# Submission by Nalcor Energy

## to the

## Commission of Inquiry Respecting the Muskrat Falls Project

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## Commission of Inquiry Respecting the Muskrat Falls Project

## Nalcor Energy Submission

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# 1. Introduction

## 1.1. The Project

The Muskrat Falls Project, often referred to in this submission simply as the Project, has four sub-projects.

One is the hydro-electric generating plant at Muskrat Falls on the Churchill River in Labrador. Its concrete and steel intake and powerhouse has four turbines that will be capable of producing 824 MW of electric power. The site includes a spillway, a south rockfill dam, a north roller compacted concrete dam, transition dams connecting the structures, and a natural feature known as the North Spur that has been stabilized to be used as a natural dam. This is all sometimes referred to in this submission as Muskrat Falls Generation, MF or MFG.

The Labrador Transmission Assets, or LTA, are two parallel HVac transmission lines connecting Muskrat Falls and Churchill Falls, with new switchyards at each end. The Strait of Belle Isle crossing, or SOBI, is a set of three undersea power transmission cables crossing the Strait of Belle Isle (one is a spare) with transition compounds at each end. The Labrador-Island Transmission Link, LITL or LIL, is a 1100 km HVdc transmission line from Muskrat Falls to the SOBI in Labrador and from the SOBI to Soldiers Pond on the Island, with converter stations to transition the electric current from alternating to direct and back again, and grounding stations.

The Project was sanctioned by Nalcor and the Government of Newfoundland and Labrador, referred to in this submission as GNL or government, in December 2012 at an estimated cost of $6.2 billion, $7.4 billion with financing, with first power planned for 2017.

The Project is currently forecast to cost $10.1 billion, $12.7 billion with financing, and is projected to deliver first power from Muskrat Falls later this year. The LTA is in service. The LIL has been used in monopole mode to transmit power from Labrador to the Island. Work continues to complete the software for operation in bipole mode.

The capital cost of the Project has grown by 63% since sanction.

### 1.2. The Inquiry

This Inquiry was called pursuant to the *Commission of Inquiry Respecting the Muskrat Falls Project Order*, made under the *Public Inquiries Act*, on November 20, 2017. The Terms of Reference are broad, spanning the sanctioning of the Project, its execution, the exemption from oversight by the Board of Commissioners of Public Utilities (PUB), the communication of risks to government, and whether government employed appropriate oversight.

Nalcor has been the subject of much of the Inquiry. It is a party with standing, has been the source of most of the millions of documents produced to the Commission, and has been a participant in the many days of public hearings.

The space and time available make it impossible for this submission to address all of the matters explored in the Inquiry hearings or even all of the issues raised by the Terms of Reference. This submission nevertheless will attempt to provide helpful comment to the Commissioner on many of those matters.

It will begin with a short chronology of the Project and will then continue with sections addressing the major headings in the Terms of Reference.

### 1.3. A Short Chronology of the Muskrat Falls Project

Since the completion of the Upper Churchill project in 1974, successive governments of Newfoundland and Labrador have attempted to develop the hydro-electric potential of the Gull Island and Muskrat Falls sites on the Churchill River.

The Progressive Conservative government of Premier Danny Williams was elected on October 21, 2003. On December 10, 2004 the Cabinet directed the development of an energy plan for the province to take full advantage of the potential of the oil and gas and electricity sectors. Before the plan was completed a number of actions were taken to advance a potential Lower Churchill development. In January 2005 a broad request for expressions of interest was issued. Responses were received and evaluated, and in May 2006 the government announced that the development would be led by the province. In January of 2016 an application was filed in Quebec for access to the Hydro-

Quebec transmission system for export of power from Labrador and in November 2006 development of the Gull Island and Muskrat Falls sites was registered for environmental assessment.

The Energy Plan was released in September 2007. One of its policy objectives was the Lower Churchill development, as a power export economic opportunity and as a means of domestic supply of power to the Island in substitution for oil-fired generation at Holyrood. Another objective was the creation of an energy corporation for the province to implement the policy objectives of the Energy Plan. The Energy Corporation of Newfoundland and Labrador, later renamed Nalcor Energy, was the result.

Between 2007 and 2010 the government carried out consultation with aboriginal groups, and reached the New Dawn agreement with the Innu. Agreement was reached with the government of Canada for environmental assessment by a Joint Review Panel. Legislation was enacted for water management on the Churchill River, and a water management agreement was established by the Public Utilities Board.

In March 2010 a memorandum of understanding was entered into by Nalcor with Emera for development of the Maritime Link, to enable power transmission between the Island and Nova Scotia, followed by execution of a Term Sheet in November. In May the application for transmission rights through Quebec was refused and by June attention had shifted from Gull Island to development of the smaller Muskrat Falls site first, with transmission of power to the Island for domestic use and for export through the Maritime Link.

In the meantime, Nalcor had been building its Lower Churchill project team and had adopted a structured stage gate decision-making process.

In November 2010 the Project passed through Decision Gate 2 with the selection of the Muskrat Falls Project as the favoured option for the supply of electric power to the Island. Shortly afterwards, on December 3, 2010, Premier Williams resigned and Premier Kathy Dunderdale took office.

In 2011 work continued towards Decision Gate 3, when a decision was to be made whether or not to sanction construction of the project. A contract for engineering, procurement and construction management (EPCM) services was awarded to SNC-Lavalin (SNCL) in February. An appeal from the refusal of the application for power transmission through Quebec was denied in April. In June the government referred to the PUB the question of whether the Interconnected Island generation expansion plan comprising the MFG, LTA and LIL was the least-cost option, compared to the Isolated Island generation expansion plan, which relied on development of new generation sources on the Island. The Joint Review Panel delivered its environmental assessment report in August. After an Innu Nation ratification vote, the three agreements implementing the New Dawn agreement were executed in November. By mid-December SNCL had completed the base estimate for the Project.

In March 2012 the PUB released its report stating that information developed for Decision Gate 2 was not sufficient for it to decide the question referred to it. Government then directly retained the PUB's consultants, Manitoba Hydro International (MHI), to provide a report based on Decision Gate 3 information. In May the MFG was released from environmental assessment. Decisions were made to carry out early works at the site, including the bulk excavation, in advance of the sanction decision. On November 30 a Term Sheet was entered into with the government of Canada for a federal loan guarantee (FLG). The House of Assembly passed the Premier's private member's bill supporting the Project on December 5. On December 17 government announced sanction of the Project at an estimated capital cost of $6.2 billion. Emera announced sanction of the Maritime Link project, subject to the approval of the Nova Scotia Utility and Review Board (UARB), on the same day.

In 2013 the UARB conditionally approved the Maritime Link in June and, after negotiation of the Energy Access Agreement between Emera and Nalcor, gave final approval on November 29. Financing, guarantee and commercial agreements were finalized by the same date, referred to as the date of Financial Close. At Financial Close the estimated cost was revised to $6.53 billion. Astaldi Canada Inc. had been selected for award of the contract for construction of the powerhouse, spillway and transition dams, had been given a Limited Notice to Proceed (LNTP) in September, and its contract was executed on November 29.

In 2014 government established an Oversight Committee in March. In June a revision of the estimated cost to $6.99 billion was announced. Through 2014 Astaldi made a poor start to powerhouse and spillway construction, requiring Nalcor intervention to provide organizational and other assistance. In September 2014 Premier Paul Davis succeeded Premier Dunderdale.

In September 2015 a revision of the Project cost to $7.65 billion was announced. Astaldi's performance had improved in 2015, but the effect on the Project schedule of its slow start and continuing difficulties remained uncertain through that year. Astaldi's contract capped the amount it was entitled to be paid for labour costs, however assessment indicated that Astaldi's costs would exceed the capped amount before its completion of the work. By the end of 2015 information available to Nalcor indicated that Astaldi would not have the funds it would need to complete the project. In the provincial election held on November 30 the Liberals defeated the Progressive Conservatives and Premier Ball succeeded Premier Davis.

In early 2016 government initiated a review of the Project cost and schedule by the Oversight Committee consultants, Ernst & Young. In April Nalcor CEO Ed Martin resigned and was replaced by Stan Marshall. Mr. Marshall initiated the splitting, or bifurcation, of the Project into transmission and generation components. Plans were adopted to commission the HVdc transmission line in monopole mode first to enable transmission of available Upper Churchill power to the Island in advance of the completion of the Muskrat Falls plant. In June the estimated capital cost was revised to $9.1 billion. Negotiations with Astaldi resulted in, at first a bridging agreement to fund continued progress of the work through the summer construction season, and in a Completion Agreement in December.

In June 2017 the estimated cost was revised to $10.1 billion.

In 2018 Astaldi was unable to continue the work due to insolvency, its contract was terminated and the remaining work is being completed by another contactor.

The $10.1 billion cost estimate remains unchanged. The Muskrat Falls plant is nearing completion as turbines and generators are being installed. The Labrador Transmission Assets and Strait of Belle Isle subsea crossing are complete and in service. The Labrador-Island Link construction is complete with work continuing on software implementation for bipole operation of the HVdc transmission. The project first power date, which at time of sanction was in 2017, is now scheduled for late 2019.

## 2. Inquiry Terms of Reference

There are four primary areas of inquiry in the terms of Reference. The consideration of options will be addressed in section 3 of this submission. Section 4 will address the difference between the estimated cost at time of sanction and the currently forecast cost to completion. Section 5 will briefly discuss the exemption from PUB review. Oversight will be dealt with briefly in section 6. In some cases the interpretation of the Terms of Reference will be referred to more fully in those sections.

## 3. The Consideration of Options

This section addresses the following matters related to Term of Reference 4(a):



### 3.1. Term of Reference 4(a)

Term of Reference 4(a) is as follows:

> 4. The Commission of Inquiry shall inquire into
>
> (a) the consideration by Nalcor of options to address the electricity needs of Newfoundland and Labrador's Island interconnected system customers that informed Nalcor's decision to recommend that the government sanction the Muskrat Falls Project, including whether
>
> (i) the assumptions or forecasts on which the analysis of options was based were reasonable,
>
> (ii) Nalcor considered and reasonably dismissed options other than the Muskrat Falls Project and the Isolated Island Option, and
>
> (iii) Nalcor's determination that the Muskrat Falls Project was the least-cost option for the supply of power to Newfoundland and Labrador Island interconnected system over the period 2011-2067 was reasonable with the knowledge available at that time.

This section of the Nalcor submission will first provide background and context for the Lower Churchill Project (LCP), a term that encompasses the development of both the Gull Island and Muskrat Falls sites on the lower Churchill River. It will then discuss the elimination of options other than the Muskrat Falls Project and the Isolated Island Option, the determination that the Muskrat Falls Project was the least-cost option in comparison to the Isolated Island Option, and the recommendation for sanction of the Muskrat Falls Project. The reasonableness of assumptions and forecasts will be discussed in the context of those issues.

It is important to note the direction in Term of Reference 4(a)(iii) that inquiry into reasonableness is to be conducted considering “the knowledge available at that time.” That is particularly relevant to assumptions and forecasts, which at the time they are made can only be based on the knowledge then available, but which with the passage of time are often found to have been inaccurate. The temptation when conducting a retrospective examination can be to focus attention on that which is known to have turned out differently than was predicted, and which has, by the time of review, become certainty. We must bear in mind that at the time forecasts and assumptions about the future are made, everything is uncertain. Clear analytical focus is required to avoid allowing hindsight to creep into the assessment of their reasonableness.

A related analytical challenge arises from the direction to retrospectively assess the choices made among available options, which fed into the recommendations and decision making leading to sanction of the Project. Only the outcome of following the selected path can be known with certainty, and even then we can only know the state that exists today. What might have been had another path been chosen is unknown. It would be a mistake to assume now that the alternative options would have turned out exactly as predicted.

A final point regarding uncertainty is that none of the options considered would have had strictly short term implications. The value of all options was subject, to one extent or another, to fluctuation over the long term. To take an extreme example, Churchill Falls can be characterized as a failed project for Newfoundland and Labrador throughout the life of the 65 year power contract, but it may be seen in an entirely different light after 2041 when substantial benefits at low cost should accrue to this province. In the medium term, and perhaps sooner than that, we do not know what the future effect of factors such as carbon pricing to fight climate change will have on the comparative advantages of renewable energy over fossil fueled electricity production, both domestically and in the export market. At time of sanction decision-making of necessity had to rely on reasonableness and judgement. Today we can judge the reasonableness of the choices made based only from the perspective of the present. How those choices might be judged in the future remains to be seen.

## 3.2. Background to the Recommendation to Sanction

### 3.2.1. Lower Churchill Development Before the Energy Plan

Jason Churchill, of Cleo Research Associates, in his report (P-00008) and testimony at the outset of this Inquiry presented a history of the attempts to negotiate development of the hydro-electric resources of the Lower Churchill River from the time of confederation with Canada in 1949 to the release of the Province's Energy Plan in 2007. The report chronicles the Churchill Falls development and the negotiation of the 1969 power contract with Hydro-Quebec, the failure of successive Newfoundland and Labrador governments to achieve redress of the imbalance in benefits flowing from that contract, and their failure to find a means to develop the economic potential of the Lower Churchill hydro-electric sites at Gull Island and Muskrat Falls.

The Churchill Falls contract has since 1969 cast a long political shadow over the Lower Churchill. The immense benefits accruing to Quebec from Churchill Falls, compared to the virtual absence of benefit to Newfoundland and Labrador has carried great political and even cultural weight in this province. The reality for any prospect of development of the resources of the Lower Churchill, since the dismissal of the “Anglo-Saxon route” in the 1960s and until the sanction of the current project, has been that excess Lower Churchill power could only be sold either to Quebec or by export through that province. Negotiations with Quebec have been chronically complicated by linkages between the 1969 Churchill Falls contract and the terms demanded for Quebec's cooperation or participation in new developments.

### 3.2.2. The Energy Plan

By 2003 development of Newfoundland and Labrador's offshore oil resources was in full swing. In 2004 the new Cabinet directed the Minister of Natural Resources to develop a provincial energy plan and to ensure that it was coordinated with the restructuring of Newfoundland and Labrador Hydro (NLH) as a broadly-based energy corporation (P-00157). The initiative led to the release in September 2007 of *Focusing Our Energy*, the Newfoundland and Labrador Energy Plan (P-00029).

In the meantime, in January 2005 the government had, through NLH, publicly sought expressions of interest and proposals for the development of the Lower Churchill hydro-electric resource (P-00025). A variety of responses from private corporations and provincially-owned utilities were received and evaluated (P-00960). In August 2005 Premier Williams, with newly appointed NLH president and CEO Ed Martin, announced that three proponents had been selected for further evaluation, but that “the option of the province and Newfoundland and Labrador Hydro developing the project on our own will be given primary consideration.” (P-00026.) In May 2006, Premier Williams announced that the government of Newfoundland and Labrador would take the lead on the potential development of the Lower Churchill. The decision, he said, had been “approached from both a public policy and business case perspective.” (P-00028, P-00169, P-01647.)

The Energy Plan followed as an important statement of public policy. It espoused the principle of levering revenues from exploitation of non-renewable energy resources to develop new renewable and sustainable energy resources for the long term benefit of the province. It called for the establishment of a provincially-owned energy corporation, similar to state-owned energy companies in other resource rich jurisdictions, to be the vehicle for implementation of that policy.

The Plan described the renewable energy potential of the two Lower Churchill sites and stated that, “To ensure this project has every opportunity to move forward, the Provincial Government is leading its development through the Energy Corporation.” The new energy corporation was charged with continuing “to advance the project on multiple fronts, including engineering and the environmental assessment process, analysis of market access options and market destinations, and a financing strategy.” The Plan stated that the government of the Province would develop a memorandum of understanding with the federal government for a joint environmental assessment process and that it would ensure that aboriginal groups in Labrador were appropriately consulted. A decision on sanction of the project was targeted for 2009. (P-00029 page 40-41.)

The Energy Plan dealt with the future of the Holyrood oil-fired generating station in a separate section, describing it as presenting the biggest challenges for the Island system in the near-term and long-term, due to both the high cost of fuel and the environmental impact of the emission of greenhouse gases and other pollutants. If the power generated by the Holyrood plant could not be replaced by power transmitted from the Lower Churchill, then the policy of the province was that scrubbers and precipitators would be installed, recognizing however that greenhouse gas emissions would still be unabated. (P-00029 pages 46-47.)

Connecting Labrador and the Island by the Labrador-Island Transmission Link and transmitting Lower Churchill power to the Island was described as the most effective way to address many of the major issues affecting the Island electrical system. The Plan stated that electricity rates would initially rise, but in the longer term would be lower than for the fossil fuel alternative and would also be stable, not tied to fluctuating fuel costs. (P-00029 pages 49-50.)

The province adopted the policy goal of achieving transmission access for export of electricity to markets in Canada and the United States. Direct access was stated to be necessary for two reasons. The first was to secure “a fair share of the economic upside potential of developments over the long term.” The second was to “position ourselves properly for realizing the long term value of the Upper Churchill development.” The export routes to be investigated were overland through Quebec in reliance on the Open Access Transmission Tariff (OATT) rules, and a subsea route from the Island to the Maritimes or northeastern United States. (P-00029 pages 51-54.)

### 3.2.3. The Creation of Nalcor Energy

The *Energy Corporation Act*, which came into force on October 11, 2007 (P-00431), shortly after release of the Energy Plan, established an energy corporation for the province, initially known as the Energy Corporation of Newfoundland and Labrador, and later as Nalcor Energy. The study of how to best restructure Newfoundland and Labrador Hydro as a broadly based energy corporation had been directed by Cabinet in 2004 and resulted in a number of papers and submissions between then and 2006, including studies of examples from other jurisdictions (P-00180, P-00183). The model that was adopted was the creation of a new Crown corporation, with Newfoundland and Labrador Hydro as a subsidiary of it. A central purpose was to separate the regulated public utility business and activities of NLH from the unregulated energy resource development business and activities to be undertaken by its parent on behalf of the province, both in the electricity and oil and gas sectors. NLH remained subject to the *Public Utilities Act* and to regulation by the Public Utilities Board, but the new energy corporation was not (P-00431 section 17(2)).

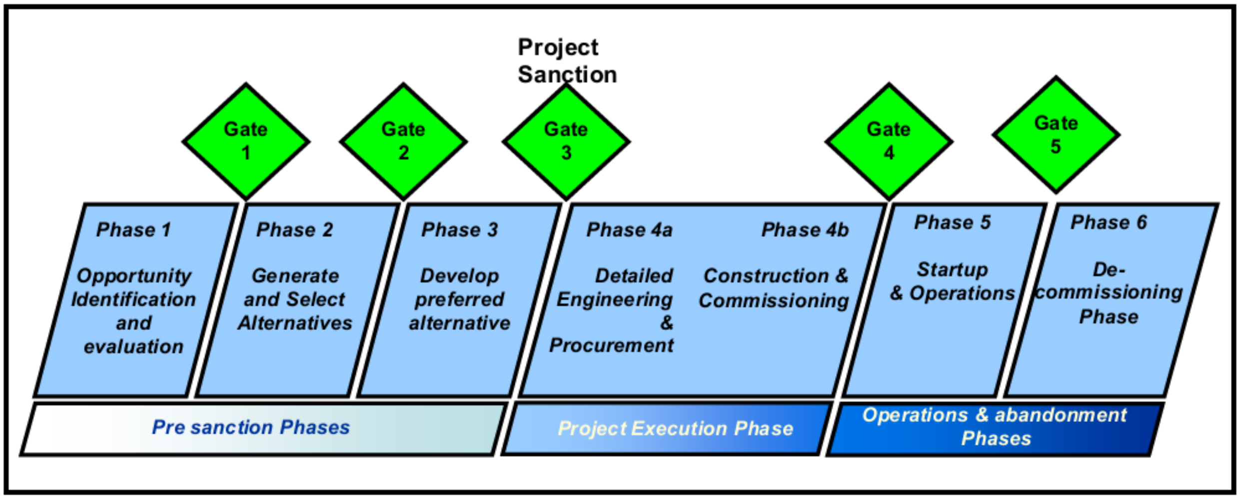
A press release issued by Minister of Natural Resources Kathy Dunderdale on May 31, 2007 (P-01586) states:

> The province's intention to pursue greater energy opportunities on behalf of the people of the province is taking a major step forward with the tabling of legislation today to create a new provincial energy corporation.
>
> The *Energy Corporation Act* allows for the creation of a holding company to separate the regulated operations of Newfoundland and Labrador Hydro (Hydro) from the unregulated activities associated with its expanded mandate. The creation of an energy corporation was a commitment in the 2003 election policy document, A Blue Print for the Future.

### 3.2.4. The Gateway Process

Prior to the establishment of Nalcor Energy, Newfoundland and Labrador Hydro had begun developing a Project Development Gateway Process for projects that might be undertaken by the planned energy corporation. Versions of the document, which is not restricted to the Lower Churchill Project, were issued between January 2006 and August 2007 (P-01317).

The core concepts are illustrated by the following diagram (P-01317 page 10).




A project, through its entire life-cycle, is divided into phases. The Pre-Sanction Phases lead to a decision on whether or not to proceed with the project, referred to as the sanction decision. The Pre-Sanction Phases are Phase 1, the development of a business idea; Phase 2, the generation and selection of alternative technical concepts and strategies to develop the business idea; and Phase 3, the detailed development of a preferred alternative. The Project Execution Phases follow sanction and the Operations and Abandonment Phases follow the completion of construction and commissioning (P-01317 pages 11-14).

It is necessary to pass through a Gate to proceed from one Phase to the next. The process relies on a designated Gatekeeper to authorize passage through a Gate. Before attempting passage through a Gate, the readiness of the project is to be assessed by an Independent Panel Review team, also called an Independent Project Review or IPR team. The 2007 Gateway Process document makes the NLH Board the Gatekeeper at Gates 1, 2 and 3. At Gate 1 approval is sought to commence the concept screening and selection in Phase 2. At Gate 2 the recommended development concept is approved and approval is given to further develop the preferred concept and carry out Front End Engineering and Design. At Gate 3 approval is sought for detailed engineering, procurement and construction (P-01317 page 15).

In March 2009, prior to Decision Gate 2, the NLH Project Development Gateway Process was adapted by the Lower Churchill Project in its own Project Gateway Process document

(P-00079 page 3). It describes Phase 2 as culminating "at Decision Gate 2, at which approval is sought for the recommended development option, the execution strategy, and to proceed with the start of detailed design" (P-00079 page 10). It describes the Key Deliverables and Decision Gate Support Package to be delivered to the Gatekeeper and the Independent Project Reviews to be conducted to assess readiness for submission of that material to the Gatekeeper and for passage through the Gate (P-00079 page 11-14). The Nalcor Energy CEO is identified as the Gatekeeper (P-00079 page 5).

A revision of the Project Gateway Process was issued in June 2011, after Decision Gate 2. The process, phases and gateways remained relatively unchanged (P-00027).

The use of a Gateway Process for staged project decision making for the LCP and the process as designed and implemented by Nalcor was reasonable and appropriate. Forensic auditors Grant Thornton determined that this procedure is best practice and is commonly used in mega projects globally and in Canada (P-00014 page 12 lines 24-26).

#### 3.2.5. The Project Charter

The Project Charter, an internal Nalcor document providing high level guidance and direction to the team charged with executing the Lower Churchill Project, was drafted and first issued for review in September 2010. After Decision Gate 2 it was revised in September 2011 and issued for use on December 12, 2011 (P-01481). It begins with this statement of purpose:

> This *Project Charter* for the Nalcor Energy – Lower Churchill Project (NE-LCP or the Project) provides the basis for defining a business opportunity and framing how that opportunity will be realized. It provides clarity as to why the Project exists, what the business objectives are and how these translate into goals and objectives of the Project …

The business objectives and goals are firmly anchored in the province's Energy Plan (P-01481 page 7). The three business objectives, derived from the policy directives given to Nalcor by government through that Plan, are:

- Develop the Project as the least-cost long-term supply of electricity for Newfoundland and Labrador;
- Export production from the Project that is not used within Newfoundland and Labrador to neighbouring markets; and

- Develop markets and market access strategies that position Newfoundland and Labrador for realizing the value of the Upper Churchill development when the Churchill Falls power contract expires in 2041.

(P-00029 page 39)

The objective of development of the Project as the least-cost long-term electricity supply option was thus but one of three business objectives. The Energy Plan, and the Project Charter, explicitly affirmed the export of electricity from the Project and positioning of the Province for the expiry of the Upper Churchill contract as the other objectives, without any ranking or prioritization among them.

The value of the completion of the first phase of the Lower Churchill Project to the enhancement of the Province's bargaining position in discussions with Hydro-Quebec over use and marketing of Upper Churchill power after 2041 was supported by the Commission's expert witness, Pelino Colaiacovo of MPA Morrison Park Advisors Inc. If the reality of an export corridor other than through Quebec was not established before negotiations begin, he testified that the Province would have no BATNA, or best alternative to a negotiated agreement, and would be at significant disadvantage. (Pelino Colaiacovo July 17, 2019 pages 16-17.)

## 3.3. Project Decision Gates

### 3.3.1. Decision Gate 1 – Concept

Project documents retrospectively record Decision Gate 1 as having been achieved in February 2007 (P-01942 page 24, P-03652 page 45), however the project record does not include a set of Decision Gate materials for Gate 1 like those for later Gates. This should not be surprising, since the Decision Gate 1 date precedes the implementation of the final version of the NLH Gateway Process in August of that year and the coming into force of the *Energy Corporation Act* in October. Gate 1 comes at the end of Phase 1 which is business idea development. Passage through Gate 1 allows entry to Phase 2 where work is done to identify a range of technical concepts and strategies to develop the business idea. The release of the Energy Plan and the direction to Nalcor Energy to undertake advancement of the Plan's objectives for development of the Lower Churchill correspond to passage through Decision Gate 1 (P-00014 page 10 lines 19-21).

By the end of 2007 responsibility for the Lower Churchill Project, until then assigned to NLH, resided with Nalcor Energy. Phase 2 activities were underway, with the focus on development of the larger site at Gull Island first.

### 3.3.2. Decision Gate 2 - Selection of the Muskrat Falls Project

The Project passed through Decision Gate 2 on November 16, 2010.

In accordance with the Decision Gate process, a Gatekeeper's Decision Support Package had been delivered to Mr. Martin, as CEO and Gatekeeper (P-00078). The recommendation contained in it was as follows:

> After a thorough and comprehensive assessment of the options and alternatives to develop the hydro potential of the lower Churchill River for domestic use and export, a phased development of the Project has been selected as the basis of the Gateway Phase 2 recommendation.
>
> Nalcor Energy (Nalcor) believes this is the best alternative to meet the Island's electricity needs, when considering the circumstances with respect to options for energy export. Phase I will include the development of the Muskrat Falls 824 MW generating station, associated HVac transmission along with an HVdc Transmission Link to the Island, associated Island upgrades, and an HVdc

> Maritime Transmission Link to Nova Scotia. First power from Muskrat Falls is targeted for the end of 2016.
>
> Phase II, which is expected to proceed no earlier than three years after the start of Phase I, will consist of the 2,250 MW Gull Island hydroelectric generation project and associated HVac transmission to Churchill Falls and export markets.
>
> (P-00078 page 5.)

The recommendation was tied back to the Energy Plan objectives of development of the Lower Churchill resources, meeting the power needs of the province, replacement of the Holyrood generating station and obtaining value from export of excess power (P-00078 pages 6-7). Reference should be made to the Decision Support Package text for explanation of the work performed during Phase 2 and the full rationale for the recommendation. The Decision Support Package included several attachments.

Attachment A.1 reported the status of Key Deliverables as required by the Gateway Process (P-00078 pages 33-42).

Attachment A.3 is the report of Independent Project Analysis (IPA), a project management research, consulting and benchmarking firm (P-00078 pages 45-53). IPA performed a “Pacesetter” evaluation in August and September 2010 with the objective of providing the Project team with an early interpretation of the drivers and expected outcomes of the Project and to offer specific recommendations. IPA maintains a database of megaproject information. It reported that the “Project is better prepared than a typical megaproject at end FEL 2 (Nalcor Energy’s Phase 2)” (P-00078 page 50). Best practices used by the Project team were identified, as were gaps for which closure recommendations were made.

Attachment A.4 is the report (P-00078 pages 54-65) of the Independent Project Review team chartered under the Project Gateway Process (P-00493). The IPR is a form of “cold eyes review”. It allows a fresh perspective from knowledgeable people who have not been closely involved in the work of the project. The team looked at two issues. The first was the readiness of the Project deliverables for passage through Gate 2, in respect of which they found that, “The quality, quantity and completeness of the work completed in each project function is a sufficient basis for the Gate 2 decision.” Of 25 focus areas examined, 17 were rated as "fully compliant/best practice" and the remaining 8 were ranked "compliant with minor ongoing work to be completed." The second issue examined was the readiness of the Project team to undertake the work required in Phase 3 prior to the mobilization of the EPCM contractor. Up to this time, all project planning work had been carried out by staff of NLH and then Nalcor. Phase 3 would require the performance of detailed engineering and other project management activities, for which an EPCM (Engineering, Procurement and Construction Management) contractor was to be retained. In the meantime the Project team would be responsible for advancing the Project work. The reviewers found that the work was underway and that the team had a good understanding of what was to be done. Priority focus areas were identified.

Attachment A.6 is the Readiness Approval signed by Mr. Martin as Gatekeeper approving that Decision Gate 2 had been achieved (P-00078 page 67).

Three binders of Decision Support Package reference information were also provided to the Gatekeeper (P-01494). These included documents such as the Project Charter (P-01481), Project Governance Plan (P-00081), Gate 2 Capital Cost Estimate Report, and the Gate 2 Project Risk Analysis (P-00097).

Although the Decision Gate process gave Mr. Martin, as CEO, the authority as Gatekeeper to approve the passage through Gate 2, he brought the matter to the Nalcor Board for approval, presenting a Decision Support Package titled *Summary Recommendation to Nalcor's Board of Directors* (P-00093). This report identifies the two fundamental drivers behind the decision process as the need to determine the next generation source to meet the province's domestic power needs, and the need to determine how to most effectively optimize the value of any excess power (P-00093 pages 10-11).

Three decision criteria were applied to the question of meeting domestic need. The first was reliability. To be considered, a power supply option had to meet a system reliability standard. The second was cost, with the least cost option, measured using the Cumulative Present Worth (CPW) method, considered most favourable. The value of power excess to the needs of the province was excluded from the analysis. The third was security of supply. Preference was given to power supply options that would be controlled within the province and would be subject to provincial laws. Other considerations that were not included in the formal criteria but that were stated to merit consideration were the overall benefits to the province and its treasury, the level and value of reductions in greenhouse gases, and the long term strategic value to the province in the context of the Energy Plan goals and objectives (P-00093 pages 11-12).

Five alternatives for meeting domestic power needs were considered:

1. The Isolated Island scenario with the Holyrood generating station continuing in service until the end of its useful life, no transmission connection to Labrador or Nova Scotia, and the addition of small hydro plants, wind turbines and oil-fired combustion turbines as needed.
2. Construction of the Muskrat Falls generating plant and HVdc transmission to the Island, assuming no revenue from sales of excess power.
3. Construction of the Gull Island generating plant and HVdc transmission to the Island, assuming no revenue from sales of excess power.
4. Construction of HVdc transmission from Labrador to the Island and purchase of power from Hydro Quebec.
5. Construction of the HVdc Maritime Link transmission to Nova Scotia and import of power from the New England Independent System Operator.

(P-00093 pages 13-14.)

Applying the criteria set out above, the second option, the Muskrat Falls Project, was selected as the favoured generation source to meet the province’s domestic needs. See the Support Package for a full description of the rationale (P-00093 pages 14-15).

The second step in the decision making process was to determine how to best optimize the value of excess power. The decision criteria applied were the extent of value creation based on the net present value and internal rate of return, the potential for further reliability enhancement by additional connection to the North American grid, and the strategic value from gaining market access, potentially for power from Gull Island, the Upper Churchill, Labrador wind and small hydro.

The alternatives considered for monetizing excess power were the Quebec Option, the Maritime Link Option and development of domestic markets. The Quebec Option would have been for transmission of excess power via surplus capacity on the Hydro-Quebec transmission system. An application to the Quebec transmission regulator relying on the OATT had, however, been refused (P-00167, P-00208). Pending appeal, access to the Hydro-Quebec system was therefore limited to the pre-existing 265 MW booking that was used to export Upper Churchill Recall Power sales (P-00097 pages 15-16).

The Maritime Link Option was based on a Term Sheet negotiated with Emera Inc. that provided for the construction of an HVdc subsea transmission link from the Island to Nova Scotia and included transmission rights through Nova Scotia and New Brunswick to Maine for sales on the spot market through the New England Independent System Operator (P-00227).

Regarding the development of new domestic markets, discussions had been unsuccessfully pursued with three potential proponents of aluminum smelters. Other potential industrial users were identified, but there were no firm arrangements (P-00093 pages 16-17).

Applying the criteria listed above resulted in the recommendation to adopt the Maritime Link Option as the favoured approach for the monetization of excess power produced from the Muskrat Falls generating plant. That option created the highest value measured by net present value and internal rate of return. It enhanced reliability by creating a second connection to the North American grid. It had strategic advantages including opening access to energy markets for future opportunities and forging a strategic relationship with Emera (P-00093 pages 17-18).

The Board Decision Support Package also addressed the project readiness assessments by IPA and the Independent Project Review team, with their reports appended, and set out the financing strategy for the Project.

On November 16, 2010 the Board heard presentations from Mr. Martin, Project Director Paul Harrington, Lower Churchill Project Vice President Gilbert Bennett and Nalcor Vice President of Finance Derrick Sturge. It approved moving through Gate 2 to proceed toward sanction of the Muskrat Falls Project and authorized negotiation of final agreements with Emera based on the Term Sheet (P-00394). Board Chair, John Ottenheimer, wrote the Premier and the Minister of Natural Resources on the same day to report the decisions (P-00093 pages 167-169).

One point to note about the Decision Gate 2 decision is that whether the Muskrat Falls Project was the “least cost option” in the sense in which that term is used in public utility regulation was only one of a broader range of factors that were, to one extent or another, taken into account by the Nalcor CEO and the Board.

Another point is that the Decision Gate 2 process adhered very closely to that laid out in the Gateway Process guidance documents approved first by NLH and then by the Nalcor Lower Churchill Project. Following that process, the examination of options for meeting the power supply needs of the Island was to be done in Phase 2 with the selection made at Decision Gate 2. After Gate 2, Phase 3 was to involve development of the selected option towards a final decision at Gate 3 to sanction or not. Those involved in the process at the time of Decision Gate 2 would likely have thought that the consideration of other power supply options was closed.

In October 2010 Premier Williams had publicly announced that he was proposing to proceed with Muskrat Falls first and Gull Island later, that a loan guarantee would be sought from Canada, and that discussions were underway with Emera (P-00219). On November 19, 2010 the Premier announced the negotiation of the Term Sheet with Emera, describing the joint project as an economic breakthrough and a chance to break Quebec’s grip on the province’s renewable energy resources (P-00228).

### 3.3.3. Decision Gate 3 – Recommendation to Sanction

#### 3.3.3.1. Events Leading to Sanction

On December 21, 2010, shortly after Decision Gate 2 had been passed, Mr. Martin reported to the Nalcor board that the Project was proceeding with all activities and analysis to get to Decision Gate 3, which was Project sanction. He described the Phase 3 activities as including detailed engineering and procurement that required the selection and mobilization of the EPCM contractor, arranging Project financing, participating in the environmental assessment hearings for the generation component, submitting the environmental impact statement for the Labrador-Island transmission component, negotiating the formal agreements with Emera, and finalizing the aboriginal negotiations (P-00645 pages 1-2). His list is consistent with Phase 3 activities as documented in the decision gate process, and does not include revisiting the Decision Gate 2 selection of the Muskrat Falls Project as the preferred source of new generation supply for the Island electrical system.

By April 2011 Robert Thompson, Clerk of the Executive Council, was engaged in discussions with Natural Resources Deputy Minister Charles Bown and Nalcor Vice President of Finance Derrick Sturge, among others, that included discussion of the possibility of arranging some form of independent review, discussion of the future role of the Public Utilities Board, and mention of an update to the alternatives analysis (P-01655). On May 20, 2011 Finance Minister Marshall and Natural Resources Minister Skinner signed a Decision/Direction Note recommending that an independent consultant be retained to conduct a review of the Project (P-00807). On May 17, 2011 Premier Dunderdale announced in the House of Assembly that the Public Utilities Board would conduct a limited review (P-01605). On June 9, 2011 by Order-in-Council the PUB was referred the question of, “whether the Project represented the least-cost option for the supply of power to the Island Interconnected Customers over the period of 2011-2067, as compared to the Isolated Island Option” (P-00038). The question, framed this way, is consistent with an approach used in public utility regulation to review capital projects. Least cost was not, however the only consideration that had been taken into account when the Project was selected as the preferred option at Decision Gate 2, as discussed above. By framing the reference as it did, government chose to have the selection of options reviewed as a utility decision excluding consideration of any broader public policy elements.

In August 2011 the report of the Joint Review Panel was released. The panel recommended that before the federal and provincial governments made their decisions on releasing the Project from environmental assessment, an independent analysis should be commissioned to review what would be the best way to meet Island electricity demand if the Project did not proceed (P-00041 page 68). Mr. Martin reviewed the Joint Review Panel report with the Nalcor board on August 25, 2011, reporting that Nalcor had already retained Navigant Consulting to do a “cold eyes” review of the supply options and that the government had made the referral to the PUB (P-00650). On March 15, 2012 the province formally rejected the Joint Review Panel recommendation (P-00051), as did Canada (P-00050) and the Project was released from environmental assessment.

Navigant Consulting delivered its report on September 14, 2011 (P-00042). Navigant had been retained to review the Decision Gate 2 decision, specifically to review the reasonableness of the long term supply options considered by Nalcor, Nalcor’s assumptions associated with the supply options, and the process followed to screen and evaluate the options. Navigant concluded:

> Based on its independent review, Navigant has concluded that the Interconnected Island alternative is the long term least cost option for the Island of Newfoundland. Relative to the Isolated Island alternative, the Interconnected Island alternative is also expected to provide similar levels of security and reliability, significantly reduced greenhouse gas (GHG) emissions and significantly less risk and uncertainty. The Interconnected Island alternative also provides a gradual decrease in real (adjusted for inflation) average wholesale electricity rates for the Island.
>
> (P-00042 page 8)

In response to the Joint Review Panel recommendation Natural Resources Canada conducted its own analysis of whether the Project would provide economic benefit to the province while representing the least cost option for supplying power to the Island of Newfoundland. The Muskrat Falls alternative was found to be least cost based on

Nalcor's assumptions about demand growth, oil price, investment and operating cost. Those assumptions were found to be reasonable and the demand projection was found to be consistent with other recent forecasts. Most sensitivity analyses examined by Natural Resources Canada favoured the Muskrat Falls alternative, except a low growth scenario did not. (P-00054 pages 42-43.)

On October 18, 2011 Premier Dunderdale, on behalf of the government, signed the commitment letter for the base level and contingent equity support required for achieving in-service of the Project (P-00868), facilitating discussions for financing and the federal loan guarantee.

On January 31, 2012 Manitoba Hydro International, which had been retained by the PUB, delivered its Report on *Two Generation Expansion Alternatives for the Island Interconnected Electrical System* (P-00048). MHI conducted its review from the information available at Decision Gate 2, concluding that the work and analysis completed by Nalcor generally met utility best practices, with several significant exceptions that were described, but that, "the Muskrat Falls Generating Station and the Labrador-Island Link HVdc projects represent the least-cost option of the two alternatives, when considered together with the underlying assumptions and inputs provided by Nalcor" (P-00048 pages 19-21).

The PUB released its report on the reference question on March 30, 2012. The PUB concluded that it was not possible to decide the least cost question based on the Decision Gate 2 material that was available, which it described as not detailed, complete or current enough to make a determination. It noted Nalcor's report that work had been ongoing since Decision Gate 2 and that by June 2012 it would have an updated load forecast, a CPW analysis with updated inputs including fuel forecasts, and better defined capital costs. (P-00052.)

Following the release of that report MHI was retained on May 22, 2012 by government to conduct a review for it prior to Decision Gate 3 (P-00770, P-01522). MHI began its work within a week.

On August 31, 2012 the Independent Project Review team delivered its report assessing the readiness of the Project and the project team to move through Gate 3 (P-00083, P-00084).

At the Nalcor board meeting on October 16, 2012 Mr. Martin informed the members that they would be asked to sanction the Project in the coming weeks (P-00666).

MHI delivered its report, *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options*, to government on October 26, 2012 (P-00058). MHI described its mandate as follows:

> MHI was asked to review the work completed by Nalcor Energy since Decision Gate 2 in preparation for Decision Gate 3 and to determine which option is the least cost based on the updated cost and technical data provided by Nalcor. MHI was also asked to complete a reasonableness assessment on all inputs into that analysis. The least cost metric for each option was computed by application of the cumulative present worth (CPW) method.
>
> (P-00058 page 7.)

MHI's summary conclusions were expressed as follows:

> MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Both options have increased substantially in cost due to escalation and scope change from prior estimates released in November 2010. However, the Interconnected Island Option continues to have a lower present value cost given the full range of sensitivity analyses and inputs provided by Nalcor. MHI therefore supports Nalcor's finding that the Interconnected Island option is the least-cost option of the two.
>
> Nothing was found in any of the technical or financial reviews that would substantially change MHI's findings under the existing assumptions.
>
> Although beyond the scope of this review, MHI also concluded that a planned new connection of Newfoundland's power system to the North American grid is not only expected to improve reliability of the province's system but also increase provincial power revenues, given that Muskrat Falls would generate more electricity than required by the province for the next two decades.
>
> (P-00058 pages 11-12.)

