REGULATING MEGA-PROJECTS: THE CASE OF MUSKRAT FALLS[1]

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Table of Contents

1. Introduction[2]

In May 2011, the government of Newfoundland and Labrador announced that costs associated with the Muskrat Falls project would be exempt from regulatory review and approval by the Board of Commissioners of Public Utilities (PUB), an independent expert agency that has a legislated mandate to ensure that electricity rates are based on the lowest cost possible consistent with reliable service.[3] The government subsequently issued an Order in Council that formally required the PUB to permit Newfoundland and Labrador Hydro to recover Muskrat Falls power costs in consumer rates. The overall cost of the 824 megawatt project, equivalent to a 40% increase in Newfoundland island capacity, was expected to be $7.4 billion in 2012, which will be accounted for in rates beginning in 2020 when the facility should become operational. While there are plans to smooth the impact of a significant increase in the effective rate base over a 50-year period, it is estimated that consumer rates will approximately double soon after commissioning in the absence of government subsidy.[4]

The decision to exempt Muskrat Falls from PUB oversight came after the government had signed an agreement with Emera Inc. of Nova Scotia in November 2010 to develop the site and to construct an interconnecting transmission link, thereby providing access to export markets.[5] The potential to develop the Lower Churchill site had been under consideration by the NL government for many years, and the 2007 provincial energy plan indicated the government's interest in proceeding with the project, spearheaded by the newly-created Nalcor.[6]

The government justified its decision to exempt Muskrat Falls from PUB review by arguing first that "projects of this scope exceed the PUB's mandate, as they are as much about economic development and job creation as they are about electricity"[7]; and second that the "[regulatory review] process could take up to a year and a half, and that's not what we are looking for from the PUB at this point in time".[8]

Although the government sidestepped the PUB regulatory review and approvals process for electricity infrastructure projects, it did solicit input from external experts and it permitted the PUB to conduct a restricted review of two specific alternative options. When the government

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[2] This report was written for the Commission of Inquiry Respecting the Muskrat Falls Project to provide an assessment of the impact of exempting the Muskrat Falls Project from regulatory oversight by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) on the development and costs of the project.

[3] Development of the Lower Churchill was originally removed from PUB oversight by the Tobin government in 1999 when it was envisaged that the project would generate electricity for export outside the province. While the scope of the Muskrat Falls project subsequently evolved to include a major within-province supply component, subsequent governments did not rescind the exemption. Newfoundland and Labrador Regulation 120/13, Muskrat Falls Project Exemption Order. Filed November 29, 2013.

[4] Since the sanction date, estimated costs have risen to $12.7 billion.

[5] NL Government News Release, November 18, 2010. Available at http://www.releases.gov.nl.ca/releases/2010/exec/1118n06.htm

[6] Newfoundland and Labrador 2007 Energy Plan. *Focusing Our Energy*. Available at http://www.nr.gov.nl.ca/nr/energy/plan/index.html

[7] CBC news report, May 17, 2011. Available at https://www.cbc.ca/news/canada/newfoundland-labrador/muskrat-project-to-be-exempt-from-pub-1.1017721

[8] CBC news report, May 18, 2011. Available at https://www.cbc.ca/news/canada/newfoundland-labrador/no-apologies-for-pub-exemption-dunderdale-1.1017720

subsequently officially sanctioned the project 18 months later in December 2012, it claimed that Muskrat Falls represented the least-cost option for electricity generation in the province.[9]

To assess the effect of exempting the Muskrat Falls project from PUB oversight, this report addresses several issues in seven sections. Sections 2, 3 and 4 examine the purpose and role of regulatory agencies in the electricity sector, best practices in regulatory governance, and the advantages and disadvantages of delegating oversight authority to independent regulators. The next section examines the NL PUB, comparing it against the best practice model to gauge its effectiveness as a utility sector regulator. Section 6 focuses on regulatory oversight of major electricity infrastructure projects such as Muskrat Falls, and assesses the NL government's approach to oversight. The seventh section provides evidence about standards of regulatory oversight of other major electricity projects in Alberta, Manitoba, and Ontario. The final section concludes.

2. The Role of Regulatory Agencies

2.1 Rationale for Regulation of Utilities

It is common practice for governments to delegate regulatory authority over the electricity sector to expert agencies, who implement broad policy objectives through administrative rules and orders. Since electric utilities often have a monopoly market position – almost always in network transmission and distribution of electricity, and sometimes in power generation – the core function of regulatory agencies is to substitute for normal competitive market pressures and to protect consumer interests by setting 'just and reasonable' rates and approving prudent utility costs. In most countries within the Organisation for Economic Cooperation and Development (OECD), regulators interpret their mandate by establishing rates that balance consumer interests – that is, the lowest possible rates consistent with reliable service – with producer interests – the need to recover operating costs and to earn a sufficient financial rate of return on capital investments.

2.2 Challenges in Utility Regulation

While the primary standard of setting 'just and reasonable' rates is simply stated, the determination of what constitutes this standard is challenging since utility operations are technologically and economically complex and each situation is specific, often without ready comparison, requiring a case-by-case analysis and determination. Regulators must assess whether utility costs and investments are reasonable, a task complicated by several inherent

[9] NL government news release, December 17, 2012. "Muskrat Falls has been endorsed by a series of renowned independent energy experts including Manitoba Hydro International (MHI), Navigant Consulting, Dr. Wade Locke, and Ziff Energy Group of Calgary. In October 2012, the province released the project's Decision Gate 3 cost estimate and the findings of a report conducted by MHI. The report confirmed the engineering, costs, and project planning completed by Nalcor and affirmed Muskrat Falls as the least-cost option for electricity generation in the province. The report included the most up-to-date information on load forecasts and cost estimates including capital costs, operating costs, financing costs, fuel and interest." Available at http://www.releases.gov.nl.ca/releases/2012/exec/1217n11.htm.

conditions: first, utilities often have better information about underlying consumer demand, technological options and cost factors than do regulators, since utilities are run by experts in engineering, accounting, IT, marketing and other professional fields. While regulatory agencies also have staff experts, their limited size and resources can prevent them from matching the scope and depth of utility expertise, making agencies partly reliant on utility's knowledge and judgement about the necessity and reasonableness of expenditures.[10] A second challenge for regulatory agencies is that cost-based regulation creates incentives for utilities to over-invest in capital assets since higher approved asset levels enable utilities to earn greater profits, which can benefit shareholders and/or managers.[11] The risk for regulators that arises from these two challenges is that they will approve operating cost and investment levels that are too high, or tolerate inefficient performance, leading to higher rates for consumers.

Such challenges in effective regulation of the utility sector may be overcome in part through the appropriate design of regulatory governance mechanisms and regulatory policy instruments. Academic experts and public policy organizations have developed recommended best practices in utility regulation, which can serve as a benchmark for evaluating regulatory institutions in a specific jurisdiction.[12] The next section summarizes the core recommended elements and discusses the impact of each on regulatory decision-making and policy outcomes.

