NLH 2013 Amended General Rate Application
Information - #27
Filed: Oct. 28, 2015 Board Secretary:

2014 Newfoundland and Labrador Hydro Planning Process Review

March 21, 2014

Prepared for:

Newfoundland and Labrador Hydro

Prepared by:

Ventyx, An ABB Company
400 Perimeter Center Terrace, Suite 500
Atlanta, GA 30346
www.ventyx.com

Contact:

Charles Adkins, Vice President
(912) 228-4278

VENTYX
AN ABB COMPANY

Liability Note

Contents

Executive Summary 3
Study Objective 6
VENTYX 7
Strategist® 8
Incident Description 8
Issues within Scope 9
Load Forecasting 9
Generation Planning Criteria 9
Scenario/Sensitivity Planning 10
Load Forecasting 10
Background 10
Conclusions 12
Recommendations 16
Generation Planning Reserve Criterion 17
Background 17
Conclusion 22
Recommendation 22
Generation Forced Outage Rates 23
Background 23
Conclusion 25
Recommendation 25
Scenario Planning 26
Background 26
Conclusions 28
Recommendations 29
Generation Outlook 2014 to 2017 29
Summary of Recommendations 31
Appendices 34

Executive Summary

Over the weekend of January 3rd, 2014, Newfoundland and Labrador Hydro ("NLH") experienced a series of largely unrelated events that led to four days of rolling blackouts. On January 17th, The Board of Commissioners of Public Utilities ("the Board") initiated a process to gather information from NLH and Newfoundland Power ("NP") with a focus on whether load requirements on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecasts, and NLH's long term (20 year) and medium-term (5 year) load forecasting. Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

In the near term, NLH's current resource expansion plan is within the reliability criteria in all calendar years except 2015.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date or an equivalent resource is not implemented the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[1] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 50 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, in addition to the nominal combustion turbine assumed, NLH would need to secure approximately 40 MW of either interruptible contracts with existing

[1] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

customers or conservation and demand management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[2] and 0.91%[3], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets, this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well, there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The current projected plan is based upon a normalized weather forecast. Weather normalization is an industry standard process that adjusts actual peak outcomes to what would have happened under normal weather conditions. Beyond the next seven days weather forecasting is complex and not always accurate. Therefore, NLH should look at a severe

---

[2] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[3] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

weather sensitivity to gauge how the system might respond to greater than expected demand particularly in making near term investment decisions.

Specific process recommendations:

- Load Forecasting
    - Continued surveying of the customer base in terms of both average energy use and saturations of heating.
    - Develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.
- Generation Planning
    - NLH should continue forward with its generation planning reserve criterion.
    - After NLH's interconnections are established in 2017, NLH should revisit both their generation planning reserve criterion and their modeling of external markets.
    - NLH should continue forward with its practice of maintaining a more conservative estimate of EFOR for the units.
    - Compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the LOLH criteria of 2.8 hours/year
- Develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.

Study Objective

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts. On January 17th, The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecast and NLH's long term (20 year) and medium term load (5 year) forecasting. Specifically, Ventyx was asked to review:

- The overall planning process and assumptions used by NLH in developing their current long range and strategic forward looking plans;
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required;
- Review of the process and assumptions used by NLH in developing their current long range load forecast and shorter term operational forecasts;
- Provide commentary on the load forecasting processes, criteria and assumptions and make recommendations as to specific improvements as required;
- Review of the Strategist model assumptions used by NLH in developing their current long range and strategic forward looking plans; and
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required.

VENTYX

Ventyx brings a dedicated team of expert consultants that combines experience, industry knowledge, market knowledge, and software expertise to support consulting engagements. Ventyx provides professional consulting services to energy companies in the areas of integrated resource planning, market price forecasting, resource evaluation and planning, trading and settlement, and electric transmission economic analysis. Ventyx has worked with NLH both in support of Ventyx's Strategist software and .with analytical modeling to evaluate the economic and system impacts of the Muskrat Falls hydro project as well as the Maritime Link project with Nova Scotia. Ventyx conducted multiple analytical modeling studies of this pair of projects over a three year period that also included analytical modeling covering the provinces of New Brunswick, Prince Edward Island, Nova Scotia and Newfoundland Labrador as well as surrounding market areas in Quebec, New York and New England for the Atlantic Energy Gateway project

Strategist®

Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. Strategist is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities, economic energy interchange, and direct load control programs are then economically dispatched based on the marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices. The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. The PROVIEW module works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system, or modifying the load through demand-side management (DSM) or marketing programs.

Incident Description

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts.

Issues within Scope

The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts. The scope of this report is focused on the load forecasting and planning criteria and assumptions. With the NLH system setting record peaks during this unfortunate event, the question of load forecast accuracy is raised. The primary planning criteria that are related to an event of this nature are planning reserves and generation forced outage rates. Finally, the issue of load forecasting and planning criteria is enveloped in the overall process of sensitivity analysis to address the inherent risk of the NLH portfolio.