A few days later, on October 30, 2012, Premier Dunderdale held a news conference, with Minister of Natural Resources Jerome Kennedy and Nalcor CEO Ed Martin, and a press release was issued jointly by the Executive Council and the Department of Natural Resources announcing the $6.2 billion capital cost of the Project and releasing the MHI report (P-00425, P-00787, P-01632). In the following days government issued a series of news releases and papers promoting sanction of the Project (P-00060, P-00061, P-00062, P-00063, P-00070, P-00071, P-00072, P-00073, P-00426, P-01286, P-01291, P-01293, P-01294).

On November 30, 2012 Premier Dunderdale announced agreement on the terms of the federal loan guarantee (P-00065, P-01298).

Nalcor and subsidiary corporation boards were given Project updates through November and into December 2012 (P-00688, P-00689, P-00670, P-00671, P-00672, P-04533) culminating in a meeting on December 5, 2012 at which the board approved sanction of the Project (P-00673). On the same date Cabinet considered a submission from Natural Resources Minister Kennedy and provided direction approving sanction and development of the Project by Nalcor, approving base equity contributions by the Department of Finance, and approving contingent equity contributions by the Department of Finance "as required to bring the Muskrat Falls Projects into service" (P-00067). Also on December 5, 2012, the House of Assembly passed the Premier's private member's bill supporting approval of the Project (P-01300). On December 17, 2012 official sanction of the Muskrat Falls Project was announced by Premier Dunderdale (P-00066) and official sanction of the Maritime Link Project was announced by Emera (P-01675).

#### 3.3.3.2. Decision Gate 3 Support Package

The Decision Gate 3 Support Package was prepared in November 2012 (P-00121). In addition to addressing the criteria for passing through Decision Gate 3 set out in the Project planning documents, it also revisited the least cost analysis. It addressed load forecasting, system planning criteria and need identification, capital cost, the descriptions of the Isolated Island and Interconnected Island generation expansion plans, the cumulative present worth analysis, and NLH's regulated revenue requirements and the overall wholesale rate analysis. The summary conclusion and recommendation was as follows:

> Nalcor has spent almost two years confirming the development of Muskrat Falls with a Labrador Island Transmission Link as the least cost means of meeting future electricity generation on the Island. Pursuing the Interconnected Island Option has an economic preference over the Isolated Island Option of $2.4 billion and is robust when tested against a range of realistic sensitivities. With more than 50% of the project engineering now complete, the DG3 or sanction quality estimates are considered to be commensurate with the requirements for a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE) International. These estimates have an expected accuracy range of plus 10% to minus 10%.
>
> For these reasons, Nalcor is recommending to its Board of Directors that it sanction Phase 1 of the Lower Churchill Project.
>
> (P-00121 page 26.)

Documents appended to the Decision Gate 3 Support Package included the October 2012 MHI report, a traffic light status report on the Decision Gate 3 deliverables, a summary of the NLH long term planning load forecast, the NLH System Planning Department Generation Planning Issues report dated November 2012, Hatch and NLH wind integration studies and a Department of Natural Resources retail rates analysis.

### 3.4. Excluded Generation Sources

Four potential sources of electricity generation that were excluded from consideration were the use of natural gas supplied by pipeline from offshore Newfoundland, the use of liquefied natural gas, purchase of power from Hydro-Quebec or the New England markets, and waiting until 2041 when the Churchill Falls contract with Hydro-Quebec expires.

#### 3.4.1. Natural Gas by Pipeline from Offshore Newfoundland

The potential for bringing natural gas from offshore Newfoundland to the Island by pipeline for use in generating electricity had been considered before the sanction of the Project in the context of promotion of development of the offshore oil and gas resources.

In 2001, government had commissioned a study by Pan Maritime Kenny of the potential for natural gas development and for a pipeline to the Island (P-00088). Pan Maritime Kenny's report, titled *Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System*, concluded that delivery of natural gas for domestic use only, without export opportunities to neighbouring markets, was not economically sound (P-00088 page 6).

The Energy Plan released in 2007 contemplated the potential export of natural gas via pipeline or as liquefied natural gas (LNG) by tanker to domestic and external markets. Section 3 of the Energy Plan proposed achieving this by compelling offshore developers to propose landed natural gas options before submitting development plans for future offshore oil projects (P-00029 pages 36, 48). The offshore oil and gas regime and existing development agreements give the operators of the offshore fields rights in the determination of how and when the gas reserves in their development areas are exploited. Oil and gas operators had, independently of government, undertaken a number of confidential studies of the potential for development of their natural gas resources in the offshore fields under their control (James Keating November 22, 2018 page 23). Much of that information was confidential, but Nalcor personnel, such as Jim Keating, Nalcor Vice President responsible for the oil and gas business unit who had worked for the oil companies and who had confidential access while with Nalcor, were aware of those investigations.

In 2007, Nalcor issued a call for expressions of interest for engineering and feasibility studies for domestic natural gas transport and natural gas onshore storage systems, in an attempt to spur interest in development of the resource. Nalcor took a phased approach to study compressed natural gas (CNG), LNG, and pipeline options (P-01305, P-01310 page 10).

Enersea Transport LLC delivered a series of reports between 2007 and 2009 (P-01306, P-01307, P-01308). Any opportunity to economically bring natural gas to the Island for use in electricity generation depended on there being an available export market in order to create a demand for sufficient volume. By 2009 natural gas prices in Canadian and United States markets were not high enough for a natural gas project to be economic (P-01310 page 11).

Other discussions with potential proponents of various natural gas projects were held prior to sanction of the Project (P-01310 pages 12-13) but the problem remained that the gas field sizes were too small to warrant the investment that would have to be made by the oil companies with the rights to those fields, so the prospects for bringing natural gas onshore were no better in 2012 than they had been when Pan Maritime Kenny did its study in 2001 (James Keating November 22, 2018 page 5, November 23, 2018 page 50).

In its submission to the PUB in November 2011 Nalcor summarized the situation as it existed at Decision Gate 2 as follows:

> The Provincial Energy Plan requires all offshore operators to propose a “landed” gas option as part of any development plan for natural gas. To date, no proposal for natural gas development, either export or “landing”, has been submitted by the offshore operators despite years of technical and economic study. Nalcor has evaluated a range of natural gas configurations including modification of the Holyrood Plant to burn natural gas, and replacement of the Holyrood Plant with new high efficiency combined cycle gas turbines. Nalcor is of the view that

> “landed” Grand Banks natural gas is not a viable option to meet the island of Newfoundland’s electricity needs.
>
> (P-00077 page 66.)

Three considerations were given in the submission as the reason for screening out offshore natural gas as a supply option. One was the lack of a confirmed development plan for Grand Banks natural gas, the second was the small domestic requirement compared to the economic threshold for development, and the third was that the offshore operators were already making use of their natural gas resources for varying purposes, such as powering their offshore facilities and re-injecting it into reservoirs to enhance oil production.

Navigant, in its report delivered September 14, 2011 concluded that natural gas generation had been appropriately excluded from both the Isolated Island and the Interconnected Island plans. The report states that, based on the Pan Maritime Kenny study, a natural gas production rate of 700 Mcfd would be required to support a pipeline to the Island, and that a 500MW gas fired generation unit would require only 5% of that volume (P-00042 pages 35-36).

The PUB, noting that examination of alternative sources of generation was not within its terms of reference, did discuss submissions it had received promoting other supply options, including a paper from Dr. Stephen Bruneau making the case for study of an offshore gas pipeline (P-00052 page 29, P-00089). Dr. Bruneau gave a presentation at the Harris Centre on the same topic on March 28, 2012 (P-00090).

It was at this time that Minister of Natural Resources Jerome Kennedy became involved in directing the response to the suggestion that a natural gas pipeline was a viable alternative. At about the same time Jim Keating, who had not participated in the Decision Gate 2 process or the screening of generation alternatives, also became involved. Mr. Keating served as the Nalcor contact for the work being carried out by Natural Resources on this issue.

Minister Kennedy directed the commissioning by his Department of Ziff Energy Group to prepare a report, *Natural Gas as an Island Power Generation Option*, which was delivered October 30, 2012 (P-00060). Ziff presented conclusions to government that included:

- Grand Banks natural gas was stranded and not available.
- Gas produced with oil was being used to power oil production systems or was being reinjected to enhance oil recovery.
- Government could not compel sale of gas to the power generation market or mandate a price.
- The return would not be sufficient to justify the capital cost of a gas development.
- The Newfoundland power market is small with seasonal demand presenting challenges to gas development.
- A subsea pipeline would be a costly and significant challenge.
- Developing natural gas for supply to the Island for electricity generation would likely require a standalone gas project.
- The low and variable volumes of gas required for electricity generation would be a challenging economic barrier.

(P-00060 pages 6-7)

Ziff gave two reasons in support of the conclusion that government could not compel sale of gas to the power generation market or mandate a price. One was that current offshore operators have licenses that cannot be unilaterally altered to compel them to produce gas they consider to be uneconomic. The other was that unilateral action to alter agreements and licences would have long term consequences for future investment. (P-00060 page 6.) Mr. Keating testified to the same effect, saying, “there would be a chilling effect for any investment in the offshore for government to compel, or otherwise, an operator to do an – not only an uneconomic project, but likely a project they had disinterest in.” (James Keating November 22, 2018 page 95.)

Another concern arising out of Ziff’s analysis is that for utility use, a gas supply must be secure and reliable. The Holyrood plant provides baseload capacity essential to meet the peak demand on the Island system. Mr. Keating testified to the potential for ice scour of the seabed to undermine the reliability of an offshore pipeline for use in providing baseload electric capacity (James Keating November 23, 2018 pages 4-5). Other disruptions to the ability of offshore facilities to continuously and reliably supply natural gas would cause similar problems. Recently, release of oil from the Hibernia platform caused all production from that facility to be halted for about three weeks.

The Department of Natural Resources engaged another international consultant, Wood Mackenzie, to review and comment on the Ziff report (P-00064). Wood Mackenzie’s conclusions were:

> Wood Mackenzie generally finds Ziff's analysis and conclusions relative to natural gas as a fuel source for Newfoundland to be reasonable in regards to the use of natural gas produced in the White Rose fields. If anything, Wood Mackenzie's estimates of costs in this area would tend to be higher, rather than lower than those determined by Ziff. Additionally, we believe that the Government of Newfoundland may find it difficult to enter a contract for that gas that would make the producers interested in producing the gas for market due to the costs of production and the low level of requirements that Newfoundland will have for power generation.
>
> (P-00094 page 3.)

Both the Ziff and Wood Mackenzie papers were publicly released by government prior to the sanction decision.

Grant Thornton in its investigative and forensic audit report on the Sanctioning Phase reviewed much of the information discussed above, except that concerning internal oil company investigations of the potential for developing offshore natural gas which had not been publicly disclosed, and concluded that nothing had come to their attention to suggest that the exclusion of natural gas piped from offshore Newfoundland as a generation alternative was unreasonable at the time the decision was made (P00014 pages 15-17, 22) .

### 3.4.2. Liquefied Natural Gas

Discussion of the elimination of use of LNG as a fuel source for electricity generation on the Island overlaps with the discussion above.

Accessing LNG from gas fields offshore Newfoundland could practically only be done in conjunction with an LNG export project developed by an offshore operator, due to the gas processing and gasification infrastructure that would be necessary. Buying LNG on world markets might have been a better option, but the costly facilities required for import, regasification and storage of the small volumes of gas seasonally required for power generation made this option uneconomic. Nalcor presented the explanation of the rationale for exclusion of LNG in its November 2011 submission to the PUB (P-00077 pages 67-70). Navigant supported that conclusion (P-00042 pages 36-37).

In early 2012, after receipt of the Navigant report, Nalcor commissioned PIRA to supplement Navigant's review of the potential for import of LNG from world markets for use in electricity generation. PIRA's report, *Newfoundland LNG Import Advisory*, was delivered September 7, 2012 (P-01203). It concluded that the best prices available for the potential sources of LNG supply, combined with the high cost of regasification, made LNG import "extraordinarily costly by international standards" (P-01203 page 4). Although PIRA was retained by Nalcor and not the Department of Natural Resources, Minister Kennedy also met with them on this issue (Jerome Kennedy December 3, 2018 page 51).

Ziff also considered LNG and concluded that securing a reliable supply could not be based on purchases on world spot markets, since peak demands in those markets coincide with peak demands for power in Newfoundland. Long term supply contracts would be required, and those would have to be for LNG prices indexed to the price of oil (P-00060 page 8). That would negate any price advantage for LNG compared to the price of oil. The capital expenditures required for regasification and storage facilities would make the LNG alternative even more uneconomic.

Just as for natural gas, Grant Thornton in its investigative and forensic audit report for the Sanctioning Phase stated that nothing had come to its attention to suggest that the decision to exclude LNG import as a source of generation supply was unreasonable at the time the decision was made.

### 3.4.3. Importation of Electricity

Two sources were considered for potential import of electricity. One was by purchase from Hydro-Quebec, or from the New York Independent System Operator (NYISO) for transmission over the Hydro-Quebec system, then for transmission across Labrador, the Strait of Belle Isle and the Island of Newfoundland to Soldiers Pond via a new HVdc transmission line. The other was by purchase through the New England Independent System Operator (NEISO) for transmission through the Maritimes, under the Cabot Strait and across the Island of Newfoundland to Soldiers Pond via a newly constructed HVdc transmission line. These options were presented to government on September 23, 2010 (P-00216 pages 24-29, Robert Thompson November 15, 2018 page 77), and to the Nalcor board on October 29, 2010 (P-00093 pages 94-99).

The presentations included the following information regarding imports from or via Hydro-Quebec (P-00216 page 25):

- Energy and capacity would be purchased at NYISO prices, since that would be the source of supply if transmitted through Quebec, and New York would also be Hydro-Quebec's alternative market for power potentially sold to Nalcor. Prices were adjusted for line losses and tariffs.
- New HVdc transmission construction would be required.
- The CPW of the revenue requirement was calculated to be $12,413 million, which was $1,809 million more than the Muskrat Falls option.
- Key risks were the ability to secure long term supply, and market price volatility.
- Connection to the North American grid would enhance reliability, but continuity of supply could not be assured.

The presentations included the following information regarding imports from NEISO (P-00216 page 28):

- Energy and capacity would be purchased at NEISO market rates adjusted for line losses and tariffs.
- New HVdc transmission construction would be required and transmission rights would have to be secured through New Brunswick and Nova Scotia.
- The CPW of the revenue requirement was calculated to be $12,398 million, which was $1,795 million more than the Muskrat Falls option.
- Key risks were project execution risk for complex multi-jurisdictional transmission and the Maritime Link, and market price volatility.
- Connection to the North American grid would enhance reliability, but continuity of supply could not be assured due to the absence of long term contracts in the NEISO market.

Issues with price volatility, security of supply and potential market structural and transmission impediments were explained in Nalcor's submission to the PUB in November 2011 (P-00077 pages 107-110).

In July 2012 the Department of Natural Resources prepared a paper on electricity import options (P-01264 page 2) with information similar to that described above. In addition, it included the information that most of Hydro-Quebec's electricity exports were on short term contracts only and that there were transmission capacity restrictions in New Brunswick and Nova Scotia that would limit imports. It stated that a disadvantage of importing electricity would be the limited benefits to the people of the province in terms of employment, income and business opportunities compared to the Muskrat Falls alternative.

Grant Thornton, in its investigative and forensic audit report for the Sanctioning Phase observed that Nalcor did not have formal discussions with Hydro-Quebec as part of the option screening and on that basis reported that the option of importing power from Hydro-Quebec may have been inappropriately eliminated (P-00014 page 8).

Mr. Bennett testified that in about 2010 Nalcor had been gathering information about Hydro-Quebec's marketing activities and had no indication that it would be willing to sell firm power. It was known also that Hydro-Quebec had launched the construction of new generation facilities, indicating that it was short on capacity itself (Gilbert Bennett November 29, 2018 pages 78-79).

Mr. Martin's evidence was that Hydro-Quebec did not have capacity available and that Newfoundland and Labrador needed firm capacity (Ed Martin December 10, 2018 page 61). During his testimony, an August 2010 power purchase agreement between Hydro-Quebec and Vermont was introduced as an exhibit (P-01637). It was suggested that the Vermont contract showed that Hydro-Quebec was willing to sell firm power on long term contracts. Mr. Martin pointed out a term of the contract stating that it did not include the sale of any capacity, meaning that it was not firm power (Ed Martin December 10, 2018 pages 59-60). Consequently Hydro-Quebec would not be obligated to deliver power at all times Vermont needed it.

Expert witness Pelino Colaiacovo was asked about the same Vermont contract and testified that it was a summer peaking contract, which would cause Hydro-Quebec no supply problems. Nalcor, of course would need capacity available in the winter. Mr.

Colaiacovo also said the price of the Vermont contract was tied to natural gas prices, which in 2008-2010 were unattractively high. (Pelino Colaiacovo July 18, 2019 pages 52-53).

A presentation to the UARB by Nova Scotia Power Incorporated (NSPI) in 2013, quoted in the UARB decision approving the Maritime Link project includes this statement:

> We have been asked about discussions with Hydro Quebec and why we didn't go through a competitive bidding process and bring forward a long term competitive contract as an alternative to the Maritime Link.
>
> Emera and Nova Scotia Power have worked with Hydro Quebec for many decades. We met with them specifically to discuss and consider this alternative and simply put, there is no long-term, fixed price energy available from Hydro Quebec.
>
> (P-00245 page 44.)

The decision goes on to quote testimony explaining the unsuccessful efforts of NSPI to interest Hydro-Quebec in the sale of firm capacity in 2009 (P-00245 pages 44-45).

Any discussion with Hydro-Quebec about the long term purchase of electricity would, of course, have needed authorization at the highest political levels in the province. In Premier Williams' testimony he clearly articulated his views regarding Hydro-Quebec (Danny Williams October 1, 2018 pages 9-11.) Discussions with Hydro-Quebec at any level other than over purely electrical system operational matters would thus have engaged public policy considerations of the province. Nalcor could not have made a decision to do so alone.

### 3.4.4. Wait Until 2041

In its November 2011 submission to the PUB (P-00077), Nalcor described consideration at the screening stage of the option of continuing use of the Holyrood thermal generating plant until 2041, adding additional thermal generation as required, and building a transmission line for use in 2041 to transmit power from the Upper Churchill when the contract with Hydro-Quebec expires.

The option was screened out for a number of reasons. There was uncertainty about guaranteeing the availability of power in 2041 because environmental and policy frameworks then in place might impede the construction of the needed transmission infrastructure, and because Nalcor was not sole owner of the Churchill Falls operation. Relying on oil until 2041 would expose Island consumers to oil price volatility and escalating Holyrood maintenance costs. There was significant reliability risk in keeping the Holyrood plant in operation until 2041. Curbs on allowable greenhouse gas emissions might force the closure of the Holyrood plant. It might become necessary to replace Holyrood, leaving its replacement stranded in 2041. The province would lose the revenue benefits from the Muskrat Falls project and the economic and employment benefits, and would instead spend funds on imported oil. The submission states that this option was modeled using the Strategist generation expansion software and presented as a sensitivity. (P-00077 pages 100-101).

On November 9, 2012, the Department of Natural Resources released a paper titled, *Upper Churchill: Can we wait until 2041?* (P-00061) and a press release (P-01294). The release includes these statements attributed to Minister Kennedy:

> "Reports released today provide clear, concise information which refute the suggestion that the province has not explored all options with respect to Quebec and the Upper Churchill," said the Honourable Jerome Kennedy, Minister of Natural Resources. "Our research and studies support the position that Muskrat Falls is the best option to address demand requirements for our province."
>
> "It is not feasible to defer Muskrat Falls under the assumption that the province will have cheap or free power in 2041," said Minister Kennedy. "Waiting for available Upper Churchill power in 2041 is not a practical, economical, or sensible alternative to Muskrat Falls."

The paper states that waiting until 2041 is not realistic for these reasons:

- CF(L)Co is partly owned by Hydro-Quebec so in 2041 NLH will not have absolute authority over the corporate actions of CF(L)Co.
- Power after 2041 may have to be purchased from CF(L)Co at prevailing market rates.
- Until 2041 the province would be reliant on oil fired power generation, and subject to the volatility of oil prices.
- The province would be unable to capitalize on export power sales and/or industrial expansion in Labrador.

Grant Thornton, in the investigative and forensic audit report for the Sanctioning Phase, referred to a quote from the UARB decision on sanction of the Maritime Link that included the statement that, "… there should be no shortage of Market-priced Energy when the Churchill Falls arrangement with Hydro Quebec comes to a conclusion in 2041" (P-00014 page 29). Grant Thornton concluded that the statement was inconsistent with the position presented by Nalcor to the PUB described above, and reported that it suggested that the Waiting until 2041 option had been inappropriately eliminated (P-00014 page 8).

Mr. Malamed from Grant Thornton was examined on that part of the report at the Inquiry hearing. He said that the statement that there was an inconsistency was a factual statement only and that no evaluation was done of the reasonableness of the choice to exclude this option from further consideration, nor did the auditors look behind the single statement quoted from the UARB decision or evaluate its reliability (David Malamed September 24, 2018 pages 8-16).

Neither Nalcor, any of its subsidiary companies nor the Province of Newfoundland and Labrador were parties to the UARB hearing. They made no representations to it on this or any other issue. The only evidence referred to in the UARB decision in support of the conclusion that there will be no shortage of market-priced energy from Churchill Falls in 2041 is a statement from the Maritime Link proponent at paragraph 189 that, "In 2041, the Upper Churchill reverts to ownership of Newfoundland and Labrador" (P-00245 page 62), which is not correct. Grant Thornton's only reason for suggesting that this option had been inappropriately eliminated was its perception of inconsistency with the UARB decision, which is not supported by the evidence.

### 3.5. Options Considered

For the Decision Gate 2 analysis, the generation expansion options were narrowed to two, known as the Isolated Island Option and the Interconnected Island Option. Each was a plan for adding and replacing sources of generation to match the forecasted load requirements over a period of 50 years. Both were developed using the same methodology, but with different choices of generation sources.

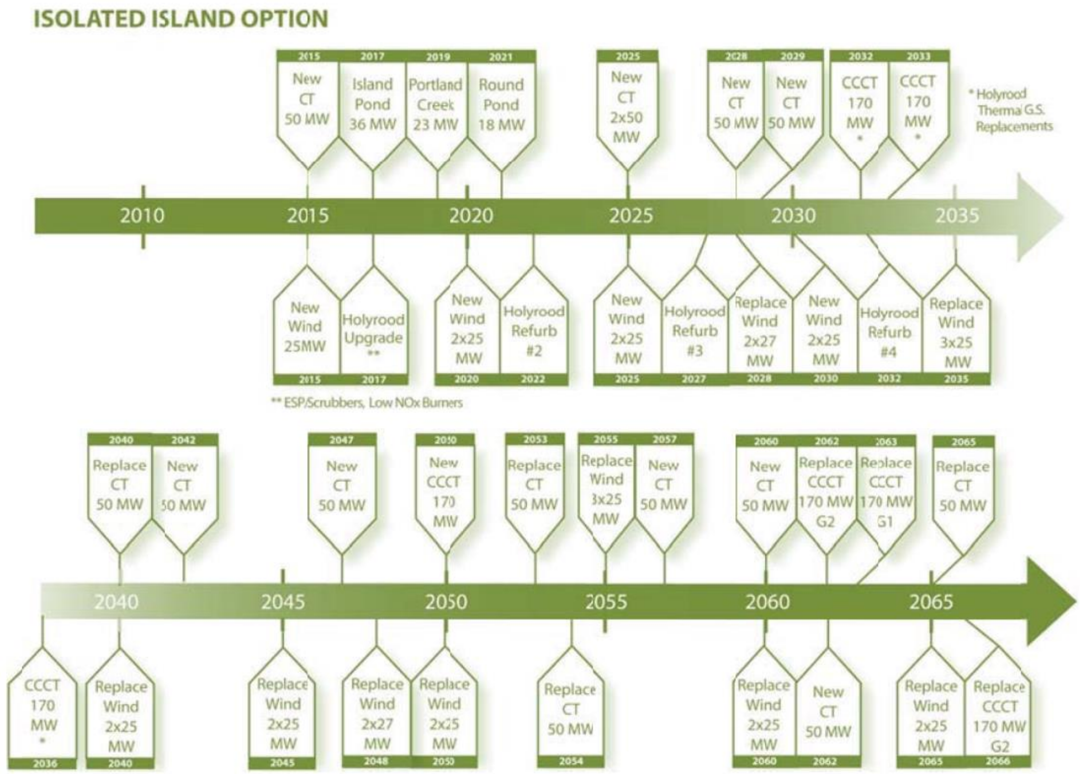
For the Decision Gate 3 analysis new versions of each plan were generated using updated forecasts and assumptions.

For descriptions of the generation expansion plans, and the forecasts and assumptions used to create them, reference should be made to the Gate 2 Decision Support Package (P-00093), the Decision Gate 3 Support Package (P-00121), the Navigant Independent Supply Decision Review (P-00042), the Nalcor submission to the PUB (P-00077), the MHI *Report on Two Generation Expansion Alternatives* (P-00048), the MHI *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options* (P-00058), and to the testimony of the CPW Panel (September 25 and 26, 2018).

### 3.5.1. Isolated Island Option

The Isolated Island Option was a current version of a generation expansion plan that had been maintained and renewed, usually annually, by the NLH System Planning Department.[1] The plan considered at Decision Gate 3 was represented by the diagram below which shows the addition and replacement of generation sources on a timeline. The generation sources used as inputs to the analysis and shown on the diagram are the refurbishment and extended operation of the Holyrood thermal plant, the addition of three small hydro-electric plants, the addition and replacement of combustion turbines (CTs) and Combined Cycle Combustion Turbines (CCCTs) and the addition and replacement of wind farms. Under this plan the Island power system remained isolated from the North American grid without construction of any transmission connections to Labrador or Nova Scotia. The generation sources shown are incremental to the existing generation sources, which are common to both options, hence sources such as the Bay D'Espoir hydro-electric plant are not shown.

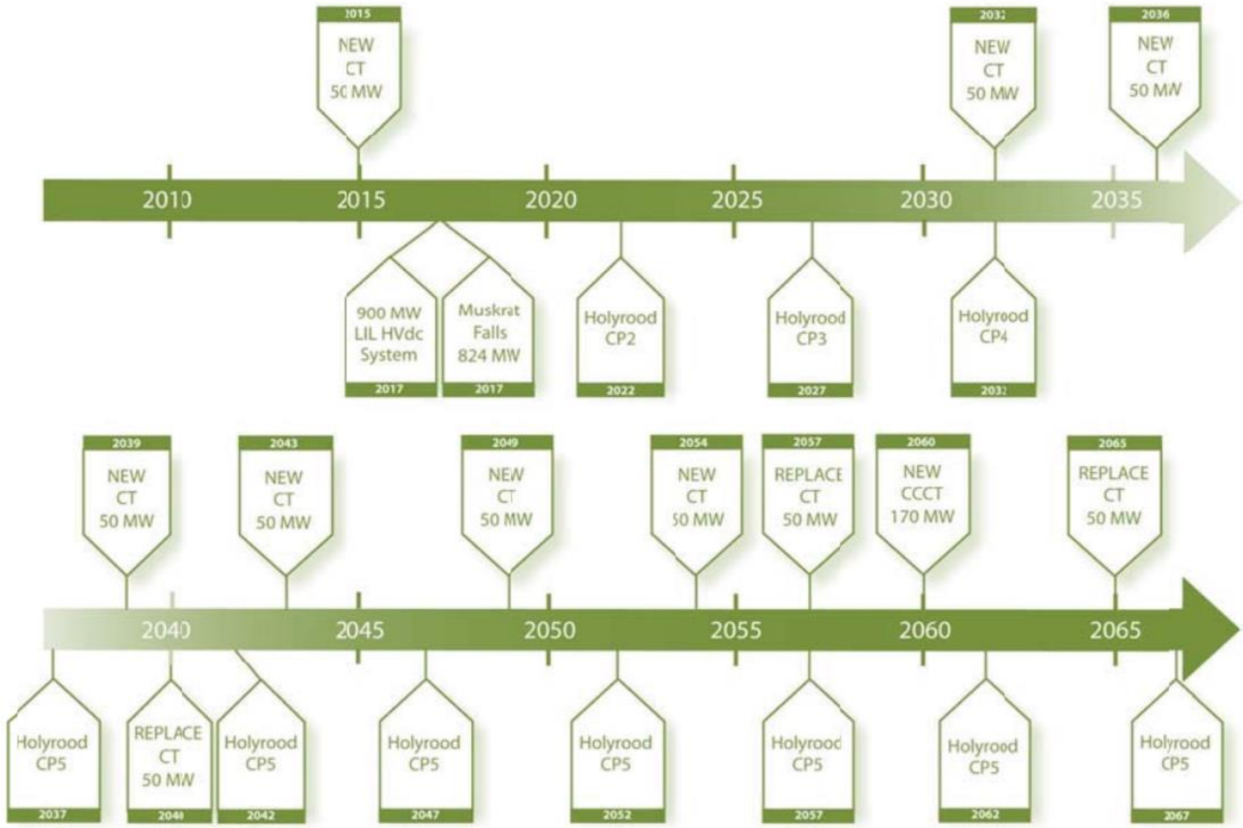
[1] For earlier examples of generation planning reports see P-00164 2006 Report on Generation Planning Issues and P-00034 Generation Planning Issues 2010 July Update. P-01136 is the Generation Planning Issues November 2012 report used at Decision Gate 3.




### 3.5.2. Interconnected Island Option

The Interconnected Island Option at Decision Gate 3 is represented by the diagram below. For this plan, the supply of power from Muskrat Falls over the Labrador-Island Link transmission line under a Power Purchase Agreement (PPA) arrangement is added as an additional generation source. Refurbishment of the Holyrood plant is excluded, but it was planned to convert and maintain one unit at Holyrood for use as a synchronous condenser. The capital costs related to that are shown as “CP” meaning capital project (CPW Panel September 25, 2018 pages 48-49). The resulting plan also shows the addition of one new CT before the Project was to come into service and the later addition and replacement of further CTs when the Project was no longer able to meet the forecasted load.

**INTERCONNECTED OPTION**



### 3.6. System Planning and Cumulative Present Worth Methodology

The NLH System Planning Department used a proprietary software program called "Strategist", which is industry standard, to create system plans. A wide range of parameters are input into the program, such as the forecasted load requirements, including the seasonal and daily load shape; system reliability criteria; the available new generation sources, their power and energy outputs, their operating characteristics, and their capital costs; and operating costs, including fuel costs where applicable.

The program will run a large number of scenarios to select the optimal plan for adding and replacing generation sources to meet the load demands at the lowest overall cost. That cost is expressed as a Cumulative Present Worth (CPW), which is a type of net present value. It provides a present value for the costs to be incurred over the future period under study. (P-00077 pages 38-55.)

The cost results of the NLH System Planning Strategist run for a generation planning scenario are then an input into economic modeling done by Nalcor Investment Evaluation to calculate rates that would be charged to the various classes of ratepayers over the planning period. Because consumer electricity consumption is affected by the cost of that electricity, the rates calculated by Investment Evaluation are fed back to the load forecaster, who prepares a new load forecast. That forecast goes to System Planning who rerun the Strategist models to get a new generation expansion plan cost to send to Investment Evaluation again. The cycle is continued until the electricity rates no longer change.

MHI reviewed Nalcor's generation resource planning process and found that it was consistent with that of leading North American utilities and that the Strategist software used by Nalcor to evaluate and select a preferred generation development scheme is appropriate (P-00048 page 34).

## 3.7. Forecasts and Assumptions

It is beyond the scope of this submission to review all inputs, forecasts and assumptions used in the generation planning process. Comments on several of the forecasts and assumptions that are more relevant to this Inquiry will be provided.

### 3.7.1. Planning Period

The planning period selected was 50 years. Normally NLH system planning used 20 years for generation plans, however there was testimony that longer periods had been used in the past when Lower Churchill options were considered. 50 years was selected because of the long life of the Project assets. (CPW Panel September 26, 2018 page 8.)

It is difficult to fairly compare two generation expansion plans where one relies on generation sources that have relatively short useful lives before needing replacement and the other has an asset such as the Muskrat Falls generating station which can have a useful life well in excess of a hundred years. A CT or a wind turbine will have to be replaced in 30 years of less, so it is relatively easy to account for its full value in a 20 year generation plan. However, depreciating the full cost of a large hydro-electric plant over the same relatively short period would overstate its cost and understate its value, compared to the shorter-life generation sources. The result could be that the true least cost alternative, when measured over its useful life, will never be selected because the short life assets will always win out.

In theory, the comparison problem might be addressed either as was done here, by using a longer time period, or it might be addressed by calculating the residual value of the hydro-electric plant after 20 years and including that in the economic analysis. Either way, some form of long term evaluation, either of all generation plan elements or of the value of the long-life asset, would have to be taken into account.

The problem with an analysis period as long as 50 years is that the reliability of the forecast values of the inputs and assumptions becomes less as time progresses so that they provide little value for the later years. The Inquiry heard some testimony that forecasts lose any useful value beyond 5 years. That problem is offset somewhat, however, by the fact that the weighting given to future costs and benefits in a present value calculation diminishes the farther into the future they reach (CPW Panel September 26, 2018 page 91). The prediction of oil prices for year 2 is given less weight that the prediction for year 1. The weight on the prediction for year 50 is extremely small.

Nevertheless, if long-term planning and investment decisions have to be made, long-term forecasts need to be prepared. The important point, perhaps, is that they should be recognized by the decision makers for what they are. Decision makers should not expect, or demand, single value certainty when only an uncertain prediction is possible. Stan Marshall testified, “When you look at it, the future is always uncertain. Any estimate is going to be wrong.” (Stan Marshall June 28, 2016 page 62.)

### 3.7.2. Load Forecasts

For its report to the PUB, MHI reviewed the load forecasting methodologies employed by NLH and the accuracy of the results, stating as follows:

> A detailed analysis of Nalcor’s load forecasting practices and methodologies confirms that the load forecast has been performed with due diligence and care using generally accepted practices, except as noted in key finding #2.
>
> (P-00048 page 10.)

Key finding #2 was that the NLH domestic, or residential forecast consistently under-predicted future energy needs by 1%. The econometric methods used for that forecast were described as acceptable, but MHI said that end use forecasting would be best practice. The methodology used for the general service class, business and institutional customers, was a combination of regression modeling and extrapolation techniques that had proven to be very accurate. The industrial load forecast, because of the small number of industrial users, had to be prepared on a individual, case-by case basis and was susceptible to unpredictable variation due to the circumstances of individual customers. (P-00048 page 10.)

End use modeling had not been adopted by NLH, partly due to the necessity of continually maintaining the required database of customer end use information. Paul Stratton, Senior Market Analyst with NLH, testified that he would not consider end use forecasting best practice, in the sense of being preferable to econometric methods, but would instead characterize it as an alternate practice that is more informative about specific loads but for which there was no guarantee that it would provide a more accurate overall forecast (CPW Panel September 26, 2018 page 10).

An important input into the load forecast was macroeconomic data, such as provincial gross domestic product, disposable income and housing starts. That data was provided to NLH in a macroeconomic forecast prepared specifically for Newfoundland and Labrador by the provincial Department of Finance, which was considered to be superior to the more general economic forecasts available from national agencies. (CPW Panel September 26, 2018 pages 6-7.)

Price elasticity, explained by Mr. Stratton as the responsiveness of demand to changes in price, was applied to the domestic load forecast using a factor that was calculated by applying a regression analysis to historical pricing and demand data. A price elasticity factor was not applied to the general service load forecast because regression analysis had not established a relationship between prices and consumption levels for that class. Similar analysis applied to the industrial customer class. (CPW Panel September 26, 2016 pages 25-27.)

The modeling of the domestic load included a technology factor which took into account changes in demand due to technological changes such as introduction of energy efficient appliances, modelled on analysis of historical data (CPW Panel September 26, 2018 page 35).

NLH did not employ a complete Integrated Resource Planning process for load forecasting and generation planning. The Inquiry has heard evidence that Integrated Resource Planning is better at factoring in the potential benefits of Conservation Demand Management, or CDM. The possibility of implementing Integrated Resource Planning has been discussed at PUB proceedings, but no order has been issued by the Board to do so and NLH had not considered the cost to be worth the potential benefits (CPW Panel September 26, 2018 pages 38-39).

### 3.7.3. Generation Sources

#### 3.7.3.1. Holyrood

The Isolated Island Option relied on extending the useful life of the Holyrood generating plant. It therefore included the cost of installing pollution abatement equipment that was mandated by government policy set out in the Energy Plan (P-00029 page 46).

The pollution abatement equipment would not reduce greenhouse gas emissions from the Holyrood plant. The potential impact of carbon pricing on the cost of operating that facility was excluded from consideration in the CPW analysis.

#### 3.7.3.2. Island Hydro

Three smaller hydro-electric developments were included in the Isolated Island Plan. Capital cost estimates were based on feasibility level engineering studies and therefore had a lower level of accuracy than the Class 3 estimate prepared for the Project.

#### 3.7.3.3. Combustion Turbines and CCCTs

Combustion turbines and combined cycle combustion turbines are not individually unique, so capital costs for acquiring the units are relatively predictable. Operating costs depend primarily on the cost of fuel and are therefore much more unpredictable.

#### 3.7.3.4. Wind

First, the difference between power and energy as the terms are used in describing electrical power systems should be explained.

Electric power, sometimes referred to as the capacity of a generation source to produce energy, is measured in megawatts (MW) that can be supplied at a point in time. The technical design and size of a generation source determines the power it can produce. A wind farm with multiple turbines operating at maximum efficiency may have the capacity to produce, for example, 20 MW of power deliverable at a point in time. The power generated from time to time would range from 0MW to 20MW depending on the wind velocity and the operating conditions of the turbines.

Electric energy is the output of a generation source measured over time. The energy generated by a wind farm in a year will be the total actual output, which will be determined by the availability of wind from time to time during that year. Similarly, the annual energy output of a hydro-electric generation plant can be measured by the volume of water available in that year. Wind farms cannot store energy. A hydro-electric plant with a reservoir can.

The Island of Newfoundland has good potential for wind power generation. Two issues have limited the amount of wind power and energy that can be incorporated into the Isolated Island electrical system.

One is that wind power is not available on demand and is intermittent. Loads on the electricity system peak at breakfast and supper time on the coldest days of the winter. The system has to have the capacity to meet that demand at the time it is needed, with some reserve in case of generation or transmission failure. Wind is not reliable enough to meet that need, so in an isolated system other sources of power sufficient to meet the peak demand are necessary. The usefulness of wind in that case is to supply energy at times it is available, to displace supply from more expensive generation sources. Excess wind energy produced at times that it is not needed can be stored in a hydro-electric plant reservoir, but only if there is spare capacity in the reservoir. Those constraints would be reduced if the system were interconnected with the North American grid.

A second limitation is technical, related to the amount of wind power that the isolated system can absorb, particularly under light load conditions, before risk of system voltage and frequency instability becomes a problem.

NLH produced a report, *An Assessment of Limitations on Non-Dispatchable Generation on the Island of Newfoundland*, in 2004 (P-00068). The report determined that up to 80MW of wind generation could be added to the isolated system before the reduced capacity of Island reservoirs to store excess wind generated energy would start to make additional wind power uneconomic. Up to 130MW of wind capacity could be added without significant technical performance repercussions. An upper limit of 80MW of wind was recommended. This study was relied upon at the time the Decision Gate 2 Isolated Island generation expansion plan was prepared (P-00077 page 82).

In August 2012 Hatch delivered a report to Nalcor titled *Wind Integration Study – Isolated Island* (P-00057). Two wind farms had been brought on-line at Fermeuse and St. Lawrence since the 2004 report had been prepared. The study examined the use of wind generation in the Isolated Island system "to decrease the use of thermal generation as much as possible without affecting voltage and frequency support, and without unduly increasing spill and causing significantly less efficient dispatch of the hydro generating units." It recommended using a maximum wind penetration of 300MW, including the installed capacity of 54MW, for the Isolated Island generation expansion plan. (P-00057 page 7).

In the same month the NLH System Planning Department prepared a report titled *Wind Integration Study – Isolated Island, Technical Study of Voltage Regulation and System Stability* (P-00950). It studied base case years 2020 and 2035 recommending dispatch of no more than 225MW of wind during light load conditions in 2020 and 300MW in 2035 under the same conditions, and no more than 500MW at peak load in both years (P-00950 page 6).

These reports were relied upon for the Isolated Island generation expansion plan developed for Decision Gate 3 (P-00121 page 19).

Natural Resources Minister Kennedy commissioned a report from MHI, which was delivered in October 2012 and was titled *Assessment of Wind for the Isolated Island of Newfoundland* (P-00059). MHI was asked to do a due diligence review of the NLH System Planning analysis and to answer the questions, "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand?" and "Is this a technically feasible and economic alternative to Muskrat Falls and the Labrador Island Link?" (P-00059 page 7.)

MHI developed two scenarios for replacement of the Holyrood plant by wind farms. One relied on combustion turbines for capacity when wind was not available. The other relied on battery storage. CPWs were calculated for each scenario. They were found to be considerably more expensive than either the Interconnected Option or the Isolated Island Option. MHI concluded that, “Based on these screening level study findings (at an AACE Class 4 estimate), and the inherent technical risks in such a massive wind development, MHI does not recommend that wind options beyond a 10% penetration level, as recommended by the 2012 Hatch study and adopted by Nalcor for the Isolated Island, be pursued at this time”. (P-00059 page 8.)