3. Best Practice in the Design of Regulatory Agencies

3.1 Organization and Structure

Clarity of role and objectives. Clearly articulated objectives and roles for regulators are a central element of a well-functioning regulatory framework, which includes the legislative and executive branches of government. Clear policy objectives that are specified in legislation enable regulators to establish their work priorities and scope, and they allow other stakeholders to hold regulators accountable for their decisions. Objectives that are principle-based rather than prescriptive are likely to be more effective in complex or dynamic environments since they permit regulators to utilize their expertise in identifying optimal policy solutions. It is typical for regulatory objectives to emphasize economic principles of industry operations, notably cost efficiency and consumer rate protection, given the natural monopoly characteristics of the electricity sector. For instance, the Ontario Energy Board is required to "protect the interests of

[10] For seminal academic work on this issue, see Baron, D. and Myerson, R. 1982. Regulating a Monopolist with Unknown Costs. *Econometrica*, 50: 911-930. Laffont, J. and Tirole, J. 1986. Using Cost Observation to Regulate Firms. *Journal of Political Economy*, 94(3): 614-641

[11] This phenomenon is sometimes referred to as the 'gold-plating effect' of cost-of-service regulation and was originally proposed by two economists, Harvey Averch and Leland Johnson, in 1962.

[12] See for example: OECD, 2014. *The Governance of Regulators*. Best Practice Principles for Regulatory Policy. Berg, S., 2013. *Best practices in regulating state-owned and municipal water utilities*. Economic Commission for Latin America and the Caribbean. Stern, J. and Cubbin, J. 2005. *Regulatory Effectiveness: The Impact of Regulation and Regulatory Governance Arrangements on Electricity Industry Outcomes*. World Bank Working Paper 3536. Berg, S. *Developments in Best Practice Regulation: Principles, Processes, and Performance,* Public Utility Research Centre, University of Florida. Holburn, G., 2011. *Guidelines for Governance of the Electricity Sector in Canada*. Ivey Business School. Australian Competition and Consumer Commission, 1999. *Best Practices in Utility Regulation*.

consumers with respect to prices and the adequacy, reliability and quality of electricity service…to promote economic efficiency and cost effectiveness… and to facilitate the maintenance of a financially viable electricity industry”.[13] It has become more common for electricity regulators to also have environmental objectives included in their mandates due to the environmental impact of some power generation technologies. In the U.S., many states have adopted legislated renewable portfolio standards that specify the percentage of electricity to be generated from wind, solar and other renewable fuel sources, while leaving state regulators and utilities to determine the best means for achieving the targets. Nova Scotia has a mandated target of 40% renewable energy by 2040, and Ontario’s regulator is required to “promote the use and generation of electricity from renewable energy sources”.

Resources and powers. In order to fulfill their mandates, regulators require sufficient organizational resources, expertise and powers. Effective regulation requires agencies to scrutinize and to test utility and stakeholder informational submissions, to develop regulatory proposals and processes, and to understand the full range of direct and indirect consequences of alternative policy decisions – all of which depend on skilled and knowledgeable agency commissioners and staff. Agencies should employ sufficient numbers of professional staff to oversee regulated entities; and recruitment procedures, including for agency commissioners, should have professional qualification criteria and transparent selection processes. At the same time, agencies should have sufficient and predictable financial resources to effectively operate. Budgets should reflect the scope and complexity of agency mandates. Agencies that are funded through cost-recovery levies incorporated in consumer rates – in accordance with transparent principles and objectives – will have greater autonomy from government than would be achieved through annual appropriations processes. Beyond organizational resources, agencies require the appropriate formal powers to function – including the powers to investigate, gather information from regulated entities, enforce regulations and to determine sanctions for non-compliance.

Regulatory independence. While regulatory agencies derive their mandate and policy objectives from government through legislation, best practice guidelines recommend that agencies operate independently from government in order to provide impartial, objective decision-making. Independence can strengthen trust with stakeholders, especially with utilities who will invest only if they are confident of being able to earn a reasonable financial return during the life time of the assets, which often extend more than 20 years. The degree of agency independence depends on formal structural relationships with the government and the extent to which an agency can make decisions autonomously without direct or indirect government influence. For instance, agencies whose decisions are subject to ministerial approval or veto, or who are subject to ministerial directives, will have less ability to exercise independent professional judgment. Agency board member appointment and reappointment mechanisms also affect independence: board members who are appointed based on professional criteria and qualifications for fixed terms of several years will be able to act more independently than board members appointed for short terms (e.g. one or two years) and who may be removed at pleasure. Agency budget processes are another way for governments to enhance or weaken agency independence: the greater flexibility and discretion that governments have in determining annual agency budgets and appropriations, the weaker will be agency autonomy in fulfilling its mandate.

[13] Ontario Energy Board Act, 1998. Available at https://www.ontario.ca/laws/statute/98o15

Accountability. Operational independence need not imply that regulators are unaccountable for their actions. The right for stakeholders to appeal to the courts is one way to ensure that regulators do not exceed their attributed powers. Internal appeal mechanisms that require regulators to review their decisions can also provide a degree of assurance for affected parties. At an organizational level, formal letters of expectations and clearly specified performance criteria enable the government to periodically review whether the regulator has met its objectives, and to decide whether to reappoint board members. External institutional checks can thus balance regulator independence with accountability to stakeholders.

3.2 Decision-making Processes and Procedures

Stakeholder consultation and participation. Regulatory decision-making procedures that permit affected stakeholders to participate and contribute evidence can profoundly shape the ability of agencies to achieve their mandates. Regulated utilities have a responsibility to demonstrate that their operations and investments are prudently managed, and that their requests for rate increases are just and reasonable, though such claims require rigorous external scrutiny since utility interests are not necessarily aligned with the public interest. One way in which regulators can overcome utilities' inherent informational advantage is by involving stakeholders, such as public consumer advocates, industrial consumer groups and other organized interest groups, in administrative decision-making processes, and by leveraging their expertise. Stakeholder groups, especially those representing consumers, have an incentive to carefully scrutinize utility proponent policy proposals, to identify weaknesses in their arguments, evidence, and assumptions, and to present their own evidence and counter-proposals. While consumers also have their own particular interests and motivations, effective participation in regulatory hearings – where each party can challenge other parties' arguments – can flush out specious or poorly supported utility claims, and provide regulators with valuable new information and perspectives on the case at hand. Intervenor participation can thus contribute to a much deeper and fact-based understanding of the likely consequences and associated risks of a specific decision – which is particularly valuable in complex or unique projects where there is large degree of initial uncertainty. Quite apart from the informational benefits of admitting intervenors to administrative hearings, there can be a procedural justice benefit as well from allowing affected parties to formally voice their views, irrespective of any impact on ultimate policy decisions.