Load Forecasting

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. As the load forecasting process passes from the short term to longer term, the reliability of forecasted weather drops dramatically. Longer term forecasts are typically represented as annual peaks and energies, with monthly detail, to support budgeting planning. Longer term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

Generation Planning Criteria

The generation planning criteria for planning reserves and generation forced outage rates combine to form a prediction of the expected LOLH reliability index. This reliability index forms the foundation of a minimum reliability threshold of 2.8 hours/year. For each year of the NLH planning horizon, the system is designed to maintain sufficient generation planning reserves to ensure the minimum reliability threshold is met. Generation planning reserves are the MW difference between available capacity and normalized peak demand that are available to meet unforeseen increases in demand, such as extreme load, and unexpected outages of existing capacity. Forecasted trends in LOLH identify whether generation capacity additions are keeping pace with load growth.

Scenario/Sensitivity Planning

Scenario planning is a strategic planning methodology used to identify and assess the inherent risks and benefits of a flexible long term plan. Scenario planning recognizes that many factors may combine in complex ways to create sometimes surprising futures. Scenario planning seeks to identify the causal relationship between factors and demonstrate a plans flexibility to adapt. Scenario planning develops an internally consistent story about the conditions in which the system might be operating in the future that differs from baseline assumptions in sometimes significant ways and usually involves alterations to all of the assumptions at one time. Sensitivity planning varies each of the assumptions either one at a time or in correlated groups to determine how sensitive the results are to changes in the assumptions. These planning techniques are important when there are variables such as weather that can potentially impact the reliability of the system.

Load Forecasting

Background

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. The short term forecasts prepared by NLH use a neural network forecasting approach using the Nostradamus modelling software.

A medium term forecast that covers a time horizon of five years is used for budgeting and near-term supply adequacy. The medium term forecasts are a combination of the NP forecast for their service territory and NLH economic and regression processes for their rural customers and customer input for the industrial loads.

Longer term forecasts cover the time horizons of 20 years and are typically represented as annual peaks and energies, with monthly detail, to support long term generation planning. The long term forecast is performed by NLH using economic and regression techniques to forecast NP, NLH rural loads, and Industrial customer forecasts of their loads. The long term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

The review of the load forecasting process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent, detailed reviews of the project, a review of the responses to the Board of questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP forecasting staff. Since the independent review of the load forecast conducted by Manitoba Hydro International ("MHI") was a detailed review of the assumptions, the review described in this report focused on the methodology and a look at the validity and accuracy of the forecast. Personal interviews were held with the staffs of NLH and NP to ascertain the sequencing and procedures of each company and the interfacing and integration of the individual component forecasts into a single product. Of particular interest was the accuracy of the winter peak as it applies to the incidents described above.

- The interviews with the NP load forecasting staff revealed the medium term forecast of NP service territory energy was performed for Domestic, General Services and Area and street light classes. Although the process was different for each class, the basic process is an average use methodology that applied econometric forecasting techniques to determine average use per consumer that was then applied to a customer growth forecast.
- The medium term peak demand for NP was developed using an average load factor methodology that calculates a 15 year average load factor that is then applied to the medium term energy forecast to determine the NP service territory Winter Peak demand. This is a standard utility practice.
- The NLH long term load forecasting process is a combination of econometric and regression analyses to determine the energy and peak demand for NP and the NLH rural

groups with industrial energy and demand requirements conditioned by individual customer input .

- The long term peak for NP is forecast by NLH using regression analyses that link NP peak demand to weather, domestic electric heat customer growth, general service sales growth and other economic factors. The peak for the NLH rural group is calculated using a long term historical load factor method that is applied to the forecasted energy. The industrial peak is developed through direct input of existing industrial customers. No forecast is made of potential new industries unless it is fairly certain that a change is going to be made either through government action or a committed industrial customer.

NLH uses historical hourly shapes to develop typical 168 hourly week shapes for each month of the year. These typical shapes are applied to each year of the study and are adjusted by the Strategist Load Forecast Adjustment ("LFA") module to meet the data entered for peak and energy from the forecast. NLH has not updated the historical data since 2002 and is scheduled to perform the update in the next 12 months as part of the next generation expansion planning exercise. Since the system has had a fairly stable load factor and since the LFA continuously modifies the shape to meet the forecast this should not impact the results of the studies. This would only be a problem if NLH was evaluating new Conservation and Demand Management ("CDM") or time dependent programs such as time-of-day rates.

NLH has elected to set the study period to 50 years so that it would cover the financing period of the Muskrat Falls project. This is typically performed using either Economic Carrying Charge calculations or infinite end-effects with a shorter study period of twenty years. However, after discussion with NLH planning staff Ventyx determined that the manner in which they performed the extension of the load forecast and other model data was consistent with the Strategist end-effects methodology.