#### 3.7.3.5. Conservation and Demand Management

Conservation and Demand Management refers to measures or programs intended to reduce the demand for electricity, either on a overall basis, which saves energy, or to lower peak demand ,which reduces the requirement for capacity. Documents entered as exhibits that describe the CDM programs implemented by NLH and Newfoundland Power (NP), which distributes electricity to the majority of domestic and general service customers on the Island, include the following:

- *Conservation and Demand Management (CDM) Potential, Newfoundland and Labrador, Residential, Commercial and Industrial Sectors*, January 31, 2008, prepared by Marbek Resource Consultants Ltd. for NLH and NP (P-00246).
- *Five-Year Energy Conservation Plan: 2008-2013, Pursuant to Order No. P.U. 8 (2007)*, June 2008, submitted to the PUB by NLH and NP (P-01555).
- NLH *Report on Conservation and Demand Management, Extracted from the December 2009 PUB Quarterly Report* (P-01550).
- NLH *Report on Conservation and Demand Management, Extracted from the December 2010 PUB Quarterly Report* (P-01551).
- *Moving Forward, Newfoundland and Labrador Energy Efficiency Action Plan 2011* (P-00789).
- *2011 Conservation and Demand Management Report*, May 2012, submitted by NLH to the PUB (P-01552).
- *Five-Year Energy Conservation Plan: 2012-2016*, August 2012, submitted to the PUB by NLH and NP (P-01556).
- *2012 Conservation and Demand Management Report*, March 2013, submitted by NLH to the PUB (P-01553).
- *2013 Conservation and Demand Management Report*, March 31, 2014, submitted by NP to the PUB (P-01640).

- *2013 Conservation and Demand Management Report*, April 2014, submitted by NLH to the PUB (P-01554).

These documents illustrate that setting CDM policy and implementing it involves the PUB, NLH and NP.

The task of the load forecaster is not to make or implement policy for CDM, but to consider how the CDM that is to be implemented in the planning period is to be accounted for in the forecast. The effect of CDM programs was accounted for in the NLH load forecast by the technology factor described above. As a check, Mr. Stratton compared his load forecast prepared for use at Decision Gate 3 to the 5 year load forecast prepared separately by Newfoundland Power. The NP forecast had a deduction for the effect of the CDM programs, but still predicted higher load growth than the NLH forecast. Consequently Mr. Stratton considered it appropriate to make no deduction from the NLH forecast for CDM in addition to the use of the technology factor (CPW Panel September 26, 2018 pages 35-36).

CDM can also be treated by system planners as a generation source. Robert Moulton, Senior System Planner with NLH at the time of Decision Gate 3, explained that NLH did not include CDM as a generation source because it had been taken into account on the demand side in the load forecast (CPW Panel September 26, 2018 page 36).

### 3.7.4. Capital Costs

The capital cost estimate for the Project, which was an input to the Interconnected Island Option, is addressed in section 4.2 of this submission.

Capital cost estimates for the various generation sources included in the Isolated Island Option, and for the CTs also included in the Interconnected Island Option, were derived from various sources. Most were not developed beyond the level of engineering definition available at Decision Gate 2, unlike the Project estimate which had reached an AACE Class 3 level of definition by Decision Gate 3.

### 3.7.5. Oil Prices

Oil price forecasts were important for the Isolated Island Option, which relied heavily on burning fossil fuels at Holyrood and in CTs and CCCTs.

The benchmark price for Brent crude was $109 USD on December 17, 2012 when the Project was sanctioned. It was still $100 USD in September 2014 and then started a decline to $63 USD in January 2015, hitting a low of $34 USD in January 2016. In October 2018 it was $84 USD and at the time of writing of this submission it sits at $57 USD.

PIRA Energy Group, now part of S&P Global Platts, is an international consulting firm known for its comprehensive and detailed research and market analysis of energy markets. It provided the long term price forecasts used in the Isolated Island and Interconnected Island Options. PIRA's methodology and considerations for developing the Reference, Low, High and Expected case forecasts are explained in a report submitted to the Department of Natural Resources on October 26, 2012 (P-00129, CPW Panel September 26, 2018 page 30).

The oil price forecasts provided by PIRA were for 20 years and were extrapolated for use in the 50 year system plans by increasing the price for inflation only. (CPW Panel September 26, 2018 pages 29, 66).

The Reference case, which was lower than the Expected case, was used in the CPW analysis at Decision Gates 2 and 3 (CPW Panel September 26, 2018 page 31).

### 3.8. Cumulative Present Worth Results

At Decision Gate 3 the CPW for the Interconnected Island Option was $8,366 million and for the Isolated Island Option was $10,778 million. The preference in favour of the Interconnected Island Option was $2,412 million (P-00121 page 91).

### 3.9. Sensitivity Analyses

The CPW is a prediction, arrived at by applying analytical process and rigor, and it is therefore appropriate to give it weight in the decision-making process used by the ultimate decision makers to decide whether or not to proceed with a project. The CPW is, however, based on inputs, many of which are forecasts and assumptions, and which may be wrong. Sensitivities are indicators of how much the CPW will change if one or more of the inputs into the modeling is different than was forecasted or assumed. As used in the Nalcor process, the sensitivities were not meant to model every possible outcome for the purpose of inputting them into some further probabilistic analysis, such as a Monte Carlo model. They were meant to provide indications of the direction and magnitude of change to the CPW if significant forecasts and assumptions changed.

In January 2012 MHI had delivered its report to the PUB, which was released publicly, and included in it the following table of sensitivity modeling that had been performed on the outcome of the Decision Gate 2 CPW analysis. The sensitivities addressed fuel prices and capital costs, had a scenario for a load decrease of 880MW equivalent to the closure of the paper mill in Corner Brook, and had two combination scenarios for changes in fuel costs, load and capital cost. (P-00048 pages 86-89.)

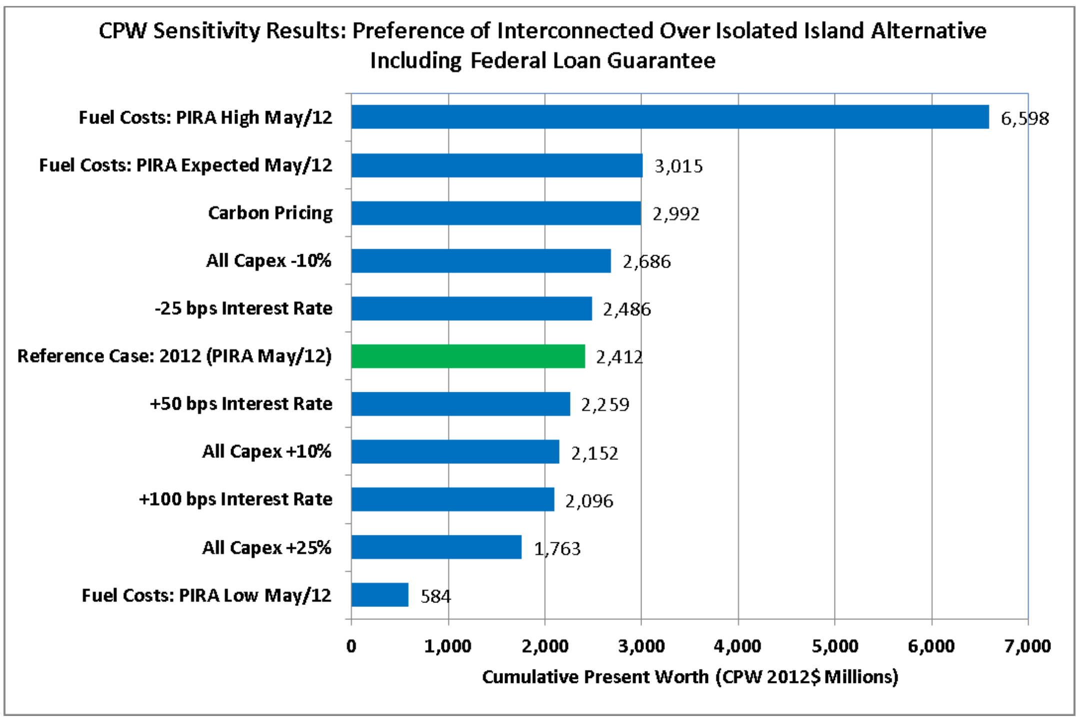
| | Sensitivity Summary | Isolated Island Option | Infeed Option | Difference |
|---|---|---|---|---|
| 1 | Base case | $8,810 | $6,652 | $2,158 |
| 2 | Annual load decreased by 880 GWh | $6,625 | $6,217 | $408 |
| 3 | Fuel costs: PIRA's low price forecast | $6,221 | $6,100 | $120 |
| 4 | Fuel price reduced by 44% from base case | $6,134 | $6,134 | $0 |
| 5 | Labrador-Island Link capital cost increased by 25% | $8,810 | $7,050 | $1,760 |
| 6 | Muskrat Falls GS capital cost increased by 25% | $8,810 | $7,229 | $1,581 |
| 7 | Muskrat Falls GS and Labrador-Island HVdc Link capital cost increase by 25% | $8,810 | $7,627 | $1,183 |
| 8 | Labrador-Island HVdc Link and Muskrat Falls capital cost increased by 50% | $8,810 | $8,616 | $194 |
| 9 | Scenario with<br>• Fuel cost decreased 20%<br>• Annual load growth decreased of 20%<br>• Capital cost increased for Muskrat Falls GS and Labrador-Island HVdc Link by 20% | $7,037 | $6,878 | $159 |
| 10 | Scenario with<br>• Annual load decreased by 880 GWh<br>• Muskrat falls GS and Labrador-Island HVdc Link Capital cost increased by 10% | $6,625 | $6,598 | $27 |

On February 17, 2012 Mr. Martin gave a presentation at a Cabinet Retreat that informed the members of Cabinet that CPW results could be significantly impacted by variations from the base case, specifically identifying load, such as the closure of the paper mill; capital costs; and fuel prices, said to be difficult to forecast over the long term (P-01616 page 10). The presentation included a different set of sensitivities than those that had been reported the month before by MHI. Among them were two scenarios for different levels of CDM savings and one for low load growth (P-00616 page 14).

On May 29, 2012 Natural Resources Minister Kennedy endorsed a Decision Note prepared by staff in his Department, approving the contract to retain MHI to complete the Decision Gate 3 report (P-01522 page 2). The appended contract included a scope of work that specified that MHI's review was to include an assessment and commentary on sensitivities for "revised capex variations", "fuel price variations" and "interest rate variations" (P-01522 page 14).

MHI delivered its report in October 2012, reporting a set of sensitivities in line with those specified in the contract. In interpreting the sensitivities MHI observed that the effect of an increase in oil prices on the difference in CPW was greater than the effect of a decrease. On the other hand, increases in interest rates had a greater adverse effect on the Interconnected Island case than on the Isolated Island case. The capital cost sensitivities were described by MHI as “directional indicators”, suggesting that the reader could extrapolate for the effects of larger deviations from budget on the CPW result. (P-00058 pages 75-77).

The November 2012 Decision Gate 3 Support Package incorporated the sensitivities from the MHI report, presenting them in the graphic below, and stating that the key levers in the CPW analysis were oil prices for the Isolated Island Option and capital costs for the Interconnected Island Option.




The green bar shows the $2,412 million CPW difference between the Interconnected Island and Isolated Island Options. The three alternative PIRA oil price cases are modelled, showing higher CPW preferences for the high and expected cases, and a reduced preference if the low case is used. Capital expenditures are modeled at 10% below the estimate, 10% above the estimate and 25% above the estimate. Effects of increases and decreases in interest rates and of imposition of greenhouse gas carbon pricing are modeled also. Each sensitivity is explained in the Decision Gate 3 Support Package (P-00121 pages 91-94).

Pelino Colaiacovo recommended a more elaborate process of using the sensitivities to run a large number of scenarios for nearly every combination of multiple variables. The results, he said, could then be analysed using Monte Carlo type methods, or they could be assessed more subjectively. He testified to the effect that the knowledge necessary to conduct modeling in this way exists in the industry, but there are no standard-setting authorities or reference materials that can be referred to for a description of how to go about it. He was aware that Manitoba Hydro had used a similar approach to that which he recommended for a project in 2013, but could not explain why MHI did not bring the same approach to its analysis of the Project Sanction decision. (Pelino Colaiacovo July 18, 2019 pages 5-16.)

## 4. Project Costs

This section addresses matters related to Term of Reference 4(b) as follow:

4.1 Term of Reference 4(b)
4.2 The Estimated Costs at Sanction
4.3 Revisions to the Estimated Costs
4.4 Currently Estimated Costs to Completion
4.5 Difference Between Estimated Costs at Sanction and Currently Estimated Costs to Completion
4.6 Project Management – Term of Reference 4(b)(i) to (iv)
4.7 Risk Assessments – Term of Reference 4(b)(v)
4.8 Commercial Arrangements – Term of Reference 4(b)(vi)

### 4.1. Term of Reference 4(b)

Term of Reference 4(b) directs the Commission to inquire into why there are significant differences between the estimated costs of the Project at sanction and costs incurred during Project execution to the time of this Inquiry. The Commission is to inquire into reliable estimates of the costs to the conclusion of the Project. Six specific areas of inquiry are to be included.

This section of this submission will address the cost estimate at sanction, amendments to the cost estimate after sanction, and the currently estimated cost to complete the Project, and provide some comment on differences between the sanction estimate and the current estimate. Each of the specific areas of inquiry listed in Term of Reference 4(b) will then be discussed separately.

## 4.2. The Estimated Costs at Sanction

The estimated capital cost of the Project at time of sanction, $6.2 billion, was composed of a base estimate, estimate contingency and an escalation allowance. It excluded financing costs. The base estimate and escalation allowance are discussed in this section 4.2. The estimate contingency is discussed in section 4.7.

### 4.2.1. Methodology for Preparation of the Estimated Costs

The methodology employed to prepare the capital cost estimate for the Project is documented in the following Project materials:

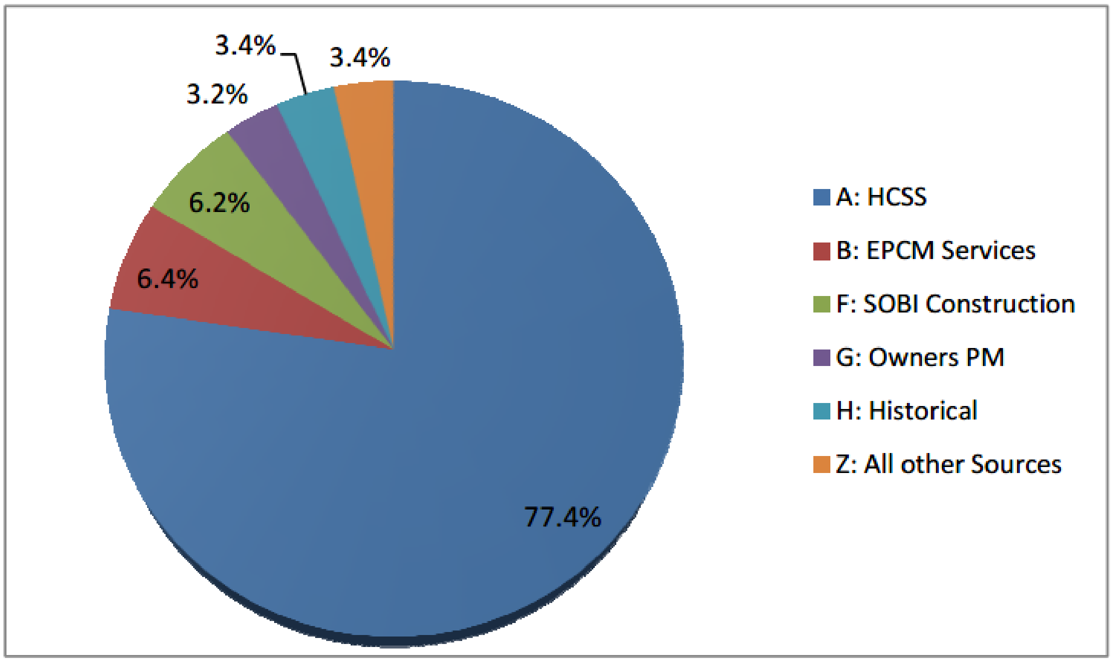
- Decision Gate 3 Basis of Estimate, revision B1 issued for use December 3, 2012 (P-01193), revision B2 issued for use May 22, 2013 (P-00094).
- Decision Gate 3 Capital Cost Estimate revision B1 issued for use December 11, 2012 (P-00124).
- Decision Gate 3 Capital Cost Escalation Report revision B1 issued for use October 4, 2012 (not exhibited but referred to at P-00124 page 13).
- Decision Gate 3 Project Cost and Schedule Risk Analysis Report version B1 issued for use October 1, 2012 (P-00130).

The Basis of Estimate is a 315 page document that includes description of the estimating approach and methodology, cost estimate inputs, processes for estimate review and benchmarking, and changes to the estimate since Decision Gate 2. Detailed sections are included on estimation of owner's costs and EPCM costs, and on costs of Muskrat Falls Generation, HVdc specialties and switchyards, overland transmission, the SOBI crossing, and Island Interconnected System transmission upgrades. The purpose of preparation of this document was to capture the history of the development of the estimate so that the project team could measure and manage change against it (Jason Kean November 8, 2018 page 6).

### 4.2.2. The Base Estimate

The Decision Gate 3 Capital Cost Estimate document reports on the results of the application of the principles and processes from the Basis of Estimate to the build up of the base estimate (P-00124 pages 18-23). Figure 11-1 from that document shows the sources for contribution to the base estimate.

**Figure 11-1:** DG3 Base Capital Cost Estimate Contribution by Source




Nalcor had responsibility for preparation of the estimate of construction costs for the SOBI crossing (P-00094 pages 251-261, P-00124 page 21), owner's project management costs (P-00094 pages 88-113, P-00124 page 21), and the allocation of historical Project costs (P-00124 page 22).

SNCL was responsible for preparation of an AACE Class 3 estimate for the construction costs of components 1 – Muskrat Falls generation, 3 – HVdc specialties and switchyards and 4 – overland transmission, all included in the figure above as "HCSS" which was the software tool used by SNCL, and for estimation of the EPCM services costs, which together comprised more than 80% of the base cost estimate (P-00124 page 20, 34).

SNCL had been awarded the EPCM contract in February 2011. The preparation of the construction cost estimate was led by SNCL Chief Estimator Paul LeMay, who had extensive experience in heavy civil estimating and, in particular, in estimating and construction management of hydro-electric projects for Hydro-Quebec and Ontario Power Generation (P-00866). Mr. LeMay built an estimating team of people with specialized expertise that included hydro-electric plant concrete placement and power transmission (Paul LeMay November 1, 2018 pages 78-79). SNCL's estimating work was underway by

June 2011 (P-02637) and was carried out by preparing a new estimate from the ground up and not by working from the Decision Gate 2 estimate (Paul LeMay November 1, 2018 page 81).

The construction cost estimate was delivered to Nalcor on December 15, 2011 (P-02472). It was presented with 42 binders of supporting material (P-00124 pages 45-84). Concrete placement and formwork made up a significant part of the powerhouse and spillway estimate, and SNCL benchmarked its estimate against productivity data available to it from a number of hydro-electric power developments in Quebec and Ontario (P-02644, P-02645), including Eastmain 1 and Eastmain 1A (Paul LeMay November 1, 2018 pages 104-105, March 28, 2019 pages 81-86). Mr. LeMay testified that an extra 20% or about $200 million, that he described as an allowance, was added to the estimate. It was derived using the benchmarking data to account for risk of lower labour productivity on the Project (Paul LeMay November 1, 2018 pages 90-91, 105-106, March 28, 2019 pages 97-98). That allowance was in addition to the consideration of labour productivity risks for the purpose of assessing contingency and reserves discussed in section 4.7 of this submission.

After delivery of the SNCL estimate, Nalcor identified a number of quality issues and deficiencies that were communicated to SNCL (P-00856, P-00857, P-00862 page 19, Jason Kean November 8, 2018 pages 1-2). Over the next several months Nalcor and SNCL personnel worked together to resolve the outstanding issues and to complete a final construction estimate for components 1, 3 and 4 (P-00869, P-00870, Jason Kean November 8, 2018 pages 2-5).

The estimate of EPCM services costs SNCL delivered in December 2011 for inclusion in the base cost was for about 5.5 million reimbursable person hours, compared to its estimate prior to the award of the EPCM contract of about 2.5 million person hours, adding about $350 million to the base estimate (P-00858 pages 2-3). SNCL and Nalcor then engaged in a process, described in the Basis of Estimate, to finalize the amount for EPCM costs that would be included in the base estimate (P-00094 pages 115-120).

#### 4.2.3. Escalation Allowance

The escalation allowance is the provision for changes in price levels driven by economic conditions, including inflation. It is estimated using economic indices weighted against the base estimate components. (P-00124 page 5.) The escalation allowance was prepared following the completion of the base estimate described above. Details concerning the calculation of the escalation allowance are contained in the Decision Gate 3 Capital Cost Escalation report (produced to the Commission by Nalcor as document NAL0019635).

#### 4.2.4. Reviews of the Estimated Costs

Prior to sanction several internal and external reviews of the capital cost estimate were completed (P-00094 pages 71-73).

##### 4.2.4.1. Check Estimates

Two check estimates for the generation component were independently prepared by Paul Hewitt and John Mulcahy, a check estimate for reservoir clearing was done, and a check estimate was prepared for transmission lines and switchyard civil work by Des Butt. All were prepared by people with lengthy experience as contractors, who prepared the estimates as if they were bidding for the work (Jason Kean November 8, 2018 pages 7, 109-110, John Mulcahy May 2, 2019 pages 12-15). The check estimators were free to apply their own means and methods for performance of the work and to use their own sources of data. The purpose of the check estimates was not to replicate the work of SNCL, but was to provide an assurance that the overall estimation of costs was within a reliable range.

##### 4.2.4.2. Validation Estimating, LLC

The Basis of Estimate document refers to an estimate review by John Hollman of Validation Estimating, LLC, which was commissioned by Jason Kean in March 2012. The purpose was to determine whether the estimate satisfied the objectives of meeting industry requirements for an AACE class 3 estimate; of serving as a basis for the Decision Gate 3 economic evaluations; and of serving as a basis for control budgeting during execution of the work (P-00094 page 73). Mr. Hollman conducted his review of the estimate as it existed on April 2, 2012. He described the estimate as still undergoing final changes and corrections and that contingency and escalation estimates had not yet been done (P-00610 page 6). Primary documents he reviewed are listed in his report and include the set of binders delivered by SNCL on December 15, 2011 presenting the base estimate, quantity take-off binders, a labour rates study and the Hewitt and Mulcahy check estimates (P-00610 page 8).

The Validation Estimating report begins with the statement that, “the findings and recommendations in this Executive Summary are focused on the quality of the deliverables and results at this point in time and recommendations to improve it by Gate 3 and thereafter.” Regarding the first objective of the review, the report states that the estimate, “meets the requirements for an AACE International Class 3 estimate,” noting that meeting the classification does not determine estimate accuracy, which must come from risk analysis. Regarding the second objective, the report states that the, “estimate is appropriate for use in Gate 3 economic analysis,” with the exception that a probabilistic estimate distribution of the capital cost should be produced. Regarding the third objective, the report states that the, “estimate is appropriate for use as an Execution phase project controls basis,” with several noted exceptions. (P-00610 page 4.)

The assessment findings section of the report opens with the paragraph below, reproduced in full, which is followed by a detailed commentary and critique, including in relation to risk analysis issues:

> First, it should be noted that while not perfect, the LCP Gate 3 estimate in its current state is one of the best mega-project "base" estimates that this reviewer has seen in some time. My conclusion is that this is in large part due to the active involvement of the owner leads in striving for best practices and quality within the construct of a solid phase-gate system. They have made the most of the workmanlike contractor resources. The typical case in Industry is minimal owner guidance and oversight of an often disjointed estimating process and team. The critiques below should be read in the light of the estimate being of generally good to high quality. Everyone was cooperative and helpful.
>
> (P-00610 page 10)

The Validation Estimating report was delivered as a draft on April 9, 2012 to Mr. Kean who shared it with Mark Turpin, who was assisting him in the process of estimate finalization. There is no documentary evidence that the report itself was further shared within the Project organization, or subsequently provided to anyone external to Nalcor, and although Mr. Kean testified that he would have expected that others on the management team would have been aware of the report he did not recall specifics of communicating it to them (Jason Kean November 7, 2018 page 76). An excerpt from the paragraph quoted above was used in internal presentations and was picked up and used in external communications concerning the quality of the base estimate.

Jason Kean testified that his purpose in requesting Mr. Hollman's involvement was to have him validate the process used for putting together the base estimate, as an "internal working level review" or a "peer review". He testified that risk analysis for Decision Gate 3 had not been done when Mr. Hollman conducted his review, that the scope of Mr. Hollman's work was centred around the base estimate and not risk analysis and he consequently regarded Mr. Holman as having drifted off course in the report (Jason Kean November 7, 2018 pages 70, 73). Mr. Hollman did not testify at the Inquiry hearings.

After the Validation Estimating report was delivered, risk workshops facilitated by Westney were held in May 2012 and probabilistic risk assessments were prepared as described in section 4.7 of this submission. Work continued to complete the estimate for use in the economic analysis and as a basis for control budgeting following project sanction.

#### 4.2.4.3. Manitoba Hydro International

The Basis of Estimate document also refers to review of the capital cost estimate by Manitoba Hydro International (P-00094 page 73).

MHI had originally been retained by the PUB as an independent consultant and had delivered a report in January 2012 (P-00048, P-00049). Following the inconclusive review by the PUB of the least cost option question, government retained MHI directly to provide an independent assessmentof the two generation supply options for the future supply of electricity to the Island. MHI was to determine which was the least cost option at Decision

Gate 3 and to complete a reasonableness review of all inputs into the analysis (P-00058 page 7). Nalcor was consulted by government on the scope of work to be given to MHI, but the decisions on what was to be included in that scope of work were made by government. MHI was not retained by Nalcor.

The MHI work was carried out by a team with assigned roles. Three witnesses who testified from MHI were involved in organization and direction of the work of the team members who engaged directly with Nalcor personnel, and were involved in consolidation and finalization of the report. (MHI Panel October 29, 2018 pages 84-91). Aside from some initial disclosure issues that were worked through, there were no reports to the members of that panel from those on the team who directly carried out the review work that they had not been able to obtain the information and documentation from Nalcor that they needed to complete their work (MHI Panel October 30, 2018 pages 10-17). Drafts of the MHI report were provided to government for review, and through government to Nalcor personnel, which the members of the MHI panel testified is normal practice. Comments were invited, but they testified that there was no pressure placed on them by government or Nalcor to change the content of their report (MHI Panel October 30, 2018 pages 27-29).

The MHI report to government on October 26, 2012 includes statements that the capital cost estimates for the HVdc transmission system and Muskrat Falls generation were within the AACE Class 3 estimate accuracy consistent with use for decision making at Decision Gate 3. The language used to describe the estimate of the cost of the Labrador Transmission Assets was slightly different but comparable, stating that the “estimate is comprehensive, reasonable and prepared in a manner consistent with the best utility industry practice”. (P-00058 pages 43, 52, 58, 59.)

#### 4.2.5. Communication of the Estimated Costs at Sanction

There is no controversy about whether the $6.2 billion capital cost estimate was communicated to the Nalcor board, to government and to the public. Communication of the consideration of risk, both included in and excluded from the $6.2 billion capital cost is discussed in section 4.7 of this submission.

### 4.3. Revisions to the Estimated Costs

Project capital costs were authorized by the Authorization for Expenditure (AFE) process, beginning with approval of an AFE by, at first the Nalcor board, and later the boards of the subsidiary corporations responsible for the Project components. Changes to these AFEs were not made without consultation with and approval of the province. Decisions about communication of capital cost information to the boards and to government were reserved to Nalcor CEO Ed Martin.

Under the processes and procedures in place, the timing of revision to AFEs was driven by the need to commit funds to project expenditures, rather than having as its direct objective the communication of the estimated final forecast cost of the Project as it might be assessed from time to time. Public announcement of changes in Project estimated costs, at least prior to June 2016, has generally coincided with revisions to AFEs, which followed the internal Nalcor assessments of potential increases in the estimated final forecast costs of the Project.

#### 4.3.1. December 2013 Cost Estimate at Financial Close

At the time of Financial Close on November 29, 2013, and for the purpose of implementing the financing for the Project including the Federal Loan Guarantee, the estimated capital cost of the project was updated to $6.53 billion. One of the factors contributing to the need to update the estimate was the inclusion in the federal loan guarantee arrangements of the COREA, or capital cost overrun escrow account, which required annual funding by the province of projected future cost overruns. Updating the estimate of the cost of the Project at Financial Close, and starting the COREA calculations at that number, meant that the province would not have to make a COREA contribution at the end of 2013.

For each work package, LCP Project Controls has tracked the original budget cost, contract award value, agreed cost changes, and potential trends for future cost changes, and has reported that information monthly. While tendering was still underway and there were therefore controls on the distribution of bid information among the project team, two monthly project team meetings were held to review cost reports. The first was with a large group where higher level information was presented. The second was with senior members of the project team, who contributed their assessments of the quantification of potential future changes in cost. (Tanya Power May 24, 2019 page 28.)

The result of the latter meeting was a “management outlook” that attempted to predict a final forecast cost based on the information then available. Based on that work, the project team periodically reported an “indicative” cost forecast up to the CEO, Mr. Martin. Gilbert Bennett, the Vice President for the Lower Churchill Project, although positioned between the project management team and the CEO on the organization chart, did not screen the information that came from the team before transmittal to the CEO. In practice, Mr. Bennett sometimes participated in the project team meetings where input to the management outlook was given, and at other times was the recipient of the forecast at the same time as Mr. Martin was. In either case it was clearly understood that Mr. Martin was the gatekeeper for communication of that information to the boards and to government.

The first indicative review of the final forecast cost (FFC) was presented to Mr. Martin and Mr. Bennett on July 22, 2013 (P-02510). It indicated an unmitigated FFC of about $7.0 billion, or $6.8 billion with identified mitigations. The forecast was based in part on contracts for which bids had been received, but which were not yet finally negotiated and awarded. Project Controls cost reports used by the management team to develop this management outlook are identified in the report prepared for the Commission (P-03779 page 1-2) and show FFCs of between $6.9 and $7.0 billion.

The next presentation of an indicative forecast to Mr. Martin on August 29, 2013 was for about $6.9 billion, over $100 million lower than in the month before (P-01821 pages 23-46). Potential mitigation to $6.8 billion was reported. The review basis was reported as considering cost reporting up to June 30, 2013 and levering insights from all RFP proposals received up to that date (P-01821 page 40). The Project Controls cost report files from August 2013 show FFCs ranging between $6.81 billion and $6.95 billion (P-03779 page 2).

A third presentation of an indicative forecast, this time presented as a range from about $6.7 billion to $6.95 billion, took place on September 12, 2013 (P-01826). The cost growth was attributed to market conditions and contractor's views on labour productivity which was driving bids higher than estimated. The Project Controls memo reports two cost report files dated between the date of that presentation and Financial Close, one with an FFC of $6.93 billion and the second for $6.81 billion (P-03779 pages 2-3).

By November 1, 2013 Nalcor Finance was looking for an update of the Project capital cost for the purpose of finalizing the financial models (P-04053), and by November 6 had been made aware that there was an approximate $300 million increase to about $6.5 billion (P-02206 page 29, P-02524). On November 15, 2013 Project Controls provided a report titled "Material Contracts Cost Summary" showing the FFC to be $6.531 billion. The Material Contracts selections align with a designation used for the purposes of the financing. A reconciliation of the $6.531 billion to the Decision Gate 3 estimate of $6.202 billion was also provided (P-02215). In his testimony Mr. Bennett explained his understanding that the indicative FFC numbers in the management outlook presentations before Financial Close were intended to be an indication of where the FFC might go, whereas the lower FFC number used at Financial Close was the more certain amount that would be used for an AFE if one were to have been put in place at that time (Gilbert Bennett June 25, 2019 pages 50-51). Otherwise there was limited evidence on the criteria used to calculate the $6.531 billion number. We can infer, however that the number should be a fair assessment of what was expected to be the final forecast cost based on what was known at the time. This is because there were two competing interests against which it could be tested. One was that it was prepared for submission to Canada as part of the loan guarantee arrangements, and for that purpose it was to be scrutinized and approved by the Independent Engineer, implying a more conservative approach. The other is that a higher capital cost at Financial Close would reduce future contributions by the province to the COREA, implying a less conservative approach.

In early 2014 documentation was prepared to formally change the AFE to $6.531 billion, but that process was overtaken by the assessment that led to the $6.99 billion AFE in June of that year (P-02401).

#### 4.3.1.1. Communication of the Estimated Capital Cost at Financial Close to Canada and Independent Engineer

On November 19, 2013 Mr. Martin approved the final form of the Material Contracts Costs Summary and Reconciliation to DG3 (P-03605 page 3) and they were posted to the data room used for securely sharing documents with the representatives of Canada and the Independent Engineer (P-02217).

#### 4.3.1.2. Communication of the Estimated Capital Cost at Financial Close to the Government of the Province

When the Material Contracts Cost Summary and Reconciliation to DG3 were posted to the dataroom, they were accompanied by instructions to, “not provide access to NL, BLG and Faskens at this time” (P-02217). When this message was first referred to in the Inquiry hearings it was received as if there had been a deliberate attempt by Nalcor to hide the capital cost increase from government. As the testimony progressed and more documents were introduced as exhibits, it became clear that was incorrect.

On November 13, 2013 a decision had been made to formally communicate the increased capital cost by briefing Deputy Minister of Finance Donna Brewer. That decision had been communicated to Nalcor Chief Financial Officer Derrick Sturge by Deputy Minister of Natural Resources Charles Bown, who had spoken to Ed Martin about it (P-02523 page 10). Early on November 20, 2013, the day after the information had been posted to the dataroom, Mr. Sturge sent an internal reminder that the meeting needed to be arranged with Ms. Brewer and Paul Myrden, also with Finance (P-02535). The meeting took place the next day on November 21, 2013 (P-02523 page 20, P-03447). The following day, November 22, 2013, Mr. Myrden made explicit reference to the $6.5 billion capital cost at Financial Close in a message to Ms. Brewer (P-03494).

Ms. Brewer testified that she was aware of the $6.5 billion amount, that it had been discussed in the context of the COREA account, and that she knew that it represented an actual increase in the budget (Donna Brewer June 17, 2019 page 5-8).

As for whether the Material Contracts Cost Summary and the Reconciliation to DG3 documents were provided to government, Mr. Meaney testified that the dataroom used for giving document access to the province was open to many people and that the reason for not posting the capital cost information there on November 19 was because information would first have to be communicated at higher levels, normally by Mr. Martin (James Meaney March 22, 2019 pages 27-28). The dataroom was closed before the Inquiry was called, so limited information about the dates and times at which documents were posted and accessed is available. However, we do know that two documents with the same file names as those disclosed to Canada on November 19, 2013 were present in a dataroom called "Finance Data Room" on March 26, 2014 (P-02843 page 3) and that persons with access to that dataroom included Mr. Bown, Ms. Brewer and Mr. Myrden (P-02843 page 2).

#### 4.3.2. June 2014 Cost Update – AFE Revision 1

On June 26, 2014 an increase in the capital cost of the Project to $6.99 billion was announced. The cost increase had been approved by the Nalcor board on June 20, 2014 and revised AFEs were approved by the subsidiary boards responsible for Project components (P-00687, P-04538). In his report to the Lower Churchill Management Corporation board Mr. Martin stated that, "The risk of further significant increases in capital costs are being mitigated by the fact that almost all of the engineering has been completed and most of the contracts have been let, however, there could be further cost increases as the project proceeds." Mr. Martin had stated publicly on April 15, 2014 that the Project was under cost pressure but that he would not announce a new cost update while major contracts were still being negotiated (P-02547).

The June update had been preceded by a project management team briefing of Mr. Martin on May 23, 2014 recommending a revision of the AFE to $6.99 billion, but also recommending $272 million in management reserve[1] for the period through early 2016, and a further management reserve of $230 million that would not be required until 2016 (P-01831 pages 6-14). If the two management reserve amounts were included, the total forecast would be $7.5 billion, which is approximately the same as the FFC amounts in the Project Controls cost reports from May 2014.

[1] Management reserve is discussed in section 4.7 Risk Assessments

#### 4.3.3. September 2015 Cost Update – AFE Revision 2

On February 13, 2015 the project team reported to Mr. Martin that an increase in AFE to $7.77 billion was needed to bring the Project to completion, subject to a number of assumptions outlined in their presentation (P-02549). At the Muskrat Falls Corporation board meeting on March 5, 2015 Mr. Sturge noted that Mr. Martin started signalling that there was pressure on costs but that the outcome was not yet clear (P-02630 page 2). By March 6, 2015 Mr. Martin had spoken to Mr. Harrington about planning a project cost update session with senior government people (P-01830 page 3). On March 9, 2015 Mr. Martin and Mr. Sturge met with senior government personnel Charles Bown, Julia Mullaley and Craig Martin (P-02630 page 3). Mr. Sturge's notes include "MF Update", references to North Spur, dams and Astaldi, and the figure "$7.5". On the following day Mr. Martin and Mr. Sturge met Premier Davis and Minister of Natural Resources Derrick Dalley. Charles Bown and Julia Mullaley, who had been at the meeting the day before also attended. Mr. Sturge's notes refer to "MF Costs" and list "(1) North Spur (2) Dams (3) Balance of Plant" (P-02630 page 4). It is reasonable to conclude that on March 9 and 10, 2015 senior government civil servants and politicians were informed of the potential increase in Project costs to about $7.5 billion.

On about August 16, 2015 Mr. Martin and Mr. Bennett gave a Project Update presentation to Premier Davis, the Minister of Finance, and others that presented the estimated capital cost as $7.65 billion with the growth attributed as $462 million due to market conditions and pressures, $120 million for construction design changes and $81 million arising from contractor performance and project management execution (P-03960 pages 12-14, 20-21, 61-69). Revised AFEs were approved at meetings of the Muskrat Falls Corporation board on September 8, 2015, the Labrador-Island Link and Labrador Transmission Corporation boards on September 22, 2015.

The representatives of Canada and the Independent Engineer had been advised of this increase in capital costs relatively late in the process. On October 16, 2015 Canada's legal counsel wrote Nalcor requesting a meeting to discuss revisions to the reporting requirements so as to allow them better insight into future cost increases (P-02290). A meeting followed on October 30, 2015 and a set of guidelines were prepared (P-02291). There have been no complaints since then.

Pursuant to the Project Financing Agreements, Nalcor delivers monthly Construction Reports to the Toronto-Dominion Bank, as Collateral Agent and to MWH Canada Inc., as Independent Engineer reporting prescribed information. The correspondence from Canada's legal counsel on October, 2015, took no issue with the accuracy or adequacy of the Construction Reports. The form of the reports and the manner of presentation of the cost information contained in them did not change after the September 2015 cost update. The costs reported in the Construction Reports are measured against approved AFEs only, as has been disclosed in the body of the reports when AFE amounts have been changed (P-02402 page 10, P-02403 pages 6, 19, 20, P-2407 pages 6, 8, 9, Gilbert Bennett June 26, 2019 pages 92-100). Mr. Meaney in his testimony was pressed by Commission counsel on the point of whether the Construction Reports were misleading. He explained that the reporting of the final forecast cost for the purpose of the Construction Reports was linked to the AFE, and only when repeatedly told to put that explanation aside did he say, "then based on that, I guess the statement wouldn't be accurate." (James Meaney March 22, 2019 pages 119-0123.) Mr. Meaney was later said to have made an admission that the Construction Reports as submitted contained misleading information, which he had not. Furthermore, Canada continued to accept the Construction Reports without complaint in the same format as before.

#### 4.3.4. June 2016 Cost Update – AFE Revision 3

Stan Marshall had replaced Ed Martin as CEO of Nalcor in May 2016 and committed to giving a cost and schedule update in June. He explained his approach in his testimony to the Inquiry:

> So the cost update I gave in 2016, very little time to do it, all I did was call in the executive, talk – bring in the management team, go through all the risks they had identified, made a determination of, you know, the level of risk that I wanted to take, and picking up – I said – I thought it was more important that we get a number out there quickly, that was generally right, rather than to spend months trying to get a more precise number. It turns out it wasn't bad.
>
> And also I indicated at that time, that there was some real uncertainty because of the Astaldi situation, for example.
>
> (Stan Marshall June 28, 2019 page 46.)

On June 22, 2016 Mr. Marshall made a presentation to Cabinet projecting in-service capital costs of $9.1 billion, $11.4 billion with financing (P-04353). On June 24, 2016 he held a news conference to announce the cost increase, stressing that it was only a projection (P-04352).

#### 4.3.5. December 2016 Cost Update – AFE Revision 4

In December 2016 an interim assessment of project costs at $9.7 billion was made, taking into account the Astaldi Completion Agreement, indicative costs from the disruptions of construction by protests at the site in October, and problems with the cofferdam and the HVdc conductor (P-00127 page 11).

#### 4.3.6. June 2017 Cost Update – AFE Revision 5

On June 23, 2017 an increase in the cost estimate to $10.1 billion was announced. The change since June 2016 was attributed in the press release to the Completion Agreement with Astaldi, costs related to the cofferdam and the HVdc transmission conductor repairs, worksite delays and interruptions in October 2016, settlement of claims with other contractors and an allowance for settlement of remaining claims (P-03187). A Nalcor presentation broke down the changes as an additional $270 million for the Astaldi settlement, $140 million for settlement of claims by Valard for transmission line construction, $90 million for unplanned work, $50 million for the direct cost of a three month delay, $60 million for the amount that the award value of the Balance of Plant contract exceeded the estimate and a $400 million increase in the estimate for future settlement of claims for delays and changes (P-00127).

The Nalcor Board of Directors had been briefed on the cost increase on June 20, 2017 (P-00721 page 3).

The cost estimate took into account an updated risk assessment for Muskrat Falls Generation prepared by Westney in May 2017 (P-01833).

### 4.4. Currently Estimated Costs to Completion

Nalcor has provided the Commission with monthly cost reports produced by LCP Project Controls (see P-03764 for a redacted example). Those reports were described in the testimony of Tanya Power. The latest available report is for June 2019 and has been provided to the Commission as a confidential exhibit. Subsequent monthly cost reports will be provided confidentially to the Commission as they become available. The reported final forecast cost has not changed from the $10.1 billion reported publicly on June 23, 2017.

