufficient spinning reserve to cover performance uncertainties in generating units, especially wind and other variable generation, and unanticipated increases in demand." Page 3
    - No mention of covering the largest unit.

- "The ECC will take appropriate action to maintain a <u>minimum</u> spinning reserve level equal to 70 MW." Page 3
    - Again, no mention of spinning reserve to cover the largest unit.

The pre- and post-2015 versions of T-001 suggest:

- No changes in operating practices vis-à-vis generation reserves between 2014 and 2016, unless such changes were implemented informally
- The current policy described in the application is quite different than that mandated by T-001, producing uncertainty about what really changed and what today's policy is.

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[18] Version 13 was also provided in the response to Undertaking #12 in the 2017 Hydro GRA, which was filed on 4/26/18, indicating that Version 13 was still current as of that date.

The inconsistency between the application and Hydro's governing procedures must be reconciled, and verification that the application is indeed accurate should be required before recovery is approved.

G. Recommendations

The Energy Supply Cost Variance Deferral Account Process

1. Hydro should be required to implement enhanced management of the Energy Supply Cost Variance Deferral Account, including periodic estimates of account balance, reporting of drivers of account balance, analysis of major deviations and prompt reporting of any decisions affecting or likely to affect the balance.

   There were numerous failings in Hydro's management of the deferral account. The most egregious included the lack of visibility given to Hydro's decisions and their cost impact. After nearly three years, the cost of the reliability improvements emerged as a major surprise. The Energy Supply Cost Variance Deferral Account represents a major benefit to Hydro, protecting it from certain significant risks. Hydro has a serious obligation to manage the process properly and it has not done so. The Board should require that, in return for this benefit, Hydro must manage the process properly.

Management Practices

2. The Board should require Hydro to be more open in its decisions that impact customer costs, including better communications on necessary changes and suitable stakeholder dialog on discretionary changes.

   We suspect that had Hydro discussed the proposed reliability improvements with stakeholders in 2015, those proposals would have garnered support. The reason Hydro did not is not clear, but second guessing of such decisions is a natural outcome when people are excluded. Hydro and the community in general will benefit from more openness and dialog as important and potentially costly future decisions are made. Public discussion three years after the fact is not a reasonable utility strategy.

3. Hydro should immediately reconcile the inconsistencies in operating practices between the application and Hydro's governing procedures (T-001).

   The inconsistencies between the application and T-001 are troubling and raise serious questions on the efficacy of Hydro's critically important operational procedures. An explanation must be provided to the Board as soon as possible.

Reliability Planning and Analysis

4. In light of what we expect to be rapidly changing cost and reliability expectations, Hydro should reexamine its approach to balancing cost and reliability.

Reliability paradigms and the priority of cost are sure to be changing in the months and years ahead. Hydro needs to get in front of these changes to assure a prudent decision-making framework is in place for important future operational decisions.

5. Recognizing the high cost and limited benefit of the new spinning reserve criterion, Hydro should immediately reexamine its options and engage in a dialog with stakeholders, including the Board, on whether the new criterion should be changed.

   The ML, and later the LIL, are sure to have a positive impact on Hydro's ability to carry a first contingency amount of spinning reserve. The use of standby generation to meet spinning reserve requirements might therefore not be required to the same extent much longer. Nevertheless, the magnitude of current costs demands that Hydro consider impacts over the near-term and decide if it is prudent to continue the current practice.

6. Hydro should incorporate the new spinning reserve requirements into its long-term power supply planning with the intent of defining suitable margins and optimizing the future cost of reserves.

   The new spinning reserve requirement creates significant new demands on the supply portfolio, such that consideration must be given to impacts on margins, on the determination of capacity requirements, and the least cost way of providing spinning reserve. System Planning should be incorporating such considerations into its process, if such considerations are not already present.

Cost Analysis and Estimation

7. Hydro should require credible cost estimates, and should develop the capability to provide them, for all significant future changes in operating practices.

   The need to make a credible cost estimate a part of any decision-making process should be self-evident. At times, however, such estimates are difficult to prepare. To the extent that Hydro lacks this capability, management should consider acquiring new skills and/or capabilities in this area.