Evidence-based decision-making. The impact on regulatory policy of intervenor participation in regulatory hearings – and the improved availability of information that follows – depends on the statutory criteria that guide regulators' ultimate decisions. In Canada and the U.S., regulatory agencies are generally constituted as quasi-judicial administrative tribunals that operate like courts, and are required to follow due process principles in their deliberations – including the fundamental requirement to rationally base decisions on the evidence presented. This evidentiary standard ensures that decisions are not made in an arbitrary manner and it elevates the importance of credible evidence and arguments in determining regulatory policy. As such, agencies are empowered to receive written and oral evidence under oath from utilities and intervenors, to permit cross-examination, and to admit expert witnesses, all in the pursuit of reliable facts and arguments that can withstand careful examination. It is common practice for regulators to conclude their analysis of case evidence with 'findings', which form the basis for their decisions. In the absence of an evidentiary standard, there is a heightened risk that policymakers will selectively eschew information about policy impacts and implement policies that prioritize ideological motivations or the interests of particular stakeholders.

Transparency. Transparency relates to the public availability of information about regulatory procedures and decisions, and is a central ingredient in ensuring regulatory institutions can be held accountable to a range of stakeholders. For instance, making publicly available the evidence and data submitted to regulators (subject to commercial confidentiality considerations), and the reasons and justification for regulatory decisions, enables regulated entities and intervenors, as well as the public, to assess whether the regulator has adhered to mandated objectives in specific decisions. Evidence of apparent failings may be used for appeal, either internally or ultimately to the courts. More broadly, transparency about government expectations of the regulator – as documented in organizational plans, operating objectives, performance indicators, and annual reports – allows ministers and the legislature to monitor regulator performance. Transparency thus sharpens incentives for regulators to perform effectively and to adhere to due process requirements.

4. Advantages and Disadvantages of Delegating Oversight to Regulatory Agencies

Delegating regulatory authority to well-functioning expert independent agencies enables public decision-makers to mitigate or overcome informational challenges in assessing whether electricity projects and expenditures serve the public interest, as defined in legislated mandates.

Agency oversight is particularly advantageous for more complex cases where there is initial uncertainty about the merits of a project, as is likely to be the case for large projects which have deeper and broader impacts, for those that involve new or unfamiliar technologies, or those that have other unique characteristics. Regulators with relevant expertise and background knowledge will be better able to evaluate, assess and adjudicate such cases. The inclusive nature of administrative processes – through which multiple stakeholders are able to provide information and testimony and to scrutinize other stakeholders' claims – is also especially beneficial for complex projects where information asymmetries are greater than normal. Anticipating close scrutiny of project proposals and expenditures – and the likelihood of disallowance of imprudent expenditures – utilities have a stronger incentive to control their costs and to implement effective internal cost-management governance mechanisms.

Likewise, the transparent, evidence-based foundation of regulatory processes is more beneficial for heavily contested infrastructure projects where there are strong political pressures exerted on government. By requiring that regulators provide a public forum for debate and that they publicly justify their decisions based on the evidentiary record, concerns about undue influence of powerful stakeholders are reduced, while public trust in the decision-making process is likely to be increased. Institutional independence from government, which may be subject to short-term political pressures, enables regulators to determine whether projects are in the long-term public interest, further strengthening public confidence in regulatory institutions and the legitimacy of their decisions. An important consequence is that policies established through a rigorous regulatory process are more likely to remain stable over time and to withstand future challenges – creating a more predictable environment for utilities and consumers alike.

There are of course potential disadvantages to delegating regulatory oversight of the electricity sector to independent agencies, which must be weighed up against the advantages. First, the quasi-judicial process can be costly in terms of time, personnel and financial resources. Reaching decisions can be timing consuming and expensive, especially for larger and more complex projects. For projects where speed is imperative – for instance when delay would cause a significant increase in costs – an expedited government review and sanction process may be preferred.

Second, while regulators often have a primary mandate to consider the economic interests of producers and consumers, electricity infrastructure projects can have environmental and social impacts, the magnitude of which generally increases with project scale. A narrow regulatory mandate may thus not provide a comprehensive assessment of the public interest. An alternative approach is to charge separate economic and environmental regulators with undertaking their own assessments and making recommendations to government which, after reviewing multiple expert reports, makes the ultimate decision whether to sanction a project. Alternatively, governments may broaden economic regulators' mandates to include environmental and other considerations, for instance by specifying targets for renewable fuel generation sources in the electricity sector. Carbon emission pricing policies – which raise the cost of hydrocarbon generation fuels – can internalize environmental impacts in economic regulatory assessments. In these cases, the limitation of a narrow regulatory scope may thus be addressed by broadening the regulatory mandate or by implementing complimentary environmental policies, rather than by abandoning the regulatory process.

5. Newfoundland and Labrador Board of Commissioners of Public Utilities

The Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB), created by statute in 1949, is an independent, quasi-judicial administrative agency that is responsible for regulating electric utilities within its jurisdiction, as well as overseeing selected aspects of other industries (automobile insurance rates, pricing of regulated petroleum products, and public bus and ambulance operating certificates).

5.1 Organization and Structure

Role and objectives. The PUB's mandate is specified in the *Electrical Power Control Act, 1994, (EPCA)* which establishes the province's policies for electricity rates and criteria for production, transmission and distribution of electricity.[14] The EPCA states that electricity infrastructure "should be managed and operated in a manner

[14] https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm#3_

i. that would result in the most efficient production, transmission and distribution of power,
ii. that would result in consumers in the province having equitable access to an adequate supply of power, and
iii. that would result in power being delivered to consumers at the lowest possible cost consistent with reliable service."

The EPCA mandates the Board to make rate decisions that are reasonable and not unjustly discriminatory. The legislation provides that utilities are permitted to earn a just and reasonable financial return while maintaining a sound credit rating in financial markets. The EPCA also delegates to the PUB the responsibility and authority for ensuring sufficient planning by utilities for future production, transmission and distribution of power in the province. Hence, in common with utility regulators in many jurisdictions, the PUB's mandate is primarily focused on overseeing economic attributes of the electricity sector, subject to the system's technical adequacy, and does not include environmental considerations.

Resources and powers. The PUB derives its powers and organizational structure from the *Public Utilities Act (PUA)*.[15] In the electricity sector, the PUB is responsible for the regulation and oversight of Newfoundland and Labrador Hydro and Newfoundland Power Inc., with a combined customer base of approximately 308,000 customers. The combined asset rate base is valued at more than $3 billion. [16]

The PUB consists of four full-time commissioners, appointed by the Lieutenant Governor in Council, including the Chair, Chief Executive Officer and Vice-Chair, and twelve permanent staff. The *PUA* specifies that the board should include commissioners with expertise in law, engineering, accountancy or finance. Commissioners are appointed for ten-year terms, which enables the long-term development of regulatory expertise and industry knowledge. As at March 31, 2016, the four commissioners had served for 19, 8, 8 and 6 years, respectively.[17] The PUB's operating expenses in 2015/16 were $2.5 million (excluding $2.9 million in hearing costs), funded through assessments charged to regulated entities or applicants.

Compared with regulatory boards in other provinces, the sizes of the PUB's budget and staff are amongst the smallest.[18] Although normal work demands are expected to be lower in a province with two regulated utilities and a small population, staff turnover or unique cases or unexpected events that require additional resources can create short-term organizational challenges.