The cost reports disclose the amounts of contingency carried within the budget that have not been committed to be spent. They also identify risks, such as the risk of a government directive to remove soil from the reservoir area and risks associated with conducting this Inquiry before completion of the Project, that are not included in the final forecast cost.

At the request of the Commission Nalcor also prepared an analysis, entered as a confidential exhibit, of 45 of the larger contract packages itemizing for each package the original Decision Gate 3 estimate; transfers between packages and the resulting revised Decision Gate 3 estimate; the estimated package value at time of contract award; the estimated package cost at Financial Close, AFE1, AFE2, AFE3, AFE4 and AFE5; the current control budget amount, the potential trends amount, the amount expended and the amount left to spend as of February 28, 2019.

### 4.5. Difference between Estimated Costs at Sanction and Currently Estimated Costs to Completion

A complete analysis of the difference between the capital costs estimated at sanction and those currently forecast would require a work package by work package analysis beyond the scope of this submission. The Grant Thornton Construction Phase report partly isolated elements of cost growth for the larger packages, but did not attempt to fully reconstruct specific work package changes.

At a higher level, a number of contributors to cost growth can be identified.

#### 4.5.1. Work Package Award Values

In many cases the proposals received from bidders on work packages were priced higher than had been estimated. Comparisons for all the major work packages are shown on the Analysis of Contracts report submitted by Nalcor to the Commission as a confidential exhibit.

While there were early indications that this would be a problem, the CH0007 Powerhouse and Spillway contract being one, the full extent of the difference could only be appreciated over time, since proposals were called for and contracts let over a period of years into the execution phase of the project. Package CH0031 for Balance of Plant was not contracted until June 2017 (P-01863). These differences have been attributed to market forces outside of the control of those executing the project, and to later contractors building the observed labour productivity at the Muskrat Falls site into their bids. Whether this a reflection on the quality of the base estimate work, or purely the materialization of risks classed as strategic is difficult to say.

#### 4.5.2. Astaldi Productivity Failure

The second significant contributor is the failure of Astaldi to productively execute the CH0007 work, particularly in 2014, and its impending insolvency in 2016 that was postponed only by infusion of funds through the Bridge Agreement and the Completion Agreement. The direct cost of the amounts paid to Astaldi over and above its entitlement under the original contract can be calculated. The cost of “knock-on” effects on other contractors can be assessed more easily for some than others. The cause of Astaldi's 2014 failures was clearly disorganization and mismanagement on its part. Nalcor intervened early and to good effect to help substantially turn the situation around. While it may have been too late to recover from the impact on Project schedule, the terms of the CH0007 contract would have protected Nalcor from Astaldi's extra cost, particularly for labour in excess of the LMAX amount. It was the insolvency of Astaldi Canada's Italian parent that undermined what would otherwise have been a position of strength, meaning that Nalcor had to choose the better of two bad options – replace Astaldi or pay it more money to keep the work going.

### 4.5.3. HVdc Transmission Line

A third area of cost growth was the HVdc transmission line construction carried out by Valard and a number of smaller right-of-way clearing and access road contractors. Former Power Supply Executive Vice President John MacIsaac gave a summary of payments made under the Valard HVdc contract and of mitigation measures that were taken by Nalcor (John MacIsaac June 11, 2019). Cost increases were contributed to by geotechnical conditions that differed in some areas from those on which the estimate had been based, and by refinements of the design of some physical components of the transmission line and upgrading of the quality of access roads to improve reliability.

#### 4.5.3.1. Geotechnical Investigation

The estimates for the costs of transmission line construction were prepared by SNCL as part of their work under the EPCM contract to prepare the base estimate for Decision Gate 3. SNCL estimators had experience with construction of transmission lines over similar terrain in Quebec. Portions of the route of the HVdc line in Labrador and on the Island were through wilderness without existing road access, making complete geotechnical investigation difficult and expensive. The geotechnical conditions were assessed by various means, including test pits, bog probes and boreholes as documented in the investigation reports (P-01900, P-02861, P-02862, P-02863, P-02859, P-02860).

Witnesses from Valard testified that these reports described the general types of investigations they would have expected to have been done. They were aware that SNCL had confidence in their estimate of the numbers of different types of transmission tower foundations, at different costs, that would be required. (B.J. Ducey and Kelly Williams April 3, 2019 pages 47 to 52).

Because of the geotechnical conditions encountered in the field, larger numbers of expensive foundations were required than had been estimated. Diligent mitigation efforts were undertaken, as described in the testimony of Jason Kean and John MacIsaac, but there were increased costs.

#### 4.5.3.2. Reliability Criteria

The evolution of the design standards for the transmission line was explored in the examination of Gilbert Bennett by Commission associate counsel Mr. Collins. Mr. Bennett explained that transmission line structures are designed to withstand expected wind and ice loads, which will vary along different parts of the transmission line. A design that satisfies a return period of 1 in 50 years means that at each location along the transmission line route, the structures will withstand the worst wind and ice loading conditions that are probable to occur in a 50 year period at that location. There is no single set of design criteria that must be met to satisfy the 1 in 50 year standard. The design criteria will vary with the expected meteorological conditions. At Decision Gate 2, a 1 in 50 year return period was adopted for the LIL. NLH had experience in design and operation of transmission lines on the Island and it was their experience that was relied upon to calculate the structural loads that would have to be met based on the meteorological conditions anticipated along the LIL route. (Gilbert Bennett June 25, 2019 pages 15-32.)

In the PUB reference Nalcor filed a technical note on reliability of the LIL (P-01669) which explained the approach being taken to the transmission line design. It refers to CSA standards, including recommendations for return periods, which vary with the line voltage and whether the line is the only source of supply. In its submission to the PUB, Nalcor explained its rationale for the recommendation that the LIL be built to the 1 in 50 year return standard (P-00077 pages 138-145).

MHI reported that the 1 in 50 year reliability return period was inconsistent with the CSA standard and recommended that Nalcor consider building the line to a 1 in 150 year standard and to a higher standard in the remote alpine regions (P-00048 pages 13-14). The PUB agreed with that recommendation in its March 30, 2012 report (P-00052 pages 108-109).

Mr. Bennett testified that the design loadings used by NLH to meet a 1 in 50 year return period were higher than those required by the CSA standard (Gilbert Bennett June 25, 2019 pages 18, 20, 21). He further testified that the HVdc transmission line as built demonstrates compliance with either the 150 year or 500 year CSA standard, depending on the region (Gilbert Bennett June 25, 2019 page 32).

Jason Kean testified that transmission design work continued into 2015 (Jason Kean May 6, 2019 page 64). He said further:

> As DG3 progressed the intention, yes, was to move to that higher reliability period. And I believe it was officially adopted but, of course, the cost estimate didn't reflect that because the design didn't reflect that. Because the design had been frozen, you know, by Christmas of 2011 and had gone through that process of final checks in the winter. So there was no further engineering input to give final new design loading to change the – to give new designs and new weights and new pricing to support a one in 150, or one in 500. So in turn what occurred was that while the good intentions and statements were that from a design perspective we're going to have a one in 150, the DG3 price estimate didn't reflect that, and it was a disconnect internally, I would say.

Construction roads in remote areas of the transmission line were built to higher standards, at greater cost, than had been estimated. There was evidence that this was due to concern, following the Island-wide power outage in 2014, about how quickly remote portions of the transmission line could be accessed for repair, and there was also evidence that better quality roads facilitated efficiency in Valard's line construction work.

### 4.5.4. Risk Quantification

The approach taken to quantification of risk and inclusion of contingency in the estimated costs has changed since sanction with inclusion of strategic risks and selection of P75 values, which has contributed to the difference between the costs estimated at sanction and the current estimate.

### 4.5.5. Project Management Team Assessment

Several members of the project management team, with Mr. Kean as primary author, prepared a set of briefing materials that were delivered to Grant Thornton and the Commission, including a volume presenting an analysis of the factors contributing to the capital cost growth (P-01769).

## 4.6. Project Management

Terms of Reference 4(b)(i) to (iv) address matters related to management of the execution phase of the Project. The LCP project team developed and documented comprehensive strategies and plans in advance of the execution of the work, which were revised as needed in the course of Project execution. This body of documentation has guided the work of the whole team and shaped the project management structures that have been implemented. Before addressing Terms of Reference 4(b)(i) to (iv) separately, some elements of the larger project management structure will be reviewed. Many of these documents are comprehensive and detailed and should be read for their full content in order to understand the whole scheme of management of the Project.

### 4.6.1. Project Management Planning Documents

#### 4.6.1.1. Project Governance Plan

The Project Governance Plan (P-00081), although issued for review in January 2009 and not formally approved for use, is referenced in subsequent project management documentation.

It provides a high level description of the basic governance structure, methodologies and principles to be used for the Project, as envisaged when the Plan was prepared. Decision-making is discussed in section 12.1. Approval of financial expenditures is discussed in section 12.2 and the financial approval matrix setting hierarchical levels of approval authority is introduced. Section 13 deals with financial controls, including capital budgets, Authorizations for Expenditure, purchasing, and hiring of personnel. Contracting and procurement is addressed in section 15, internal audit in section 16 and management of change in section 17.

#### 4.6.1.2. Project Execution Plan

The Project Execution Plan (Scope and Approach) was first issued for review in August 2010, issued for use in September 2011 (P-01966) and later revised in March 2014 to reflect the change in project delivery model from EPCM to the integrated team (P-01967).

The Project Execution Plan is a foundational document for management of execution of the Project. Its purpose is stated to be to:

- Set out guidelines to ensure a consistent execution strategy and approach to the planning, organizing, directing and controlling of the Lower Churchill Project (LCP),
- Provide a basis to develop detailed procedures for the execution of the work,
- Provide a communication tool for the Nalcor Energy Lower Churchill Project (NE-LCP) Project Team and other project stakeholders, and
- Provide a high level overview of the LCP scope, facilities and execution strategy.

(P-01966 page 5, P-01967 page 5)

The Project execution delivery strategy is developed in section 10 (section 3 in the revision) where the division of responsibilities between Nalcor and the EPCM contractor is set out, the anticipated main supply and construction packages are listed, and the approaches to engineering, technical interface management and procurement are described, as is the general construction sequence for the components of the Project (P-01966 pages 34-55, P-01967 pages 26-33). Section 11 (section 4 in the revision) describes the organizational model including the roles of, and inter-relationships among, the Project Director, Project Managers and functional managers, as well as the concept of area-based management (P-01966 pages 56-60, P-01967 pages 34-43). The Plan continues with a listing of specific functional management plans and addresses financial control, project controls, management of change, risk management including identification of key risks and management strategies, quality management, health and safety management, environmental and regulatory compliance management and information management.

#### 4.6.1.3. Overarching Contract Strategy

The Overarching Contract Strategy document was issued for review in October 2011 (P-01177 and P-01941) and approved for use on February 29, 2012 (P-01942). The purpose is stated as:

> …. to outline the overall contractual strategy as implemented by Nalcor for development of Phase I of the lower Churchill River, including the Muskrat Falls Generation, Labrador Transmission Assets, and Labrador – Island Transmission

> Link. It includes an overview into the adopted process to determine this strategy, and insights into the reasons for selecting the overall management approach and contract packaging.
>
> (P-01942 page 8)

This document contains a valuable summary of the process and approaches used to develop the optimum contracting strategies, and the considerations that were taken into account. See in particular section 7.4 Contracting Strategy Formulation Process (P-01942 pages 22-23), 7.5 Major Formulation Steps & Timeline (P-01942 pages 23-26) and 8.0 Overall Project Delivery Method Selection (P-01942 pages 29-40).

The high level contracting strategy selected for the supply and construction activities for the physical works within each of the three Project components of Muskrat Falls Generation, Labrador Transmission Assets and Labrador-Island Link is set out in 9.0 Overall Contracting Strategy Design (P-01942 pages 41-55). Included within this section is discussion of procurement, specific contract provisions, contract types, and considerations for achieving the maximum extent of firm pricing and cost certainty.

Considerations leading to the selection of the EPCM model for project management are detailed in 10.0 EPCM Contracting Strategy (P-01942 pages 56-61).

Specific contracting strategies are elaborated for Muskrat Falls Generation (P-01942 pages 62-75), the Labrador Transmission Assets (P-01942 pages 76-84), and the Labrador-Island Link (P-01942 pages 84-98). In each case there is discussion of the strategic guidelines and considerations applicable to the Project component, and separate consideration of the strategy for each major contract package within that component.

The Overarching Contract Strategy is also summarized in the Grant Thornton Construction Phase report (P-01677 page 106-107).

#### 4.6.1.4. Procurement Management Plan

The Procurement Management Plan, issued for review in March 2011 and issued for use in February 2012 (P-03534), is an implementation of the Overarching Contract Strategy.

It "provides guidance and references key supporting plans and procedures that define the manner in which procurement of goods and/or services will be undertaken and managed by Nalcor for the Project". It includes a Procurement Management Guide in section 7.0 (P-03534 page 12) and lists separately documented procedures for specific procurement activities in Table 9.0 (P-03534 page 22).

##### 4.6.1.5. Construction Management Plan

The Construction Management Plan was issued for review in April 2012 and issued for use in May 2012 (P-03275). It was revised and reissued in April 2014 to reflect the transition from the EPCM project delivery model to the integrated team model (P-04028). The Plan sets objectives and strategies for many construction management activities (P-04028 pages 13-30) and defines construction management responsibilities (P-04028 pages 31-39).

#### 4.6.2. Term of Reference 4(b)(i) - Retaining and Dealing with Contractors and Suppliers

Term of Reference 4(b)(i) is as follows:

> 4. The commission of inquiry shall inquire into
>
> > (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether
> >
> > > (i) Nalcor's conduct in retaining and subsequently dealing with contractors and suppliers of every kind was in accordance with best practice, and, if not, whether Nalcor's supervisory oversight and conduct contributed to project cost increases and project delays.

For discussion of the challenges in identifying "best practices" see section 4.7.2.3 of this submission.

##### 4.6.2.1. Findings of the Investigative and Forensic Audit

Investigative and forensic auditors Grant Thornton investigated this Term of Reference and reported on it in their Construction Phase report (P-01677 pages 64-70). Grant Thornton assessed Project policies and procedures, their implementation and the compliance with them for bidder selection, evaluation and award recommendation; for post award contract administration; for procurement; and for invoice attest and accounts payable. Prior audit activity in those areas by Nalcor Internal Audit was reported. Compliance with standards such as those from the Project Management Body of Knowledge (PMBOK) and the COSO[2] Internal Control Framework was noted. The Grant Thornton report states that this review was focused on considering if Nalcor's supervisory oversight and conduct contributed to project cost increases and project delays.

Grant Thornton found that Nalcor had well documented policies and procedures specific to the Project that were reviewed and updated periodically. They concluded that "the documented policies and procedures governing Nalcor's conduct in retaining and subsequently dealing with contractors were in accordance with best practice." (P-01677 page 70.) Grant Thornton also concluded as follows:

> Generally, with the exception of Nalcor's oversight of Astaldi's work (as described in section 4[3] of this report), their conduct in retaining and subsequently dealing with contractors did not contribute to project cost increases and project delays.
>
> (P-01677 page 70.)

When examined by Nalcor counsel on these conclusions, Mr. Shaffer confirmed that, apart from the Astaldi exception, the conclusion of the investigative and forensic audit work was that Nalcor's conduct, both in the way that contractors were retained and in how they were dealt with, did not contribute to Project cost increases or Project delays (Scott Shaffer February 20, 2019 pages 27-28). Furthermore the exception for the Astaldi contract was limited to Mr. Shaffer's opinion that Nalcor had waited too long before engaging Westney in 2016 to formally review the costs and benefits of potentially replacing Astaldi as CH0007 contractor, and the exception did not refer to any other concerns with respect to the retention of and dealing with Astaldi (Scott Shaffer February 20, 2019 pages 20, 27-28).

Whether replacing Astaldi should have been seriously considered earlier is addressed in section 4.6.2.3.1.

[2] Committee of Sponsoring Organizations of the Threadway Commission, www.coso.org
[3] In testimony Mr. Shaffer acknowledged that the reference should be to section 3 of the report.

#### 4.6.2.2. Nalcor's Conduct in Retaining Contractors

##### 4.6.2.2.1. Procurement Generally

In addition to the Project planning documents described above, the exhibits also include the following documents, also reviewed by Grant Thornton:

- Invitation for Bidder Selection (P-01945)
- Bid Receipt and Opening (P-01946)
- Bid Evaluation and Award Recommendation (P-01947)
- Guidelines for Creditworthiness Verification (P-02130)

Reference can be made to the testimony of Project Supply Chain Manager Pat Hussey for a full explanation of the implementation of the documented plans, policies and procedures (Pat Hussey March 1, 2019), and to the presentation titled *Contracting Strategy and Process* prepared by project management team members (P-00888).

There has been no evidence presented that challenges the quality and appropriateness of the procurement plans, policies and procedures and Nalcor submits that they should be accepted as in conformity with "best practice".

##### 4.6.2.2.2. Procurement for Specific Work Packages

During the Inquiry hearings how those procurement processes were applied to three particular work packages was explored. They were for CH0007 Construction of Intake and Powerhouse, Spillway and Transition Dams awarded to Astaldi Canada Inc., CH0009 Construction of North and South Dams awarded to Barnard Pennecon Limited Partnership and CT0327 Construction of 350KV HVdc Transmission Line awarded to Valard Construction LP.

###### 4.6.2.2.2.1. CH0007 - Awarded to Astaldi Canada Inc.

The Recommendation for Award Summary Report (P-01964) presents the results of the CH0007 procurement process, following the prescribed path of approving a bidders list, issuing requests for proposals, addenda and clarifications, evaluating proposals, holding bidder clarification meetings, shortlisting bidders and requesting updated proposals, performing final bid evaluations, and recommending contract award. Eight separate evaluation reports, including those for commercial, technical, quality and schedule, and execution are appended.

The initial RFP documents had requested bidders to provide a combination of fixed prices, unit prices and lump sum prices. During the bid period several bidders expressed concern about the risks of those pricing strategies – generally, fixed prices transfer risk to the contractor – and in response the bidders were provided with the alternative of pricing reimbursable labour with a target cost of labour and a fixed maximum, along with unit prices and lump sum prices for non-labour components (P-01964 pages 4-5).

Four bidders were qualified. Three, Astaldi, IKC-ONE Civil Constructors and Aecon-Flatiron-Barnard Construction joint venture, submitted proposals on the alternative basis and one, Salini/FCC/Impregilo joint venture, submitted a fixed price proposal (P-01964 pages 4-5). The value of each pricing proposal could vary depending on the actual quantities for unit price items and whether labour costs were below the cap. The result of comparing estimated prices was that Astaldi was lowest bidder at $1,103 million, Salini was second at about $150 million higher and IKC-ONE and Aecon were much higher, with the difference between the Astaldi price and the IKC-ONE price being about $800 million (P-01964 page 14). Grant Thornton uses different evaluated prices in its report, but the relative differences are much the same (P-01677 page 28). The proposals were scored in four categories – commercial/benefits, quality/risk management, execution of the work and labour hiring strategy – with different weights assigned to each (P-01964 page 15). Astaldi scored highest for commercial/benefits and execution of the work and was competitive for the other two. The weighted results strongly favoured Astaldi. (See also the presentation at P-02207 page 2.)

Three matters addressed during the Inquiry hearings concerning the CH0007 bid valuation were Astaldi's experience in northern climates and in Canada, the difference between the low and the high bids, and the evaluation of Astaldi's creditworthiness.

#### 4.6.2.2.2.1.1. Astaldi's Experience

The suggestion that Astaldi should not have been considered because it had not previously carried out a project in a northern Canadian climate was responded to by Lance Clarke, Business Services Manager at the time of the contract award, in his testimony to the Inquiry:

> So the decision was made based on the best information that would have been available at the time. The factors that you referenced were considered. So, there was a pre-qualification that was done, SNC came up with the company list. There was extensive companies, I don't remember the numbers. Astaldi was listed with ENR in the top ten globally from a hydropower construction perspective referencing dams and powerhouse's construction. So, they are a 100-year-old-plus organization working all over the world so whether they can do big civil construction, was not a question.
>
> In terms of their abilities within Canada, their – 'cause we did ask questions about all this stuff – their proposal included an approach that involved some extremely experienced Canadian team members from a construction perspective, construction management downward, superintendents and that. And, so, based on that and the submission they had put together and come in when the team had reviewed it, they obviously had a very good proposal put together and it was understood and believed that these folks could do it.
>
> As well, we – to ensure, as we would for a contract this large, we did go and have some key people go and look at other Astaldi construction sites. We sent a couple of people to South America to – I believe was a hydro job they were working there. So again, challenging conditions in the mountains, these sorts of things. Cold is not the only challenging condition, okay, but these folks clearly understood that stuff. They – and, as I said, they had a Canadian construction contingent added in to what they were doing, so there was no reason to believe that they wouldn't be able to do it.
>
> In terms of whether, you know, someone can come into a jurisdiction who hasn't been there before that – the megaproject construction industry is global, it is. And yes, there are challenges with it, but you always look for what those risks are, as we did, and saw the Canadian folks and that they were gonna be able to handle this. So the fact that Astaldi could go and work in multiple countries around the world means they understood country risk, they understood the nuances, they understood how to react and relate to those things and how it applied to their systems.
>
> Newfoundland alone, so the Norwegians came in and completed the Hibernia piece of work. Aker was involved in coming in and doing topsides here, so they come in out of Norway. Dragados is very successful in Canada, a Spanish company, have come in. Impregilo is now, actually, one of the companies, one of the predecessors of the company that is now morphing into Astaldi with Salini.

> Impregilo was heavily involved in working with Hydro-Québec. So, right now ACCIONA – I believe it's ACCIONA – is one of the largest contractors, is new to the country in BC, with BC Hydro.
>
> So this is not a unique, uncommon thing. The rhetoric of saying that oh, you should've known 'cause these guys had never worked here before – sorry, we're not that special.
>
> (Lance Clarke May 23, 2019 pages 14-15.)

###### 4.6.2.2.2.1.2. Astaldi's Low Bid

It has also been suggested during the Inquiry hearings that the fact that Astaldi's bid was substantially lower than the two bidders with North American partners in their joint ventures was a factor weighing against their selection.

Very low bids can suggest that a bidder may have misjudged the true cost of the work and will have to perform the contract at a loss, however in most contracting situations the low bid is favoured since it is the lowest cost means to have the work performed. It would normally require a well founded concern to justify discounting a bid just because it is low. Several factors supported the conclusion that the Astaldi bid was not so low as to warrant suspicion.

Firstly, based on the estimated values in the Recommendation for Award (P-01964 at page 14) the Astaldi bid was not an outlier, since the Salini bid was within 15% of it. Secondly, the Astaldi bid was substantially higher than the CH0007 package estimate that had been prepared by SNCL utilizing its experience in hydro-electric plant design and construction for Hydro-Quebec, led by experienced lead estimator Paul LeMay. Thirdly, it was believed that the North American bidders had other work to keep them busy and may have incorporated a premium into their bids to account for it.

It should be considered what the alternative to accepting the Astaldi bid (or the Salini bid if Italian based contractors are to be excluded) would be, remembering that Astaldi scored highest or equal to the other bidders on the other evaluation criteria. Arbitrarily selecting one of the North American joint ventures would have started the contract at a price $600 to $800 million higher without assurance that there could be no additional costs.

With hindsight it may be tempting to argue that Astaldi ran out of cash because their bid was too low. However Astaldi's problems are rooted in their mismanagement of labour. Whether the work could not have been completed had the contract been properly managed from the start may be speculation only.

#### 4.6.2.2.2.1.3. Astaldi's Creditworthiness

Guidelines for Credit Worthiness Verification were issued for implementation in 2010 (P-02130) that set out the process for credit worthiness verification of Project contractors by Nalcor Treasury.

In compliance with that procedure, Treasury completed the credit worthiness evaluation of the CH0007 bidders, including Astaldi, and reported formally on September 25, 2013 (P-02514).

The work of Treasury had been reported up to Robert Hull, Nalcor General Manager (Commercial, Treasury and Risk) as a draft. He had carried out a due diligence review and on September 12, 2013 he had provided comments by email to Derrick Sturge, Vice President Finance, concluding that Astaldi was creditworthy based on the established criteria, had posted an acceptable performance security package, and would be recommended for acceptance from a creditworthiness perspective, noting however that the decision makers should be "eyes open" to any risks identified in the report. (P-02512, P-2513). Mr. Hull's report and comments are quoted in the Recommendation for Award (P-01964 pages 7-8). See also the testimony of Derrick Sturge (March 27, 2019 pages 83-85 and March 28, 2019 pages 67-68) concerning the role of Treasury and the review carried out by Mr. Hull.

Mr. Hull also prepared a table calculating the exposure to default by Astaldi Canada Inc. taking into account the contract performance security held, but excluding the guarantee of its parent Astaldi S.p.A., which showed that exposure was highest at the start of the work and diminished to nil when the work was about 70% complete. For an explanation see the testimony of Mr. Sturge (March 27, 2019 pages 85-88 and P-2511).

Nalcor submits that at the time of contract award to Astaldi Canada Inc. reasonable measures were taken to confirm Astaldi S.p.A.'s creditworthiness.

#### 4.6.2.2.2.1.4. Astaldi's Integrated Cover System

During Inquiry hearings the feasibility of Astaldi's plan to use an integrated cover system (ICS) to enclose the powerhouse site was questioned. We now know that the ICS failed to achieve its intended purpose of allowing concrete work to continue productively during the winter, which would have progressed the performance of the work and also smoothed the peaks and valleys of construction labour compared to seasonal construction. Nalcor submits that the reason was the failure of Astaldi and its subcontractor in planning, organizing and executing the ICS installation, not a fundamental problem with the ICS concept.

Grant Thornton included a section on the ICS in its Construction Phase report, but did not offer any analysis apart from quoted passages from the report prepared for them by Williams Engineering (P-01677 page 38, Scott Shaffer February 20, 2019 pages 4, 16-18). The Williams Engineering report acknowledged that temporary structures like that proposed by Astaldi are common in cold weather climates for projects of all sizes (P-01678 page 16). Mr. Gilliland from Williams Engineering testified to what he regarded as challenging aspects of the design of the ICS, including that it required interior columns and that there were multiple overhead cranes to be coordinated. He also testified that his personal experience in their design and use was very limited (Jim Gilliland March 21, 2019, pages 10-11).

Although not mentioned in the text of their report, Grant Thornton had also asked R.W. Block Consulting to comment on the use of the ICS. R.W. Block confirmed that structures such as the ICS were commonly used and that Astaldi's proposal had been properly evaluated by Nalcor. They viewed the issues related to the Astaldi ICS as being execution related, and not due to it being a flawed concept. (P-01683 pages 2-4.)

Nik Argirov, Canada's Independent Engineer, testified that the ICS was a very good idea that could and should have worked but for Astaldi's organizational problems and its difficulties with its subcontractor (Nik Argirov March 19, 2019 pages 60-61).

Astaldi was not the only bidder to propose an integrated cover system with complexities in its design. The Aecon-Flatiron-Barnard joint venture, a consortium with acknowledged North American construction experience, planned on using three large steel framed winter shelters over the spillway, intake and powerhouse with multiple overhead cranes in each (P-04275 pages 19, 37).

There was no basis to discount Astaldi's proposal because of its proposed use of the integrated cover system structure over the powerhouse site.

As an aside, questions were asked about the cost of the removal of the failed ICS, based apparently on the idea that the cost was a contributor to the increased cost of the Project. In one sense it was an indirect contributor, since the labour costs involved counted towards the exhaustion of the labour costs that Astaldi was entitled to be paid before LMAX, and therefore may have caused Astaldi to suffer its cash flow crisis earlier than it would have otherwise. However, in another sense the cost of removal of the ICS is immaterial. Regardless of whether the ICS was a success or failure, or whether Astaldi could have completed the work profitably or unprofitably, the ICS was a temporary structure and was from the outset intended to be removed. The cost of the removal was a cost to be borne by Astaldi and, like all the work, to be paid for by Nalcor to the extent that the terms of the contract allowed, but no more than that. (Lance Clarke May 23, 2019 page 64.)

###### 4.6.2.2.2.2. CH0009 – Awarded to Barnard Pennecon Limited Partnership

On May 22, 2016, not long after Stan Marshall became CEO of Nalcor, he received a message from a former Project contractor, Mark Turpin (P-01901). Among other things, Mr. Turpin wrote that a topic that needed to be investigated was the award of the CH0009 North and South Dams contract. He wrote that he had been involved in making an award recommendation in favour the H.J. O'Connell-Dragados joint venture but that after he had moved to work on the North Spur, the contract was awarded to the Barnard Pennecon joint venture on what he described as less favourable terms. In his testimony Mr. Turpin stated that in his message to Mr. Marshall he was not saying that it had been wrong to award the contract to Barnard Pennecon, just that it was something that he felt should be investigated (Mark Turpin April 3, 2019 page 106).

Grant Thornton became aware of Mr. Turpin's message to Mr. Marshall near the end of their work on the Construction Phase report, in which they included quotes from an interview with Mr. Turpin, but they had no time to conduct further investigation. Mr. Turpin's questions about the award of CH0009 thus made it into the Construction Phase report without any verification by the investigative and forensic auditors of whether there was any basis for the concern. (P-01677 pages 54-56, Scott Shaffer February 20, 2019 page 22.)

The process leading to the award of the CH0009 North and South Dams contract to the Barnard Pennecon joint venture is documented in the Bid Evaluation and Award Recommendation (P-01870). See also the Contract Strategy (P-02750), Bid Evaluation Plan (P-01867) and Civil Works Agreement (P-01864).

The Bid Evaluation and Award Recommendation ranked Barnard Pennecon first based on Final Estimated Contract Value, described as a composite value which takes into account the initial bid price, bid normalization, commercial assessment and technical evaluation (P-01870 page 3).

The contract awarded to Barnard Pennecon included compensation for work performed on a lump sum basis, on a unit price basis and on a reimbursable basis (P-01889 pages 3-7). Trade labour was paid on a reimbursable basis, subject to a target cost of labour and a cost sharing arrangement. If the final trade labour cost was less than the target, Nalcor would pay Barnard Pennecon 50% of the difference. If the final trade labour cost was greater than the target, then Barnard Pennecon was to credit Nalcor with 50% of the overrun. The amount of that overrun credit was capped at the trade labour overhead amount, which was fixed at 7.9% of the trade labour target amount. (P-01889 page 5.) This arrangement incentivized Barnard Pennecon to achieve lower than target labour costs in order to be rewarded with payment of 50% of the savings, and to avoid exceeding the target which would deprive it of its labour profit. Nalcor acquired the benefit of Barnard

Pennecon's incentivization to minimize labour costs but retained the risk that labour cost could exceed the target.

Because the H.J. O'Connell joint venture had bid a lump sum for labour, the Barnard Pennecon joint venture bid had to be 'normalized', or adjusted to enable it to be fairly compared to that of H.J. O'Connell. The adjustments are explained in the Bid Evaluation and Award Recommendation and its attachments (P-01870 pages 3, 11-16). Barnard Pennecon's estimate of trade labour hours was increased by 113,295 hours to make it equivalent to the hours carried in a pre-bid work package estimate prepared by John Mulcahy (P-02797), resulting in an upward adjustment to the Barnard Pennecon bid by $6,100,000. The calculation was done taking the risk/reward scheme into account. The adjusted value was used for the purpose of the comparison (P-01870 page 3).

A sensitivity analysis was performed to find the number of labour hours that would make the value of the Barnard Pennecon trade labour proposal equal to that of the H.J. O'Connell joint venture. The result was that Barnard Pennecon would have to incur 220,000 more trade labour hours than its estimate, an overrun of 40%, before the bid values would match (P-01870 page 3). Nalcor's consideration of whether this represented an acceptable risk would have also taken into account its assessment of the technical and construction management abilities of the bidders and the fact that their estimates of trade labour hours would have already accounted for the known labour performance being experienced by Astaldi at the site.

The bid evaluation team had proposed using different weighting of evaluation scores than had been set out in the original Bid Evaluation Plan, focussing more on project execution, schedule and quality of the proposed management teams, but was ultimately directed to stick with the original weightings. Had the alternate scoring methodology been used, an additional 382,000 trade labour hours would have had to have been added to the Barnard Pennecon estimate before the preference shifted to the H.J. O'Connell joint venture. (P-01870 page 4.)

Commission counsel undertook a thorough investigation of the CH0009 bid evaluation and contract award. Witnesses who were involved in the bid evaluation process and who testified on this topic included Mark Turpin, Ken McClintock, Scott O'Brien, John Mulcahy, Ed Over and Greg Snyder. The evidence became focussed more on the details of the bid evaluation, including the normalization calculations and the commercial and technical scoring. The strength of witness recollections of the details varied and much had to be reconstructed by them from the documentary record. The intricacies of that evidence are beyond the scope of what can be presented in this submission, however a chronology of some of the pertinent exhibits, with reference to events, is as follows:

| | |
|---|---|
| July 31, 2014 | The Contracting Strategy document for CH0009 was issued (P-02750). |
| August 1, 2014 | The Invitation to Bidders was issued (P-02749). |
| September 15, 2014 | The Bid Evaluation Plan was drafted (P-02753). |
| October 24, 2014 | The Bid Evaluation Plan was finalized (P-2757). |
| October 27, 2014 | The bids were opened (P-2758). |
| | By this time the low labour productivity being experienced by Astaldi was observable, and can reasonably be assumed to have influenced bidders' willingness to undertake labour risk and thus the amount of fixed price bids for labour. |
| December 15, 2014 | Bid evaluation team member Roy Lewis is known to have prepared a page of bid evaluation results, without a recommendation for award (P-2766). |
| | Mr. Lewis left the Project soon after. Despite Mr. Turpin having told Grant Thornton that a completed recommendation for award to H.J. O'Connell had been submitted by him and Mr. Lewis at about this time, no evidence of that has been found. |
| December 23, 2014 | The CH0009 work package had been scheduled to have been awarded on this date, however it was delayed due to the lack of progress in construction of the powerhouse and spillway by Astaldi, and to allow for a cost reduction program due to the fact that bid prices exceeded budget by more than 50% (P-01870 page 5). |
| January 30, 2015 | Evaluation team member Ed Over circulated a draft Bidder and Short List document for use in continued evaluation of the proposals (P-02770). |
| | Discussion with the bidders to find opportunities to lower the cost was initiated. Mark Turpin remained involved. |

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| March 3, 2015 | H.J. O’Connell submitted clarifications to its commercial proposal (P-02771). |
| March 4, 2015 | H.J. O’Connell submitted a proposal for cost savings (P-02775). |
| March 6, 2015 | Barnard Pennecon submitted a proposal for cost savings (P-02772). |
| March 8, 2015 | Barnard Pennecon submitted a revised proposal (P-02773). |
| March 13, 2015 | H.J. O’Connell submitted a revised target price model (P-02776). |
| May 22, 2015 | Mark Turpin had by this time left to work on the North Spur and Ken McClintock, as process leader, joined the bid evaluation team with John Mulcahy, Ed Over and Greg Snyder (P-02777, P-01870 page 4). |
| May 29, 2015 | H.J. O’Connell was requested to update its proposal (P-02780). |
| June 3, 2015 | Barnard Pennecon was requested to update its proposal (P-02782). |
| June 30, 2015 | H.J. O’Connell submitted revised pricing and Barnard Pennecon submitted a revised proposal (P-02789, P-02798). |
| July 9, 2015 | H.J. O’Connell and Barnard Pennecon submitted revised pricing (P-02796, P-02853). |
| July 20, 2015 | Mr. Mulcahy sent Mr. McClintock the calculation that Mr. McClintock used for the “normalization” of labour hours to allow the bids to be compared (P-02797). |
| July 21, 2015 | Tony Scott sent an analysis of the two bidders’ schedules for performing the work (P-02799). |
| | Mr. Over circulated a draft of a bid evaluation presentation (P-02800). |
| July 24, 2015 | Mr. McClintock, with John Mulcahy, delivered a presentation to Ron Power, Scott O’Brien and Pat Hussey recommending award to Barnard Pennecon (P-02802, Ken McClintock May 14, 2019 page 15). |
| | The recommendation was based on evaluation scoring criteria that were weighted differently than in the original bid evaluation plan. The bid evaluation team was asked to rescore the evaluation using the original criteria. (Ken McClintock May 14, 2019 pages 15-16.) |

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| July 27, 2015 | Mr. Over sent Mr. McClintock commercial evaluation scoring “per the original evaluation plan” (P-02804).<br>Greg Snyder sent Mr. McClintock revised technical scoring reviewed by him and Mr. Mulcahy (P-02805). |
| August 5, 2015 | The Bid Evaluation and Award Recommendation was signed off by Mr. McClintock (P-01870). |
| August 12, 2015 | Mr. McClintock sent Scott O’Brien the Bid Evaluation and Award Recommendation with additional descriptive wording but no change to the substance of the report. Mr. O’Brien signed the Recommendation as Project Manager. (P-02813, P-01870.) |
| August 13, 2015 | Mr. Mulcahy sent Mr. O’Brien a message with bullet point reasons supporting the award to Barnard Pennecon (P-02967). |
| August 14, 2015 | Mr. Power signed off on the Bid Evaluation and Award Recommendation as Project General Manager (P-01870).<br>Gilbert Bennett emailed Ed Martin informing him of the contractor selection (P-02814). |

The investigation into the award of this contract likely originated from an inference, based only on Mr. Turpin’s original message, that there might have been some improper motivation to award the contract to Barnard Pennecon or to somehow extend it a preference. Nalcor’s submission is that there was absolutely no evidence presented to support such a suspicion, let alone a conclusion to that effect. No witnesses said that they were aware of any impropriety. Nor was there any evidence of any reason or motivation for giving any preference to the Barnard Pennecon proposal, other than one based on the genuine evaluation of its merits. There was no evidence of any attempt by Barnard Pennecon to exert any improper influence on the process. All team members supported the final recommendation to award to Barnard Pennecon.

The bid evaluation process undertaken by the bid evaluation team of necessity involved the discretionary exercise of skill and judgment on a large number of evaluative factors. Unanimity is not to be expected on all points. Some deviations from prescribed process are to be expected and can be tolerated if not material to the outcome. The Commission is charged with examining whether Nalcor’s conduct in retaining contractors was in accordance with best practice, which Nalcor submits the CH0009 process was, but the Commission is not charged with re-evaluating the bid proposals to determine whether the outcome of the contract award could have been different had the judgment of those carrying out the technical and commercial evaluations been exercised differently.

#### 4.6.2.2.2.3. CT0327 – Awarded to Valard Construction LP

CT0327 is the contract for construction of the HVdc transmission line from Muskrat Falls to the subsea link at the Strait of Belle Isle in Labrador and from the Island of Newfoundland termination of the SOBI to Soldiers Pond near St. John's, awarded to Valard Construction LP. The procurement process is explained in the Bidder Selection and Preliminary Award Recommendation (P-01886).

At Decision Gate 3 the construction of the 1100 km transmission line had been broken down into three separate work packages, CT0327, CT0345 and CT0346. Based on knowledge gained from the execution by Valard of the CT0319 contract for construction of the HVac transmission lines between Muskrat Falls and Churchill Falls, and the HVdc procurement process, those three work packages were combined into a single work package designated CT0327. (P-01886 page 5.) A thorough bidder selection process was carried out in two phases. The Phase I screening reduced the number of potential contractors to eight (P-01886 pages 10-19). Phase II screening included application of observations and learnings from CT0319, analysis of marketplace issues and trends and identification of options (P-01886 pages 20-34). The recommendation was that only Valard had the capability and capacity to undertake the work. It was recommended to aggressively pursue open book negotiations with Valard and to consider all available options to achieve the objective of balancing absolute cost against cost predictability (P-01886 page 35). The results of the open book negotiations are set out in the Award Recommendation (P-01886 pages 36-43). Grant Thornton provides a summary in its Construction Phase report (P-01677 pages 43-44).

An open book contract negotiation differs from a competitive process in that there is more open exchange of cost information for the purpose of negotiating pricing and other contract terms that are fair to each party. It may be used where the competitive bidding process cannot achieve that objective due to lack of bidders. (Jason Kean May 6, 2019 page 14.) The process used for CT0327 is, in part, outlined in a presentation prepared by Nalcor participants and contributed to by those from Valard (P-02732 pages 3-12, B.J. Ducey April 3, 2019 page 8).

Grant Thornton in its Construction Phase report did not provide any analysis of the choice of open book negotiations for the CT0327 agreement. Grant Thornton's project management consultant, Derek Hennessey of R.W. Block Consulting, did review the appropriateness of the use of the open book negotiating approach and concluded that, "Based on the information presented by the evaluations team in the [Award Recommendation] document, if only one firm was capable of performing the work, that would be a reasonable justification for a sole source award." (P-01681 page 6.) There was no expert testimony provided to the Inquiry that questioned the appropriateness of the choice of the open book negotiating strategy or whether it conformed to what would be best practice.

#### 4.6.2.3. Nalcor's Role in Dealing with Contractors

The second branch of Term of Reference 4(b)(i) calls for inquiry into whether Nalcor's dealing with contractors was in accordance with best practice.

The project management documents discussed above are among those that address how the project team is to manage of the work of the contractors, and give structure to Nalcor's relationship with them. Each work package contract also has its own terms and conditions modelled on Project standard terms, with variations to suit the particular contract. The terms of the contract and the project management procedures and documents incorporated by reference into it will govern the relationship between Nalcor and the contractor.

For example, coordination procedures are set out in exhibits to work package contracts. For package CD0501 awarded to Alstom Grid Canada, later GE Grid, Exhibit 3 Coordination Procedures is 59 pages with headings Early Activities and General Execution; Organization, Administration and Reporting; Interface Management; Procurement and Material Management; Cost Management; Schedule Management;

Changes to the Work; Risk Management; Engineering Requirements; Construction Management; Invoicing and Payment; and Information Management (P-03201). Contractors come to the Project having signed on and agreed to implement and comply with this organizational structure. It addresses how decisions are made for the day to day conduct of the contractor's work and how decisions for changes to that work, and for extra payment to the contractor, are to be made.