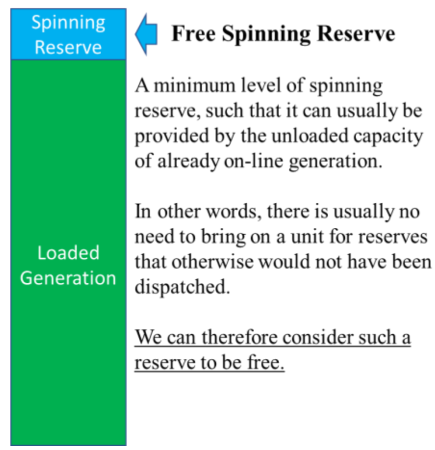
8. Hydro should evaluate Liberty's recommended methodology for estimating and attributing the standby generation costs (Appendix A) and, if appropriate, implement the process, either through monitoring of costs or simulation.

   Liberty does not believe that its recommended process (Appendix A) is the only solution, or perhaps even the best solution. It can nonetheless represent a starting point for Hydro to develop its own approaches. Hydro should seize the opportunity. A credible method for defining costs will prove a real benefit to Hydro and enhance the timing and extent of related recoveries.

Appendix A: An Alternate Approach to Estimating Costs and Determining Attribution

Our scenarios of interest, which align with Hydro's categories, are (1) the new reliability requirements implemented in 2015; (2) a number of *forced* outages of large units; (3) a number of *planned* outages of large generators; and (4) a number of *planned* outages of transmission facilities. Hydro's overlap in these four categories is the problem we are addressing. In each scenario, we will examine (a) additional standby generation costs that are caused by the loss of facilities, whether planned or forced, and (b) additional standby generation costs to meet Hydro's new reliability standards. Note that our first step here was to simplify the challenge by focusing on only two specific standby generation costs: (a) replacement power costs and (b) cost to provide reserves.

Let us first consider a hypothetical scenario in which there is a minimum spinning reserve, perhaps 70 MW as in Hydro's past practice. For our estimating purposes, we can consider that level of reserve to be free, since it can typically be met by the unloaded capacity of already on-line generators; i.e., there is usually no need to bring on a unit that otherwise would not have been dispatched. Our costs associated with normal operation in this scenario can be considered baseline and, of course, that includes no spinning reserve costs.



Now let us add the N-1 criterion, which considerably increases the spinning reserve required. It is now more likely that an otherwise off-line generator must be brought on-line and up to minimum load in order to support the higher reserve requirement. Our costs increase, but in a very straightforward way. The added cost is the cost associated with the generator added, and we would attribute those costs to the new reliability requirement. This simplifies our estimating challenge in that we need not be concerned with before and after costs for spinning reserve, since the "before" costs are zero. The estimating problem is therefore solved if the only driver is the new spinning reserve requirement.

But complications, and our dilemma, arise when we combine drivers. Consider now a scenario in which a large unit trips. This is illustrated in the simplified diagram below. We begin with a normal operating situation in which capacity is on line to support the load plus the spinning reserve requirement to cover the loss of the largest unit. When the largest unit trips, the spinning reserve picks up the load for the lost unit (ignoring any unique UFLS considerations). After such a contingency in our scenario, the System Operator will bring on standby generation[19] and rebalance the system, reestablishing the spinning reserve in the process and restoring "normal operation".