Conclusions

The methodology used by both NP and NLH are consistent with accepted utility practices. It has been noted by another independent review, by MHI, that the process could be improved by changing to an end-use forecast. It is Ventyx's opinion, based on experience, the complexity and time to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

The econometric methods being used by NLH are prudent and well validated. The regression equations all have statistical coefficients of determination (R^2) that are in the very high range. The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 1 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided. The R^2 for the regression equations that directly impact the forecast of system peak demand in the long term are included below.

Equation	R^2
NP Domestic Class	
Customer Additions	93.4%
Penetration of Elect. Heating	88.5%
Conversion of Non-Elect Heat	78.9%
NP General Service Class	
Electric Heat Customer Load	99.9%
NLH Rural Domestic Class	
Average Use	98.1%
NLH Rural General Service Class	
Energy	99.6%
NP Peak	99.7%

Table 1 Coefficients of Determination[4]

No attempt was made in this review to verify or validate the actual data used since a previous report was issued by MHI showing a detailed discussion of the data. It is obvious weather has a significant impact on the resulting energy and peak demand forecasts. NLH's forecasting models include weather variables to account for the impacts due to changing weather conditions through the historical period. However, what is missing is an evaluation of the energy and demand impacts due to extreme weather conditions. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 1, shows a comparison of the forecasted winter months peaks to the actual peaks for the system for the years 2004 to December 2013. Since 2004 the actual winter peaks have consistently been below the forecasted peaks with the exception of seven months out of forty winter months that the actual has been higher than the forecast. However, since those seven times do not occur in the same month it would suggest that there was some random pattern

[4] Manitoba Hydro International, *MHI-Report-Volume II-Load Forecast* (February 2012)

such as weather that is impacting the actual. A review of the deviations shows that it is largely weather that impacts all the discrepancies As indicated by the red bars, the actuals are consistently less than the forecast because NLH has experienced a period of warmer than normal peak weather conditions over this period. The December 2013 discrepancy was impacted additionally by the “exceptional” loads resulting from unavailable Avalon generation that resulted in higher system demand loads than expected. If a variable such as the number of customers was off it would be impacting the forecast for all winter months in that period.

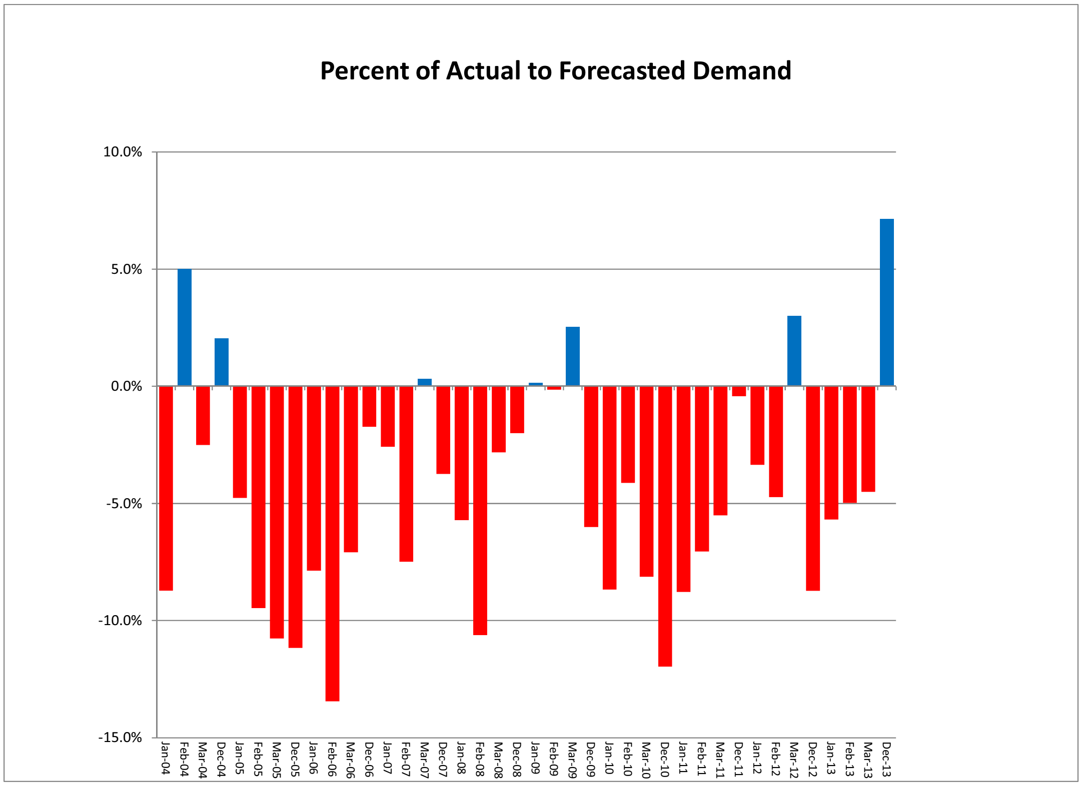


Figure 1[5]

Recommendations

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy

[5] Newfoundland and Labrador Hydro, *PUB-NLH-011* (Newfoundland and Labrador Hydro: Board Response, February 2014)

benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine their models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. Later in the report, Ventyx will discuss using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.