On the Project team side the same matters are addressed in formal plans and procedures, such as in the Change Management Plan (P-01940), Change Management Procedure (P-03775), Financial Authority Procedure (P-01545), Technical Interface Management Plan (P-03750) and Technical Interface Management Procedure (P-3773). The Procedure for Post Award Contract Administration (P-01944) provides guidance to the Site Manager, Area Construction Managers, Site Contracts Manager, Contracts Administrators, Cost Control, Estimating, Planners and Schedulers, Supply Chain Manager and the Information Management Team. It is an example of the pre-planned project management structure that organizes how the Project deals with its contractors. It lists 30 subsidiary procedural documents (P-01944 pages 9-10) for example:

- Procedure for Change Request
- Procedure for Change Order
- Payment Certificate Procedure
- Procedure for Site Query
- Procedure for Concession Request
- Procedure for Engineering Change Notice
- Procedure for Field Work Order
- Capital Expenditure Authorization Procedure

The performance of the contractor, the approach it brings to the management of its work, and the approach it brings to the advancement of its commercial interests, which are understandably oriented toward maximization of its profit, will also bear on how the Nalcor project managers must respond to them and on how they must act to ensure that the Project's interests are promoted.

This balance of this section 4.6.2.3 of the Nalcor submission will address the reservation made by Grant Thornton from its conclusion that Nalcor's conduct in dealing with contractors did not contribute to project cost increases and project delays, which was whether earlier consideration should have been given to terminating the CH0007 contract with Astaldi (P-01677 page 70), as well as two other issues that were discussed in testimony. Those are whether there was sufficient decision-making authority at the Muskrat Falls site, and whether an appropriate approach was taken to responding to contractor claims for extra payment.

#### 4.6.2.3.1. Potential Termination of Astaldi

The Astaldi contract was terminated in 2018 due to Astaldi Canada Inc.'s insolvency. Prior to then the amount to be paid to Astaldi for completion of the work within its contractual scope had been increased, first by the Bridge Agreement (P-01868) and then by the Completion Agreement (P-01869). Comprehensive and confidential analysis had been performed by Nalcor in 2015 and 2016 that was the basis for the conclusion that terminating and replacing Astaldi by another contractor would be more costly and entail more risk to the project than paying Astaldi the amount necessary to allow it to fund completion of its work.

No expert opinion was presented at the Inquiry concerning whether Astaldi could or should have been removed from the performance of the CH0007 work earlier than it was, other than the commentary of Mr. Shaffer of Grant Thornton, who was not qualified as an expert in the area and who did not provide any analysis to support his conclusion.

Termination of any contractor, let alone one with as significant a role in the Project as Astaldi, is not something to be taken lightly, and would come with substantial risks. It is a step that could only be taken after the most thorough analysis and planning. Termination of Astaldi was an alternative considered in late 2015 and into 2016 prior to the finalization of the Completion Agreement. The materials compiled to document the process leading to that agreement illustrate some of the work that had been carried out to examine all alternatives (P-03803, P-03804).

It has been suggested in examination of witnesses at the Inquiry that the decision to give Astaldi the contract should have been reconsidered because it failed to take full advantage of the opportunity to advance the work after the Limited Notice to Proceed

(LNTP) was entered into on September 24, 2013 (P-02139) and before the CH0007 contract was signed on November 29, 2013 (P-01865).

The Commission has heard testimony from several witnesses that slow starts are not unusual on major contracts. On November 7, 2013 Project Director Paul Harrington had reported Astaldi's slow start on the LNTP work to Ed Martin. Mr. Martin replied with four questions, one of which was, "Still the right contractor?" Mr. Harrington responded that Astaldi was, but that Mr. Martin should mention the concern at a senior level with Astaldi and that, "They may push back on you that we have not signed the contract so they cannot attract the best people …" (P-03707). Mr. Harrington testified that the process for selecting Astaldi had taken a year and that it would have been premature to start over based on less than two months performance (Paul Harrington June 6, 2019 page 22). Mr. Harrington's suspicions about Astaldi claiming difficulty attracting staff was similar to the testimony of Astaldi's Mauro Palumbo who, whether it was correct or not, claimed that Astaldi could neither hire people nor enter into subcontracts until the contract was executed (Mauro Palumbo May 8, 2019 pages 15-16). It seems reasonable that, at the time, Astaldi's work performance under the LNTP could not have been taken as an indication that it would fail as badly as it did in 2014.

When, on November 29, 2013, Astaldi executed the CH0007 contract and a release of any claims arising before that date (P-03055), it committed to meeting the construction milestones. Assurances were given to Nalcor personnel, including from the CEO of Astaldi, that Astaldi would meet the schedule (Lance Clarke May 23, 2019 page 56).

In 2014 when Astaldi's poor performance and lack of progress was apparent, the Project team focussed on providing Astaldi assistance to turn around the situation. Both Mr. Power and Mr. Harrington testified that there was some discussion about the possibility of replacing Astaldi, however Mr. Harrington said that the advice received was that, at that time, there were insufficient grounds to terminate the contract (Ron Power May 21, 2019 pages 47-48, Paul Harrington June 5, 2019 page 13). The reality was that Astaldi had a contract that, if improperly terminated at that early stage before it was known whether and to what extent Astaldi could recover schedule, would likely have resulted in

Astaldi bringing a substantial claim. Nalcor would have had to find a replacement contractor, negotiate terms with it from a position of relative weakness, and inevitably incur further schedule delay as the new contractor mobilized to the site. Instead the belief was that it was possible for Astaldi to improve its performance, which it did accomplish in 2015 with Nalcor's assistance.

Several things were different in 2016. Astaldi's productivity had improved, but it was clear that it could not complete the work without reaching the LMAX limit on payment for its labour costs. Astaldi S.p.A. had suffered setbacks in Turkey and Venezuela that jeopardized both its ability to fund Astaldi Canada's losses and Nalcor's ability to rely on the parental guarantee. On the other hand, Nalcor had advanced its readiness to put a replacement contractor in place. But even then, the cost of terminating and replacing Astaldi was still assessed to be in excess of the cost of entering into the Completion Agreement.

Considering the thoroughness of the analysis in 2016, it is unreasonable to conclude that it would have been advantageous to cost or schedule to have terminated and replaced Astaldi in 2016 or at any time earlier.

#### 4.6.2.3.2. Site Based Decision Making Authority

The Project has a well planned and documented staffing and management structure, with roles and responsibilities clearly defined, as discussed above.

Expenditure authorization limits flow from the Authorization of Expenditure approved by the Nalcor Board for the CEO, and are then delegated downward. The process is fully documented in the Capital Expenditure Authorization Procedure (P-03535). The Muskrat Falls site manager held authority to authorize an expenditure up to $250,000 without requiring approval of any other person in the organization (P-03535 page 24, Des Tranquilla May 14, 2019 page 40).

Muskrat Falls Project Manager Scott O'Brien explained the authority and responsibilities of the site team and how they are integrated with the home office. He explained the empowerment of the site for day to day decision making to facilitate the execution of the work and the importance of the financial authority structure for extra expenditures. He spoke of the management of change processes, and the importance of wider involvement of different disciplines in decisions that may have longer term consequences that would not be properly addressed if the home office were not involved. (Scott O'Brien May 30, 2019 pages 87-89.)

Questions concerning the allocation of spending authority and the idea that decisions could only be made out of the St. John's office and not the Muskrat Falls site were asked of a number of witnesses.

The testimony of Des Tranquilla, who was Site Manager in 2014 and for part of 2015, has been referred to as authority for the proposition that there was insufficient authority delegated to the site from St. John's. Mr. Tranquilla's evidence was actually tempered and balanced on that issue. He did say that most of the direction came from St. John's, but continued, "I'm not saying that's a bad situation". He accepted the model that was being employed at the Project, but also said that based on his prior experience on mining projects he did not see himself as a good fit with it. (Des Tranquilla May 14, 2019 pages 38-39, 41.) Regarding his $250,000 spending authorization he said, "It's a little light. I mean, I think we all realize that, yeah. But with the assured communication, I guess, and ability to get to St. John's for that guidance and approval. That's how we worked." And further, "I probably communicated with Scott [O'Brien], on a daily basis. And, you know, a lot of what we undertook was, obviously, in excess of that." (Des Tranquilla May 14, 2019 page 40.)

Resignation letters from site team members Ted van Wyk in May 2014 and Brian Cottrell in June 2014 were tendered as exhibits (P-03048, P-03049). Both expressed disagreement with the project management model and both would have preferred to have had more authority delegated to them at the site. Mr. Tranquilla described Mr. van Wyk as having been his deputy on a mining project and that "he would be like-minded to myself." (Des Tranquilla May 14, 2019 page 44.) Neither gentleman testified.

There is therefore evidence that in 2014 there were members of the site team who, coming from other backgrounds, did not want to work under the particular management model adopted for Muskrat Falls. Mr. Tranquilla was gracious about it, saying, “it was different for me, and I did struggle with that. Now, I’m not saying it’s wrong; I’m saying I did not necessarily fit that style of application.” (Des Tranquilla May 14, 2019 page 38.) There was no evidence that subsequent Site Managers or other site team members shared that view after 2014.[5]

Other complaints about the limits on decision making on site were attributed to contractors. The Astaldi witnesses, Mr. Delarosbil and Mr. Bader, certainly took that view, however their testimony should be approached cautiously considering that Astaldi is pursuing an arbitration claim against Nalcor for hundreds of millions of dollars, and that Mr. Delarosbil when he testified remained in the employ of the otherwise insolvent Astaldi Canada Inc. Other contractor representatives did not express the same concerns, or not to the same degree. Regardless, it would be expected that contractors would have a preference for strong financial authority at site where they have closer access to site staff and that they would prefer the financial oversight of the home office to be more limited.

Reference should also be made to the testimony of Ron Power (May 21, 2019 pages 57-59) and Paul Harrington (June 5, 2019 pages 73-76) who addressed the matters described above.

Particular attention was paid to how often Mr. O’Brien visited the Muskrat Falls site. Tallies were prepared to count his days on site and to compare them to those of Gilbert Bennett. While the result was that Mr. Bennett spent more days on site, they both visited it about the same number of times. Other evidence showed the extent of Mr. O’Brien’s travel elsewhere in connection with his duties as Project manager. The question, though, is what does that prove? The comparison of each person’s days on site is of little value without considering the reasons why they were or were not there, their overall roles and responsibilities and where they could be best discharged, and whether their presence at

[5] John Mulcahy, Construction Specialist based at the St. John’s home office resigned in 2017 and did express his opinion that compared to projects had been involved in as contractor in the past there was less decision making authority on the Muskrat Falls site.

or away from site had any adverse impacts. Conclusions should be based on evidence rather than simple assumptions that presence on site is good and absence is bad.

The approach of the Project to change management, financial authorities, and role descriptions is all well documented. The Commission has not been presented with a systematic evaluation, which would have required the involvement of experts, into whether the model and its manner of implementation was appropriate, or “best practice”, which is the first question posed by Term of Reference 4(b)(i). Nor has it been presented with a systematic, cause and effect analysis of whether the model adopted, or any of the matters addressed in the anecdotal evidence described above, had any impact on cost or schedule.

#### 4.6.2.3.3. Resolution of Contractor Claims

The approach to be taken to resolution of claims brought by contractors for extra payment was a topic of examination of various witnesses during the Inquiry hearings. There was no expert evidence presented to assist the Commission in deciding whether the approaches taken by Nalcor to resolving claims, of many types arising under different circumstances and brought by different contractors, were best practice and, if not, whether Nalcor’s conduct contributed to cost or delay, which are the questions posed by Term of Reference 4(b)(i).

How claims are to be managed is governed by the contractual arrangements between the contractors, and by the Project management documents, as described above. The question under consideration seems to be not so much how it is to be done, but what attitude each party should bring to the process.

Contractors are private businesses accountable to their owners and have to be oriented towards achieving profits. Changes in work scope, additions of extra work, unforeseen site conditions, and interference in the performance of the contractor’s work by the owner or other contractors are all opportunities for contractors to enhance the profitability of a job. Claims usually require some measure of negotiation, with the contractor seeking higher compensation and the owner working to limit cost increases. Their interests are not the same. It is for this reason that the contracts normally contain dispute resolution processes and, where satisfactory resolution cannot be obtained by negotiation or dispute resolution, recourse may be had to arbitration or the courts.

Representatives of several contractors testified, as did their Project team counterparts. All the contractors have made claims for extra payment to one extent or another, and detailed review of that evidence is beyond the scope of this submission. The evidence illustrates, however, that some contractors can be motivated to pursue claims for extra payment more aggressively than others. Likewise, some project managers can be motivated to push back harder than others. What is the right balance? On the owner side appropriate priority has to be given to paying only the claims that merit payment and only in the amount justified. In making that assessment broader factors, such as indirect impacts on timely performance of remaining work by the contractor or effects on work of other contractors, can factor into the commercial analysis. On the contractor side those same considerations can provide leverage to exploit opportunities for higher payment than the work alone justifies.

The Astaldi situation has been unlike that of other contractors, due to the nature and extent of the problems encountered.  The working relationship in the field and with those executing the work has been good, including through the period of Astaldi's performance difficulties in 2014 and the attempts to recover afterwards. The commercial relationship has been at all times businesslike and professional, but became strained as Astaldi's commercial, and its parent's financial, difficulties began to affect its performance of the work.

The Commission has heard evidence of dispute concerning the Andritz Hydro Canada Inc. contract for spillway and powerhouse gates and hydro-mechanical equipment. The problems were precipitated by Astaldi's delays, causing the start of the Andritz work to be postponed. Performance of it then had to be accelerated to meet the crucial river diversion date. Andritz had to be directed to proceed with acceleration when pricing for a change order could not be agreed and was placed in default when it failed to fully implement the change order. Litigation was commenced but the dispute was resolved by consensual mediation. What could or should Nalcor have done differently? Should it have agreed to pay Andritz the amount it had asked for? Should it have risked river diversion by not ordering acceleration? Was the negotiated settlement reasonable? Was any of this driven by inappropriate “attitude” on the part of either Andritz or Nalcor? These are all matters of strategy, judgment and exercise of discretion. Assessing whether there is a best practice to which the parties’ conduct can be compared is a challenge, as is determining whether there was an alternate course of action that could have been expected to produce a better result.

One example where several witnesses described a change in approach to dealing with contractor claims was in resolution of outstanding claims from Valard on the HVdc transmission line construction. John MacIsaac became Vice President responsible for the transmission side of the Project after it was bifurcated by Stan Marshall in 2016. He brought his personal approach to dealing with contractors to that position, but it is also significant that it coincided with a change in strategy for the completion of construction and commissioning of the HVdc line. The schedule had been driven by the availability of Muskrat Falls power, which was delayed, but was then changed in favour of bringing the line into service earlier for transmission of Recall Block power from the Upper Churchill. Arguably this may have changed the balance between policing contractor entitlement to extra payment and encouraging contractor cooperation in timely completion of the work, reflected then in the attitudes brought by both sides to resolving outstanding claims. Was the Nalcor approach before bifurcation right or wrong? Was the change after bifurcation the right choice? Views are divided on both. Again, these are matters of strategy and judgment that are not amenable to comparisons framed by “best practice”.

#### 4.6.2.4. Investigative and Forensic Audit of Specific Expenditures

The Commission engaged Grant Thornton to conduct an audit of four areas of specific expenditure that bear some connection to the retention and dealing with contractors and suppliers. The four areas were living out allowances; supplies, including personal protective equipment and small tools; non-arm’s length contracts; and recording of daily work hours. These may be placed under Term of Reference 4(b)(i), Nalcor’s conduct in retaining and subsequently dealing with contactors and suppliers.

The results of the audit were presented in a report dated April 22, 2019 (P-04335) and in testimony by Jennifer Fiddian-Green (June 28, 2019). No significant issues were identified and no sources of material contribution to cost increases or Project delays were found.

### 4.6.3. Term of Reference 4(b)(ii) - Terms of Contractual Arrangements

Term of Reference 4(b)(ii) is as follows:

> 4. The commission of inquiry shall inquire into
>
> (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether
>
> (ii) the terms of contractual arrangements between Nalcor and the various contractors retained in relation to the Muskrat Falls Project contributed to delays and cost overruns, and whether or not these terms provided sufficient risk transfer from Nalcor to the contractors.

#### 4.6.3.1. Development of the Contracting Strategy

The Overarching Contract Strategy document, referred to in section 4.6.1.3 above, describes the deliberate and thorough steps taken in the process of development of the Project contracting strategy from 2005 to the end of 2011 (P-01942 pages 22-26). It included acquiring data from other megaprojects in the province, from Lansvirkjun Power in Iceland, and from international megaproject consultant IPA. Market surveys were conducted, discussion papers were drafted, and workshops were held. Implementation of the strategy involved a two step process, the first being the selection of EPCM as the overall contracting model and the second being the selection of contracting strategies for the physical supply and construction activities.

Section 9.4 of the Strategy discusses implementation of contracting policies and practices through particular provisions in the contract documents. The objectives for each provision are discussed as are risk implications where applicable (P-01942 pages 44-51).

Section 9.5 sets out considerations for selection of lump sum, unit price and other types of contracts. Preference was expressed for lump sum and unit price contracts, where the only variables would be scope change and quantity variation, but where circumstances required, other types of contract such as reimbursable, cost plus or target price could be considered (P-01942 pages 51-53).

Sections 9.7 and 9.8 discuss the strategy and considerations to be applied to achieve the maximum extent of lump sum contracting and cost certainty, recognizing that there would be trade offs between cost and risk transfer for different contract types (P-01942 pages 54-55).

A specific strategy for Muskrat Falls Generation, in section 11.0, identifies general strategic guidelines and considerations to be applied, lists 17 major work packages with the security strategy and notional form of contract for each, and goes on to lay out specific strategies for each work package (P-01942 pages 62-75). There are similar strategies for contracts related to the Labrador Transmission Assets (P-01942 pages 76-83) and the Labrador-Island Transmission Link (P-01942 pages 84-98).

As procurement activities progressed, contracting selections were refined and tailored to the circumstances, taking into account the contractor responses to requests for proposals. Many contracts were ultimately combinations of lump sum, target price, unit price and reimbursement elements.

The Overarching Contract Strategy document, other procurement policies and procedures, and the testimony of those involved in procurement make it clear that finding the right balance between risk transfer and price was an important consideration throughout and was taken very seriously by those implementing the contacting strategy.

#### 4.6.3.2. Investigative and Forensic Audit

Investigative and forensic auditors Grant Thornton addressed the reasonableness of the terms of work package contracts in their Construction Phase report (P-01677 pages 71-84). The audit focused on the CH0007 powerhouse and spillway contract awarded to Astaldi and the CT0327 HVdc transmission line contract awarded to Valard.

Grant Thornton retained the services of lawyers Miller Thomson to review the contracts from a legal perspective and consultants R.W Block from a contracting perspective. Miller Thomson provided a written report (P-01679). The Executive Summary states:

> In brief, we have concluded that the Agreements generally provide the tools necessary for an owner of the Project to proceed toward completion of the Project. Although we have identified certain limited concerns about the final Agreements, it is our view that these points do not meet the threshold of being a significant negative impact on the Project.

(P-01679 pages 1-2.)

A footnote indicates that the identified “limited concerns” are the items listed in Appendix A to the report and were ones where the contract provision deviated from the Project’s standard template. In the Astaldi agreement they are sections 21.4, 21.5 and 30.1. Reference should be made to the Miller Thomson report for details, however in each case Miller Thomson concluded that they did not believe that the contractual provisions were, for sections 21.4 and 30.1, “unreasonable”, and for section 21.5, “inappropriate”. For the Valard agreement the only section included in Appendix A was section 21.5 which limited Valard’s liability to 100% of the contract price, and which Miller Thomson found to be “generally reasonable”.

Regarding the CH0007 Astaldi contract specifically, the Miller Thomson report states:

> Therefore, it is our view that the Astaldi agreement largely included the necessary and typical tools found in an agreement of this type to allow MFC to limit cost overruns and delays by withholding any requested approvals and seeking alternative solutions at that time.
>
> (P-01679 page 4.)

Derek Hennessey of R.W. Block delivered a memorandum reviewing the CH0007 Astaldi contract (P-01813), a clarification memorandum responding to questions from Grant Thornton (P-01680), a memorandum for his review of the CT0327 Valard contract (P-01681) and a clarification memorandum responding to questions form Grant Thornton (P-01682), as well as a memorandum commenting on several specific questions (P-01683).

Regarding the performance security in the CH0007 Astaldi contract, which is the parental guarantee, letters of credit and a performance bond, the R.W. Block commentary was that it exceeded that called for in the Request for Proposals for that work package and that Nalcor’s approach was consistent with that which it has seen on other large contracts (P-01813 page 3).

The contract pricing in the CH0007 Astaldi contract was a combination of reimbursable labour with a risk shared target and a maximum amount payable by Nalcor, called the LMAX, plus unit price and lump sum items. R.W. Block wrote that the reimbursable labour concept “established a maximum amount of reimbursable labour that Nalcor would be responsible for, while also providing an opportunity for cost savings if the labour productivity on the project was better than had been estimated by Astaldi." (P-01813 page 1.) They observed that payment for reimbursable labour was not linked to the percentage of completion of the concrete work, although in their experience they had not observed instances where payment under cost reimbursable contracts was linked to work put in place (P-01813 page 4). In the clarification memorandum they added:

> The approach Nalcor used for reimbursing the labour costs under the contract (i.e. paying them as costs were incurred and not linking the progress payments to work put in place in the periods of time covered by the progress payments is similar to other target price utility industry contracts we have reviewed.
>
> (P-01680 page 2.)

R.W Block also stated that the pricing provision of the CH0007 Astaldi contract, as designed, should have limited Nalcor's cost exposure (P-01813), and made the same finding for the CT0327 Valard contract (P-01681 page 2).

For the CT0327 Valard contract R.W. Block stated that the performance security, consisting of a parental guarantee and a letter of credit was consistent with approaches it had seen for other large contracts (P-01681 page 3). In the clarification R.W. Block explained that performance security that did not include a performance bond was regarded as consistent with what they had seen in other large contracts because those contracts typically do not require both parental guarantees and performance bonds for more than 50% of the contract value.

The opinions of Miller Thomson and R.W. Block support a conclusion that the terms of contractual arrangements with contractors were reasonable at the time those contracts were entered into.

#### 4.6.3.3. Allocation of Risk

The question of whether the contracts for the performance of the work provide an appropriate allocation of risk between the contractors and Nalcor must be considered strictly from the point in time when each contract was finalized and under the circumstances then existing, with reference to the particular terms of each contract.

The outcomes are by now largely known, or nearly so, as the work gradually comes to a conclusion. As shown on the latest forecasts provided confidentially to the Commission, some work packages are forecast to exceed their contract award estimate, some by small amounts and others by larger amounts, and some work packages are forecast to come in under their contract award values. That information, however, should not be allowed to colour the assessment of whether sufficient risk was transferred from Nalcor to the contractors at the time of contracting.

The opinions of Miller Thomson and R.W. Block would support a conclusion that sufficient risk was transferred to contractors.

### 4.6.4. Term of Reference 4(b)(iii) - Overall Project Management Structure

Term of Reference 4(b)(iii) is as follows:

> 4. The commission of inquiry shall inquire into
>
> (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether
>
> (iii) the overall project management structure Nalcor developed and followed was in accordance with best practice, and whether it contributed to cost increases and project delays.

#### 4.6.4.1. Nalcor's Project Management Structure

A number of the foundational documents for the project management structure are discussed in section 4.6.1. above, and the structure is discussed generally elsewhere in this submission.

#### 4.6.4.2. Investigative and Forensic Audit

Term of Reference 4(b)(iii) was reported on by investigative and forensic auditors Grant Thornton in their Construction Phase report (P-01677 pages 85-105). Grant Thornton concluded that, "Nalcor has detailed and well documented policies and procedures governing their project management process." (P-01677 page 105.)

Particular matters discussed in that section of the Construction Phase report include the project team experience, the selection of the EPCM contractor and transition to the integrated project team, and the bifurcation of the project in 2016. Those will be addressed below.

#### 4.6.4.3. Project Management Team

The Lower Churchill Project was established as a separate business unit within Nalcor. It could draw on human resources within Newfoundland and Labrador Hydro to the extent Hydro had personnel available. Otherwise the Project management team had to be built up from people drawn from other sources. This was done over a period of time starting in 2005 before Nalcor was created, adding personnel as they were needed.

#### 4.6.4.3.1. Recruitment

Various methods were used to recruit the best qualified people available, as described in the testimony of a number of witnesses, often in the context of their own recruitment to the team. Many people came from oil industry projects, which gave them megaproject experience that was transferrable to their roles in the Project. Often people were acquainted or had worked for the same employers in the past, which is not surprising considering the size of the industry in this province and region and the specialized skillsets needed, plus the nature of megaproject management which involves moving from one project to another as projects are completed. Recruitment processes were structured, governed by policy and procedure, and competitive. Positions were awarded based on the merit of the applicants.

Evidence heard at the Inquiry concerning the recruitment of project team members was largely limited to the experiences of individual persons. There was no audit or expert investigation of project management team hiring specifically, but Grant Thornton was asked to investigate non-arms length contracts in the Specific Expenditures audit (P-04335 pages 19-25). That audit touched on recruitment practices, since most project management team members are contractors working through either private companies or recruitment agencies. No conflicts of interest were found.

#### 4.6.4.3.2. Contractual Arrangements

There was consistent evidence that contract-based employment arrangements or staffing through agencies is common and accepted for megaprojects. Paying day rates under contracts relieves the Project from overhead costs associated with conventional employment and gives it the flexibility to terminate contracts on short notice without having to prove cause or pay severance.

The Inquiry has not been presented with any evidence to support criticism of the rates, terms or conditions in the project management team members’ employment contracts.

#### 4.6.4.3.3. Experience and Qualifications

Much has been made of who on the project management team has and has not previously worked on a hydro-electric project. Tables listing years of experience on megaprojects and in hydro-electric construction are informative to a point, but they offer only a shallow understanding of what the attributes of the individual people are that make them suited, or not, to the positions they hold. The question is more complex than that and deserves a more thoughtful consideration.

Some points arising from the evidence are:

- Ron Power was not the only person on the project management team with hydro-electric construction experience, as detailed in the material he provided during his testimony.
- Megaproject skills gained in the Canadian oil industry are transferrable and can be of value on a hydroelectric project. Dr. Flyvbjerg acknowledged this proposition (Dr. Bent Flyvbjerg September 17, 2018 page 46).
- There was evidence that there are very few persons with the ideal combination of hydro-electric and mega project experience available to be found.
- Even within the oil industry, people working in project management have generic skillsets that they apply to different types of projects.
- Where hydro-electric experience is most important is in the engineering design, as well as cost estimating, carried out by SNCL which brought extensive hydro-electric experience to the Project.
- SNCL provided personnel for many other project management positions, but interestingly some of them did not have hydro-electric experience, coming from the mining and even oil and gas sectors.

The question should be asked, did the extent of hydro-electric experience among the core project team members have any effect on cost and schedule? We can speculate that it did, or that it didn't. Intuitively one may think that it must have had an effect, but is there any evidence of that? Findings of cause and effect require proof. Grant Thornton in the

Construction Phase report described the experience of project management team members but expressed no conclusions one way or the other.

We should also remember that this discussion is under Term of Reference 4(b)(iii) which places the question in the context of execution of construction of the Project, not sanction. Nalcor CEO Stan Marshall has expressed the opinion that the question of decision making at time of sanction is a different one that would have benefited from a conservative utility oriented approach. However, he has publicly praised the performance of the project management team in the construction of the Project.

#### 4.6.4.4. EPCM and Transition to Integrated Project Team

Large construction projects can be organized using a variety of models.

The Engineering, Procurement and Construction (EPC) model usually involves contracting a fixed scope of work, either the whole project or a discreet part of it, to a construction company that will complete the design to the owner's specifications, procure the services and materials, and carry out the construction and commissioning. The owner may retain a consultant to act on its behalf to manage the relationship with the EPC contractor, or may use its own staff to do so. The CH0030 Turbines and Generators contract is an example of an EPC type arrangement.

Under the Engineering, Procurement and Construction Management (EPCM) model, a single consultant is contracted to prepare the engineering design for the owner, manage the procurement from suppliers and contractors that are contracted directly to the owner, and provide the construction management oversight of the work of the contractors on the owner's behalf.

The integrated project team model is a variation of the EPCM model where the owner builds a team drawing on contracted expertise to carry out some or all of the EPCM functions.

Grant Thornton concluded that both EPCM and integrated teams are acceptable management frameworks (P-01677 page 105). Nik Argirov testified that use of an integrated team was a normal process, that he had been part of an integrated team with Newfoundland and Labrador Hydro personnel for the Granite Canal project, and that the Site C project in British Columbia uses an integrated team model (Nik Argirov March 19, 2019 pages 128-129). Ron Power was part of an integrated team on the Terra Nova project (Ron Power May 21, 2019 page 4).

Nalcor had originally planned to use an engineering and support services model for the Lower Churchill Project, which is a type of integrated team where a consultant performs the engineering and provides personnel resources (P-01817 pages 4-7, Ron Power May 21, 2019 page 4). A call for expressions of interest was issued and responses indicated greater interest in using the EPCM model, where contractors would use their own methods, systems, processes, procedures, tools, support services and general know-how (P-01817 page 8). After careful consideration a decision was made to switch to the EPCM approach (P-01817 pages 10-11).

A request for proposals for options for full or partial EPCM services was issued in July 2010 (P-01056). SNCL was selected and an EPCM contract was executed with it on February 1, 2011 (P-01817 pages 12-13, P-00037, P-01436). SNCL's work started with a kick-off meeting on March 30 and 31, 2011 (P-02456, P-02457).

The quality of the engineering performed by SNCL was high, but in other aspects of the contracted work SNCL failed to perform. Details are set out in presentations prepared by the project management team (P-00858, P-01817 pages 15-25) and further explanation was provided by General Project Manager Ron Power (Ron Power May 21, 2019 pages 34-39). The problems included difficulty filling positions and turnover of senior managers; failure to meet deadlines for Decision Gate 3 deliverables (P-03686); failure to implement the promised SNCL management tools, systems and corporate processes; lack of coordination between engineering design and procurement resulting in missed procurement deadlines; very substantial growth in estimates of EPCM contract cost compared to estimates given at the bid stage (P-00858 pages 2-3); problematic construction management of early works; turmoil in SNCL senior leadership due to the corruption scandal; approaches to contracting strategy that conflicted with the approved

Project model; and deficiencies in the management of engineering deliverables and in change management processes.

The result was a gradual transition through 2011 and 2012 of procurement and then project management functions to the integrated team approach, staffed by personnel from SNCL, from within the Nalcor project team and also drawn from other engineering and project management firms such as Hatch. In September 2013 SNCL gave notice that due to the change in project execution method the EPCM contract should be amended, which was formally done in 2017, retroactive to April 1, 2012 (P-01446).

The evidence supports the conclusion that Nalcor acted prudently under the circumstances to initiate the change from EPCM to an integrated team model, and that the transition was successful in resolving the urgent problems arising from SNCL's performance failures in 2011 and 2012. The integrated team model is a recognized and generally accepted approach to project execution. It was familiar to the Nalcor senior project team members who implemented it, both due to their prior experiences working under that model and due to the early project planning that had been based on use of an integrated project team.

The transition did not result in loss of important hydro-electric experience. SNCL remained responsible for engineering design, where that experience was most important, and contributed other personnel with hydro-electric experience to the project team. Would the Project cost and schedule outcome have been different had SNCL been left with the full EPCM scope? We can speculate, but there is no basis in the evidence to conclude that the outcomes would have been any better. Had SNCL been left to continue on the track it was on in 2011 the outcome would most likely have been worse. Indications also are that had the change not been made the cost of EPCM services would have been higher than the costs that have been incurred for carrying out those functions through the integrated team.

#### 4.6.4.5. 2016 Project Reorganization

In May 2016 Nalcor's new CEO Stan Marshall initiated a Project reorganization that has been referred to as the "bifurcation". Mr. Marshall testified that when he took on the position he found that Nalcor and the Project were in crisis. The top priority was Astaldi, which was going to run out of money in July, but Mr. Marshall also quickly decided that there needed to be better executive control over the Project. He considered Project Vice President Gilbert Bennett to be overwhelmed. He saw two distinct projects, the generation project and the transmission project, each massive in their own right and with different challenges. The Muskrat Falls generation portion he regarded as not unlike the Hibernia project in that project team focus was on completion of construction, but transmission needed to be prepared for transition to operations and integration into the NLH electricity distribution system. He also wanted to clearly separate the regulated part of Nalcor's business. Another important consideration was the opportunity to escalate earlier completion of the transmission system to allow import to the Island of power already available from the Upper Churchill, offsetting expensive power produced by burning oil at Holyrood. (Stan Marshall June 28, 2019 pages 35-38.)

Splitting the Project into generation and transmission was thus one part of a larger reorganization that saw the creation of the Nalcor Power Supply division with responsibility not just for completing the transmission component of the Project but also for operating it into the future.

Early 2016 was a time of high stress for members of the project management team. The Astaldi problem was serious enough, but it was compounded by uncertainties resulting from the change of government, the change in Nalcor leadership, and the public criticism of the Project and the management team coming from many quarters, including from government (Paul Harrington June 5, 2019 page 17). Some saw disruption from the reorganization as a significant risk to the project. Paul Harrington, after consultation with project team members, wrote to Mr. Marshall to express those concerns (P-03181). Mr. Marshall recognized that his plan had risks but there were risks from doing nothing. He appreciated hearing the honest opinions Mr. Harrington expressed but decided to keep moving ahead. (Paul Harrington June 5, 2019 page 22, Stan Marshall June 28, 2019 pages 38-39.) Mr. Harrington accepted that the decision was made and moved forward with Mr. Marshall to implement it.

The fact that changes to project organization were made in 2016 cannot be taken as proof that the prior organization was deficient at the time it was put in place. Large projects taking years to complete can be expected to evolve over time as the needs and circumstances change. The Project split was a reasonable response to the situation that Mr. Marshall found when he assumed the CEO position and indications are that it has been successful.

### 4.6.5. Term of Reference 4(b)(iv) - Construction Package Size

Term of Reference 4(b)(iv) is as follows:

> 4. The commission of inquiry shall inquire into
>
> (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether
>
> (iv) the overall procurement strategy developed by Nalcor for the project to subdivide the Muskrat Falls Project into multiple construction packages followed industry best practices, and whether or not there was fair and competent consideration of risk transfer and retention in tis strategy relative to other procurement models.

#### 4.6.5.1. Advantages and Disadvantages of Large and Small Work Packages

It seems to be generally accepted that a benefit of larger work packages is that they reduce the risks associated with having multiple interfaces between the work of different contractors that would require logistical and scheduling coordination. If that coordination is not achieved there are risks of claims by contractors against the owner for delays and interference in the performance of their work, even if the cause is attributed to another contractor. For a large work package some of that risk is transferred to the contractor, who may have to engage subcontractors and manage the interfaces itself, however the contractor can be expected to put a premium on the contract price to account for that.

Larger contracts may also allow efficiencies of scale. One contractor setting up and operating a large concrete batch plant should be more efficient than three contractors each with their own batch plants.

A principle advantage of smaller work packages is that more contractors will have the capability of performing the work and there will therefore be more competition during the procurement process, which may result in more competitive pricing. It has also been suggested that the consequences of a contractor failing to perform or becoming insolvent is reduced if the packages are small, however with more contractors on site the likelihood of one of those failures occurring is higher.

Another consideration is that the cost of administering a large number of small contracts would be expected to be higher than the cost of administering a smaller number of large contracts.

#### 4.6.5.2. Project Package Sizes

Discussion in Inquiry testimony about whether a strategy for fewer large work packages or more smaller packages is to be preferred has been conducted in mostly general terms. Much of the discussion has been in the context of the CH0007 contract for construction of the intake, powerhouse, spillway and transition dams. Its potential application to other parts of the work has not been explicitly considered. A short review of some major work packages and their amenability to further subdivision into smaller packages follows.

- CD0501 Converter Stations and Transition Compounds was let as one package. Smaller packages would be problematic because of the importance of using common technology for the HVdc transmission system. Risks from technological incompatibility and interface issues would be very large.
- CD0502 AC Substations was let separately as a single package. Further subdividing it would likely raise similar concerns as for CD0501.
- CD0534 Synchronous Condensers was a sufficiently discrete part of the transmission system that it was let as a separate, smaller package.
- CH0002 Accommodations Complex Buildings was one package and would have been difficult to efficiently split.
- CH0003 Administration Buildings was let separately from the Accommodations Complex, even though it is a similar type project in close proximity to the camp.
- CH0004 Southside Access Road was let as one package. It would have been difficult to split it efficiently into separate packages.
- CH0006 Bulk Excavation was a single package for what was predominantly a single excavation. Efficient subdivision would be difficult.
- CH0008 North Spur Stabilization Works was a single package for similar reasons.

- CH0009 North and South Dams was a single package however the dams were to be constructed sequentially, so the contractor's resourcing could be based on what was needed to build one dam at a time.
- CH0023 and CH0024 Reservoir Clearing was split into two packages, one for the North Bank and the other for the South.
- CH0030 Turbines and Generators was a single package. These units obviously all had to come from a single supplier.
- CH0031 Mechanical and Electrical Auxiliaries was a single package for outfitting the electrical and mechanical system in the powerhouse, separate from the CH0007 powerhouse construction package. Breaking it down any further would have added more contractors to the powerhouse at a time when both the CH0007 contractor and the CH0030 contractor were working there.
- CH0032 Spillway and Powerhouse Hydro-Mechanical Equipment had started as separate packages for the spillway and powerhouse, but were reconsidered and combined into a single package.
- CT0319 315kV AC Transmission Line was a single package for the line from Churchill Falls to Muskrat Falls.
- CT0327 350kV HVdc Transmission Line started as four packages but was combined during the open book discussions with Valard, the only contractor found capable of performing the work.

(See P-02103 for a listing of work packages)

The opportunities to reasonably subdivide more contract packages thus were limited and the question of whether smaller work packages should have been used seems to apply primarily to package CH0007.

Pat Hussey testified that a combination of large and small work packages were selected based on what fit the market. He described it as a logical breakdown of the project. He said that he did hear from SNCL that they favoured smaller packages for the transmission line but regarding the spillway and power house he said that, "SNC were heavily involved in that strategy and they signed off on it." (Pat Hussey March 1, 2019 pages 24-25.)

#### 4.6.5.3. Investigative and Forensic Audit

Term of Reference 4(b)(iv) was reported on by forensic auditors Grant Thornton in their Construction Phase report (P-01677 pages 106-110). Grant Thornton had R.W. Block provide an opinion on the use of large construction contract packages (P-01683). Mr. Hennessey stated that Nalcor had chosen to use primarily large contract packages, without explanation of how he came to that conclusion. He listed advantages and disadvantages of each, noted Nalcor's financial rating agencies' preference for larger packages, added that there were other benefits from larger packages, and concluded that Nalcor's decision seemed reasonable (P-01683).

Scott Shaffer presented the Grant Thornton Construction Phase report and agreed that it was reasonable for Nalcor to have proceeded with larger work packages (Scott Shaffer February 19, 2019 page 51.)

## 4.7. Risk Assessments

### 4.7.1. Risk Assessments - Term of Reference 4(b)(v)

Term of Reference 4(b)(v) is as follows:

> 4. The commission of inquiry shall inquire into
>
> (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether
>
> (v) any risk assessments, financial or otherwise, were conducted in respect of the Muskrat Falls Project, including any assessment prepared externally and whether
>
> (A) the assessments were conducted in accordance with best practice,
> (B) Nalcor took possession of the reports, including the method by which Nalcor took possession,
> (C) Nalcor took appropriate measures to mitigate the risks identified, and
> (D) Nalcor made the Government aware of the reports and assessments.

This section 4.7 will first address the questions posed in the Term of Reference for the risk assessments carried out by Nalcor in conjunction with Decision Gates 2 and 3 and the Quantitative Risk Analyses completed for cost updates in June 2016 and June 2017. It will conclude with discussion of the risk assessment carried out internally by SNCL in April 2013.

### 4.7.2. Term of Reference 4(b)(v)(A) – Were Risk Assessments Conducted in Accordance with Best Practice?

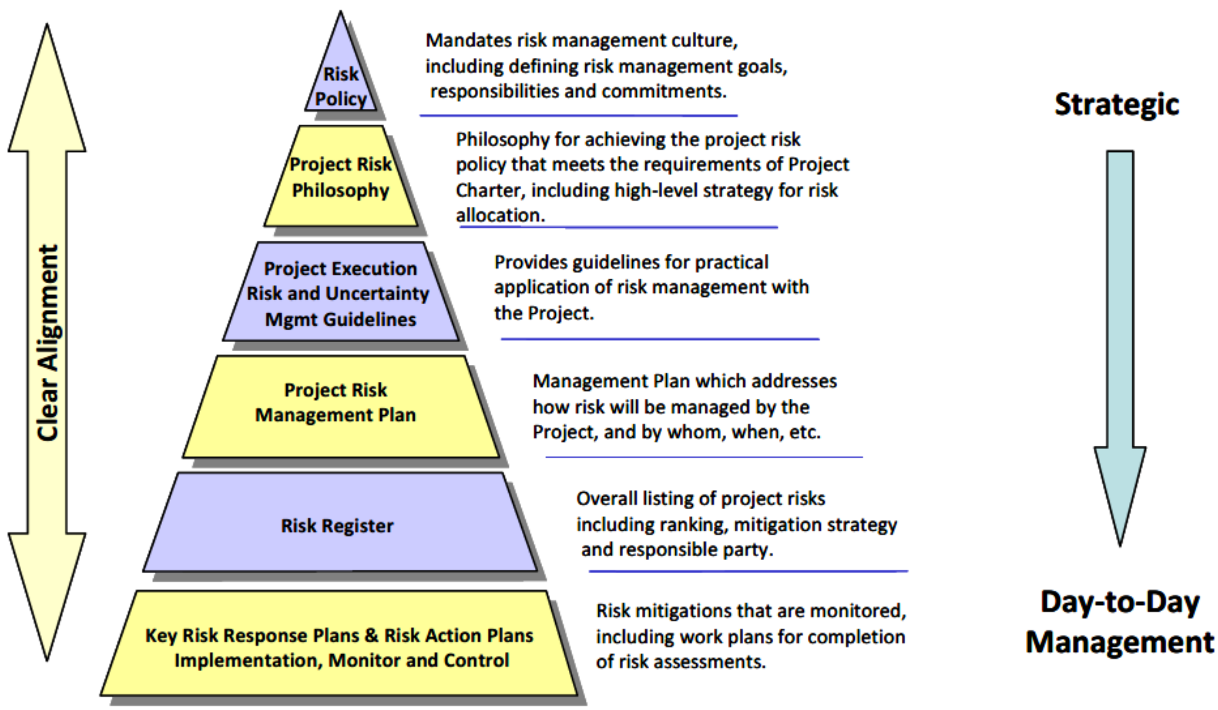
In order to assess whether risk assessments were conducted in accordance with best practice the process used to the conduct risk assessments should be examined, best practices identified, and the two compared.