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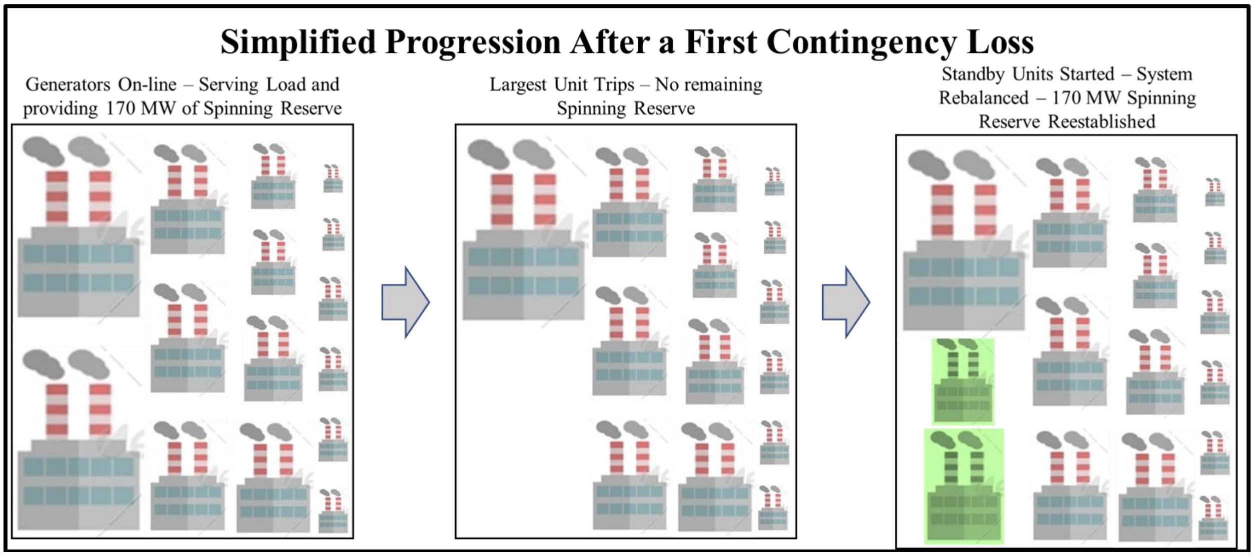
[19] Recall that we are only concerned with the challenge of pricing standby generation here. If other generation is available, and standby generation is not needed, that case is therefore excluded from our study.



After this event, we clearly have a more expensive generation mix, having removed the largest and presumably lowest cost unit and replaced it with two standby units. But should these costs be attributed to the new N-1 reliability requirement or to the forced outage of the unit? We answer that as follows:

- If the standby unit is needed to serve load:
  - The added costs compared to the lost unit are replacement costs
  - They are attributed to the outage
  - Any resulting spinning reserve benefits are free

- If the standby unit is only started to meet the spinning reserve requirement:
  - Fuel costs are incurred to start up and run at minimum load
  - The costs are attributed to the reliability standard, since they would not have been incurred absent that standard
  - Any resulting benefits in replacement costs are free.

We have therefore defined how to determine and attribute costs for Hydro's first two categories for the use of standby generation: spinning reserve and the *forced* outage of a large unit. We can now consider Hydro's third category: the *planned* outage of a large generating unit. The treatment of costs for a planned outage should be no different than the forced outage scenario, except that the rebalancing is far more orderly in the case of a planned outage. Also, since planned outages are invariably in the off-peak season, it is much less likely that the standby units will be needed to serve load.

We can apply this same concept to the category of planned transmission outages, except that the load serving component does not apply. Further, we understand that the use of added reserves in transmission outages was for Avalon support, which we link to the enhanced focus on Avalon operating parameters, a key component of the new operational philosophy. Accordingly, all such costs should be attributed to the new reliability standard and operating practices.

This approach is summarized in the table below. It offers clear definitions, with no overlap, and a cost solution for each of Hydro's four categories:

(1) The new requirements for spinning reserve implemented in 2015 (Method A)

(2) Forced and (3) planned outages of large generating units (Method B)

(4) Planned transmission outages (Method C)

A Methodology for the Estimation and Attribution of Added Standby Generation Costs

A. In "normal operation", when a standby generator is required to provide spinning reserve:

- The cost impact is the actual cost for standby generators to provide that reserve; i.e., the cost to start the unit and bring it to min load
- That cost is attributed to the reliability standard

B. When a large unit becomes unavailable, necessitating standby generation to serve load or provide reserves:

- If the standby unit is needed to serve load:
  - The added costs compared to the cost of the lost unit are replacement costs
  - They are attributed to the outage
  - Any resulting spinning reserve benefits are free
- If the standby unit is <u>only</u> started to meet the spinning reserve requirement:
  - Fuel costs are incurred to start up and run at minimum load
  - The costs are attributed to the reliability standard
  - Any resulting benefits in replacement costs are free

C. When a planned transmission outage requires added reserves on the Avalon:

- The cost impact is the actual cost for standby generators to provide that reserve
- That cost is attributed to the reliability standard broadly, and to the enhanced focus on Avalon operating parameters in particular.