Independence. The PUB is constituted in statute as an independent entity with a clearly specified mandate, authority and resources. The PUB does not require approval for or consent from government in its decisions, and it is able to utilize its own expert judgment as the basis for rules

[15] http://www.assembly.nl.ca/Legislation/sr/statutes/p47.htm
[16] See Newfoundland Power 2019/20 General Rate Application available at https://www.newfoundlandpower.com/-/media/PDFs/About-Us/Regulatory-Matters/2018-06-01-NP-2019-GRA-Volume-1.pdf and Newfoundland and Labrador Hydro 2017 General Rate Application available at http://pub.nl.ca/applications/NLH2017GRA/applications/1609%202017PU%20%20NLH%202017%20GRA%20Application%20Volume%20I%20-%202017-07-28.pdf
[17] Commissioners' service terms are estimated based on appointments reported annually in PUB Annual Reports.
[18] Power Advisory and Hatch Ld. 2015. *Review of the Newfoundland and Labrador Electricity System* (page 138).

and orders. Lengthy commissioner appointment terms – which extend well beyond political election cycles – strengthen operational autonomy, as does PUB funding from industry assessments rather than from government appropriations. These follow best practice and help insulate the PUB from potential short-term political pressures around utility regulation, permitting an impartial approach.[19]

5.2 Decision-making Processes and Procedures

Accountability. The PUB is accountable both to the courts and to the government. Specific decisions and orders of the PUB may be appealed by affected parties to the Court of Appeal based on a question of jurisdiction or a question of law.[20] The PUB is accountable to the Minister of Justice and Public Safety who presents the PUB's annual budget for approval by the Lieutenant Governor in Council. The PUB is also subject to the Transparency and Accountability Act, which requires the PUB to prepare and submit activity plans and annual performance reports. The PUB submits its annual performance report, which details how the PUB has achieved its objectives, to the House of Assembly. As such, executive and legislative branches of government are able to regularly evaluate the operations and performance of the PUB.

Stakeholder consultation and participation. The PUB affords the opportunity for affected parties to intervene in regulatory hearings by presenting oral and written testimony and by cross-examining other parties. An example is Newfoundland and Labrador Hydro's 2013 Amended General Rate Application, which involved 43 days of public hearings in 2015/16.[21] The eight participating intervenors included Hydro, the provincial consumer advocate, Industrial Consumer Group, Innu Nation, Newfoundland Power, Nunatsiavut Government, Towns of Labrador, and Vale – a typical mix of different stakeholders for utility rate proceedings. The PUB has discretion to award participation costs to intervenors at the end of a hearing in order to encourage representation of stakeholder interests.[22]

Evidence-based decision-making. As with regulators in other provinces, and in accordance with administrative law, the PUB relies on evidence filed by utilities, intervenors and PUB staff in making its decisions. The PUB sometimes retains external consultants to assist staff analysis on particular issues as a means to obtain specific expertise or to augment internal resources. The PUB has the power to summon witnesses, to obtain utility records, and to take evidence under

[19] The NL government has the authority, specified in the EPCA, to issue directives to the PUB over utility rate structures, Newfoundland and Labrador Hydro's debt-equity ratio and rate of return, PUB oversight over the Muskrat Falls project, whether the PUB should conduct a provincial electricity supply and demand enquiry, and whether a utility is exempt from PUB regulation under the EPCA, amongst others. These limit the PUB's scope but not the exercise of PUB independence within its jurisdiction. The government has utilized its directive powers, for instance through Order in Council OC2009-063, which directed the PUB to set Hydro's target return on equity and maximum equity ratio the same as permitted by the PUB for Newfoundland Power. During the period 2006 to 2016 the government issued several directives that deferred PUB-approved rate increases for non-government customers on isolated systems. The government funded the revenue requirement impacts of these deferrals (see PUB Decision and Order 49(2016) on Newfoundland and Labrador Hydro's General Rate Application for 2014 and 2015 Test Years at http://www.pub.nf.ca/orders/order2016/pu/PU49-2016.pdf)

[20] Public Utilities Act, section 99. http://www.assembly.nl.ca/Legislation/sr/statutes/p47.htm#99_

[21] http://www.pub.nf.ca/orders/order2016/pu/PU49-2016.pdf

[22] http://pub.nf.ca/download/Hearing%20Participation%20Guidelines.pdf

oath. Like a court, after considering testimony and evidence from multiple stakeholders, the PUB makes adjudicative decisions. Consistent with best practice, the PUB publishes written decisions and orders, explaining the evidentiary basis and rationale.

Transparency. The PUB operates with a high degree of transparency in its regulatory activities and decision-making processes. Notices of applications and pre-hearing conferences are published in local media to notify a broad audience of forthcoming actions, and documentation related to applications is made publicly available on the PUB website. The PUB launched a new electronic document management system in 2013 providing greater public accessibility to a large volume of information. In 2015/6 more than 10,000 records were filed with the PUB, including 3,676 information requests in utility rate proceedings, 540 power outage reports, and 113 compliance reports.

5.3 Summary

In many respects, the PUB is structured and operates in a manner consistent with recommended best practice. Although it has limited financial and human resources, the PUB, like other provincial utility regulators, is structured to provide expert, independent evaluation of utility investments and expenditures, and to determine whether they are consistent with providing the lowest-cost power to consumers amongst feasible alternatives. It has the mandate and administrative powers, as well as organizational experience, to mitigate informational hurdles in setting reasonable rates and approving utility expenditures that fairly balance consumer, producer and other stakeholder interests, the fundamental task for any regulator. The PUB adheres to administrative due process principles, and is accountable in its decisions to the courts and government, providing safeguards for stakeholders.

In 2015/16, the PUB issued 36 orders under its public utilities mandate, 22 of which related to applications by Newfoundland and Labrador Hydro and 14 to Newfoundland Power. Over the ten-year period 2006/7 to 2015/16, the PUB issued a total of 419 public utility orders, involving issues ranging from rate applications to capital budget applications and capital financing. In many cases, it approved utility requests. The PUB has also denied applications and it has initiated prudence reviews when it has had reason to be concerned about utility actions.[23]