#### 4.7.2.1. LCP Risk Management Program

Development of the risk management program for the Lower Churchill Project began in 2007. Westney Consulting Group had been retained in that year to advise on its development (Exhibit P-01002 NLH-LCP Risk Management Meeting Notes). Westney remained involved in risk assessment work on a periodic basis after that and did important quantitative risk assessment work at Decision Gates 2 and 3 and in 2016 and 2017.

The risk management program that was in place by 2011 is illustrated by the following diagram, found in various risk-related Project documents.

**Figure 1:** NE-LCP Risk Management Program




#### 4.7.2.1.1. Project Risk Management Policy

The pinnacle of the pyramid, at the strategic end of the scale, is the Project Risk Management Policy, first approved for use in December 2007 and reissued in June 2012 (Exhibit P-00896). It is a concise statement of policy goals opening with the statement that, “the Lower Churchill Project Management Team is committed to planning and executing the Lower Churchill Project in such a way as to minimize the potential negative effects of risks and to maximize opportunities.”

#### 4.7.2.1.2. Risk Management Philosophy

The first layer in the pyramid below the Risk Management Policy is the Risk Management Philosophy, first issued for use in April 2008 and reissued in June 2012 (Exhibit P-00897). It begins to refine the approach to risk management and states these objectives:

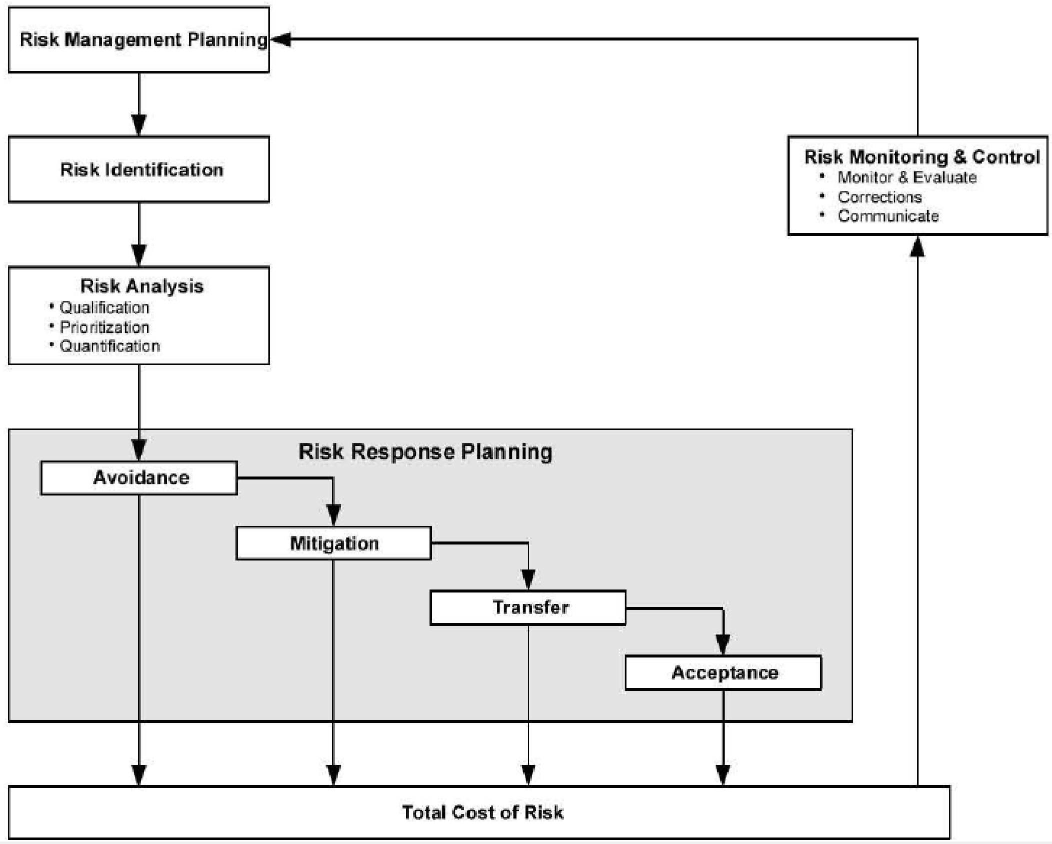
- Identify, assess, respond to, manage and mitigate all key risks and uncertainties;
- Allocate project risk to the party who can most efficiently and effectively manage the risk;
- Identify the timeframe in which a risk may be realized;
- Improve decision-making by thoroughly understanding project risks and uncertainties.

It identifies risk resolution strategies as avoidance, by eliminating the risk cause; mitigation, by reducing the probability or consequence of materialization of a risk; allocation, by shifting the risk to a third party and thereby reducing Project exposure to the risk; and acceptance, which may include allocating contingency funding.

#### 4.7.2.1.3. Project Execution Risk and Uncertainty Management Guidelines

The Project Execution Risk and Uncertainty Management Guidelines, the third layer in the pyramid, were first approved for use in December 2007 and were reissued in June 2012 (P-01007). This document describes processes for risk identification, qualitative and quantitative risk analysis, risk response and risk monitoring and control. It is a guide to risk management in five phases, summarized in the following diagram:

Figure 6.2 illustrates how these phases interrelate to form the overall Project Risk Management Program. Although shown as discrete, individual steps, there is considerable overlap among stages. In addition, some stages may be repeated during the life of a project.




#### 4.7.2.1.4. Project Risk Management Plan

The Project Risk Management Plan is an important document that carries forward the policy, philosophy and guidelines from the documents above it in the pyramid.

Version B1 was issued for use in June 2011 (P-01155) and incorporates the risk management role of SNCL as EPCM contractor. SNCL issued its Sub-Project Risk Management Plan, version B2, in November 2011 (P-02470). It mirrors many provisions of the Project Risk Management Plan and elaborates on them in some areas, particularly where SNCL had responsibility.

The Project Risk Management Plan, version B2 was issued in October 2014 ( P-03751). It is in large part a consolidation of the prior LCP and SNCL plans without change in policy or process for risk management, but reflecting the change to an integrated project team for procurement and construction management.

Section 3 of the Project Risk Management Plan, version B2 defines terms used in this and other Project documentation that are instructive for understanding the approach taken to risk identification, classification and management. Selected definitions are as follows. Note that there is some variation in these definitions over time and among documents.

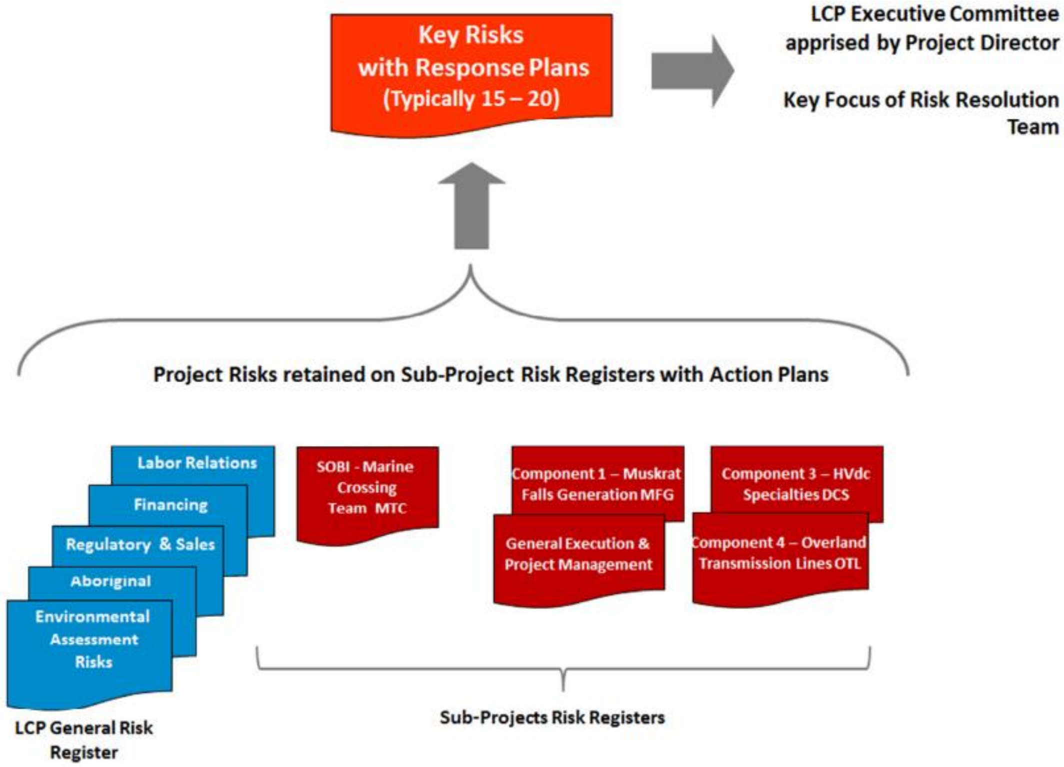
| | |
|---|---|
| Base Estimate | Reflects most likely costs for known and defined scope associated with project's specifications and execution plan. |
| Allowance | Costs added to the base estimate, based on experience, to cover foreseen but not fully defined elements. |
| Escalation | Provision for changes in price levels driven by economic conditions. Includes inflation. |
| Estimate Contingency | Provision made for variations to the basis of an estimate of time or cost that are likely to occur, that cannot be specifically identified at the time the estimate is prepared but, experience shows, will likely occur. Contingency does not cover scope changes outside the Project's parameters, events such as strikes or natural disasters, escalation or foreign currency impact. |
| Management Reserve | Approved capital budget held in reserve and controlled by Gatekeeper, which is used to provide a higher confidence cost level (i.e. comfort factor).<br><br>It is often used by Gatekeeper as a mechanism to support scope additions in a project raised as part of the change management process which would not be covered by Estimate Contingency. The Management Reserve is also used to handle the impact of strategic risk.<br><br>Unlike Estimate Contingency, Management Reserve is not expected to be spent unless the Gatekeeper so directs. |
| Risk | An uncertain event or condition that, if it occurs, has a positive (opportunity) or negative (threat) effect on a project's objectives. |
| Tactical Risk | Identified background risks that are inside of the controllable scope of the project team. Basically it refers to risks associated with the base capital cost estimate as a result of uncertainties with the four components of the |

| | |
|---|---|
| | estimate: (1) project definition and scope omission, (2) construction methodology and schedule, (3) performance factors, and (4) price. It excludes price escalation. |
| Strategic Risk | Identified background risks that are outside of the controllable scope of the project team, typically pertaining to external issues such as enterprise level issues, governance, financial markets, stakeholders, hyperinflation, and regulatory approvals. Managing these risks requires significant effort and influence by the Gatekeeper with external stakeholders. strategic risk is also referred to as the risk of failure of the general execution plan. |
| Strategic Risk Exposure | Probabilistic impact of Strategic Risks that is quantified. Covered by Management Reserve. |
| Risk Management | Risk Management is the act or practice of dealing with threats and opportunities. It includes creating an environment and a context for dealing pro-actively with them, identifying and analyzing potential threats and opportunities, prioritizing threats and opportunities (by comparing the probable consequence of different risks) so that the right resources can be applied in a timely manner, preparing and implementing mitigation plans, recording and communicating threats and opportunities, as well as the eventual close-out of specific risks and the Project itself. |
| Risk Register | A database or register of the identified project risks. |
| Action Plan | Action plan prepared to address Risks identified in the Sub-Project Risk Register. |
| Key Risks | A risk selected to be overseen by the Risk Resolution Team or LCP Executive Committee due to the risk's complex nature and high profile. |
| Risk Response Plan | Management strategy and action list prepared for Key Risks. |

The "Sub-Projects" referred to are the four Project Components; Muskrat Falls Generation, Labrador Transmission Assets, Strait of Belle Isle Crossing and Labrador Island Link.

Section 6 of the Project Risk Management Plan describes roles and responsibilities including those of the Project Director, Risk Owner, LCP Executive Committee and LCP Risk Coordinator. The Risk Advisor is identified as Westney Consulting Group with responsibility to provide process expertise and specialized tools for conducting risk assessments, assisting with the assessment of financial exposure of strategic risks, participating in Risk Resolution Team reoccurring meetings, and acting as independent risk broker. Strategic and Tactical Risks are defined in more detail in Section 7.

Section 8 presents an overview of the Risk Management Process and concludes with a diagram that illustrates how Strategic Risks are maintained on the LCP General Risk Register (shown in blue) and Tactical Risks on the Sub-Projects Risk Registers (shown in red), collectively referred to as Project Risks, that are managed with Action Plans. Typically 15 to 20 of those risks flow up to become Key Risks that require Response Plans. They are the key focus of the Risk Resolution Team and are to be reported by the Project Director to the LCP Executive Committee.[6]




Section 9 of the Project Risk Management Plan, version B2, addresses Risk Identification and Organization and Section 10 is Risk Assessment and Prioritization. Both the Project

[6] This diagram is from P-03751 Project Risk Management Plan, version B2 at page 22. P-01155 Project Risk Management Plan, version B1 at page 20 is slightly different in that the four Project Sub-Components are identified as “EPCM Consultant’s Risk Registers”.

Risks recorded in the Risk Registers and the Key Risks are to be updated on a regular basis as part of ongoing risk management (P-03751 Sections 9.4 and 10.5).

More comprehensive Risk Assessments were to be carried out periodically as described in Section 10.3:

> The LCP Project Risk Coordinator has primary responsibility for developing a schedule for Risk Assessments (Tactical-Risk, Strategic-Risk, and Time-Risk analyses) to evaluate risks at the LCP Project and Sub-Projects.
>
> Where required, the LCP Risk Coordinator, working with the Risk Advisor (Westney Consulting Group), will facilitate the discovery (document review and interviews) and workshop discussions associated with the Risk Assessments. It is intended that a broad range of project knowledge holders participate in the discovery process and Risk Workshops. LCP Strategic Risk Frames will be used to describe the attributes of each Key Project Risk.
>
> Prior to LCP Gate 3, the Risk Advisor (Westney) will be responsible for performing the analysis and creating reports to document findings. The analysis, including Monte Carlo-type simulation techniques, will be structured to gain insights on important issues identified by Nalcor; these issues may pertain to individual risks or groups of risks. Risk Assessments may consider both the impact of risks as well as the impact of potential mitigations. The Risk Assessment results are carefully considered in the determinations of both project contingency and management reserve levels (reference Project Controls Management Plan, reference document No. LCP-PT-MD0000- PC-Pl-0001-01).
>
> Post LCP Gate 3 - Project Execution, the Risk Advisor (Westney) will be engaged in an “as needed” basis.

The Project Risk Management Plan thus anticipated conduct of a full Quantitative Risk Assessment (QRA) with Westney support prior to Project sanction but, while leaving the door open for subsequent QRAs, did not mandate that they be carried out on a fixed schedule.

Section 11 of the Plan addresses Risk Responses for risks carried on the two Risk Registers and for Key Risks. Section 12 is Risk Monitoring and Control and Section 13 introduces the Iris Risk Management Software.[7]

An important observation is that there are two risk reporting functions. One is the regular reporting of the ongoing risk management and mitigation activities undertaken by the project management team as recorded in the risk registers and reported in the Monthly Progress Reports. The objective of this reporting is primarily for project management. The other category is the formal QRA. The ongoing risk management activities and periodic QRAs share identification and assessment of risks and documentation of the means by which they may be eliminated, mitigated or allocated to another party. The QRA, however, addresses quantification, which is the estimation on a probabilistic basis of cost at different levels of confidence, should a risk materialize. A QRA provides information that can be used to estimate contingency and, when combined with other elements, the estimated cost of a project. It thus may be used for purposes of decision making and budget setting.

#### 4.7.2.2. Nalcor Risk Assessment Reports

Risk assessment reports were prepared by Nalcor, with guidance and support from Westney, in connection with Decision Gate 2, Decision Gate 3 and the capital cost updates in June 2016 and June 2017.

Risk registers tracking risks and responses are maintained on an ongoing basis. This section 4.7.2.2 of this submission will address the risk assessments and not the risk registers. Also, how the information presented in the risk assessments was used in the decision-making process is dealt with more fully elsewhere in this submission.

##### 4.7.2.2.1. Decision Gate 2 Risk Assessment Report

The Gate 2 Project Risk Analysis, version B1, was issued for use on June 16, 2011 (Exhibit P-00808). Version B2 was issued for use on September 15, 2011 (P-00097). On

[7] See for exampleP-04086 LCP Monthly Progress Report Period Ending 31-August-2015 at pages 112-116 for risk reporting using Iris output.

November 16, 2010, the Nalcor board had given approval for the corporation to move through Gate 2 and proceed towards sanctioning of the Muskrat Falls Project (P-00394 page 5). Its chairperson had reported that decision to the Premier and Minister of Natural Resources on the same date (P-00093 page 167). The Gate 2 Project Risk Analysis, although prepared later, documents the risk analysis process and information available at the time of Gate 2.

The direction to inquire into risk assessments in Term of Reference 4(b)(v) is contained in a subparagraph under the direction to inquire into the difference between estimated costs at sanction and actual costs, and should be considered in that context. The Gate 2 Project Risk Analysis was prepared for Decision Gate 2, and was superseded by the Decision Gate 3 analysis for use in determination of the estimated costs at sanction. However it is useful to review it as background to the later assessment.

###### 4.7.2.2.1.1. Gate 2 Project Risk Analysis, version B1

This report (P-00808) begins by summarizing elements of the risk management process as described in the policy, philosophy, guidelines and plans referred to above that were utilized at Decision Gate 2 to arrive at recommendations for contingency and reserve amounts for tactical and strategic risks, and to assess the risk of schedule delay.

Beginning at page 9 of the report the engagement of Westney is described, as is the adoption of Westney's trademarked *Risk Resolution* methodology to augment the processes already in place. In September 2009, prior to the selection of Muskrat Falls as the first phase of the Lower Churchill Project, Westney had presented a report assessing time and strategic risks for the Gull Island development and transmission line to the Island, appended as attachment B.4. In July 2010, Westney presented a new report, appended as attachment B.3, built on work performed in June and July 2010 to assess the time, tactical and strategic risks associated with the Muskrat Falls Generation project and associated transmission development.[8]

[8] This Westney report was submitted by Nalcor to the Public Utilities Board with confidential exhibit CE-52 in 2011. See P-00600 PUB Report at pages 60-61.

Regarding the schedule risk assessment, Nalcor provided the schedule and identified key activities to be modeled. Westney met with Nalcor representatives to discuss possible outcomes for each activity. The Nalcor team performed the final ranging of possible outcomes, but they were vetted and questioned by the Westney participants. Westney then used its Monte Carlo probabilistic modeling techniques to model the results. The predictive range for full commercial power was 9 to 16 months later than scheduled, with 9 months having a P25 value and 16 months P75. The key activities driving those results were identified, as was the most likely critical path (P-00808 at page 112).

A central purpose of this risk analysis work is to identify opportunities for actions that will eliminate or mitigate risks. Regarding the schedule risk assessed by Westney, the Gate 2 Project Risk Analysis includes this statement:

> The analysis has facilitated the identification of a number of de-risking tactics, reference Table 1.0, however a subsequent re-run of the Time-Risk Model with de-risk adjusted ranges was not undertaken. Several of these de-risking activities are currently under implementation, including the issue of a Request for Proposals for Turbine Model Testing. These activities, combined with a decision to issue a mass excavation contract for powerhouse, are considered significant de-risking activities for the schedule.
>
> (P-00808 at page 19.)

For the tactical risk assessment, Nalcor provided a cost estimate broken down by major category. Westney met with Nalcor representatives to discuss best and worst case ranges for each category. Nalcor performed final ranging, but it was again vetted and questioned by Westney participants. Westney selected probability distributions and ran the Monte Carlo simulation. The result was that Westney recommended a P50 contingency for tactical risk, which was equivalent to 16% of the base estimate. (P-00808 at pages 17, 127.)

For the strategic risk assessment, the Westney report states that the risks were identified and framed by the Nalcor team. Westney consultants met with them to discuss possible outcomes for mitigated and unmitigated cases, and the final ranging was performed by the Nalcor team but was vetted and questioned by the Westney participants. Westney ran the Monte Carlo simulation. Westney’s report states,

> The Strategic Risk Exposure is the range of the costs that might be incurred that currently would not be incorporated into the estimate. A decision will be required as to whether these risks become costs in the estimate or remain as Risk Exposure above the estimate.
>
> (P-00808 page 133.)

If strategic risks were not mitigated, the predictive range was reported by Westney as \$490 million at P25 to \$852 million at P75, and if mitigated, from \$187 million at P25 to \$413 million at P75 (P-00808 at page 133). The Westney report includes descriptions and ranges for 34 Key Risks and rankings of the seven risks with the greatest exposure (P-00808 at pages 134-146, 151). The Gate 2 Project Risk Analysis states that Westney recommended that a P75 reserve be established to cover the mitigated risk exposure level of \$413 million, which equated to approximately 12% of the base estimate (P-00808 page 22).

The Gate 2 Project Risk Analysis also includes, as Appendix B.2, the “Strategic Risk Frames” being tracked in the risk register (P-00808 page 38). The risks are grouped in categories such as “Enterprise”, “Environmental Assessment” and “Financial”. Consistent with the risk management processes adopted by Nalcor, each risk frame describes the risk details, the risk response and the risk trend and status update. Revision dates for each appended risk frame range from September 1, 2010 to February 14, 2011, reflecting the fact that the Gate 2 Project Risk Analysis document had been prepared after Decision Gate 2 was reached, and that maintaining the risk registers was an ongoing and continuous process.

In Section 8.5, the Gate 2 Project Risk Analysis states that the purpose of estimating values for estimate contingency and strategic risk exposure at Decision Gate 2 was for economic modeling. This is consistent with the Decision Gate process, under which Decision Gate 2 was the point at which options were to be narrowed to a single project, and Decision Gate 3 would be when a decision was to be made whether to proceed with that project. An overall P50 probability factor was adopted for estimate contingency and strategic risk exposure. The estimate contingency was set at 15% which was 1% below the Westney P50 recommendation, strategic risk exposure was set at 6% which was half the Westney P75 recommendation, and the full power date was assumed to be June

2017. The Analysis lists a series of decisions and developments that post-dated the Westney work in support of the values selected, including advances in design and planning for the SOBI, the selection of LCC technology instead of VSC technology for the HVdc transmission line, and results from geotechnical work at the Muskrat Falls site, all of which addressed items that Westney had regarded as high risk. (P-00808 page 24.)

The Analysis has a note, added by document author Jason Kean, that Nalcor senior management had elected to drop the 6% strategic risk exposure during negotiations of the term sheet with Emera, which is discussed further below.

#### 4.7.2.2.1.2. Gate 2 Project Risk Analysis, version B2

Version B2 of the Gate 2 Project Risk Analysis (P-00097) is substantially the same as version B1. There were no changes to the attachments. A new paragraph was added to the Recommendations section addressing the schedule as follows:

> Subsequent to the June 2010 Risk Assessment, Nalcor placed significant effort on developing and implementing a de-risking strategy for the delivery schedule. Mitigation activities have included preparing to issue a Bulk Excavation Contract Package to facilitate an early commencement of Powerhouse Excavation, and late 2010 award of 3 separate contracts for Turbine Model Testing in an effort to de-risk the overall turbine component delivery schedule, which is critical to maintain the planned Powerhouse concrete schedule.
>
> (P-00097 page 24,)

A fuller explanation of the decision to value potential strategic risk exposure as nil, for the purposes of the DG2 economic modeling, was added to the Analysis. In particular, the benefit of a federal loan guarantee, which was under negotiation in 2010 but not quantified when the risk analysis work had been done, was valued as $300 million at a P50 probability. Plus, the risk reduction benefit from the switch to LCC technology was valued at $100 million, also on a P50 basis. These more than offset the P50 mitigated strategic risk exposure that had been determined by Westney earlier. Therefore, “Nalcor executive determined that it was not appropriate to create a positive or negative financial reserve provision at DG2." (P-00097 at pages 25-26.)[9]

The note found in version B1 attributing the removal of the 6% strategic risk exposure to negotiations with Emera does not appear in version B2. In testimony to the Commission, Mr. Kean, who authored the note, said that he was not part of the negotiations with Emera and was unable to say what his source for the information in the note had been (Jason Kean November 7, 2018 page 58).

Chris Huskilson, who was the President and CEO of Emera when the term sheet for the Maritime Link was negotiated provided a statement to the Commission (P-01462) and was interviewed by Commission counsel (P-01670). Mr. Huskilson said that Emera and Nalcor used different terminology for classifying risk and contingencies. In particular Emera did not use the term strategic risk. Because Emera had to submit the Maritime Link Project to the UARB there was discussion about the need for Nalcor to align its terminology with theirs. However there was no discussion about the removal of any amounts from the Nalcor estimate. Mr. Huskilson was clear that the discussions started on the basis that Nalcor had estimated the cost of the Muskrat Falls Project at $5.0 billion and the Maritime Link at $1.2 billion and they ended with no change to those numbers. He was presented with testimony from Gilbert Bennett, given to the Inquiry on November 26, 2018, which suggested that an amount of contingency may have been removed from the Nalcor estimate during the discussion (Gilbert Bennett November 26, 2018 pages 60-63). Mr. Huskilson stated that was not correct and that there was no change to the estimate.

#### 4.7.2.2.2. Decision Gate 3 Risk Assessment

The Decision Gate 3 Cost and Schedule Risk Analysis was issued for use on October 1, 2012 (P-00130). Section 7.0 presents a statement of the scope and focus of the analysis:

> The objective of the cost and schedule risk analysis completed for DG3 is to holistically assess quantitative cost and time exposure that known risks may have

[9] This description of the rationale for excluding an amount for strategic risk from the DG2 modeling was also presented in P-01050 Technical Note – Strategic Risk Analysis and Mitigation submitted to the Public Utility Board as CE-52 Rev. 1 (Public).

on the Project's Cost and scheduling planning basis as used in the DG3 CPW analysis to:

1. Recommend a P50 cost estimate
2. Identified expected estimate contingency requirements
3. Confirm the accuracy of the base estimate
4. Endeavour to quantify any potential financial exposure beyond the P50 cost estimate related to risks considered outside the control of Nalcor.

(P-00130 page 7.)

Section 8.0 describes Westney's role, which was similar to that for the Gate 2 assessment, and states that reliance was placed on AACE International Recommended Practice 42R-08 (P-00130 page 8). The process used to conduct the assessment is set out in section 9.0 (P-00130 page 9). In summary, use was made of the risk management activities carried out since 2008, including the Gate 2 assessment and the implementation of the Project Risk Management Plan. Risk registers and other information (P-00130 pages 21, 53, 93, 107 and 123) were collected and used as inputs at workshops held at St. John's on May 24 and 25, 2012 (P-00130 pages 134, 145). The first day was to address tactical risks for Muskrat Falls, the Labrador Island Link and the Labrador Transmission Assets and included SNCL personnel. The second day was restricted to Key Risks[10], which under the Project Risk Management Plan were the primary responsibility of Nalcor, although the risk register was maintained by SNCL while the EPCM arrangement was fully in place and by integrated management team members provided by SNCL after that. No personnel affiliated with SNCL attended the second day session. Westney personnel facilitated both sessions.

The result of the workshops was the selection of best and worst case risk ranges for the identified tactical risks (P-00130 at page 239), and best and worst case durations for tasks identified in the high level schedule (P-00130 page 251). Risk ranging for strategic or key risks was completed later when Paul Harrington and Jason Kean visited Westney's

[10] See Exhibit P-00899 for a message from Jason Kean to Westney personnel concerning planning for the workshop and Exhibit P-01155 for a message from Jason Kean to potential key risk workshop participants describing the plan for the workshop.

Houston offices. Westney then conducted Monte Carlo simulations and presented two reports.

Westney's report *Estimate Accuracy Analysis for Lower Churchill Project* was delivered June 15, 2012 (P-00130 page 262). Westney reported that the scope of the project was well defined and represented design development consistent with project sanction, as did the base estimate. They stated:

> The estimate, plus an amount to reach the P50 on the results curve, should represent the cost at which the project can be executed according to the plan exclusive of external uncertainties.
>
> A P50 contingency is $368 million which equates to 7% of the estimate.
>
> (P-00130 page 265.)

The Westney report includes a curve showing that at P25 the required tactical risk contingency would have been $16 million and at P75 it would have been $754 million. The P50 value of $368 million for estimate contingency was adopted in the Decision Gate 3 Project Cost and Schedule Risk Analysis Report. At 7% of the base estimate, this is less than the 15% contingency that had been recommended at Decision Gate 2. However, the same risk assessment methodology was applied for the 2012 assessment as had been used in 2010, and the amount of contingency had been expected to decline as project definition advanced between Gates.

Westney's modeling of the schedule risk produced three curves, one for first power for the Muskrat Falls plant and the Labrador-Island Link, a second for full power for the same combination, and a third for ready for power for the Labrador-Island Link and the Labrador Transmission Assets (P-00130 page 279). In all three cases, the P25 to P75 predictive range was later than the target schedule dates, that for first power by 11 to 21 months.[11] This information was assessed in the Risk Analysis Report as follows:

> In summary, the analysis indicates that based upon the identified unmitigated time risks, there was a low probability of achieving a July 2017 First Power, rather the

[11] Throughout the Inquiry hearings, the Project was often described as having a "P1 schedule" referring to the probability assigned on the Westney curve to achieving the target first power date of July 2017. In fact, the Project had a deterministic schedule to achieve first power by the target date that had been built up from detailed analysis of about 10,000 activity line items. Technically the risk analysis did not change the schedule. What it did was to assess a high risk of there being failure to achieve it.

> risk-adjusted schedule suggests the potential of an 11 to 21 month delay for Full Power (P25 to P75). However caution must be considered when attempting to directly interpret the probability that a given schedule date will be achieved as this is a simplified modeling of a very complex construction schedule, and does not consider the mitigations that may be implemented should a risk event be expected to occur in the near term. Given the inherent nature of such time-analysis, the predictive range (P25 to P75) should only be used to facilitate informed decision making with respect to establishing realistic targets for project completion, rather than blindly considering the output as 100% accurate. To that effect, these results support the merit of leveraging the natural schedule reserve that exist between July 2017 and December 2017 or when power is required on the Island to meet energy requirements.
>
> (P-00130 at page 15.)

The Risk Analysis Report goes on to describe an update to the time-risk modelling that was done in September 2012 to take into account some logic changes and mitigation measures, but which showed little change in the analysis (Exhibit P-00130 page 16).

Westney's report addressing the strategic or key risks is titled *Analysis of Potential Management Reserve and Lender's Owner Contingency for the Lower Churchill Project* (P-00130 page 283). Westney reported that there was a predictive range for potential Strategic Risk Exposure, beyond the contingency for tactical risk, of $330 million at P25 to $633 million at P75, influenced mostly by the risk of time extension to the schedule (the 11 to 21 month delay discussed above) and risk related to construction productivity (P-00130 page 290). $497 million was presented as the mean value for the sum of the potential schedule risk of time extension, the potential performance risk associated with productivity and the potential skilled labour risks related to the possible need for completion bonuses and higher wage rates (P-00130 page 287).

Management reserve requirements were discussed in the Risk Analysis Report which concludes:

> With consideration of the potential cost to mitigate the contributory risks as well as the residual risk exposure, the total financial exposure remains within the $300 to $600 million exposure identified at DG2; presently an expected value is approximately $500 million. For the LCP, this Management Reserve would be funded by Contingent Equity from the Shareholder.
>
> (P-00130 page 18.)

#### 4.7.2.2.3. 2016 and 2017 Quantitative Risk Assessments

Quantitative risk assessment reports were prepared by Westney to support project cost updates in June 2016 (P-01954,P-03380) and in June 2017. In each case Nalcor included contingency for tactical and strategic risks assessed at P75 in the forecast cost for completion of the project. Certain strategic risks, such as the risk of government direction to remove soil from the reservoir area, remain excluded. Risk assessment in 2016 and 2017 has not been a focus of the Inquiry hearings and will not be dealt with further in this submission.

### 4.7.2.3. Comparison to Best Practice

The term “best practice” is often ill-defined and difficult to apply objectively. Several of the expert witnesses who testified at the Inquiry hearing were questioned on what they regarded “best practice” to be. There appears to be no consensus on whether it is, for example, practice prescribed by a standard-setting body such as the AACE, whether it is practice accepted and applied within an industry or whether it is the product of some form of expert consensus. Dr. Jergeas went so far as to say that industry practices for cost estimating that are accepted as “best practice” are in fact not the best practice. He would do things differently.

The result is that it is difficult to find a reliable source for authoritative definition of what is “best practice" in risk assessment. That is not to say that there are no expert opinions available, but that fact may not be sufficient to allow the Commission to identify risk assessment practices that should be recognized as “best practice”. The only alternative may be for the Commission to determine for itself what it considered “best practice” should be. The distinction is important, because to the extent that there may have been an established and recognized “best practice”, the Project would have been reasonably expected to have applied it. To the extent that “best practice” can only now be determined based on consideration of expert opinion, a comparison to practices used for the Project would be an application of hindsight only.

We do know that the Westney Consulting Group provides recognized processes for the conduct and modeling of risk assessments. Had they not been involved in providing services to the Project, they are exactly the type of organization that one might look to for an opinion on what is "best practice". There is therefore a reasonable measure of assurance that the practices, procedures and technologies brought to the Project by Westney should be representative of what might be considered "best practice" in the field. The risk management processes adopted by Nalcor and detailed in the process documents described above are consistent with, and in part built upon Westney approaches to the subject. Nalcor also had the benefit of input from SNCL in the design of risk management processes (P-02470). As well, Manitoba Hydro International, in its report to the Public Utilities Board following Decision Gate 2 stated that the approach adopted for determination of project cost contingencies was reasonable (P-00048 pages 97-98). Prior to Financial Close in November 2013, the Independent Engineer delivered a report to Canada, later disclosed to Nalcor and the Province, which stated that, "the methodology applied to the risk analysis is considered to meet GUD [Good Utility Practice] expectations for quantifying pricing uncertainties utilizing range modeling against group subtotals with standard statistical techniques." (P-01986 page 105.)

Concerning Nalcor's risk assessment process itself, there has been no material criticism of it from experts or other witnesses during the Inquiry hearings. Nalcor submits there is no basis to find that the policies, practices and procedures adopted for performance of risk assessments did not conform to "best practice".

There are a number of specific issues related to inputs and results of the risk assessments that were discussed in testimony during the Inquiry hearings. They are:

1. the risk ranging values selected for tactical and strategic risks,
2. the P values selected for contingency setting,
3. the reasonableness of the resulting amounts of contingency included in the estimated cost of the Project, and
4. the exclusion of a reserve for strategic risks from the Project budget.

#### 4.7.2.3.1. Risk Ranging

One of the inputs to the probabilistic quantification of risk using Monte Carlo techniques is ranges of best and worst case costs for the materialization of specific risks. The selection of best and worst case values is a subjective process that draws upon the knowledge and experience of those involved. For the Decision Gate 3 quantitative risk assessments, tactical risk ranges were selected at the May 2012 workshop with the participation of a broad group of Project personnel including many in positions staffed by SNCL. Westney personnel facilitated, but would also be expected to have applied their knowledge and experience gained from multiple prior projects. For strategic risks, for which under the Project Risk Management Plans SNCL had a more limited role, updating of the risk identification and assessment was done in a workshop session with Nalcor and Westney personnel. The final risk ranging was performed at Westney's offices in Houston with participation by Paul Harrington and Jason Kean.

In the end, the selection of each best and worst cost value is a matter of the application of a combination of skill and judgment. It may be possible to find a "best practice" for how to do it, although there is little evidence to allow the Commission to do so, but it difficult to see how the concept of "best practice" can be applied to the determination of the best and worst case values themselves.

#### 4.7.2.3.2. P Value

The P factor is a concept used to express the probability that a cost estimate will be accurate. The values at different P factors are shown on risk curve diagrams such as those produced by Westney. Generally a risk analysis that results in a prediction that a project cost will be \$X at P50 means that there is a 50% probability that the actual cost will be lower and a 50% probability that the actual cost will be higher. The analysis allows for the determination of how much contingency should be added to a base cost estimate to match the cost predicted on the curve.

In general, selecting a higher P value increases the contingency value and thus the budgeted cost for a project and thereby reduces the likelihood of the actual cost being higher than budgeted. The selected P value affects the budget amount, but has no effect on the actual cost. Using a higher P value can reduce the adverse effects of unplanned cost overruns because the owner has the opportunity to be better prepared to fund them. A higher P value may also risk impairing good decision making when project options are considered, because a project with an estimated cost that is set high to account for risks that may never materialize may be overlooked in favour of another project of less overall value.

Some of the history of the evolution of the use of P values in estimating costs for the Gull Island and Muskrat Falls Project is as follows:

- In June 2008, a presentation to the Nalcor CEO as Gatekeeper recommended a contingency for tactical risk at a P50 or "expected cost" value and a management reserve for strategic risk at a P75 value (P-00901 pages 20, 25 and 26).
- An April 2010 presentation given to Premier Williams and Minister Dunderdale, when switching priority from Gull Island to Muskrat Falls was under consideration, stated that P75 capital costs were being used for the modeling of the alternative cases (P-00206 page 14).
- By Decision Gate 2 in November 2010, P50 had been adopted for the Muskrat Falls project estimated capital costs that were being used in the CPW modeling of the Interconnected Island Option, which was considered to be comparable to the confidence level for capital cost estimates being used in the Isolated Island Option and for other inputs, such as future oil prices, in both options. The concept was that using the expected cost provided a fair basis for comparison.
- For Decision Gate 3 and Project sanction in December 2012 the estimated capital cost of the Muskrat Falls project included contingency for tactical risks at P50. No reserve for strategic risk was included in the Project budget.
- In 2016, Nalcor CEO Stan Marshall directed use of a P75 value for the updated cost estimate released in June. He testified that this selection was based on observation of actual results since the beginning of construction, rather than on some other theoretical basis (Stan Marshall June 28, 2019 pages 69-70).

For setting contingency for tactical risks, that is risks within the control of the project management team and not external to the Project, the P50 value had thus been consistently used until 2016. Mr. Martin testified that as CEO and Gatekeeper it had been ultimately his decision to select the P50 value (Ed Martin December 10, 2018 pages 87-88).

Evidence concerning whether there is a particular P value that is equivalent to "best practice" varied among witnesses and depending on the purpose for which contingency or reserve is to be assessed. Mr. Martin testified that in his prior experience with Petro-Canada P-50 was generally used (Ed Martin December 11, 2018 pages 1-2). Jason Kean said that P50 is normally used as the estimate contingency in a control budget, which is the equivalent of the tactical risk contingency. He was familiar with AACE estimate guidance materials and, to the best of his knowledge, they did not make specific P value recommendations. (Jason Kean November 8 pages 114-115.)

Richard Westney, who oversaw but was not directly involved in the QRA work for Nalcor, wrote Commission counsel that there was general agreement that the budget given to a project manager and team, including contingency for tactical risks, should be set using P50. He wrote that "corporate funding" was a different matter, and that there was general agreement that funding for the potential impact of strategic risks is not usually released to the project team, so "management may select P75 (for example) to use in the funding strategy". He reported that in his discussions with the Westney team he was told that it was discussed with Nalcor that a P factor of at least P75 would be appropriate, as would a funding strategy for strategic risks. (P-00955.) In his testimony he confirmed that P50 for tactical risk, used to set the contingency given to a project team, was generally accepted practice. He testified that while it was not Westney's practice to make recommendations for P value for strategic risks or management reserve, and none was made in their written reports to Nalcor, Westney's Keith Dodson had a "conversation" suggesting P75. (Richard Westney November 16, 2018 page 51.) Keith Dodson confirmed the recommendation for P50 for tactical risk and verbal discussion of P75 for strategic risk (Keith Dodson February 25, 2019 page 8-9). Neither Mr. Harrington nor Mr. Kean recalled discussion of P75 for strategic risk with Mr. Dodson, although Mr. Kean said it was possible. (Paul Harrington November 19, 2018 page 31, Jason Kean November 7, 2018 page 52).

Al Snyder of MHI testified that in 2012 “Manitoba Hydro, BC Hydro, Hydro-Québec all used P50 for hydro development projects that they were considering at that particular point in time, so P50 for use in Newfoundland seemed to be appropriate.” (MHI Panel October 29, 2018 page 78.)

Among the expert witnesses, Dr. Gilliland said that the P25 to P75 estimate range produced by a Monte Carlo probability analysis should be reported and, when asked, agreed that one number had to be selected for inclusion in the budget. Regarding what P value should be used to do that he said that P50 is a reasonable number to pick and stated “… honestly, I don’t think there is a – one hard and fast rule … I think if the context is provided around why the decision was made I think, whatever logical process is reasonable.” (Jim Gilliland March 21, 2019 page 52-53, 61.)