Generation Planning Reserve Criterion

Background

The purpose of a Generation Planning Reserve Criterion is to establish the minimum reliability threshold for a power system. The reliability of a power system is defined as the probability of providing customers with continuous service of a satisfactory nature. Reliability is one of the primary factors that drive the planning, design, operation, and maintenance of a power system. The most common index for reliability is the Loss of Load Probability ("LOLP") which is "the probability of the system load exceeding the available generating capacity under the assumption that the peak load of each day lasts all day."[6] Through a series of analytical processes the reliability index, LOLP, is translated to a reserve criterion stated in terms of Loss of Load Hours ("LOLH") or a defined reserve margin percentage. In Strategist, Loss of Load Hours is the expected total number of hours a year during which the utility will not be able to serve all of its customers. The percent reserve margin is based on the reserve margin at the time of the annual peak and defined as the amount of installed reserves, in MW, divided by the

[6] J. Endrenyi, *Reliability Modeling in Electric Power Systems* (Ontario Hydro: John Wiley & Sons, 1978), 4

system peak demand, in MW. This reserve criterion serves as an input to capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

NLH's capacity planning reserve criterion for capacity planning is "The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours ("LOLH") expectation target of not more than 2.8 hours per year."[7] The LOLH target is based upon a Loss of Load Probability of 1 day in five years or, more commonly denoted as, 0.2 days per year. In 1977, the NLH System Planning department determined that "The LOLP index to be adopted depends upon the availability of capital. System Planning feels that a .1 days/year is not realistic and would suggest .2 days/year as an optimum value to aim for".[8] The results of NLH's recent 2012 capital planning study, 2012 DCL–PLF IT1–A-0801-_R-105 FE-1 Strategist 4.4.1, are enumerated in Table 2.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

Table 2 Expected Loss of Load Hours

[77] PUB-NLH-008

[8] System Planning Department, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions* (Newfoundland Labrador Hydro: internal memo, May 16, 1977), 19

Previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[9] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

---

[9] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[10] and 0.91%[11], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The standard industry practice is to apply a LOLP of 0.1 days/year, or "one day in ten years". However, it should be noted that the 0.1 days/year standard applies to ***interconnected*** utilities. For true "stand alone" utilities, the cost to achieve a 0.1 days/year standard is often cost prohibitive. In 1977, NLH conducted a thorough analysis of system reserves and concluded with the recommendation of 0.2 days/year, or "one day in five years". NLH justified the 0.2

[10] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[11] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

days/year over 0.1 days/year based on the economics of meeting the more stringent requirement. The incremental present value revenue requirements necessary to move from a reliability index of 1.0 days/year to 0.2 days/year was approximately $24 Billion[12]. The incremental present value revenue requirements necessary to move from a reliability index of 0.2 days/year to 0.1 days/year was approximately $17 Billion[13]. Simply stated, the cost to serve the last tenth of the reliability index was 71% of the cost to serve the total of the first eight tenths of the reliability index. NLH was justified in its decision to adopt a reliability index of 0.2 days/year.

From a generation mix perspective, the NLH system is "roughly" the same as it was in 1977; there is no reason to reassess its reliability standard of 0.2 days/year. The primary drivers that would prompt a utility to reassess its reliability standard include: resource mix, plant reliability and maintenance, and interconnections. In 1977, the NLH system was 63% hydro and 37% thermal. Today, the NLH system is 67% hydro and 33% thermal. In terms of plant reliability, the capacity weighted average effective forced outage rate in 1977 was 3.74% versus 4.05% today. From a system reliability standpoint, the NLH system is virtually equivalent to the system in 1977. However, NLH expects to complete the Maritime Link to Nova Scotia in 2017. When NLH interconnects with the North American grid, NLH should reassess its reliability standards in light of their access to new markets.

Loss of Load Probability is a characterization of the adequacy of the generation within a system to serve the load of the system. It is important to note that LOLP does not represent the reliability of the bulk transmission or distribution systems. For the purposes of NLH's planning criteria, it was necessary to translate the LOLP, which is a based on the peak load of each of the 365 days, to an hourly equivalent, LOLH. "When Hydro switched from SYPCO generation

---

[12] Ibid, Table V. Grand Total (0.2) 2,896,178 (1977 K$) minus Grand Total (1) 2,872,516 (1977 K$) equals 23,662 (1977 K$).