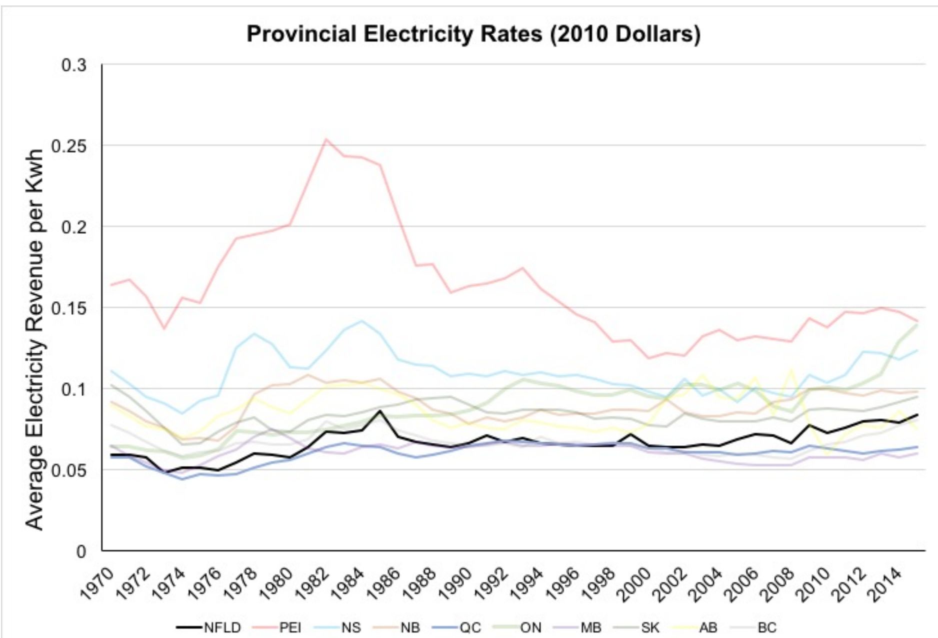
A consultants' review of NL's electricity system commissioned by the government in 2015 after a series of extended winter outages identified a number of areas where the PUB could improve its regulatory practice: first, although the PUB has the authority to do so, it has historically not required utilities to file periodic integrated resource plans that provide a long-term plan for investment in the sector, as do regulatory agencies in some other provinces. Second, time-of-use rate structures could be developed to encourage more efficient consumption and to reduce peak demand levels. Third, while PUB regulation of Newfoundland Power has proceeded smoothly, regulation of Hydro's rates has been infrequent (due to extended periods between general rate

[23] For instance, the PUB commenced a prudence review of certain NLH projects and expenditures in February 2015, leading to Order P.U. 13 issued on April 26, 2016. The board denied recovery of costs deemed imprudent related to overhauls of breakers, equipment and transformer repairs, professional services consulting fees and overtime.

cases) and twice appealed to the courts; more regular rate cases may facilitate a smoother regulatory relationship.[24]

While implementing these initiatives could produce some beneficial changes in future regulatory policies, it is notable that historically the PUB has presided over electricity rates in NL that have remained below the national average. Furthermore, from the mid 1980s to the mid 2000's average rates did not grow in real terms (see Figure 1). Since the early 2000's, rates have grown slightly faster than the national average, due in part to greater reliance on oil power generation. Newfoundland Power has commented that, "*Regulation in this province has been stable, has worked well and is currently moving in the right direction. Under the existing system, customers have benefited from improved operating efficiencies, enhanced reliability, customer service excellence and environmental diligence*."[25]

Figure 1(a): Average Electricity Rates by Province, 1970-2015

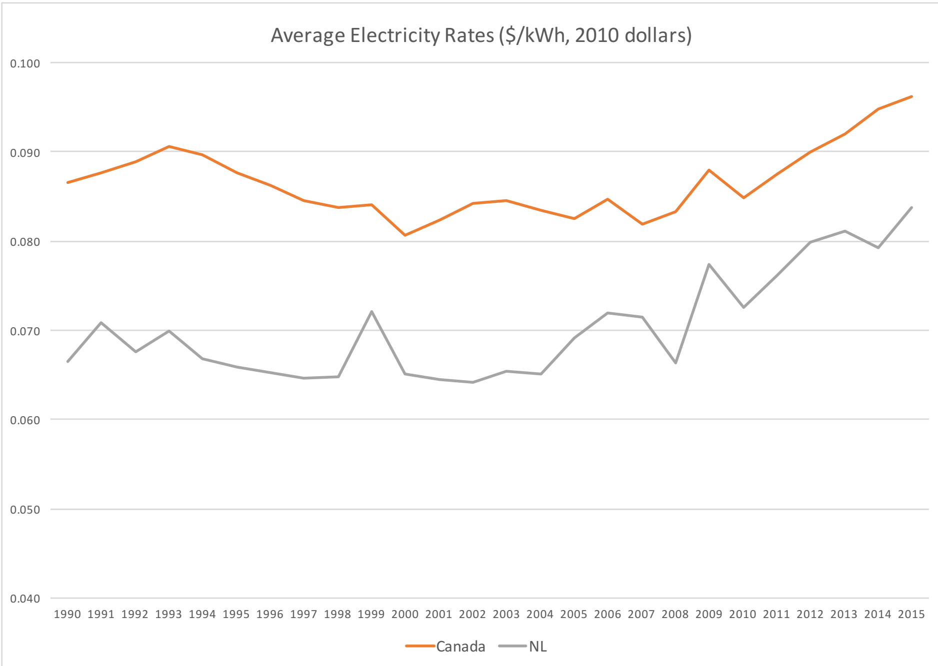


Source: Statistics Canada. Electric Power Statistics, Volume 2 (1970-1996); Electric Power Generation, Transmission and Distributions (1997-2004); Supply and Disposition of Electric Power (2005-2015). Table 127-008.

[24] See Power Advisory and Hatch, 2015. *Review of the Newfoundland and Labrador Electricity System*. Prepared for the Department of Natural Resources.

[25] Newfoundland Power 2006 submission to the provincial Energy Plan consultation (page 16). Available at http://www.nr.gov.nl.ca/nr/energy/plan/pdf/doc_1664.pdf

Figure 1(b): Average Electricity Rates in NL and Canada, 1990-2015



Source: Statistics Canada. Electric Power Statistics, Volume 2 (1970-1996); Electric Power Generation, Transmission and Distributions (1997-2004); Supply and Disposition of Electric Power (2005-2015). Table 127-008

6. Regulatory Oversight of Muskrat Falls

The risk of significant cost overruns and delays for megaprojects, especially for hydro-electric power generation infrastructure, has been well documented, prompting close examination of optimal project governance structures and practices. Oversight by independent regulators such as NL's PUB can also play an important role in minimising the risk of adverse outcomes at each stage of a project's development: (1) Project Need Identification, (2) Evaluation, (3) Approval, (4) Execution and Oversight, and (5) Cost Review and Recovery. This section evaluates the nature and impact of regulatory oversight of Muskrat Falls at each of the five stages.

6.1 Project Need Identification

The initial need for an electricity infrastructure project may be identified by a project proponent or by a system planning agency as part of an integrated resource plan (IRP) that assesses a range of generation and transmission options, as well as demand management and conservation programs, to ensure that supply is sufficient to meet long-term electricity demand in a cost-effective, reliable and environmentally sustainable manner. In Ontario and Alberta, for example, independent planning agencies have undertaken detailed periodic needs assessments of future generation and transmission requirements, which form the basis for subsequent public consultation and regulatory evaluation. In Nova Scotia, utilities are required to file integrated resource plans with the Utility and Review Board, which form the basis for hearings, stakeholder discussions and UARB review. IRPs provide a strategic framework against which specific project proposals can be evaluated in how they meet system objectives relative to other alternatives.