The recommended treatment for added standby generation costs will permit a more accurate and non-overlapping assessment of the Energy Supply Deferral Account as it is impacted by standby generation costs. It remains to be seen if Hydro has the current capability to produce such estimates, either through direct measurement or, more likely, simulation.

c. An Interim Approximation

Hydro Category	Replacement Costs	Reliability Costs
Support of spinning reserve		✓
Backup due to the loss of a major generating unit	✓	✓
Planned generation outages	✓	✓
Planned Avalon Peninsula transmission outages		✓
Testing		

In the inability to implement the above methodology at the present time, the methodology nonetheless suggests a way to approximate the standby generation costs using Hydro's overlapping breakdown. We will do this by first defining the two types of costs that result from the use of standby generation: costs to serve load when a large unit is lost (Replacement Power Costs) and costs to support reserve requirements (Reliability Costs). Note in the accompanying table that both costs do not necessarily apply to each of Hydro's categories. This is an important simplifying factor.

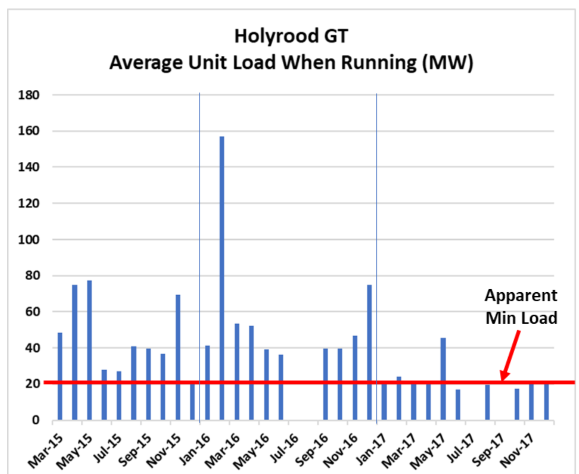
The next challenge is (a) to determine the costs associated with each of Hydro's categories and (b) how those costs are distributed among replacement and reliability costs. Hydro has provided the operating hours for each of Hydro's categories, so a simplifying assumption might be that the total standby generation costs ($51.8 million) can be allocated to each Hydro category in proportion to that category's operating hours. The results of such a proportional spreading are listed in the accompanying table.

Hydro Category	Standby Gen Costs (Million $)
Support of spinning reserve	16.0
Backup due to the loss of a major generating unit	22.0
Planned generation outages	7.9
Planned Avalon Peninsula transmission outages	4.6
Testing	1.3
Totals	51.8

Hydro has provided another data point that can be used as a "sanity check" on the concept of proportional allocation of costs based on operating hours. NP-NLH-333, 334 and 335 provide operating hours and fuel costs for when the Holyrood GT was operated for spinning reserve. The resulting fuel costs for spinning reserve, for the Holyrood GT only, were $16.9 million versus our $16.0 million prediction above, or an error of only 6%.

Our final question is how to allocate cost between replacement or reliability. We saw above that this question only applies to the categories of forced and planned outages of large generators, as the other categories involve only reliability costs.

The accompanying chart will help. In this chart, average load was calculated by dividing the kWh generated in each month[20] by the operating hours for the unit in each month.[21] Note that the minimum load while running appears to be about 20 MW. Therefore, in any month averaging only about 20 MW, the Holyrood GT is likely to be running nearly exclusively for the provision of spinning reserve. In months that are clearly higher than minimum load, we can assume that the supply of load was the primary objective.