[13] Ibid. Table V. Grand Total (0.2) 2,912,924 (1977 K$) minus Grand Total (1) 2,896,178 (1977 K$) equals 16,746 (1977 K$). 16,746 is 70.07% of 23,622.

planning software to PROSCREEN II [now called Strategist], it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system."[14]

In 2017, the Maritime Link to Nova Scotia will be completed. Post 2017, NLH will be interconnected with the rest of the North American grid. In addition, there will be a long term sales agreement with Nova Scotia that will provide scheduling flexibility. NLH's current long term planning system does not reflect the reliability benefits of these incremental additions to the NLH portfolio.

Conclusion

NLH's generation planning reserve criterion of a LOLH of 2.8 hours per year is prudent and consistent with standard industry practices. NLH has consistently used the generation planning reserve criterion as an input to their capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

Recommendation

NLH should continue forward with its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. It may be possible that this approach to reserve criterion, if still appropriate may be improved at minimum cost. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to

[14] Newfoundland and Labrador Hydro, *PUB-NLH-056* (Newfoundland and Labrador Hydro: Board Response, February 2014),1

allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Generation Forced Outage Rates

Background

The purpose of generation forced outage rates in generation planning is to represent the probability that a specific unit will not be available for service when required. Generation Planning periodically confirms the resource adequacy of a system through detailed reliability simulations that compare the expected load profiles with specific generating unit forced outage rates and maintenance schedule to determine LOLH values. A typical unit's contribution to resource adequacy is typically a function of the unit's capacity and its equivalent forced outage rate ("EFOR"). NLH uses the convention Derated Adjusted Forced Outage Rate ("DAFOR") which is known as EFOR as used by the North American Electric Reliability Council[15]. For the purposes of this report EFOR and DAFOR have the same meaning. A unit's equivalent forced outage rate is defined according to the following formula:

[15] Roy Billinton, *Reliability Data Requirements, Practices and Recommendations* (Department of Electrical Engineering University of Saskatchewan) page 55.

$$EFOR = \frac{FOH + EFDH}{FOH + SH + Synchronous\ Hrs + Pumping\ Hrs + EFDHRS} \times 100\%$$

Where:

FOH	– Forced Outage Hours
$EFDH$	– Equivalent Forced Derated Hours
SH	– Service Hours
$Synchronous\ Hrs$	– Synchronous Condensing Mode Hours
Pumping Hrs	– All hours pumped storage unit in pumping mode
$EFDHRS$	– Equivalent Forced Derated Hours during Reserve Shutdowns

For the purposes of this discussion, Ventyx focused on NLH's largest aggregate resources that drive overall system reliability, Holyrood, 465.5 MW; and Bay D'Espoir, 592 MW. These two plants comprise 1057.5 MW and represent 54.3% of NLH's installed capacity. The EFOR used in NLH's generation planning and serving as an input to Strategist is derived from the Canadian Electrical Association's ("CEA") 2004 Report and is based on the period from January 1, 2000 through December 31, 2004. Ventyx compared these rates to the current CEA data covering the period from January 1, 2008 through December 31, 2012. NLH's other smaller CT's and Hydro units have less impact upon reliability.

Table 3 lists the five year CEA capacity weighted average EFOR based on the most recent CEA data and the EFOR assumptions in NLH's Strategist database.

Unit Name	NLH Strategist Assumptions	NLH Average 2008 - 2012
Holyrood	9.64%	10.69%
Bay D'Espoir	0.91%	0.41%

Table 3

Conclusion

NLH's overall assumptions are consistent with industry standards. While there might be some rationalization that a significant increased investment might improve Holyrood performance further, given the time until the infeed is realized, the age of the units and outage availability it appears that the time required to gain results will be longer than the relatively short timeframe to interconnection with the North American Grid.