An advantage of agency-led long-term planning is impartiality regarding generation technology choices and utility beneficiaries. Agency processes also tend to incorporate consultation with a broad range of stakeholders and to include public hearings, contributing to confidence in agency proposals. Independent agencies have an incentive to recommend or adopt more aggressive conservation and demand management targets than utilities, who typically benefit from increasing electricity demand and larger asset portfolios. Ontario's 2013 Long-Term Energy Plan emphasized that regulatory agencies would "put conservation first in their planning, approval and procurement processes", reflected in a conservation target of 16% of gross electricity demand by 2032 and a peak-demand reduction target of 10% by 2025.[26]

In NL, concerns have been raised several times over the last decade about the approach to electricity system planning, which has been led by Newfoundland and Labrador Hydro rather than by the PUB. In 2006, Newfoundland Power noted in its submission to the 2007 Energy Plan, "*system planning guidelines that have the benefit of input from all significant stakeholders would be desirable to ensure both fair competition and appropriate system development. To attract the most competitive proposals for system additions, the system plan should be available publicly. The status of the plan and any material change in circumstances should be available through the publication of periodic reports (e.g., annually or biannually), as necessary*".[27]

Several years later, the 2011 Joint Review Panel, noting reports that Hydro and Newfoundland Power's conservation and demand efforts had substantially lagged targets, recommended that the province should use integrated resource planning, stating "*Such an approach would involve interested stakeholders and look simultaneously at demand and supply solutions and alternative uses of resources over the medium and long term*".[28]

An extensive review of NL's electricity system by a consulting firm in 2015 made similar observations, recommending that "*requiring that the entity responsible for supplying customers file with the regulator its evaluation of future resource requirements would be appropriate" … "a public IRP process would provide a transparent framework for the evaluation of these [options].*"[29]

In the absence of a comprehensive integrated resource planning process that involves relevant stakeholders and that is conducted in a transparent, public manner, there is a greater risk that more efficient approaches to managing electricity supply and demand are missed or overlooked, and that higher cost options will instead be selected.

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[26] See Ontario 2013 Long-Term Energy Plan, *Achieving Balance*, at https://www.ontario.ca/document/2013-long-term-energy-plan
[27] See http://www.nr.gov.nl.ca/nr/energy/plan/pdf/doc_1664.pdf
[28] Report of the Joint Review Panel on Lower Churchill Hydroelectric Generation Project, August 2011.
[29] Power Advisory and Hatch, 2015. *Newfoundland and Labrador Electricity System Review*, pages 155 and 245.

6.2 Evaluation

The significant complexity and uncertainties around megaproject economic, environmental, social and technical impacts makes rigorous upfront evaluation important in mitigating the probability of approving projects that in retrospect would not have been selected.

Reliable evaluation of electricity infrastructure project proposals may be developed through comprehensive reviews conducted by expert, independent regulatory agencies that follow established due process, as outlined in section 3. By obtaining as much information and evidence as possible from stakeholders, and subjecting it to careful examination by knowledgeable experts, regulators can determine whether a project is likely to achieve specified criteria such as being the lowest-cost alternative or efficiently meeting customer needs.

An example of an effective evaluation process is the 2013 review of the Maritime Link conducted by the Nova Scotia Utility and Review Board (UARB), an independent, expert regulatory agency. In 2010, Nalcor and Emera agreed to jointly develop the Maritime Link, a 500MW transmission line linking Newfoundland with Nova Scotia, enabling power generated by Muskrat Falls to be delivered to Nova Scotia and New England power markets. Under the terms of the agreement, Emera's subsidiary, NSPML, would pay 20% of the estimated cost of the Muskrat Falls project and Maritime Link in exchange for 20% of the estimated energy and capacity from Muskrat Falls for a 35-year period as well as approximately 240 GWh of supplemental energy for the first five years.[30] NPSML's share of the cost was predicted to be $1.6 billion, based on Nalcor's DG3 cost estimates. [31] NPSML would not be liable for any cost overruns in the Muskrat Falls project after the DG3 estimates were finalized, thereby protecting Nova Scotia ratepayers.

The UARB was required by the government of Nova Scotia in 2012 to undertake a comprehensive evaluation of the Maritime Link project proposal and was given the authority to approve the project if it was "*the lowest long-term cost alternative for electricity for ratepayers in the Province*" and if it was consistent with the province's environmental objectives for the electricity sector.[32] On January 28, 2013, after Nalcor had determined DG3 cost estimates, NSPML filed an application for approval of the Maritime Link Project with the UARB. Under the Maritime Link Act and regulations, the UARB had wide-ranging powers to review the proponent's application, to obtain information, to conduct examinations, to order any terms and conditions it considered necessary, and to approve the cost.

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[30] For an overview of the arrangement, see Harrison, R. 2013. Nova Scotia Maritime Link Decision. *Energy Regulation Quarterly*, Vol. 1, Fall 2013.

[31] See Term Sheet between Nalcor Energy and Emera, November 18, 2010; and Nova Scotia Utility and Review Board Decision in the Matter of the Maritime Link Act and in the Matter of an Application by NSP Maritime Link Incorporated for Approval of the Maritime Link Project. July 22, 2013.

[32] When the Maritime Link project was publicly announced on November 18, 2010, the Nova Scotia government stated that it would be subject to public review and approval by the UARB. See https://novascotia.ca/news/smr/2010-11-18-Power-Deal/ Subsequent legislation and regulation explicitly authorized the UARB to conduct the review and to determine whether approval was warranted. See the Maritime Link Act, S.N.S. 2012 at https://nslegislature.ca/sites/default/files/legc/statutes/maritime%20link.pdf and Maritime Link Cost Recovery Process Regulations (N.S. Reg. 189/2012) at https://novascotia.ca/just/regulations/regs/mlcostrecovery.htm

Public hearings were conducted over nine days during May and June 2013, involving UARB staff and fourteen intervenors. The Board, proponent and intervenors hired seven sets of expert consultants to provide evidence and advice, and to evaluate the cost and feasibility of alternative options such as wind power, other imports and hybrids, based on assumptions about load forecasts, capital costs, fuel prices, and the impact of conservation and demand-side management programs. Different parties naturally had different positions on various matters, requiring the Board to determine which evidence was more credible and useful. For instance, the Board found that "*the evidence of NSPML and Synapse to be most useful in focussing on the issue of the alternatives analysis. Their evidence provided useful data on completed alternative scenarios, which were tested across a range of sensitivities. Accordingly, the Board assigns more weight to the evidence of NSPML and Synapse…Morrison Park provided a balanced high level review of the alternatives, which greatly assisted the Board by providing an important context to the consideration of the relevant issues*".[33]

A central issue that emerged during the Board hearings was the availability to NSPML of market-priced energy from Muskrat Falls, which was identified as a significant risk by half of the intervenors since there was no guarantee of either quantity or price in the original agreement. After considering the evidence and views from all parties, the UARB concluded that "*the availability of Market-priced energy is crucial to the viability of the ML Project proposal as against the other alternatives…the Board finds that without some enforceable covenant about the availability of the Market-priced Energy, the ML Project does not represent the lowest long-term cost alternative for electricity*".[34] The UARB subsequently imposed a condition that NSPML obtain from Nalcor the right to access market-priced energy, which led to a subsequent application and review of the new access agreement in October and November 2013. Under the agreement negotiated with NSPML, Nalcor committed to provide an average of at least 1.2 TWh of non-firm market-priced energy per year over the term of the agreement, which was expected to be the 24-year period from 2017 to 2041. The Board issued its decision approving the energy access agreement on November 29, 2013, thereby giving the go-ahead for the Maritime Link.[35]

The regulatory review process – focused around open, transparent, evidence-based hearings – thus proved effective in evaluating the merits and risks of the proponent's application and in identifying a regulatory solution that would protect rate-payer interests.