Dr. Jergeas gave his opinion that the project team should get a budget with a P50 contingency for tactical risks and that the P value to be used for management reserve held at a higher level in the organization is a management decision. His current recommendation is to use P85 for management reserve. (George Jergeas June 18, 2019 pages 77-79.)

Dr. Klakegg testified that the Norwegian State Project Model uses a similar approach. The project manager works from a base estimate with some allowance for unspecified work determined at a P value less than P50. The governance agency responsible for executing the project works from a budget that includes contingencies determined at P50. The responsible ministry, as project owner, holds a further reserve to cover uncertainty assessed at P85. (P-04438 pages 17-18.)

The use of P50 to set the budget contingency for tactical risk seems to accord well with industry practice and academic opinion and should thus be accepted as “best practice” If a reserve is established for risks outside the project team’s ability to manage, then there seems to be a consensus that P75 is within an appropriate range.

#### 4.7.2.3.3. Contingency Amount

The risk assessment work and the Westney Monte Carlo modeling resulted in a dollar value for contingency at sanction, $368 million assessed at P50. The expression of contingency as 7% of the base estimate is derived from that dollar value, rather than the reverse.

Viewed as a percentage, the Inquiry has heard evidence that the contingency was in the low end of the range. A variety of opinions have been heard concerning what might be an appropriate percentage of contingency to carry and whether the absolute value of the contingency was sufficient. Again, discerning a “best practice” for percentage of contingency is difficult.

- In September 2010, Independent Project Analysis carried out a “Pacesetter” review of the preparedness of the Project to pass through Decision Gate 2. Based on their data, megaprojects at stages of “front end loading” similar to the Lower Churchill Project on average carried 15% contingency, which declined as the extent of front end loading improved (P-00080 at page 91).[12] At Decision Gate 2, the estimated cost for the Project included a 15% contingency.
- Manitoba Hydro International found that at Decision Gate 2 the capital cost estimate, which included the 15% contingency, was within the accuracy range of an AACE Class 4 estimate, which was the target for that stage of the Project evaluation (P-00049 page 98).
- In its review for GNL prior to the sanction decision, Manitoba Hydro International found that for the HVdc transmission project, sufficient contingency had been allocated to offset unforeseen project risks (P-00058 page 39). For the Muskrat Falls Generation project, MHI reported that the contingency might be higher, without suggesting a value, but concluded that the contingency amount included in the cost estimate was reasonable for the “Decision Gate 3 project sanction stage” (P-00058 page 58).

[12] Note that the indication that the Muskrat Falls Project carried 12% contingency is incorrect. The contingency assessed by Westney at DG2 was 16% and 15% was adopted in the DG2 Risk Assessment Report .

- The Independent Engineer, reporting to Canada at Financial Close in November 2013, stated that Nalcor had adopted “a theoretical P50 contingency based on analytical modeling (i.e., range uncertainty) of the project’s sub-element summary budgets” and expressed the opinion that the amount of “scope contingency is aggressive relative to our legacy experience with similar remote heavy-civil construction endeavors.” (P-01986 page 109.) The report states that the Independent Engineer, “typically sees contingency allowances in the range of 6 percent to 10 percent at this state of project development”. The final version of the report dated December 30 2013, after Financial Close, states:

> The IE typically sees scope or tactile contingency allowances in the range of 8 percent to 12 percent at comparable DG3 stage gates, A mitigating circumstance for the current LCP budget is the fact that cost certainty has been achieved for the awarded-to-date work (See Section 5.1.4) that provides a rationale to carry a reduced contingency allowance.
>
> (P-01930 page 113.)

A variety of other views were expressed by witnesses testifying at the Inquiry to the effect that a higher amount of contingency could have been budgeted at the time of sanction.

The totality of the evidence available, while suggesting that the amount of contingency carried at Project sanction could have been higher, falls short of establishing a failure to adhere to a defined “best practice” in setting the amount of contingency.

#### 4.7.2.3.4. Reserve for Strategic Risk

As discussed above, the Project risk management documentation contemplated the creation of a management reserve in some form, held outside of the estimated cost included in the Project budget, to cover the potential materialization of strategic risks. Prior to sanction it was quantified by Westney at a mean value of $497 million. That value was not included in the $6.2 billion Project cost, nor was there a specific reserve account set up outside of the Project budget. The work done within Nalcor on quantification of strategic risk was reported up to Mr. Martin who, as CEO, has taken responsibility for the decision to exclude it from the Project budget (Ed Martin December 11, 2018 pages 16-17). The fact that it was explicitly excluded was made publicly known during the PUB referral process (P-01050).

The Project costs estimated and announced in June 2016 and June 2017 include allowance for strategic risks and were assessed at a P75 value.

###### 4.7.2.3.4.1. Reserve for Strategic Risk and the Contingent Equity Commitment

On March 18, 2011 Natural Resources Deputy Minister Charles Bown notified Minister Shawn Skinner that Nalcor needed direction on the issue of contingent equity in support of the request for the federal loan guarantee, and that a meeting had been scheduled in the Premier's office that would include Deputy Minister of Finance Terry Paddon (Exhibit P-00839).

A Cabinet paper was drafted for Minister Skinner's signature on August 31, 2011, recommending the execution by the Premier of a commitment letter to be used in the financing process. One of the purposes of the letter was to state Government's intention to provide investment including the amount determined during the financing process "and any additional Government investment needed to address any contingencies required to ensure Project completion." (P-00043 page 3.) Cabinet Secretariat prepared an analysis dated September 2, 2011 (P-01394). Cabinet approved the submission (P-00043 page 23).

The letter, dated October 18, 2011, was signed by Premier Dunderdale and includes the statement that Government is committed to "provide the base level and contingent equity support that will be required by Nalcor to support successful achievement of in-service for MF, the LTA and the LIL, in cases with and without the participation of Emera." (P-00868.)

The Commission heard no evidence that government's contingent equity commitment was formalized as a quantified or funded reserve held either by Nalcor or government. While there was no written process put in place between Nalcor and government addressing how draws would be made against contingent equity, in practice increases in Project budget had to be approved under Nalcor's Authorization for Expenditure procedures and no increases were implemented without prior consultation with and approval of government.

#### 4.7.2.3.4.2. Reserve for Strategic Risk Best Practice

What is “best practice” for how reserves for risks of the type categorized by Nalcor as strategic should be treated? The Commission has heard testimony that has categorized risks in various ways and that commented on when the existence and value of such reserves should be made known to parties.

One observation is that there seems to be consensus that there is a difference between the treatment of risks that are likely to materialize and that are within the power of those managing the project to mitigate on the one hand, and on the other hand the treatment of risks that are entirely unanticipated, risks that can be defined in advance but it is unknown whether or not they will occur and risks that cannot be influenced or mitigated by the project team.

For the former, those that Nalcor has called tactical, it makes sense to set up a budget contingency for them, but to keep that contingency in a separate bucket, unassigned to particular contracts or work scopes, and to draw on the contingency when needed. Nalcor adopted this process. Senior project team members were aware of the total contingency funds available at any time. Team members in positions more directly connected to the work of the contractors may not have been. Drawing funds from contingency required satisfaction of a formal process involving Project Change Notices approved by the Change Control Board (P-00081 Project Governance Plan page 28, P-1940 Change Management Plan, P-03775 Change Management Procedure, P-03776 Project Change Management Plan).

A widely held view, evidenced by the testimony of many Inquiry witnesses, is that contractors are motivated to find means to increase revenue by taking advantage of opportunities to claim for changes to the work scope, delays caused by the owner or other contractors, and the like. It is also a widely held view that this behaviour can be encouraged by knowledge that those managing the project have access to a fund of money that has already been approved to be spent on the project, and that can be drawn upon to pay claims like those that may be advanced by the contractor. This is why it is a common practice to withhold information about contingency funds from contractors.[13]

For a management or strategic reserve there are more questions. Who should hold the reserve? Should it be project management? Should it be the corporate executive or CEO? Or in the case of government as ultimate owner, should it be held outside the corporation altogether? Should it be quantified or capped somehow? Should it be funded? Who should know that it exists and how much is in it? For private projects maintaining different levels of knowledge about reserve funds within and without the organization is possible. In the case of a public project, what information can be released publicly without effecting cost control of the project?

Dr. Jergeas' opinion was that ideally risk should be divided into three buckets, contingency to cover operational project risks, Scope Contingency to cover strategic risks and Management Reserve to cover contextual risks (P-04102 pages 49, 58). He testified that operational risks are unknowns that are within the scope of the work and that can be managed by the project team. The amount of contingency for operation risk is known to the project team, who have authority to spend it, but unknown to contractors. When asked how to quantify the amount of the contingency he said it was a "guestimate" based on the judgment of the leadership of the organization. The AACE guidance is, he said, a guessing exercise. You can pick an "amount divisible by five".

His second bucket is scope contingency for strategic enterprise risks. These are unknowns outside the scope of work and the control of the management team, but within the control of the enterprise. Whether to add scope to the work is an example. The amount of the scope contingency is known to the project director. It may be known to the project team, but not known to contractors. Authority to spend it may rest with the project director or the sponsor. How is it quantified? Dr. Jergeas says it is another guestimate, although reference can be made to other projects.

[13] This concept was often referred to in questions by legal counsel at the Inquiry hearings as the "red meat syndrome", a term that was generally not used by Nalcor witnesses.

The last bucket is management reserve for contextual global risks. These are unknowns outside the scope of the work and the control of the enterprise. They are things that cannot be influenced or mitigated against. The reserve is under the control of the sponsor. As for how to quantify it, Dr. Jergeas says “pick a number” and “there is no formula”. In the end it is all an exercise in good judgment. (George Jergeas June 19, 2019 pages 26-32.)

Dr. Ole Jonny Klakegg described the variety of ways that reserves are organized and disclosed for public infrastructure projects in Norway and several other jurisdictions. A common element, however, was that it is usually the agency of government that funds the project that sets, holds and manages the equivalent of a management reserve, not the agency charged with execution of the project. If that model were applied to Newfoundland and Labrador, it would be either the Department of Natural Resources or more likely the Department of Finance that would take responsibility, perhaps with the assistance of external consultants, for quantifying, holding and managing a management reserve.

### 4.7.3. Term of Reference 4(b)(v)(B) – Did Nalcor Take Possession of the Reports?

The risk assessment reports discussed above were prepared by Nalcor, or were prepared for Nalcor by Westney and delivered to Nalcor.

### 4.7.4. Term of Reference 4(b)(v)(D) Did Nalcor Make Government Aware of the Reports and Assessments?

The quantitative risk assessment prepared by Westney in June and July 2010, which was later appended to the Gate 2 Project Risk Analysis, was an input into the estimated capital cost of the Muskrat Falls Project, which in turn was an input into the CPW analysis that compared the interconnected option with the isolated island option.

The results of the analysis were reported to the Nalcor Board of Directors prior to their decision to approve the passage through Gate 2 as part of a Decision Support Package (P-00093). It would be impossible, and unreasonable, to have to bring all the underlying material that supported the recommendation to the Board for its review. Mr. Martin, as Nalcor CEO took responsibility for determining the level of detail that should be provided to the Board to enable decision making (Ed Martin December 10, 2018 pages 20, 24-25 and 28 and December 11, 2018 pages 19, 48 and 83). The Westney report was not included in the Board package.

The Decision Gate 2 decision was communicated to government by correspondence from the Board Chairperson. At and prior to DG2, information about the inputs into the decision making process was communicated to government by presentations, and in meetings and in conversation, the prime points of contact for important information being between the CEO of Nalcor to the Premier and the CEO to the Minister of Natural Resources. No evidence was presented to the Inquiry to show that the Westney report of June July 2010 or the Gate 2 Project Risk Reports versions B1 or B2 were provided to government. However, the results of the development of the cost estimate for the purpose of the CPW analysis and the results of that analysis were provided to government. There was no evidence presented to the Inquiry that anyone from government sought and was denied disclosure of supporting materials such as the risk assessments. Mr. Martin testified that he consistently presented information about the risks to the Project and mitigation measures undertaken, confirmed by the testimony of a number of other witnesses.

In 2011, the Government referred the question of whether the Muskrat Falls Project was the least cost option to the Public Utilities Board. Exhibits and submissions filed with the PUB included explanation of the risk assessment process that had been carried out, the involvement of Westney, the manner in which the estimate contingency had been determined, and the rationale for not including a reserve for strategic risk. That information was publicly disclosed and was available to Government (P-00077 page 247). The Westney report itself was given to the PUB as a confidential exhibit (P-01003). MHI, in its report to the PUB, stated that a contingency for tactical risk had been included in the estimated cost, but that:

> "…the project cost estimate (sum of Base Estimate, plus contingency, plus escalation allowance) does not include any provision for changes to elements such as the project scope, or unexpected events such as strikes, abnormal weather, etc. A financial contingency would normally be established to allow for such factors in creating the project budget."
>
> (P-00049 page 98.)

The PUB’s report to government, released publicly, states:

> A contingency amount of 15% was selected by Nalcor following a risk analysis performed for Decision Gate 2 which included a review by the Westney Consulting Group (Westney) of available cost and schedule estimates. Westney recommended a contingency of 16% but Nalcor decided that 15% would be appropriate as, in its view, there had been progression of the project definition since Westney’s recommendation. Westney had also recommended the creation of a strategic reserve for the Decision Gate 2 cost estimate. The amount of this reserve was set out in a confidential exhibit reviewed by the Board and MHI. This recommendation was not accepted by Nalcor as in its view there had been a reduction in the key risks identified by Westney since its recommendation as a result of factors such as the commitment by the Federal Government for a loan guarantee and the selection of a conventional technology for the HVdc transmission line. Nalcor stated that it would reconsider the need for a strategic reserve amount at Decision Gate 3.
>
> (P-00052 page 61.)

Similarly, at Project sanction in December 2012, the risk assessments that had been performed by Westney were inputs into the Decision Gate 3 Cost and Schedule Risk Analysis and the determination of the contingency amount that was included in the $6.2 billion capital cost estimate.

The Nalcor Board met on August 23, 2012 and was given a presentation on Decision Gate 3 capital costs (P-00664 minutes, P-01009 presentation). The presentation included a slide showing the elements making up the project estimate which were the base estimate, estimate contingency and escalation allowance. The estimate contingency was described as excluding scope changes outside the Project’s parameters, events such as strikes or natural disasters and foreign currency impact among other things. The graphic does not include management reserve for strategic risks. (P-01009 page 81.) The minutes state that Mr. Bennett reviewed information contained in the presentation relating to estimate accuracy and noted that the biggest cost risk was construction labour productivity, and state that Mr. Martin emphasized that there were still risks due to the size of the project. (P-00664 pages 3-4.)

The Board met again on September 28, 2012 (P-00665). The minutes note a report on the completion of cost estimates and that a copy of the draft MHI report was distributed. On October 16, 2012 a meeting was held for the purpose of giving the Board a Project update and answering questions, considering that it would soon be asked to sanction the Project (P-00666). More material was distributed and meetings held on November 5, 2012 (P-00667), November 13, 2012 (P-00668), November 20, 2012 (P-00669) and November 25, 2012 (P-00670).

The Decision Gate 3 Support Package, dated November 28, 2012 (P-00121), was also provided to the Board on December 3, 2012 (P-00672 page 1). It included as an appendix the MHI report that disclosed the contingency percentages for the capital costs of Project components. Further meetings followed on December 3, 2012 (P-00671), December 4, 2012 (P-00672) and finally December 5, 2012 (P-00673) when the Board sanctioned the Project.

The Board was provided with information about the preparation of the estimate and the assessment of risk, but was not provided with the underlying documents. In particular there is no documentary evidence that the Board was given the Westney reports concerning contingency and management reserve. Board member Ken Marshall testified that details of the amount of contingency or the decision to not carry a reserve for strategic risk were not discussed at the Board. He said that he was aware that Westney had been involved in advising regarding risk. Neither Mr. Marshall nor Board members Gerald Shortall, Tom Clift or Terry Styles recalled seeing the Westney reports. (Board Member Panel October 15, 2018 pages 67-69.)

Government had retained Manitoba Hydro International to review the recommendation to sanction the project and whether it was the least cost option. MHI personnel were given a DG3 Estimate Overview presentation on June 17, 2012. It disclosed the value and percentage of contingency being carried for tactical risk, included the Westney risk curve with values between P25 and P75 and identified and described significant strategic risks that were excluded from the estimate contingency. (P-00817 pages 11-14.) Jason Kean recalled delivering the presentation to Tom Moffatt, Gerry Proteau and Al Snyder and talking about strategic risk exposure (Jason Kean November 8, 2018 page 20). Mr. Snyder recalled visiting Nalcor in St. John's in June 2012, did not recall specifics of the presentation, but did acknowledge that information presented in it made it clear that the estimate contingency addresses in the report did not include strategic risks (MHI Panel October 30, 2018 pages 21-23). MHI received the Westney *Estimate Accuracy* report addressing tactical risk, but there is no documentary confirmation that it was provided with the management reserve report. Nor is there documentary confirmation that the Westney reports were provided directly to government.

Nalcor CEO Ed Martin had made the decision that a reserve for strategic risk would not be carried in the $6.2 billion estimated cost for the Project. His explanation of what and how he communicated risk information to government includes the following:

> From a – what – your term, a strategic risk, I didn't use those terms with the province. And in my career I often didn't use – usually didn't use those terms. All through my career in the private sector as well when I was dealing with executive committees, and various shareholder groups and analysts who represented shareholder groups, I was always – and that was the norm in where I worked. We always talked about the risk in clear terms, things such as what the project team would have control over. Things that – over and above that – that could happen that they don't have control over.
>
> We didn't put names to it – you know, strategic, tactical. That wasn't the point. The point was to make sure everyone understood those things. And that's what I did with the province.
>
> And, you know, whether I'm sitting with Premier Dunderdale or the larger group with the ministers and others in it, there was no question that we talked about the comparative analysis; we talked about the numbers would grow as I just mentioned. We talked about the fact that the province would have substantial ability – through the reasons I just mentioned – the, you know, return on equity, the excess sales, water rentals and some other items I won't get into right now – that would give them the ability, you know, to fund an overrun.
>
> Now, that being said, you know, I believe that they had a clear understanding of what the 6.2 was. I did express confidence in that number. There's no question I expressed confidence in that number to them. And – but respect to adding up the strategic risk on top of that – as we're calling it now – they were clear that other things could happen, and they were clear that there was funding available to handle that. And that's the way I described it.
>
> (Ed Martin December 11, 2018 pages 7-8.)

It was also his testimony that he had orally advised Premier Dunderdale of the potential for a cost overrun, in addition to the $6.2 billion estimated costs, that could be hundreds of millions of dollars (Ed Martin December 11, 2018 pages 54-55, 59, 61). This was corroborated by Premier Dunderdale who testified that she had been told by Mr. Martin that the estimated $6.2 billion cost could be exceeded by about $500 million (Kathy Dunderdale December 17, 2018 pages 56-57, 72). Although apparently not presented to her as a management reserve for strategic risk, the amount is consistent with that recommended by Westney for such a reserve.

#### 4.7.5. Term Of Reference 4(b)(v)(C) – Did Nalcor Take Appropriate Measures to Mitigate the Risks Identified?

Nalcor corporate and project management personnel recognized the importance of risk mitigation from the outset of the Project and incorporated it into the Project policies, practices and procedures as well as into the Project culture. The Project processes for responding to risks that have been identified and assessed is described above as avoidance, mitigation, transfer and acceptance (P-01007). Risks have been tracked in the risk registers described above and continue to be. The registers also record the mitigation measures and current status. Risk mitigation activities are thoroughly reported in Project documentation, some examples of which have been made exhibits (see for example P-04086 Monthly Progress Report for Period Ending 31-Aug-2013 at pages 112-116).

There have been too many risks tracked and mitigated to comment on them in this submission, however brief comment will be made on several risks that were the subject of questioning during the Inquiry hearings.

In 2016, protestors occupied the camp and parts of the Muskrat Falls site causing construction to be suspended, resulting in increased cost and delay. A variety of concerns related to indigenous and environmental matters contributed to the protests, although the organized indigenous groups were not involved. Risk of disruption from protests had been carried on the Project risk registers but was considered largely mitigated by actions of government, which had the responsibility for indigenous matters, and which through Nalcor had conducted consultations with indigenous groups. Those actions resulted, in particular, in significant agreements with the Innu Nation and Bands, who had recognized rights to the lands affected by the Project. Public concern regarding the potential for increases in methylmercury in the Churchill River and Lake Melville became more prominent after sanction. Nalcor continues to respond with monitoring, research and communication as prescribed by, and in addition to, the conditions of release from environmental assessment. Nalcor's mitigation actions taken and planned at the time of sanction, in conjunction with measures taken by government, were reasonable responses to the potential risk of lawful protest, which could not be eliminated. The 2016 occupation had significant unanticipated unlawful elements which could not have easily been prevented by mitigation actions. The evidence has been that there is no doubt that project costs increased as a result of the protest, particularly the occupation, but precise quantification of the amount of the increase is difficult.

In 2012, the SNCL role in procurement and project management was gradually transitioned from that of pure EPCM contractor to participation in an integrated team staffed by personnel from SNCL, Nalcor and other contractors, addressed more fully elsewhere in this submission. The risk of that change becoming necessary was not something that could have been reasonably anticipated and recorded on the risk register, nor was it. Instead, the transition was a response to a problem that had materialized and that had to be dealt with in real time, rather than a mitigation of a previously catalogued risk.

There has been much testimony directed at whether the transition from EPCM to integrated team was good or bad for the project, however there has been no evidence that has identified any actual negative cost or schedule impact from the transition. Instead, the reasonable conclusion is that the transition avoided cost and schedule impacts that would have resulted had SNCL been allowed to continue in the full EPCM role.

### 4.7.6. SNCL Internal Risk Report

In 2013, SNCL conducted an internal risk assessment and quantification process that was not commissioned by Nalcor.

#### 4.7.6.1. Public Disclosure of the SNCL Internal Risk Report

In June 2016, new Nalcor CEO Stan Marshall opened his door to anyone who wanted to talk to him about the Project. One visitor was Brad Chaulk, who had worked on the Project while with SNCL. It was Mr. Chaulk who brought the existence of a report prepared by SNCL in 2013 assessing risks to the Project to Mr. Marshall's attention. Mr. Marshall caused a search to be carried out among Nalcor records, but the report could not be found there. He was already scheduled to meet with senior SNCL personnel the following week, so he asked about the report and was sent a copy. He consulted with Gilbert Bennett, and seeing nothing of current value in the report, he put it aside, but did speak of it to Government officials.

In his testimony Mr. Marshall described being suspicious about SNCL's motives, since he recognized that the report had been prepared in 2013 not long after SNCL's role as EPCM contractor had been reduced, and because at the same time that SNCL personnel gave him the report they also presented him with a proposal for reinstatement of that EPCM role (Stan Marshall July 2, 2019 pages 16-17; P-02633).

In June 2017, Greg Mercer from the Premier's Office called to ask for the report. Mr. Marshall could not give it to him, since it was an SNCL document and not Nalcor's, and suggested that Mr. Mercer obtain it from SNCL directly, which is what was apparently done (Stan Marshall July 2, 2019 pages 16-18). On June 23, 2017 the Premier held a news conference to release the report to the public (P-01987).

#### 4.7.6.2. Origin of the SNCL Internal Risk Report

Nalcor had entered into the EPCM contract with SNCL on February 1, 2011 (P-01436). As discussed elsewhere in this submission, SNCL failed to adequately deliver on its obligations related to procurement and construction management, leading to the evolution away from a strict EPCM delivery model to an integrated team model for those aspects of the work. The change was eventually formalized in August 2017 by Amendment 10 to the EPCM contract which was made retroactive to April 1, 2012 (P-01446). The move to the integrated team represented a significant loss of anticipated revenue for SNCL.

The risk assessment report was prepared by SNCL independently of Nalcor, without involvement of any Nalcor personnel, and without SNCL having given any notice to Nalcor that it was being prepared. The copy of the report eventually given to Mr. Marshall and placed in evidence is noted as having been prepared on April 23, 2013. On May 17, 2013 it was approved by signatures of four senior SNCL personnel, including the SNCL Project Manager Normand Béchard, who worked from the Project offices in St. John's, but it was not signed in the space provided for approval by Executive Vice President Scott Thon. It bears the notation "Confidential for SNC-Lavalin internal use only" on the first page and on the third page states that it was prepared at the request of the SNCL Project Director (M. Béchard) by a team made up solely of SNCL personnel led by the Risk Director of the SNCL Mines and Metallurgical Division (P-01977 pages 1 and 3). Three SNCL witnesses gave varying accounts of the reason for preparation of the report.

M. Béchard said that the new SNCL CEO Bob Card had put a plan in place in response to World Bank concerns following the bribery scandal that had embroiled SNCL, which included conducting corporate risk assessments of large projects, the purpose being to better control the exposure of SNCL. SNCL's role on the Project included managing ongoing qualitative risk assessment and maintaining risk registers, but did not include quantitative risk assessment, for which Nalcor retained Westney. M. Béchard testified that he initiated the internal quantitative risk assessment, drawing on the resources from the Mines and Metallurgical Division, and made sure that it was conducted on SNCL time. By his account, the report was purely for internal SNCL purposes. (Normand Béchard March 26, 2019 pages 57-59 and 77-78.)

Jean-Daniel Tremblay of SNCL had been the Risk Coordinator for the Project since June 2012 and therefore had full knowledge of the risks carried on the risk registers. He testified that he and M. Béchard were the only two persons involved in the Project who participated in the identification of risks which were later quantified, without his involvement, by the other SNCL participants. He said that when he and M. Béchard later met with Paul Harrington, M. Béchard explained that the SNCL Hydro Division had requested resources from the SNCL Mines and Metallurgical Division and that the latter Division made their cooperation conditional on the preparation of the risk assessment. He said that it was intended to be used for SNCL internal purposes only. He even understood that he should not disclose that it was being prepared to Nalcor personnel, including those whom he worked closely with on a daily basis. (Jean-Daniel Tremblay March 25, 2019 pages 80-83 and 89-90.)

Scott Thon, SNCL Executive Vice President, also testified that the report was an internal SNCL initiative, but described the origins differently than M. Béchard or M. Tremblay. He said that conducting the risk assessment was Bernard Gagne's and Normand Béchard's idea and was meant to inform SNCL personnel so that they could focus on key risks and mitigations in Project steering committee meetings, which Mr. Thon attended. He said, "It was primarily for internal purposes – was so that we could take a look at what the risks were and we could discuss them with Nalcor." (Scott Thon March 25, 2019 pages 120-122.)

The conclusion from this evidence is that the SNCL personnel involved in preparation of the report did not intend to deliver it to Nalcor. It was prepared for internal SNCL use. At most, they were prepared to use the qualitative risk information that had been generated in discussions with Nalcor, which in fact was part of their role as managers of the risk registries, but they did not intend to share their quantifications of the risk.

#### 4.7.6.3. SNCL Did Not Give Nalcor the Report Until 2016

On April 25, 2013, two days after the report had been drafted, but before it was approved in May, SNCL CEO Bob Card met Nalcor CEO Ed Martin in St. John's. When the report was publicly released in 2017 it was alleged that Mr. Card had offered Mr. Martin a copy at that meeting, which Mr. Martin has denied.

Mr. Card did not testify, but he was interviewed by the Grant Thornton investigators. The interview notes record him as saying that he and Mr. Thon discussed risks with Mr. Martin, but he did not say that he gave Mr. Martin the report or even that he informed anyone of its existence or of the SNCL quantifications of risk (P-01838). Scott Thon was present at the meeting between Mr. Card and Mr. Martin and recalls risks being discussed, but not the report, or its existence. He further testified that he did not recall the existence of the report being disclosed at steering committee meetings or to Nalcor by any other means" (Scott Thon March 25, 2019 pages 122-123 and 135). Mr. Martin denied "categorically" that the report "was produced, offered or otherwise at the April 2013 meeting with Mr. Card (Ed Martin June 13, 2019 page 52). Consequently, M. Béchard's evidence, which was that when Mr. Card met M. Béchard in his car Béchardafter the meeting Mr. Card told him that Mr. Martin had refused the report, must be rejected. The reasonable conclusion is that Mr. Card did not give Mr. Martin the report or inform him of the existence of it.

Paul Harrington testified that he had become aware that there had been some high level discussion of risk by SNCL personnel with Ed Martin, and so scheduled a meeting with Normand Béchard and Jean-Daniel Tremblay for May 28, 2019 (Paul Harrington June 5, 2019 page 62, P-01837, P-01903). M. Tremblay, in notes he kept of that meeting, wrote that M. Béchard reported to Mr. Harrington that the risk work had been done as a condition for Mines and Metallurgy Division support and that a report was with SNCL Hydro Division top management. He noted concerns expressed by Mr. Harrington including that the assessment had been conducted by SNCL without Nalcor knowledge and that Nalcor needed to know about any new risks that had been identified (P-01836). Mr. Harrington, M. Béchard and M. Tremblay all agree in their testimony that the report was not given to Mr. Harrington.

Mr. Harrington then, on May 29, 2013, reported by email message to Gilbert Bennett and Lance Clarke, copied to Jason Kean and Brian Crawley. He stated three reasons why the report should be declined if offered by SNCL. First, that it was based on the same data that Westney had already used. Second, that the results would be misleading and inaccurate because it was based on unmitigated risk and did not employ probabilistic analysis. Third, that there had been no opportunity to challenge assumptions or factual accuracy of input data. He went on to discuss the importance of revitalizing risk identification and mitigation efforts and that he would involve M. Tremblay and Mr. Kean in that process. (P-03740.)

Jason Kean replied to Mr. Harrington's May 29, 2019 message (P-03159) but no other replies have been found. When Gilbert Bennett was asked by Mr. Marshall about the report in 2016, he had no recollection of it. He checked his email at that time and found nothing. Searches of his email records conducted using the complete Nalcor system backup taken July 2017 did not locate the message. (Gilbert Bennett June 21, 2019 at pages 67-69.) Searches of other email accounts did not find any replies by Mr. Bennett or forwards of the message to any other person. Nalcor Information Technology personnel have informed us that over a two week period around May 29, 2013 Nalcor mail accounts were migrated to a new mail system, but that it was not possible to determine whether there had been any impact on the transmission of the missing message (P-04058). Although there is evidence that Mr. Harrington sent his message disclosing the existence of the SNCL risk report to Mr. Bennett, there is no evidence to confirm that it came to Mr. Bennett's attention.

Nalcor and all contractors, including SNCL, used the Aconex document management system for transmittal and storage of documents. If SNCL intended to give Nalcor a copy of the report it could easily have done so by Aconex transmittal, by email or by correspondence. Nalcor has conducted extensive electronic searches, using search terms agreed with Commission Co-Counsel, and has produced a separate database of search results for the purpose of finding any evidence of delivery of the report. None was found until after it had been provided to Mr. Marshall in 2016.

#### 4.7.6.4. Were There Any New Risks in the SNCL Internal Risk Report?

M. Béchard testified that most of the risks identified in the report were already known to Nalcor and were recorded in the risk registers. He acknowledged that he told Mr. Harrington at the May 28, 2019 meeting that if there were any new risks Nalcor would be informed. He concluded,

> "But I don't think there was any new risk. It was just those risks were already known, they were just not quantify."

(Normand Béchard March 26, 2019 at pages 78-79.)

Mr. Thon testified that all material risks included in the report were discussed with Nalcor at steering committee meetings (Scott Thon March 25, 2019 at pages 122-123 and 135-136). M. Tremblay in his testimony acknowledged Mr. Harrington's request to be advised of any new risks identified by the SNCL work, but did nothing specific to respond, other than saying that, "I carried on doing what I was doing for the better part of a year in identifying new risks and everything. So I was, in my mind, contributing to that effort of identifying new risk on a daily basis." (Jean-Daniel Tremblay March 25, 2019 at page 94.) M. Tremblay, as Risk Coordinator, was in a position to ensure that if any new risks were identified by the SNCL internal work, they would be included in the Nalcor risk registers.

The conclusion from this evidence is that although Mr. Harrington did not ask to be given a copy of the SNCL internal report, he did ask to be informed of any new risks that had been identified. M. Béchard and M. Tremblay undertook to do so. Neither identified anything that needed to be specifically brought to Mr. Harrington's attention. Instead, M. Tremblay carried on with maintaining the Nalcor risk registers, including by adding any new risks as they were identified. Mr. Thon discussed risks that he regarded as important with Nalcor at steering committee meetings. It was reasonable for Nalcor to rely on SNCL to advise it of risks that were not otherwise incorporated into the risk registers, if there were any.

In 2017 after the SNCL report had been released to the public and had become the topic of media reports and commentary, Mr. Harrington, after first asking Mr. Kean for an initial view (Jason Kean May 7, 2019 page 9), commissioned Westney to compare the risks identified in the report to those listed in the risk registers forming part of the October 2012 Decision Gate 3 Project Cost and Schedule Risk Analysis Report (Paul Harrington June 5, 2019 pages 67-69, 71, P-03172). Westney delivered their comparison in December 2017 concluding that all risks identified in the SNCL report had already been identified by Nalcor, that the range of outcomes in Westney's 2012 analysis were inclusive of the results in the SNCL report and that top risks had been identified by Nalcor prior to Decision Gate 2 in 2010 with mitigations planned or already underway in 2013 (P-01847).

No witness from Westney was examined concerning the accuracy of the risk cross referencing in their report, however Commission Co-Counsel did examine Jason Kean at some length on that subject. Mr. Kean was able to provide informative and well-reasoned commentary supporting the reliability of the work done by Westney (Jason Kean June 7, 2019 pages 14-28).

That Westney analysis was held internally by Nalcor and was not released publicly, even though it would have been supportive of the work done by the project management team in identifying and mitigating risk as a response to concerns raised in the media following the release of the SNCL report. It has become publicly available as part of this Inquiry process.

#### 4.7.6.5. Conclusions Regarding the SNCL Internal Risk Report

Reasonable conclusions that may be drawn from the evidence are:

- The report was an internal SNCL document not intended for disclosure to Nalcor.
- The report was not delivered to Nalcor by SNCL until 2016.
- Mr. Harrington was aware of the existence of the report in 2013. Mr. Martin and Mr. Bennett were not.
- It was reasonable for Mr. Harrington to not demand a copy of the report and to instead ask that Nalcor be informed of new risks that had been identified, if any.
- The risks identified in the report were included in the Nalcor risk registers and discussed at the steering committee level. There were no new material risks that were not disclosed. Delivery of a copy of the report was not necessary to address risk identification and mitigation.
- In 2016 the report was outdated and of no current value. Consequently Mr. Marshall’s evaluation and treatment of it was reasonable.

### 4.8. Term of Reference 4(b)(vi) - Commercial Arrangements

Term of Reference 4(b)(vi) is as follows:

> 4. The commission of inquiry shall inquire into
>
> (b) why there are significant differences between the estimated costs of the Muskrat Falls Project at the time of sanction and the costs by Nalcor during project execution, to the time of this inquiry together with reliable estimates of the costs to the conclusion of the project including whether
>
> (vi) the commercial arrangements Nalcor negotiated were reasonable and competently negotiated.

#### 4.8.1. Investigative and Forensic Audit

As written, this Term of Reference directs inquiry into only those commercial arrangements that could have contributed to costs of the Muskrat Falls Project. In the Construction Phase report Grant Thornton interpreted the mandate given by this Term of Reference to overlap with Term of Reference 4(b)(ii) concerning contractual arrangements with contractors and contractual risk transfer, and addressed them together (P-01677 page 71).

Two separate reports were commissioned from Grant Thornton that are related to the broader commercial arrangements for the Project. Tom Brockway gave expert testimony to present the reports.

One report is the *Review of Emera Agreements and the UARB Experience* (P-00453). The Commission's request to Grant Thornton was for a report explaining the contractual relationships between Nalcor and Emera and the effects of those agreements on Newfoundland and Labrador ratepayers and taxpayers. The paper was also to examine the UARB review of the Maritime Link Project and compare the process to the June 2011 reference question submitted to the PUB. Reference should be made to Nalcor's written reply (P-00525), and Grant Thornton's response (P-00606).

The second report is the *Review of the Federal Loan Guarantees and the Power Purchase Agreement* (P-00454). The Commission's request to Grant Thornton was for a report explaining the Federal Loan Guarantees and the Power Purchase Agreement and related legislative changes. The paper was also to address the effect of the legislative monopoly and the PPA on Federal Energy Regulatory Commission (FERC) compliance. Nalcor submitted a written reply including an appended report from Nalcor's United States legal counsel regarding compliance with FERC requirements (P-00526), and Grant Thornton responded (P-00723).

### 4.8.2. Other Commercial Issues

Two issues related to commercial arrangements that were discussed during the Inquiry hearings were the models adopted for recovering payment for the Project costs from the consumers of electric energy on the Island, and the negotiation of the Energy Access Agreement with Emera and Nova Scotia Power Incorporated (NPSI).

#### 4.8.2.1. Recovery of Project Costs

The structure for recovery of the costs of the Project through rates charged to the consumers of power on the Island was put in place through commercial agreements and provincial legislation. The arrangements are complex. Simplified explanations follow.

For the Muskrat Falls Generation and Labrador Transmission Asset components, a PPA was executed between Muskrat Falls Corporation and Newfoundland and Labrador Hydro on November 29, 2013 (P-00457). It used an escalating supply price for cost recovery, which spread the cost recovery over the 50 year term of the PPA. The price escalates by 2% per year, roughly equivalent to expectations for inflation. Because demand was forecast to rise over the term of the PPA, the total amount to be paid each year also rose. (See the Nalcor submission to the PUB P-00077 page 48.)

For the Labrador-Island Link (LIL), the Transmission Funding Agreement applies a Cost of Service approach to cost recovery. Cost of service is a methodology often employed for recovery of capital costs by regulated public utilities, and is accepted by the PUB as a principle applied to rate regulation in this province. It depreciates the capital costs over time, but the effect is that. When combined with the annual asset financing costs, larger expense is incurred in earlier years than in later years. When applied to the regulation of a public utility that invests capital in assets annually, the effect is much the same as if the expense was evenly spread over the life of the assets. For the LIL, the effect is that larger amounts are recovered in the early years of the recovery period than in the later ones.

Because of the size of the capital investment in the LIL and its non-recurring nature, the consumer rate setting mechanism would also tend to cause rates to be higher in early years.

The effect of combining the escalating supply price approach for the MF and LTA assets and the cost of service approach for the LIL assets is that they tend to balance each other and result in a relatively even recovery of the total project capital investment over time.

The methods of accounting for return on equity are also different for the project components. For the MF/LTA an Internal Rate of Return, fixed by the PPA at 8.4%, is to be earned on the equity invested by the province over the life of the Project, which includes both construction and operation, with returns in nominal dollars that are low in the early years but grow over time.

For the LIL, a non-cash allowance for funds used during construction (AFUDC) accrues at the Return on Equity rate approved by the PUB for privately owned regulated utilities during the construction period. The AFUDC is added to the capital costs that are included in the “rate base”. When the LIL assets come into service, the Province of Newfoundland and Labrador and Emera are entitled to receive a return on their equity investments, including the AFUDC accrued during construction, based on the Return on Equity rate approved by the Public Utilities Board for privately owned regulated utilities. The nominal dollar returns are high in the early years and decline over time as the assets depreciate.

For both MF/LTA and LIL, all returns to be paid on equity investment were factored into the modeling used for the CPW analysis at Decision Gates 2 and 3, and are included in the amounts to be recovered from electricity consumers.

(See Auburn Warren June 4, 2019 pages 83-85, Stan Marshall July 2, 2019 pages 83-85.)

#### 4.8.2.2. Energy Access Agreement

The Energy Access Agreement was entered into among Nalcor Energy, Emera Inc. and NSPI on April 13, 2015 (P-00462). It came about as a result of the decision of the UARB on July 22, 2013 that conditionally approved the Maritime Link Project as the lowest long-term cost alternative for supply of energy to Nova Scotia, conditional on Emera obtaining an agreement for secure access to excess energy from Newfoundland and Labrador at market prices (P-00245). The NSPI application to the UARB had assumed the availability of that energy through the marketplace, but the UARB wanted that access secured.

The operation of the Energy Access Agreement is explained in the Grant Thornton report (P-00453), as supplemented by the Nalcor reply (P-00525) and the Grant Thornton response (P-00606). Generally, NSPI will make market requests for the purchase of energy. Nalcor will respond up to the limits set out in the agreement and NSPI may accept or reject the offers. Rejected offers count towards the cumulative amount of energy Nalcor is obligated to offer. If offers are rejected, Nalcor is free to sell on the market.

A question explored in the Inquiry hearings was whether the UARB decision, coming after sanction of the Muskrat Falls Project by the Province and Nalcor and after sanction of the Maritime Link Project by Emera, gave NSPI a negotiating advantage and consequently that the resulting Energy Access Agreement must have come at a cost to Nalcor. The terms and effect of the Agreement do not support that proposition.

The Energy Access Agreement serves to formalize commercial opportunities already available to both parties that would have worked in their interests, either with or without the execution of the Agreement. Nalcor’s sales of non-firm excess energy into the northeastern United States markets, over the Maritime Link and the transmission access through Nova Scotia, New Brunswick and Maine arranged through the Emera agreements, would be at prices available in those markets for non-firm energy, but Nalcor would bear the cost of transmitting the energy there. The cost of transmitting the energy to Nova Scotia is less. Energy bought by NSPI, other than from Nalcor, would be from those same U.S. markets, at the same market prices plus transmission costs to Nova Scotia. The transmission cost savings realized from sales of non-firm energy by Nalcor to NSPI can therefore benefit both parties, without Nalcor receiving a price for the energy that is any lower than its best alternative, sale into the U.S. market. (Ed Martin December 12, 2018 pages 4-6.)