Recommendation

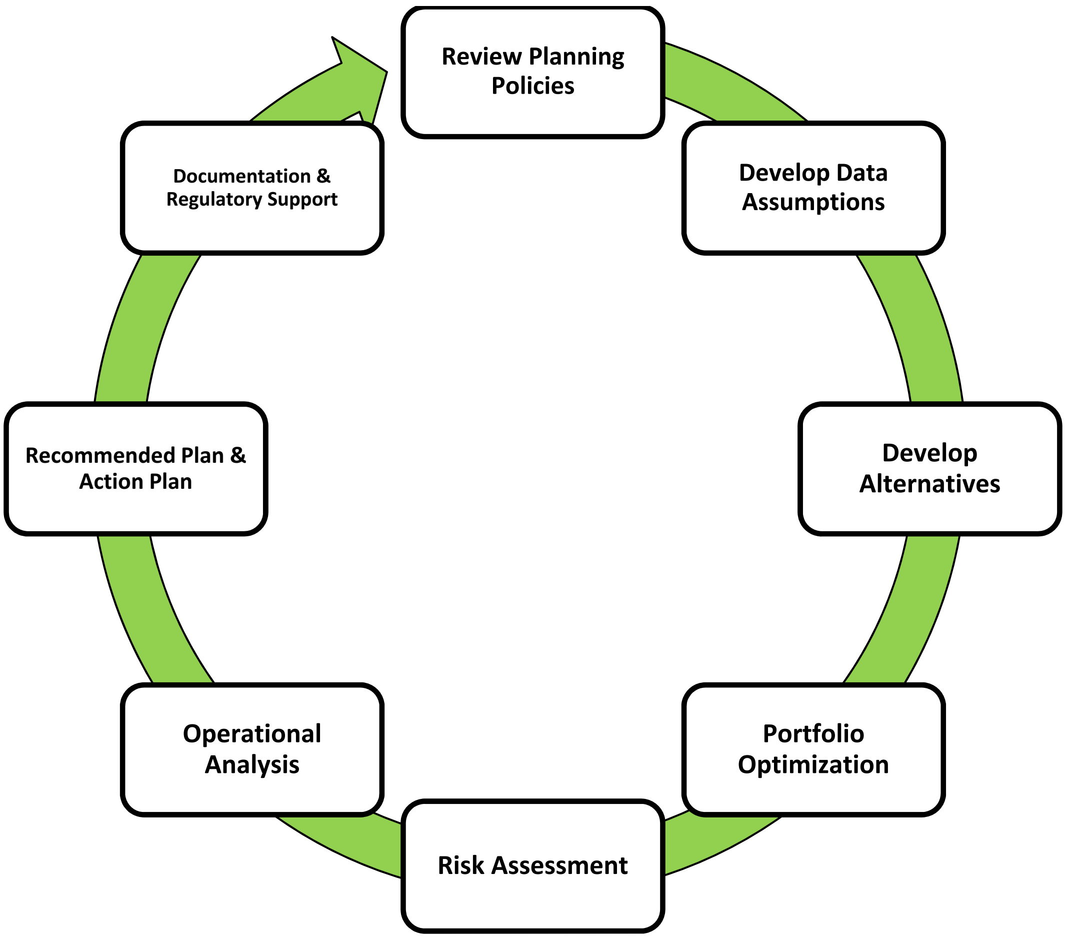
Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model its EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, for which the maximum EFOR would be between 9.7% and 9.8%. At this point, the units' contribution to LOLH would exceed 2.8 hours/year.

Scenario Planning

Background

The purpose of this part of the review is to examine the NLH planning process with respect to accepted utility practices and procedures. The standard that the NLH planning process was compared is the Ventyx Integrated Resource Planning ("IRP") process. This process was developed and used by Ventyx n its worldwide consulting practice.



© Ventyx, an ABB Company

Figure 2 IRP Planning Process

Description of each step:

- **Planning Policies Review** – This is the initial IRP project planning step in which the objectives of the IRP are set up. This includes the review of all of the rules and constraints that must be met in performing the planning process
- **Data Assumptions** – In this step all of the data assumptions are gathered and vetted. This includes the operating assumptions of all existing and proposed future alternatives, commodity prices, environmental and market prices, and transmission limits.
- **Develop Alternatives** – The simulation models for the various alternative Demand-side, Supply-side and market/transmission options are developed.
- **Portfolio Optimization** - In this step the potential resource alternatives are pre-screened using economic and operational methods. Through the use of optimization software, such as Strategist, one or more optimal plans are developed that meet a set of defined attributes and constraints.
- **Risk Assessment** - This step takes optimized plans from alternative scenarios and subjects them to sensitivity analysis to determine the impact of changes in assumptions to results. This step also determines the robustness of optimal plans to statistical distributions of sensitive variables. Then using multi-criteria decision making analysis techniques determines the trade-off between competing attributes such as risk and least cost.
- **Operation Analysis** – Selected plans are then further analyzed in terms of financial viability and operational constraints such as hydrological studies.
- **Recommended Plan and Action Plan** - The results of all the above steps is a recommended plan that the utility wished to present as its integrated resource Plan. In conjunction with this overall long –term plan an Action Plan is developed that focuses on the decision period in which actions must be decided on today. With-in the Action Plan a set of signposts are developed from the sensitivities that determine which variables should be monitored, at what value an action should be triggered, and what the contingent actions should be.

- **Documentation and Regulatory Support** –The heart of the IRP is the final documentation. These are the documents that will be filed with regulators and all other parties. It should be thorough, accurate and defendable. Note that this step is best performed as the overall IRP process is being performed.

The review of the resource planning process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent detailed reviews of the project, a review of the responses to the Board's questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP planning staff.

Conclusions

The resource planning process being performed by NLH conforms to the basic structure laid out in the Ventyx IRP process. All areas in the IRP process were deemed as being acceptable. However, two areas, Alternative development, and Risk Assessment were found to be acceptable but in need of improvements.