Muskrat Falls was also the subject of review by its provincial regulator (the PUB) but the terms of reference, unlike in the case for Nova Scotia's Utility and Review Board evaluation of the Maritime Link, were highly restricted. On June 17, 2011, the government requested the PUB to undertake a review and to evaluate the cost of two options defined in the terms of reference – an "Island Interconnected" option consisting of the Muskrat Falls generation facility and Labrador-Island transmission link, and an "Isolated Island" option consisting of the Holyrood generation station and some small hydroelectric, wind resource, and combined cycle combustion turbine

[33] Nova Scotia Utility and Review Board. July 22, 2013. Decision in the Matter of the Maritime Link Act and in the Matter of an Application by NSP Maritime Link Incorporated for Approval of the Maritime Link Project. Page 37.
[34] *Ibid*, page 72.
[35] In addition to the economic analysis, the UARB also determined that the Maritime Link was consistent with the province achieving its target of 40% of electricity supply from renewable fuel sources by 2020.

additions. The terms explicitly excluded the Maritime Link and potential export sales from the scope of analysis. The terms also required the PUB to determine which of the two options was the lowest cost over a long timeframe – 56 years from 2011 to 2067.

The PUB engaged an expert consultant, Manitoba Hydro, to assist with the review and it conducted public hearings with two weeks of presentations by Nalcor, the government-appointed consumer advocate, and other parties.

The PUB was limited in its ability to fully evaluate whether Muskrat Falls was the lowest cost option amongst feasible alternatives for providing reliable long-term electricity for several reasons.

First, the PUB was prevented from investigating other potential supply options such as wind, natural gas, and the availability of Upper Churchill power after 2041. Consideration of imports through the Maritime link or a similar transmission line was excluded as another potential option.[36] The PUB also had to accept the future inclusion of costly pollution abatement equipment in the Holyrood option even though hearing participants questioned the need for these upgrades given the usage of low-sulfur fuel.[37] The PUB thus did not have the latitude to evaluate other options that could have proved to be lower cost than the Interconnected option.

The second limitation was that Nalcor's capital cost estimates for the Muskrat Falls option were imprecise and were based on Decision Gate 2 analysis, for which the degree of project definition was in the 5% - 10% range. Capital costs could range from 30% lower to 50% higher than the forecast at this conceptual stage of project definition. Sensitivity analyses suggested that capital costs had a pivotal impact on which option would be lower cost: if the Interconnected Option's capital costs increased by 50%, or by 10% coupled with a reduction in Island load of 880 GWh (about 12% of 2010 total system load), the Isolated Island option would achieve a similar expected cost.[38] If the PUB had had the benefit of DG3 cost estimates, which were available after the PUB concluded its review, the PUB may have been able to assess which of the Isolated Island and Interconnected options would be the lower cost.

The third constraint was the short period of time (six months) initially allocated to the PUB's review and the late delivery of Nalcor's submission in November 2011 (three months later than scheduled), which limited PUB analysis capacity.[39] The PUB had to cancel a technical conference with stakeholders and shorten the hearing schedule. Manitoba Hydro International's

[36] Navigant stated in its 2011 report (p. 63) that Nalcor had considered the option of importing electricity via a transmission link but deemed it too costly. The Navigant report did not conduct its own assessment of this option. See *Independent Supply Decision Review* report prepared for Nalcor by Navigant Consulting Ltd. September 14, 2011.

[37] Newfoundland and Labrador Board of Commissioners of Public Utilities. *Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067*. Report to Government. March 30, 2012. Page 25.

[38] *Ibid*, page iii.

[39] By comparison, an independent review by Manitoba's Public Utility Board of the Keeyask generation project and related generation and transmission projects lasted 13 months (see section 7.3). In Nova Scotia, the UARB had six months to complete its review of the Maritime Link project after Emera's subsidiary, NSPML, submitted its complete application.

report, which was commissioned by the PUB, was also delayed until late January 2012 as a consequence of the delay in receiving complete information from Nalcor. The government granted an extension for the PUB to complete its review until 30 March, 2012, but denied a request to extend the deadline until June 30th.

One consequence of the time constraint was that it limited the PUB's ability to fully evaluate demand-side options such as conservation and energy-efficiency programs and new pricing structures that could reduce load forecasts – thereby delaying the need for costly supply-side investments. The PUB expressed concerns particularly about Nalcor's load forecast, a key input in option evaluation.[40] The PUB found that end-use modelling – which Nalcor did not use in its 2010 Planning Load Forecast – would allow a better assessment of the impact of potential conservation and demand-management (CDM) programs on load forecasts, which have been at the forefront of other province's energy strategies.[41] Navigant's 2011 report for Nalcor identified CDM as an area where NL Hydro could implement improvements.[42] Independent experts also argued that demand-side management through new pricing structures could reduce consumption and obviate the need for significant new generation capacity investment.[43]

Hence, unlike Nova Scotia's UARB unrestricted evaluation of the Maritime Link, the PUB was not able to undertake a wide-ranging, comprehensive analysis of whether Muskrat Falls was in fact the least cost option for providing long-term reliable power to the Island. In March 2012, the PUB declined to make a recommendation to the government on which option was the lower cost, concluding that "*the information provided by Nalcor in the review is not detailed, complete or current enough to determine whether the Interconnected Option represents the least-cost option*".

The PUB was not the only independent body that did not endorse the economic case for Muskrat Falls. The federal-provincial Joint Panel Review (JRP), established in January 2009 primarily to assess the environmental impact of the Muskrat Falls project, also considered the need for and alternatives to the project as part of its mandate. Unlike the PUB, the JRP had the latitude to consider all possible options. After more than 32 months of deliberations and 30 days of public hearings with 230 presentations in nine locations, it issued its 389-page report and recommendations in August 2011. Based on the evidence submitted by Nalcor and intervenors, the Panel concluded that:

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[40] Newfoundland and Labrador Board of Commissioners of Public Utilities. *Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067*. Report to Government. March 30, 2012. Page 66.

[41] *Ibid*, page 40. Power Advisory also noted that end-use modeling was best-practice and would be beneficial in estimating the impact on load forecasts of the adoption of new technologies such as mini split heat pumps (Power Advisory, 2015, page 231).

[42] Navigant noted in its 2011 report (page 37) that NL Hydro and Newfoundland Power were targeting conservation savings of 79GWh savings in 2013 (based on their 2008 Five-Year Conservation Plan). Actual conservation savings were estimated at 46GWh (about 0.5% of annual energy demand in 2013), as reported in the 2016-2020 Five-Year Conservation Plan (page 6). Power Advisory subsequently noted in its 2015 report that Hydro and Newfoundland Power's conservation targets were quite "modest" compared to other provinces such as Ontario and Nova Scotia where conservation accounted for about 5% of customers' energy requirements (page 226).