The Feb-16 data point is an anomaly, since max capacity is 123 MW

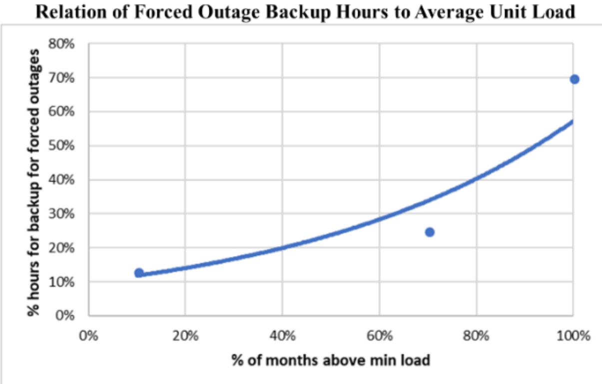
Liberty verified this relationship with the charts below. Note that when the forced outage component (left chart) was only 12%, which occurred in 2017, average min load was exceeded in only 10% of the months. But when the forced

[20] Application, Schedule 1, Appendix L, Page 10, 21 and 31
[21] Extracted from the data in Appendix L

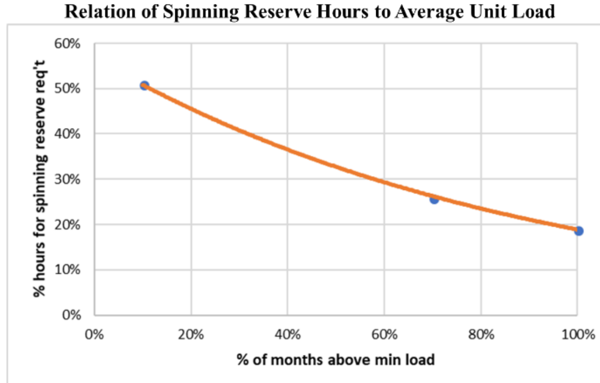
outage fraction reached 70% (in 2016), average load was exceeded in 100% of the operating months.

The converse is true when we look at spinning reserve hours (right chart). When spinning reserve is at its high (50%), average min load was exceeded in only 10% of the months. When spinning reserve was minimal (20%), average min load was exceeded in all months.

Relation of Forced Outage Backup Hours to Average Unit Load



Relation of Spinning Reserve Hours to Average Unit Load



Recall our estimating methodology above dictates that replacement costs should be free when the unit is run for the sole purpose of providing spinning reserve. That purpose is revealed by the unit running at min load. On the other hand, spinning reserves should be free when the unit is running primarily to serve load, and that purpose is revealed by average unit loading well above minimum. This permits us to attribute costs in the forced outage category as follows:

Cost Allocation in the Hydro Forced Outage Category
"Backup Due to the Loss of a Major Generating Unit"

Months in which average load is about min (Replacement costs are free)	12	40% to Spinning Reserves
Months in which average load is higher (Reserve costs are free)	18	60% to Replacement Power

We now have enough information to (1) complete our cost estimate, broken down by Hydro's categories and then (2) allocate costs to our relevant prudence questions. The new cost table is as follows:

Hydro Category	Standby Gen Costs (Million $)	Replacement Costs (Million $)	Reliability Costs (Million $)	To Be Analyed for Prudence?
Support of spinning reserve	16.0	0.0	16.0	Yes
Backup due to the loss of a major generating unit	22.0	13.2	8.8	Yes
Planned generation outages	7.9	0.0	7.9	No
Planned Avalon Peninsula transmission outages	4.6	0.0	4.6	No
Testing	1.3			No
Totals	51.8	13.2	37.3	

We have allocated the costs for the loss of a major unit (forced outage) on a 60-40 basis as above. Meanwhile, we allocated costs for planned generation outages all to the supply of reserves since such outages were primarily off peak, minimizing any power replacement needs. Finally, the transmission outages are all allocated to the supply of reserves since there is no replacement power involved in this account.

The prudence questions are now simply the sum of the appropriate accounts, as illustrated by the colored cells in the above table. The results are:

- New spinning reserve requirement $32.7 million
- Forced outages of major units $13.2 million