In the development of alternatives it was found that although existing demand-side programs were included in the development of the resource plan there was a lack of additional demand-side alternatives. The report only mentions the presentation of CDM alternatives to the Board, no mention of the use of demand-side as alternatives to supply resources is made. Due to slow growth requirements of demand programs the use of demand-side alternative will not be effective to solve short-term issues. It will also not change the need for the capacity and energy from the Muskrat Falls project long term. However, it is Ventyx's recommendation that the use of demand-side alternatives be further explored in the period post 2017 while there is ample capacity to cover requirements. In reviewing the documents it was noted that there is no formal risk assessment being performed.

Sensitivities were performed and included in the original documentation but focused mostly on commodity and costing assumptions. Future scenario and sensitivity processes should be expanded to include the impacts of extreme loads. These expanded sensitivity analysis can then be formally included into a risk analyses process to determine the robustness and impacts of resulting plans. The additional load sensitivities are discussed above in the section on load forecast.

Recommendations

It is noted that while NLH's Resource Planning processes meets the overall IRP process requirements, there are two areas that could be incrementally improved.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternatives to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Generation Outlook 2014 to 2017

On January 17th, the Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. In the near term, NLH's current resource expansion plan is within the reliability criteria.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57.

NLH is currently considering six options[16] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[16] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[17] and 0.91%[18], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if Holyrood unit could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

Summary of Recommendations

Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

---

[17] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[18] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine its models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. It has been recommended above that NL begin using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecast in both the scenario development and the sensitivity analysis phases.

NLH should continue to use its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model it's EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the

EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, the maximum EFOR would be between 9.7% and 9.8%. At this point, the unit's contribution to LOLH would exceed 2.8 hours/year.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternative to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Appendices

PUB-NLH-008

PUB-NLH-011

PUB-NLH-056

PUB-NLH-062

Q. How does Hydro determine the appropriate reserve to have available to meet the Island Interconnected system load?

A. From a long-term planning perspective, Hydro has established criteria related to the appropriate reliability for the system, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the system to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year[19].

---

[19] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[20].

From an operational perspective, Hydro manages generation resource availability on the Island Interconnected System and schedules generating units out of service for planned maintenance in order to meet a (n-1) system contingency reserve criterion. In this manner, sufficient reserves are planned to be available to meet the Island Interconnected System load under a contingency of the largest (MW rating) available generating unit. Hydro does not rely on capacity from wind and other non-dispatchable[21] resources to provide reserve. However, if these resources are in production they can further increase the reserves available. Following the (n-1) criterion results in no extended planned maintenance scheduled during the winter period. However, if the short-term load forecast permits, Hydro may take the opportunity to schedule a short duration generating unit outage to address running or corrective maintenance issues.

[20] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Generation) is based on energy capability adjusted for maintenance and forced outages.

[21] Please refer to PUB-NLH-044 for a definition of "non-dispatchable".

Q. Provide the forecast and actual peak demand for each month in the winter period in each year from 2004 to 2013 and the forecast each year for 2014 to 2017 for each month in the winter period.

A. Please see below for the forecast and actual peak demand supplied by Hydro for the Island Interconnected System. Please note that Hydro interprets the winter period to be from December through March and that the forecasts provided are Hydro's Operating Load Forecasts. Please refer to Hydro's response to PUB-NLH-014 on timing of preparation.

Island Interconnected System Supply Issues and Power Outages

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-04	1399	1277
Feb-04	1338	1405
Mar-04	1237	1206
Dec-04	1374	1402
Jan-05	1429	1361
Feb-05	1405	1272
Mar-05	1301	1161
Dec-05	1353	1202
Jan-06	1385	1276
Feb-06	1369	1185
Mar-06	1256	1167
Dec-06	1333	1310
Jan-07	1358	1323
Feb-07	1350	1249
Mar-07	1238	1242
Dec-07	1336	1286
Jan-08	1367	1289
Feb-08	1356	1212
Mar-08	1242	1207
Dec-08	1350	1323
Jan-09	1388	1390
Feb-09	1377	1375
Mar-09	1262	1294
Dec-09	1349	1268

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-10	1372	1253
Feb-10	1361	1305
Mar-10	1243	1142
Dec-10	1371	1207
Jan-11	1401	1278
Feb-11	1390	1292
Mar-11	1270	1200
Dec-11	1405	1399
Jan-12	1433	1385
Feb-12	1417	1350
Mar-12	1302	1341
Dec-12	1432	1307
Jan-13	1461	1378
Feb-13	1446	1374
Mar-13	1332	1272
Dec-13	1401	1501
Jan-14	1478	-
Feb-14	1429	-
Mar-14	1322	-
Dec-14	1425	-
Jan-15	1523	-
Feb-15	1470	-
Mar-15	1361	-
Dec-15	1447	-
Jan-16	1543	-
Feb-16	1498	-
Mar-16	1383	-
Dec-16	1466	-
Jan-17	1567	-
Feb-17	1515	-
Mar-17	1395	-
Dec-17	1473	-

Note: Forecast and actual peaks reflect gross requirements.