This commercial analysis applies equally before and after the Energy Access Agreement. What the Agreement gives NSPI is assurance that the energy will be offered to it. There is no cost to Nalcor for conferring this benefit on NSPI, because the non-firm nature of the energy it has available to sell means that it cannot expect to get a price any higher than that agreed to be paid by NSPI under the Agreement. (Derrick Sturge November 1, 2018 pages 61-64.)

## 5. Exemption from Public Utilities Board

### 5.1. Term of Reference 4(c)

Term of Reference 4(c) is as follows:

> 4. The Commission of Inquiry shall inquire into
>
> (c) whether the determination that the Muskrat Falls Project should be exempt from oversight by the Board of Commissioners of Public Utilities was justified and reasonable and what was the effect of this exemption, if any, on the development, costs and operation of the Muskrat Falls Project;

### 5.2. Exemption

The *Labrador Hydro Project Exemption Order* was made by the Lieutenant Governor in Council on November 30, 2000 under the authority of section 5.2 of the *Electrical Power Control Act, 1994* and section 4.1 of the *Public Utilities Act* (P-00023). It exempted Newfoundland and Labrador Hydro from those two Acts for all activities pertaining to generation facilities at Churchill Falls, Gull Island and Muskrat Falls, and works related to reservoirs and to transmission to the Island and the Quebec border.

The *Muskrat Falls Project Exemption Order* was made by the Lieutenant Governor in Council on November 29, 2013, also under the authority of section 5.2 of the *Electrical Power Control Act, 1994* and section 4.1 of the *Public Utilities Act* (NLR 120/13). It exempted Newfoundland and Labrador Hydro from the two *Acts* for enumerated activities and obligations related primarily to the Power Purchase Agreement. Muskrat Falls Corporation was exempted for its activities related to the Muskrat Falls Generation project. The Labrador Transmission Corporation was similarly exempted for the Labrador Transmission Assets. The companies and partnerships put in place for the shared ownership with Emera of the Labrador-Island Link transmission project were also exempted in respect of that project.

The 2013 order extended the exemption originally applied in 2000 to the corporate bodies created to carry out one of the projects addressed in the 2000 exemption order, the Muskrat Falls Generation project and the work necessary for the ancillary reservoir and transmission lines. While the need to make the 2013 order could have caused government to consider the question of whether the exemption was appropriate, in a sense it was only the continuation of a long standing government policy. The timing coincided with Financial Close, which was when the government caused the legislative and regulatory structures needed to give effect to the agreed conditions for the federal loan guarantee, and thereby the financing for the Project, to be put in place.

There is precedent for exemptions of this type in this and other provinces such as British Columbia, Manitoba and Quebec. Hydro-electric projects built by Newfoundland and Labrador Hydro, such as Granite Canal, had been similarly exempted.

The decision to exempt the corporate bodies involved in the Project from the operation of the two *Acts* removes them from the oversight of the PUB in respect of those activities. Normally the PUB would have to approve capital expenditures by a public utility that are intended to be included in the rate base and therefore paid for by rates charged to consumers of electricity. The PUB would also determine the amount and structure of the rates.

The exemption orders effectively allowed the ultimate decision maker, government, to take into account non-utility factors such as other benefits expected to accrue to the province when making the decision, and to direct that the full costs be recovered through rates charged to consumers.

# 6. Government Oversight

## 6.1. Term of Reference 4(d)

Term of Reference 4(d) can be broken into two parts as follows:

> 4. The commission of inquiry shall inquire into
>
> (d) whether the government was fully informed and was made aware of any risks or problems anticipated with the Muskrat Falls Project, so that the government had sufficient and accurate information upon which to appropriately decide to sanction the project
>
> and
>
> whether the government employed appropriate measures to oversee the project particularly as it relates to the matters set out in paragraphs (a) to (c), focusing on governance arrangements and decision-making processes associated with the project.

## 6.2. Was Government Kept Fully Informed for Sanction?

The first part of Term of Reference 4(d), whether government was kept fully informed, is directed to communication of information bearing on sanction of the Project.

See section 3.3.2 Decision Gate 2 – Selection of the Muskrat Falls Project, and section 3.3.3.1 Events Leading to Sanction, for references to communications between Nalcor and government related to Project sanction. Communication to government of information about Project cost and risk at the time of sanction is also addressed in section 4.2 The Estimated Costs, and 4.7 Risk Assessments.

Other evidence before the Inquiry related to this issue, and that illustrates how in many cases government was not just informed but was closely involved, includes the following.

- On April 23, 2010 Ed Martin gave a presentation to Premier Williams, Natural Resources Minister Dunderdale, Clerk of the Executive Council Gary Norris and others regarding the options and strategies under consideration (P-00206, P-01676).

- On August 1, 2010 Premier Williams was briefed and given a presentation from Mr. Martin with detail about the options analysis and other work then underway to advance the Project (P-00213).

- On September 23, 2010 government was given what Robert Thompson described as a cornerstone presentation concerning choice of development of Muskrat Falls first (P-00216).

- On September 30, 2010 Robert Thompson was actively keeping Minister Dunderdale informed on negotiations underway with Emera (P-01059).

- Between October 25 and November 11, 2010 Robert Thompson, Charles Bown and Todd Stanley were involved in drafting text for the Nalcor Decision Gate 2 Support Package (P-01066, P-01071, P-01072, P-01374).

- On October 30, 2010 Premier Williams and Minister Dunderdale were involved in making decisions on negotiating positions with Emera (P-00220, P-00221, P-00642).

- On November 9, 2010 Cabinet was briefed on the Emera negotiations and gave approval for selection of the project as the next generation source and for the entry of a non-binding term sheet with Emera (P-00223, P-01208 page 1, P-00223 page 10, P-00643).

- On November 11, 2010 Charles Bown sent Robert Thompson a draft of the letter that later came from the Nalcor board to government advising it that the project had passed through DG2 (P-01076, P-00093 page 167).

- On December 21, 2010 Robert Thompson was involved in drafting the announcement of the award by Nalcor of the EPCM contract (P-01085).

- On June 15, 2011 Ed Martin reported on the Project to Finance Minister Marshall (P-00913, P-00914).

- On October 26, 2011 Robert Thompson prepared a draft of a letter to go from Nalcor to the PUB (P-01099).

- On November 7, 2011 Charles Bown commented on the draft of the Nalcor submission to the PUB (P-01399).

- On January 11, 2012 Minister Kennedy and Robert Thompson contributed to drafting a letter to go from Nalcor to PUB Chairperson Andy Wells (P-00592, P-01106, P-01217, P-01404).

- On February 12, 2012 Robert Thompson made comments on Nalcor's latest submission to the PUB (P-01107).

- On February 17, 2012 Ed Martin briefed Cabinet, including on sensitivities (P-01616).

- In July 2012 a joint communications steering committee was formed between government and Nalcor (P-01118, P-1119, P-00926, P-01625, P-01423, P-01426).

- On October 30, 2012 Ed Martin gave government a technical briefing in preparation for Decision Gate 3 (P-01535, P-01525 page 35).

- In November 2012 government led a public relations campaign in support of the Project.

### 6.3. Government Oversight, Governance and Decision-Making

The second part of Term of Reference 4(d) is whether government provided appropriate oversight of the Project, whether it put appropriate governance arrangements in place, and whether government's decision-making processes associated with the Project were appropriate.

### 6.3.1. Did Government Provide Appropriate Oversight?

Nalcor will make only limited observations regarding the oversight provided by government over the Project.

Implementing an appropriate program of oversight of an agency executing a major public project falls within government's area of responsibility. It has the authority to decide on the content, frequency and manner of oversight activities and who will carry them out. The agency has an obligation to cooperate with oversight activities. There is a balance to be struck between effectiveness of oversight and overly burdensome demands that detract from the execution of the project. Dr. Klakegg provided interesting examples of how this is approached in other countries.

For the Project, government did not establish the oversight function early, at the time when the project management structure and execution plans were being developed. The Project was sanctioned with the project management team fully in place and engaged in the work before the Oversight Committee was set up. Consequently it is not surprising that it could take time to integrate the oversight function.

Oversight Committee Chair, Paul Carter has testified that the Committee is working effectively and getting the cooperation it needs from Nalcor.

### 6.3.2. Did Government Put Appropriate Governance Arrangements in Place?

Matters concerning the constitution and remuneration of the Nalcor board have been explored in the Inquiry hearing and Nalcor makes no further submission.

### 6.3.3. Were Government's Decision-Making Processes Appropriate?

Nalcor makes no submission on this question.

## 7. Other Matters

A number of other matters that are not specifically described in the Terms of Reference, but that have been of significant interest to a number of parties with standing, have been explored during the Inquiry hearings and with the filing of exhibits and submissions.

Section 5(a) of the *Commission of Inquiry Respecting the Muskrat Falls Project Order* directs the Commission, in carrying out the Terms of Reference in section 4, to consider participation in the Inquiry by the established leadership of Indigenous people, whose settled or asserted Aboriginal rights or treaty rights to areas in Labrador may have been adversely affected by the Muskrat Falls Project. The Commissioner has issued an interpretation concerning the application of that provision to the section 4 Terms of Reference, particularly as it relates to consultation with indigenous people. At the request of the Commission Nalcor has submitted a paper describing the consultation activities carried out by it on behalf of government, which has the primary responsibility for consultation (P-00271).

Nalcor has provided the Commission with technical reports and other documents that have been made exhibits, and witnesses have testified, concerning the assessment of the potential for generation of methylmercury following impoundment of the reservoir and describing the mitigation measures and activities that have been and will continue to be undertaken.

Nalcor has also provided the Commission with technical reports and other documents that have been made exhibits, and witnesses have testified, concerning the stabilization of the North Spur and assessment of its safety for use as a natural dam.

The Commission has heard evidence and exhibited documents concerning the potential mitigation of increases in consumer power rates, which is also the subject of a referral by government to the PUB (P-04313).

Respectfully submitted on behalf of Nalcor Energy this 8th day of August, 2019.

Daniel W. Simmons QC

Dana Martin

McInnes Cooper
Counsel for Nalcor Energy
Party with Standing

# Reply Submission by Nalcor Energy

# to the

# Commission of Inquiry Respecting the Muskrat Falls Project

**August 16, 2019**

McInnes Cooper
Counsel for Nalcor Energy
Party with Standing

## Commission of Inquiry Respecting the Muskrat Falls Project

## Nalcor Energy Reply Submission

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## 1. Indigenous Consultation, Environmental Matters and Labour Relations

This reply submission is in response to the submissions of Innu Nation, NunatuKavut Community Council (NCC), Nunatsiavut Government (NG), Conseil des Innu de Ekuanitshit (Ekuanitshit), and Grand Riverkeeper Labrador Inc. and Labrador Land Protectors. Rather than respond to specific items from each submission, Nalcor will provide a general response to the issues arising from those submissions concerning indigenous consultation, the North Spur and methylmercury, focusing on ensuring that relevant evidence is identified.

This reply submission will also provide brief comment of the submission made on behalf of the Resource Development Trades Council of Newfoundland & Labrador and the Newfoundland and Labrador Building Trades Council (RDTC/NLBTC).

### 1.1. Term of Reference 5(a)

Term of Reference 5(a) is as follows:

> 5. The commission of inquiry, in carrying out the terms of reference referred to in section 4 shall consider:
>
> (a) participation in the inquiry by the established leadership of Indigenous people, whose settled or asserted Aboriginal or treaty rights to areas in Labrador may have been adversely affected by the Muskrat Falls Project;

In his interpretation of the Terms of Reference, Commissioner Leblanc makes the following remarks regarding the scope of examination of Indigenous consultation:

> [47] […] I have decided here that a contextual and purposive review of the Order in Council permits me to investigate into what consultation occurred between the established leadership of the Indigenous people and Nalcor as well as the Government prior to sanction, what risk assessments and reports were done as regards the concerns of the Indigenous people, whether these assessments were appropriately and reasonably considered by Nalcor and the Government and whether appropriate measures were taken to mitigate against reasonably potential adverse effects to the settled or asserted rights of the Indigenous people both at the time of and post sanction. In investigating these matters, I will not be determining any claims or treaty rights for any of the Indigenous people as this clearly does not fall within the Commission's mandate.
>
> (Pages 17-18.)

### 1.2. Consideration of Environmental Concerns

The Commissioner has provided the following comments with respect to the scope of his investigation into environmental considerations at paragraphs 41 and 54 of the interpretation of the Terms of Reference, as follows:

> [41] […] As well, I must consider whether appropriate or proper consideration was given and actions taken regarding potential risk to the environment, human safety and property related to the stability of the North Spur and methylmercury contamination. How these reports or assessments were received by Nalcor and whether they were made available to the Board of Nalcor as well as the Government will also be a part of the investigation to be conducted. (page 15.)
>
> [54] I will also investigate what analyses, risk assessments, etc., were done as regards environmental concerns and whether these were appropriate and reasonable in the circumstances based upon accepted industry standards and the knowledge that the parties had at the various times when the analyses or risk assessments were completed. Included in this will be a review of the measures taken, if any, to address any legitimate environmental concerns. I will not, however, assess the correctness of the positions taken by the various parties. As well, I am satisfied that the Terms of Reference do not permit me to conduct any further environmental assessment and nor does the time I have to conclude this Inquiry permit this. (page 20.)

## 2. Consultation of Indigenous Communities by Nalcor

At the request of the Commission, Nalcor Energy prepared a submission on consultation of Indigenous communities carried out on behalf of government in relation to the Lower Churchill Project (P-00271). A detailed overview of consultation with a number of Indigenous groups has been made an exhibit at this Inquiry and for the sake of efficiency will not be repeated in this submission.

Aubrey Gover, current Deputy Minster of Indigenous Affairs and former Assistant Deputy Minister of Indigenous Affairs from 2010 to 2013, testified before the Commission regarding the degree of consultation required of a proponent seeking government approval of a project. He testified that the level of consultation turns on the strength of the Indigenous group's claim. The responsibility for assessing the strength of claim, thereby informing the level of consultation required, lies with government, and cannot be delegated by government to a project proponent (Aubrey Gover October 3, 2018 pages 23-24).

Nalcor took its direction from the province regarding the degree and form of consultation required in respect of the Project. Gilbert Bennett, Executive Vice President Lower Churchill Project, testified that he acted as Nalcor's primary contact for Indigenous groups and the government during the consultation process (Gilbert Bennett November 27, 2018 page 1). At the time of the environmental assessment process, Innu Nation had an accepted land claim, within which the Project area was included, and the Nunatsiavut Government had a land claim agreement in place. NunatuKavut Community Council had asserted a land claim, but it had not been accepted by the governments of Canada or Newfoundland and Labrador for negotiation. (Gilbert Bennett November 27, 2018 pages 6-7).

### 2.1. The Environmental Assessment Process

Registration of the Lower Churchill Project on November 30, 2006 triggered the environmental assessment process and consultation with Indigenous groups on the Environmental Impact Statement Guidelines (P-00041 page 35, Aubrey Gover October 3, 2018 page 5, Gilbert Bennett November 27, 2018 page 2). For the Environmental Assessment (EA) of Generation, ten (10) indigenous groups were consulted (NG, NCC and Innu Nation, plus seven (7) groups in Quebec) in the development of the guidelines for the Environmental Impact Statement (EIS) to be prepared by Nalcor and the Terms of Reference of the Joint Review Panel (JRP) (Aubrey Gover October 3, 2018 pages 4-5). Once the EIS and supplemental information were accepted in January 2011 by the JRP, the process shifted to the Joint Review Panel hearings, at which the Indigenous groups presented (P-00041 page 39). The government established funding for Indigenous organizations to participate in the EA process (Aubrey Gover October 3, 2018 page 5).

The government issued Aboriginal Consultation Guidelines for Regulatory Approval Applications for the Lower Churchill Hydroelectric Generation Project on May 30, 2012

(P-01353) and for the Labrador-Island Transmission Link Project on July 2, 2013 (P-01354).

In the case of both the generation and transmission environmental assessments, the government delegated procedural aspects of consultation to Nalcor, but responsibility for discharging the duty to consult ultimately remained with the province (Aubrey Gover October 3, 2018 page 5).

### 2.2. The Joint Review Panel Report

In August 2011, following hearings and representations by interested parties including Indigenous groups and Grand Riverkeeper Labrador, the JRP submitted its report to the governments of Newfoundland and Labrador and Canada (P-00041). The Report outlined recommendations for Canada and Newfoundland and Labrador to consider in deciding whether to release the Lower Churchill generation projects (Gull Island and Muskrat Falls) from environmental assessment. Responses to the JRP Report were formally prepared by Canada (P-00050) and Newfoundland and Labrador (P-00051). The Indigenous groups also responded to the recommendations of the JRP. Nalcor was not involved in the decisions taken by government in preparing its response to the JRP recommendations (Gilbert Bennett November 27, 2018). Nalcor's review of the JRP's recommendations has been entered as exhibit P-01492.

As the regulators, the governments retain responsibility for the acceptance or rejection of any recommendations, as well as any subsequent implementation of recommendations.

The JRP Report made a number of conclusions in respect of the potential impacts of the Project on Indigenous communities, noting as follows:

- Adverse, but not significant, effects on NCC and Quebec Innu (P-00041, Aubrey Gover October 3, 2018 pages 6-7);

- Permanent, lasting adverse effects on Innu Nation, but these concerns were being addressed by mitigation measures (P-00041, Aubrey Gover October 3, 2018 page 7);

- High degree of concern for methylmercury and impact on Inuit, in this case, NG (P-00041, Aubrey Gover October 3, 2018 page 7).

On March 15, 2012, the Generation project was released from environmental assessment (P-02702,). Nalcor made a number of commitments as a condition of release including the development and implementation of monitoring plans subject to government approval (Aubrey Gover October 3, 2018 page 14). Nalcor was required to gather information about historic land and resource use, impacts on groups, and opportunities to mitigate (Gilbert Bennett November 27, 2018 page 2). As the regulators, governments are responsible for ensuring any mitigation undertaken is satisfactory (Aubrey Gover October 3, 2018 page 11).

### 2.3. NunatuKavut Community Council

Nalcor entered into a Community Development Agreement with NCC on December 1, 2017 (P-01709). Mr. Gover’s evidence was that the government believed NCC’s concerns could be adequately addressed through the mitigation measures it required of Nalcor (Aubrey Gover October 3, 2018 page 16).

### 2.4. Conseil des Innu de Ekuanitshit

In May 2009, Nalcor sent a draft Community Consultation Agreement to Ekuanitshit. In Spring 2010, there was another attempt to send a Community Engagement Agreement to Ekuanitshit (Gilbert Bennett November 29, 2018 pages 37-38).

Nalcor developed mitigation measures and a plan to respond to Ekuanitshit’s concerns about the impact on caribou. This plan was approved for use by government (Aubrey Gover October 3, 2018 pages 17, 23).

## 3. Methylmercury

Nalcor understood methylmercury was an important issue that formed part of the discussions during the EA process and continues to be a topic of public debate and concern today (Gilbert Bennett November 27, 2018 page 3). During the JRP process, Indigenous and public interest participants raised concerns about elevated methylmercury levels, impact on human health and downstream effects.

The JRP Report recommended full clearing of timber from the reservoir, but acknowledged the benefit from methylmercury reduction may be small (P-00041 pages 14, 80). Recommendation 6.5 suggested Natural Resources Canada, in consultation with Nalcor, pilot test the possible removal of soil and vegetation (but not in the Lower Churchill watershed and effort should be made before a sanction decision for Gull Island) as a mitigation measure (P-00041 pages 16, 108). In its response to the report, the province concluded that partial clearing of trees in the reservoir, in conjunction with other measures such as monitoring, would be sufficient to address the risks associated with increased methylmercury (P-00051, Aubrey Gover October 3, 2018 pages 8-10).

The JRP made several other recommendations relating to methylmercury, including assessment and publication of analysis of downstream effects (P-00041 pages 123-124), use of consumption advisories where necessary and human health and mercury monitoring (P-00041 page 274). Nalcor has been tracking its commitments under the EA, with a June 2019 status update exhibited at this Inquiry (P-04331). Work undertaken by Nalcor to address some of the JRP's recommendations on methylmercury in particular is described in further detail below.

In the Fall of 2015, the Nunatsiavut Government launched the Make Muskrat Right campaign focused on the possible impacts of methylmercury (P-03591 page 1). In 2015 and 2016, NG commissioned studies of methylmercury production and possible downstream effects. It has been NG's position that the impact of methylmercury will be more significant than predicted by Nalcor and Nalcor's scientific experts, and that full clearing of vegetation and soil is required to mitigate the risk to Inuit in the Lake Melville area and downstream (P-01684 page 23).

To facilitate discussion of the research surrounding methylmercury, government organized two workshops, the first on March 22, 2016 (P-04128 page 7) and the second on August 4, 2016, to which Nalcor, Innu Nation, NG and NCC were invited to participate (Aubrey Gover October 3, 2018 page 11). Representatives of all three Indigenous groups attended the second workshop (P-03591 page 1, P-04131, P-04132, P-04133).

As a condition for release from EA, Nalcor had to create a Human Health Risk Assessment program, resulting in establishment of the Human Health Risk Assessment Program, Final Baseline Human Health Risk Assessment report and Baseline Dietary Survey and Human Hair Sampling Program report (P-02119 page 3). Government accepted the Human Health Risk Assessment Plan on June 14, 2016, with the following condition:

> Should downstream methylmercury monitoring identify the need for consumption advisories as a result of the project, Nalcor shall consult with relevant parties representing Goose Bay and Lake Melville resource users. Based on the location of the consumption advisories these users could include Aboriginal Governments and organizations as well as other stakeholder groups. Following consultation, Nalcor shall provide reasonable and appropriate compensation measures to address the impact of the consumption advisory (P-04128 page 9).

This decision was communicated to Nalcor via correspondence from Perry Trimper, then Minister of Environment and Conservation, on June 14, 2016 (P-04129) and announced publically on June 14, 2016 (P-04130). The Minister denied NG's appeal of the decision to approve the Plan (P-04139, P-04142).

On October 14, 2016, NG called on GNL to halt the Project until concerns about methylmercury had been addressed. Initial flooding of the Muskrat Falls reservoir was set to occur in October 2016 (P-04148 page 2). GNL prepared an Information Note on October 16, 2016 which addressed work completed to date and a plan forward, including possible creation of an independent advisory committee (P-04149). A draft framework for the Independent Expert Advisory Committee (IEAC) was sent to NG President Lampe on October 18, 2016 (P-04150).

Following the protests on the Muskrat Falls site in October 2016, government resolved to establish the IEAC to review issues relating to methylmercury. The Terms of Reference for the IEAC established March 24, 2017 (P-01694) describe the IEAC's mission, mandate, objectives and structure. Its mission is stated as follows:

> "To oversee and provide independent assessment of the adequacy of mitigation, monitoring and management measures, and provide recommendations to the Responsible Ministers with respect to those and addition of any further such measures for the protection of the health of the Indigenous and local population impacted by the Lower Churchill Project, and in particular increases of methylmercury in country foods in the Churchill River near Muskrat Falls and downstream, all along the river and including Lake Melville." (P-01694 page 1).

Nalcor, the province and Canada were non-voting members of the IEAC (Jamie Chippett June 20, 2019 page 47).

Preliminary recommendations from the IEAC issued on September 26, 2017 suggested a feasibility study be undertaken for the removal of soil and vegetation from the reservoir and that Nalcor expedite its methylmercury modelling work (P-01695 page 1).

On March 5, 2018, the IEAC's Independent Expert Committee submitted a series of recommendations to the IEAC Oversight Committee in respect of human health management (P-01698), mitigation (P-01699) and monitoring (P-01700). The members of the Independent Expert Committee also provided written justifications on their recommendations for mitigation (P-01701). The IEAC's second set of recommendations were formally delivered to the Minister of Municipal Affairs and Environment on April 10, 2018 (P-01702). The IEAC recommended Nalcor undertake targeted removal of soil and capping of wetlands to mitigate methylmercury impacts (P-01702 page 2). The IEAC submitted its recommendations to government for consideration. Implementing any IEAC recommendations would require a decision of government and direction to Nalcor where required.

As requested by the IEAC, SNC-Lavalin (SNCL) prepared a feasibility report with targeted scenarios for soil and vegetation removal from the future reservoir area, as well as wetland capping, dated March 22, 2018 (P-04226). SNCL assumed for scheduling purposes that wetland capping would begin in August or September 2018 and that the work would be completed by April 2019 (P-04226 page 59).

On July 24, 2018, Peter Madden, Regulatory Compliance Lead for LCP, wrote the director of government's Water Resources Management Division to request an amendment to its permit to complete wetland capping (P-04277).

A November 1, 2018 government technical briefing on the IEAC recommendations notes the lack of consensus among the IEAC members and states that "Nalcor will be ordered to proceed to wetland capping" which "had unanimous support among the voting IEAC members" (P-04304 page 16).

On January 14, 2019, Gilbert Bennett attended a Deputy Minister's meeting and upon being informed by Jamie Chippett, Deputy Minister of the Department of Municipal Affairs and Environment, that government intended to proceed with wetland capping, Mr. Bennett advised that it was too late to do that work (P-04255 page 4, P-04256 page 5) and followed up with an email message with further explanation (P-04188).

Since the Phase 2 hearings concluded in early July, an agreement was reached with each of Innu Nation and NCC for a financial contribution to fund social programs and activities relating to the health of the members of those organizations using funds earmarked for work related to wetland capping (P-04543).

A number of independent studies and reports, commissioned and made available to the public by Nalcor, have been entered as exhibits at this Inquiry, including the following:

- Azimuth Consulting Group Partnership (Azimuth) submitted a Technical Memorandum to Nalcor on February 25, 2018 evaluating methylmercury production by the Muskrat Falls Reservoir and the implications for Lake Melville using a "top-down, mass-balance approach" (P-02118 page 1). The memo examines the assumptions used in the 2016 Calder et al. analysis regarding methylmercury in the reservoir and downstream effects on the Lake Melville marine food web. Azimuth draws the following conclusion:

> "When viewed from a top-down, mass-balance perspective, the assumptions and findings of Calder et al. (2016) are not supported. We wish to be very clear that the potential for the MFR to burden the aquatic food web of Lake Melville with MeHg has been greatly over-estimated. While we are not saying 'no change will occur' in Lake Melville, the evidence presented here strongly suggests that if any increase in MeHg burden were to occur, it would be extremely small and probably difficult to measure, given the lack of a strong pre-flood, baseline dataset of MeHg in lower trophic level biota in Lake Melville, where changes would be first observed (Hall et al. 1997)." (P-02118 page 17).

- Wood's study of predicted increases in fish methylmercury muscle tissue concentrations in Goose Bay and Lake Melville was published in July 2018 (P-02120).

- Azimuth prepared a Technical Memorandum dated July 19, 2018 summarizing "the effects of updated methylmercury modelling and predicted increases in key aquatic species on the Human Health Risk Assessment" (P-02115 at page 1). The Memo concludes, "there is an extremely low likelihood of risk to human health from consumption of seafood from Goose Bay or Lake Melville at peak mercury levels in a post-impoundment scenario." (P-02115 page 6).

- W.F. Baird & Associates Coastal Engineers Ltd (Baird) analyzed downstream effects of methylmercury in Goose Bay and Lake Melville waters in an August 2, 2018 Technical Memorandum (P-02116).

- Reed Harris Environmental Ltd provided an updated analysis of predicted increases in methylmercury concentrations and downstream export from the Muskrat Falls Reservoir on August 3, 2018 (P-02117).

- On November 20, 2018, Rob Willis of Dillon Consulting prepared a technical memo with an overview of the Human Health Risk Assessment Program status and supplementary assessment of potential future human exposures and risks due to methylmercury. This memo provides a useful summary of the Human Health Risk Assessment work completed from 2013 to 2018, as well as the key outcomes of the technical memoranda prepared by various experts for Nalcor (P-02119). The introduction notes:

> “As is described in the following sections of this technical memo, the various studies and programs conducted by the external experts predict with reasonably high confidence that no significant future increases in MeHg levels (relative to baseline) would occur in aquatic biota downstream of the Muskrat Falls Reservoir, and consequently, no significant increase in human MeHg exposure or risk (relative to existing current baseline exposure and risk levels) would be anticipated in the future.” (P-02119 page 1).

Presentations of the expert reports noted above have been entered as exhibits P-04230 to P-04237.

Nalcor has been monitoring the downstream effects of methylmercury (Gilbert Bennett November 27, 2018 page 19). The monitoring data available in 2017 and 2018 does not show the increases in methylmercury that were anticipated by the Calder model in 2015 (July 4, 2019 Dwight Ball page 73).

## 4. The North Spur

The North Spur is a 1-kilometre natural dam, composed of sands overlying silty sands, silty and clayey soils, located between the rock knoll in the south and the kettle lakes in the north (P-00435 page 2). Geotechnical investigations on the spur have been ongoing since the 1960’s with a view to stabilizing the spur. An overview of field investigations studies between 1965 and 2013 is provided in “Stabilization of the North Spur at Muskrat Falls: An Overview” (P-00435 pages 3-10). A 1979 field investigation study for the Lower Churchill Development Corporation identified the need to resolve stabilization issues with the North Spur (P-00049 page 83). In January 1999, SNC-AGRA completed a Final Feasibility Study (Volume 1 – Engineering Report) on the Muskrat Falls Hydroelectric Development for NL Hydro (P-00022).

SNCL was the designer and engineer for works on the North Spur. Hatch completed a cold eyes review of SNCL’s work (P-04213 page 1). Further geotechnical drilling was completed on the North Spur starting in 2010 (P-00264 page 15).

The JRP referred to concerns about North Spur stability in its August 2011 Report in the chapter on terrestrial environment and wildlife (P-00041 page 128). It notes Nalcor was operating a pump system to maintain stability at the North Spur due to instability following a landslide in the 1980s. Nalcor proposed a series of mitigation and monitoring steps, including conducting additional field investigations to monitor seepage and stability analysis once the project reached the detailed geotechnical design phase (P-00041 page 129).

Works on the North Spur were addressed again by Nalcor during the review of the Project by the PUB. In its November 10, 2011 submission, Nalcor stated the following:

> […] some civil works will also be taking place on the North Spur to stabilize the spur and ensure its viability as a natural dam, holding back the reservoir. This work is not expected to be critical and can be performed during the prime construction months over several years, with the only constraints being access to the spur, and ensuring that all of the work is completed prior to filling of the reservoir (impoundment). (P-00077 page 213)

Manitoba Hydro International (MHI) reviewed LCP documents from 1999 to 2011 related to the North Spur (P-00049 page 85). MHI's January 2012 Report confirms "a significant investigation effort has been undertaken for the north spur zone as described in the Technical Note: Muskrat Falls North Spur" (P-00049 pages 87-88). MHI notes in its Report:

> The layout and dimensions of the structures were selected as part of the Final Feasibility Study and the subsequent project optimization update studies. The layout of the dam has been prepared by experienced consulting firms and appears to be consistent with the conditions at the site and hydropower industry practice. The north spur structure at the site is a natural dam that extends from the rock knoll adjacent to the main river channel northwards across the valley. The spur comprises a soil and rock formation derived from the geological history of the site. The bedrock foundation is deep and extends below the river bed level. The Final Feasibility Study focused on the stability and water tightness of the north spur.
>
> The possibility of instability of the north spur under reservoir loading was identified early and analysed to develop a remedial works program. This consisted of installation of dewatering wells that reduce the phreatic surface in the soil, with the result that the factors of safety are increased. The well program has been examined during subsequent technical studies, and the consultants have confirmed the satisfactory operation of the pump wells to date. Stability of

> the north spur relies on the well system to manage the phreatic surface through the structure along with remodelling of the topography to reduce the loading on the slopes. The Final Feasibility Study included an analysis to substantiate the design concept but the detailed design studies must demonstrate the long term viability of this concept. The long term viability of this scheme is subject to further analysis and detailed design of the necessary stabilization works.
>
> Design for the permanent works includes the extension of the de-watering well system by increasing the number and extent of the wells. Some local excavation will be undertaken to lower the height of the ridge, thereby reducing the loading on slopes.
>
> The consultants involved have undertaken a comprehensive review of the stability of the north spur including the response of the structure to changes in water levels. There is no reason to believe that the north spur would not be stable during the life of the project.
>
> (P-00049 page 90.)

The permit to perform the North Spur stabilization works was issued by the Department of Environment and Conservation on July 10, 2013 (P-04197). The Department's permits are issued in accordance with Canadian Dam Association (CDA) Dam Safety Guidelines (June 20, 2019 Martin Goebel pages 21, 64).

The Independent Engineer (IE) also confirmed the reasonableness of the measures taken by Nalcor to address the stability of the North Spur. MWH concluded in its interim November 29, 2013 Report "the stabilization works have been designed in accordance with currently accepted geotechnical design practices and effectively stabilize the North Spur when the reservoir is impounded" (P-00435 page 9; P-01958 page 30). Geotechnical design work was ongoing at the time of the release of the IE Report (P-01958 page 31). Nik Argirov testified that the only remaining work to be provided after financial close was related to seismic analysis which was completed and reviewed by their own seismic evaluation expert (March 19, 2019 Nik Argirov pages 51-52). The IE reviewed the studies completed by SNCL throughout the Project and found they were prepared using good practice and satisfied industry standards. Mr. Argirov testified they also reviewed the reports by Hatch and peer review of Dr. Bernander's work (outlined later in this document), met with geotechnical designers to confirm the design followed the original approved methodology, and signed off on the work completed by Nalcor in respect of the North Spur. (March 19, 2019 Nik Argirov page 52.) Dr. Bernander's work was also reviewed by the IE's own experts (March 19, 2019 Nik Argirov page 52). MWH was confident the North Spur work up to financial close met expected standards (March 19, 2019 Nik Argirov page 69). The North Spur is under a monitoring program and the IE receives a dam safety report on a regular basis (March 19, 2019 Nik Argirov page 124).

A Request for Proposals was issued for CH0008 North Spur Stabilization Works package on February 20, 2014 (P-00862 page 43). A Limited Notice to Proceed for package CH0008 was issued to Gilbert Construction NL on December 31, 2014. Construction of the North Spur Stabilization Works began in March 2015 (P-00435 page 13).

An October 2015 technical paper by SNCL called "Stabilization of the North Spur at Muskrat Falls: An Overview" presented at the Canadian Dam Association 2015 Annual Conference notes:

> "The design of the stabilization works of the North Spur followed the state-of-the-art methods and complies with appropriate standards and guidelines. The guidelines prepared by the Canadian Dam Association (CDA) were used as a basis for the design and constitute the primary framework. In the context of the Lower Churchill project, the North Spur is treated as a dam for the selection of the design criteria. The final engineering design of the stabilization works of the North Spur was completed after last assessment of the geological and hydrogeological conditions of the Spur taking into consideration all previous engineering design studies and considering advances in technology available since the start of investigations in 1965. […] The final design calls for a complete control of the groundwater in the North Spur; erosion protection both the upstream and downstream side of the Spur and local unloading of the upper part of the Spur."
>
> (P-00435 page 12.)

In response to public scrutiny, further studies were completed including a dynamic study, a hydrogeological study and a progressive failure study (P-00435 pages 12-13). SNCL has prepared a number of reports related to the North Spur for Nalcor, including, but not limited to, the following:

- North Spur Stabilization Works Dynamic Analysis Study dated December 11, 2015 (P-04206);

- North Spur Stabilization Works - Progressive Failure Study dated December 21, 2015 (P-00447). This report reviews landslide hazards, stabilization measures, progressive failure potential, seepage analyses and stress distribution analyses.

- North Spur Stabilization Works - Design Report dated January 30, 2016 (P-00448). The field investigation programs and engineering studies between 1965 and 2013 on the North Spur are also reviewed in this document (See pages 16-60).

A number of reviews have also been completed by Hatch in relation to the North Spur, namely the following:

- Cold Eye Review of Design and Technical Specifications, North Spur Stabilization Works - Final Report dated January 9, 2014 (P-04420)

- North Spur Dam Break Analysis Final Report dated June 26, 2015 (P-00446)

- Assessment of North Spur Construction Processes dated September 18, 2015 (P-02834)

- Independent Dam Safety Audits throughout 2017 (P-00440, P-00441, P-00442)

The Lower Churchill Management Corporation's Muskrat Falls Dam Related Emergency (Full Supply Construction Phase) - Emergency Preparedness Plan was approved for use on June 30, 2016 (P-04208). An emergency preparedness plan for the Winter Headpond Construction Phase was also issued for use on June 30, 2016 (P-04209). The plans were created to "assist communities and external agencies in developing emergency response plans for a dam failure or passage of a major flood at the Muskrat Falls site" (P-04208 page 6; P-04209 page 5).

Dr. Stig Bernander of the Lulea University of Technology in Sweden prepared three reports concerning the North Spur for Grand Riverkeeper Labrador: a November 26, 2015 Report "Lower Churchill River Riverbank Stability Report" (P-00437), with an Errata published October 13, 2016 (P-00436); a October 13, 2016 report submitted to the PUB during the Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, entitled “Safety and Reliability of the Muskrat Falls Dam, in light of the Engineering Report of 21 December 2015 by Nalcor/SNC-Lavalin” (P-00438); and a technical report published in July 2018 by Lulea University of Technology called “Response to and Comments on “Geotechnical Peer Review of Dr. S. Bernander’s Reports and Analysis of the North Spur” (P-00434).

Nalcor responded to concerns raised by the public, including Dr. Bernander, in “Responses from Nalcor Energy to Public Questions on the North Spur” in January 2017 (P-00445).

On January 17, 2018, at the request of Natural Resources Canada, the Independent Engineer formally commented in response to reports critical of the North Spur prepared by Dr. Bernander (P-00443). The IE has been observing construction on the North Spur since 2013 and notes that the design works done for the North Spur were completed by a “major engineering firm with substantial experience in design of dams, and in accordance with international standards and practices. The designers consulted with various specialist consultants, including consultants with recognized expertise in landslides in sensitive clays. The design was also reviewed by another major engineering firm with substantial experience in design of dams” (P-00443 page 1).

The IE noted that downslope progressive failures, a concern identified by Dr. Bernander, were considered in design of the North Spur works and analysis completed to confirm reservoir loading would not trigger a failure (P-00443 page 2). Some of Dr. Bernander’s analysis was based on incomplete data and so would be unreliable (P-00443 page 3). The IE concludes “the overall design, review and due diligence process for the North Spur was consistent with what is expected for a major hydroelectric project.” (P-00443 page 4).

A geotechnical peer review of Dr. Bernander’s work was published on February 2, 2018 (P-00439). The Geotechnical Peer Review Panel (GPRP), composed of academics in civil engineering and geotechnical work from Canada and Norway, analyzed the available engineering documentation for the North Spur and concluded “the overall approach, concepts and methods used for checking the stability and integrity of the North Spur follow the current standards and state of the art practice” (P-00439 page 5). The GPRP made a number of findings, in light of the concerns raised by Dr. Bernander, among them the following:

- The methodology used to evaluate the stability of an initial slide on the North Spur slopes corresponds to the current state of practice.

- The analyses by SNCL are conceptually acceptable to take into account the initiation of progressive failure and to ensure a proper design of mitigation measures.

- State-of-the-Art methodology has been applied to the North Spur to assess its resistance to earthquakes.

- With respect to the mitigation and remedial measures at the North Spur, the GPRP finds that the analyses of the cut-off walls presented by Dury and Dr. Bernander are based on several incorrect assumptions and that the results are therefore not realistic. The GPRP is strongly against Dr. Bernander's proposal of driving closely spaced piles in the North Spur to investigate if metastable soils are present, stating that such an investigation could generate excess pore pressure in the sensitive clay and undermine the stability of the slopes.

- The aspects of dam breach and consequences downstream at Muskrat Falls have been investigated by SNCL.

  (P-00439 page 5).

Most recently, Nalcor has released additional reports from its consultant SNCL on the North Spur, as follows:

- Lower Churchill Project - Engineering Report - North Spur - Post Construction Assessment dated September 7, 2018 (P-04282).

- North Spur Stabilization Works - Construction Report dated January 27, 2019 (P-04283). Appendix C of this Report provides detailed foundation (geological) mapping of the North Spur, including various soil types (See pages 200-206).

- Memo dated May 1, 2019 from Regis Bouchard to File, Greg Snyder, et al re North Spur - Downstream Slope Stability - Sensitivity Analysis Addendum to the Post Construction Assessment Report (PCA) (P-04281).

Mr. Bennett testified Nalcor is confident the North Spur has been diligently investigated by qualified geotechnical engineers and third party reviewers (November 28, 2018 Gilbert Bennett page 38). A geotechnical engineer was on site observing the work on the North Spur throughout (June 26, 2019 Gilbert Bennett page 105).

## 5. Labour Relations

In addition to the submission of the RDTC/NLBTC, Nalcor notes that the Commission has received a written submission from IBEW Local Union 1620, which has been distributed to parties with standing, expressing concern that “the evidence as presented may leave a wrong impression regarding the practice and demeanor of labour relations on the Project.” That submission speaks positively of the constructive approach to managing labour relations taken by Nalcor and the Muskrat Falls Employers Association (MFEA), including the role carried out by labour relations consultant David Clark. The submission of the IBEW is in stark contrast to that of the RDTC/NLBTC, and to the evidence of the union witness panel.

Exhibit P-03875 was entered when the union panel witnesses testified. It is a letter from counsel for the RDTC/NLBTC which is in essence a submission of evidence and argument. Nalcor was given leave to file a response, which has been entered as Exhibit P-04557. The matters addressed in that response are also responsive to matters raised in the written submission of the RDTC/NLBTC.

As well, reference should be made to the testimony of Lance Clarke concerning the development and implementation of the labour relations regime for the Project (Lance Clarke May 23, 2019 pages 4-10, 51-53 and 66-68).

Nalcor submits that the submissions of the RDTC/NLBTC, in particular that "the approach of Nalcor, the MFEA, and the Government of Newfoundland and Labrador" was to "circumvent labour laws and constitutional principles for the benefit of the employer", and that "the MFEA was controlled by the owner, Nalcor", are unfounded and unsupported by the evidence.

Respectfully submitted on behalf of Nalcor Energy this 16th day of August, 2019.

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