Q. Further to the response to PUB-NLH-008, state the date(s) the criteria used for generation source additions was last reviewed by Hydro. In the response state whether Hydro is of the opinion it should be reviewed in light of Hydro's aging infrastructure and when is the appropriate time to review this criteria.

A. Hydro's generation source additions criteria have been in use for over 35 years and in that period they have been reviewed on a number of different occasions and found to provide a good balance of reliability versus cost.

Before 1977, there were no approved long-term reliability criteria for generation planning in Hydro. The basis of the current criteria is a report, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions*, System Planning Department, May 16, 1977. In that report, a LOLP of 0.2 days per year, or 1 day in 5 years was established. In 1997, when Hydro replaced the SYPCO generation planning software with ProScreen II (now renamed Strategist) generation planning software, it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system. From that point onward, Hydro established the capacity criteria that the Island Interconnected System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.

In 1991, at the direction of the Board, George C. Baker, a consultant working for Hiltz and Seamone Company Limited carried out a study and produced a report -*Report on the Technical Performance of Newfoundland & Labrador Hydro* - October 2, 1991. On page 9 of the report, in Section *7 System Planning,* it states:

Hydro uses two criteria for generation planning in its interconnected system.

(a) Sufficient production capacity to meet all needs under firm water conditions (lowest recorded flows), and

(b) A loss of load expectancy of one day in five years.

The first criterion is usual for utilities with significant dependence on hydraulic generation. The second differs from the one-day-in-ten-years LOLE[22] *adopted by many utilities.*

The main reason for permitting a higher LOLE is economic. Hydro, unlike almost every other major utility, is an isolated system. Other utilities can, and do, rely on capacity support from interconnected utilities in meeting the one-day-in-ten-years criterion. Hydro cannot do this, and would have to maintain a much higher generation reserve.

[22] Loss of Load Expectation. LOLE is another way of stating LOLP and the two are equivalent.

Hydro believes the costs of doing so would not be justified by the difference in reliability. The Consultant agrees.

In 1999, at the direction of the Board, Quetta Inc. and Associates carried out a study and produced a report *Technical Review of Newfoundland and Labrador Hydro Final Report* March 17, 1999. On page 23 of the report, in Section *2.1.3.2 Capacity*, it states:

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) target of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in five years. It results in a capacity reserve requirement of 18%.

The LOLE capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America (one day in 10 years or 0.1 days/year). Considering the non-interconnected status of the Island's electric utility system, (reserve sharing is not an option) the cost of providing higher reliability level is probably in excess of the benefits to be derived.

Quetta is of the opinion that the capacity and energy criteria are reasonable in the circumstance.

Most recently, the criteria were reviewed in the *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volume 2: Studies January 2012*. This report was prepared for the Board by Manitoba Hydro International. In the report, *Section 3 – Reliability Studies* runs from page 57 to page 71. *Section 3.11 – Conclusions and Findings*, page 70, states the following:

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities.

As part of its internal review of recent events, Hydro has engaged an outside consultant (Ventyx) to review its generation planning practices. One of the areas to be reviewed is the criteria used for generation source additions. As well, in light of Hydro's aging infrastructure, it is also appropriate to review the inputs to the generation expansion model, such as the current and expected forced outage rates of Hydro's generating units. These will also be reviewed.

Q. Further to the response to PUB-NLH-018, which states that there is a capacity deficit identified for 2015, explain in detail each of the "*several generating options potentially available to meet winter peak demand*" that Hydro stated it was pursuing, including the status of the review of each option and the time required to construct or install each option.

A. The options under consideration for meeting the deficit currently expected in 2015 include the following and may be a combination of two or more to meet the potential deficit:

1. **Retain the 16 MW diesel facility at Holyrood (presently under a lease-to-own arrangement).** Once installed, 10 MW can immediately be supplied to the system on a sustained basis. This facility is currently being prepared for commissioning in early March 2014.
2. **Review what is needed to make the remaining diesel power available to the system.** Please refer to Hydro's response to PUB-NLH-064.
3. **Enter into interruptible contracts with large Industrial Customers.** Discussions with Industrial Customers (CBPP, Vale and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored. Please refer to Hydro's response to PUB-NLH-050.
4. **Seek already built combustion turbines in the 50 to 85 MW range**. Preliminary discussions indicate that these options can provide in-service to meet the 2015 requirement. However, discussions with manufacturers, brokers and owners are

ongoing to determine the delivery times, operating experiences, the extent of modifications required, and the facilities required to connect to the Island Interconnected System.

5. **Initiate the supply of a new 60MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart functionality.** All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by 2015.
6. **Conservation and demand management initiatives, with the focus on demand management**. Work is being conducted to assess customer end use options with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.