[43] Feehan, J. 2012. *Newfoundland's Electricity Options: Making the Right Choices Requires an Efficient Pricing Regime*. CD Howe Institute.

"*the Panel did not accept that developing the hydroelectric potential of the lower Churchill River was a "need", and that therefore the Project should be compared to reasonable alternatives that addressed the future demand for electricity… the Panel concluded that Nalcor had not demonstrated the justification of the project as a whole in energy and economic terms…*"

"…the Panel concluded that Nalcor's analysis, showing that Muskrat Falls to be the best and least-cost way to meet domestic demand requirements, was inadequate and recommended a new, independent analysis based on economic, energy and environmental considerations. The analysis would address domestic demand projections, conservation and demand management, alternate on-island energy sources, the role of power from Churchill Falls, Nalcor's cost estimates and assumptions with respect to its no-Project thermal option, the possible use of offshore gas as a fuel for the Holyrood thermal generation facility, cash flow projections for Muskrat Falls, and the implications for the province's ratepayers and regulatory systems".

The Joint Review Panel relied on Nalcor's DG2 cost estimates in its analysis and, like the PUB, did not find them to be sufficient to justify the case for Muskrat Falls.

It not possible to predict with certainty what the PUB would have concluded had it been allowed to explore all possible options without restriction and if it had had more accurate and reliable cost information (e.g. DG3 cost estimates). However, with the latitude and time to examine all other potential supply- and demand-side options – rather than just the two options defined by the government in the 2011/12 review – the probability that the Interconnected option would ultimately prove to be least cost would likely have fallen. For instance, uncertainty about the feasibility and potential impact of more aggressive conservation and demand-management programs, and of novel pricing structures, could have been addressed by focussed consulting studies.

In addition, with the benefit of more accurate cost estimates and the time to carefully assess a range of options, the PUB would have been able to make an explicit, reasoned recommendation to the government about which option to pursue. *If*, after an extensive review, the PUB had determined that Muskrat Falls was not the least-cost option, this may have exerted pressure on the government not to subsequently approve the project since otherwise the government would have needed to carefully justify why it was reasonable to overturn an independent, expert regulator's recommendation.

6.3 Approval

Government ministers or cabinets may make final sanction decisions on megaprojects, weighing up economic, social and environmental considerations, and drawing on recommendations and evidence developed by expert agencies. In Ontario, the Minister of Energy endorsed the $12.8 billion Darlington nuclear power plant refurbishment project after a series of long-term system planning reviews by the planning agency and the development of high-confidence cost estimates, which affirmed both the need for the project and its low unit cost relative to alternatives (see Section 7.1). In the pipeline sector, the federal government has the authority to approve or deny major pipeline proposals following review and recommendation by the National Energy Board

(NEB).[44] In Nova Scotia, on the other hand, the regulator had the final approval decision for the Maritime Link, but was required by legislation to approve it if the regulator concluded that the project satisfied two specific criteria. If the government had delegated final sanction authority to the PUB – as the Nova Scotia government did for UARB approval of the Maritime Link – it is less likely that Muskrat Falls would have been approved in March 2012, when the PUB issued its report.

Systematic data on the respective roles of regulators and governments for megaprojects in Canada is scarce, but one study of major pipeline approvals has found that the federal government almost always followed the recommendation of the NEB from 2007-2017.[45] In only one out of 26 cases studied did the government differ, when it denied approval following a recommendation for approval by the NEB. In no case has the government approved a project that was previously not recommended for approval by the NEB.[46]

In its sanction announcement on December 17, 2012, the government cited support for its decision from several expert energy consultants who had written reports that it or Nalcor had commissioned: Navigant's September 2011 report for Nalcor, which compared the Isolated Island and Interconnected options using Nalcor's DG2 cost estimates, reporting a $2.2bn difference in cumulative present worth (CPW) in favour of the latter; Manitoba Hydro International's (MHI) October 2012 report for the government, which reported the Interconnected option would be $2.4bn lower in CPW than the Isolated Island option based on DG3 cost estimates; and Ziff Energy's October 2012 report, which estimated that natural gas would not be an economically viable method for producing electricity at Holyrood power station.[47] MHI had also completed a report for the PUB in January 2012 that evaluated the two options based on DG2 cost estimates, reporting a $2.2bn lower CPW for the Interconnected option relative to the Isolated Island option.

Consultant reports can provide a valuable perspective on policy issues by drawing on consultants' knowledge of the sector and by applying analytical expertise. However, consulting report conclusions depend on the assumptions and forecasts, data used and methodologies selected, all of which require an element of subjective judgement. Depending on the specific decisions made, findings and conclusions may or may not change. Further, given the financial

[44] For a discussion of the federal approvals process for major pipelines, see Holburn, G. and Loudermilk, M. 2017. Risks and Costs of Regulatory Permit Applications in Canada's Pipeline Sector. Available at https://www.ivey.uwo.ca/cmsmedia/3776986/risks-and-costs-of-regulatory-permit-applications-in-canadas-pipeline-sector-march-2017.pdf

[45] Ibid, page 13.

[46] The federal government gained the power to approve pipeline projects that had previously been denied a certificate by the NEB in amendments to the NEB Act made in July 2012. Seven major pipeline projects have filed for NEB approval since July 2012.

[47] See http://www.releases.gov.nl.ca/releases/2012/exec/1217n11.htm. Navigant Consulting, September 14, 2011. Prepared for Nalcor. *Independent Supply Decision Review*. Manitoba Hydro International, October 26, 2012. Report prepared for Government of NL. *Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options*. Ziff Energy, October 30, 2012. Report prepared for Government of NL. *Natural Gas as an Island Power Generation Option*. The Oversight Committee also referenced the Navigant 2011 report and the two MHI 2012 reports as the key pre-sanction reports in its July 2014 report, available at https://www.gov.nl.ca/mfoversight/pdf/mfoversight.pdf

relationship between consultants and their clients, consultants may not necessarily act independently of their clients' interests, raising the prospect of possible bias in report findings.

As such, due to potential questions about robustness and possible bias, the value and quality of a consulting report is not always immediately apparent. The regulatory hearing process, however, can assist in determining the value of consulting reports: regulatory staff and intervenors are able to publicly probe, test and cross-examine to ascertain the validity of assumptions, data and methodologies, and to uncover the reliability of findings. At the conclusion of the hearing process, regulatory commissioners are obliged to weigh up and evaluate the merits of all the evidence presented – they cannot cherry-pick – and to explain their decisions in a rational manner with reference to the evidence. The process of external scrutiny reveals which evidence and reports are higher quality – and which will have a greater impact on regulatory decisions – and which are of lower quality. Consulting reports can thus be viewed as an important *input* into the process for developing reliable policy decisions or recommendations rather than as a substitute for the regulatory process.

Two of the reports (MHI, October 2012 and Ziff Energy Group, October 2012) the NL government cited at sanction were released after the PUB and Joint Review Panel had concluded their independent reviews, and thus did not have the benefit of regulatory evaluation of their findings. The other reports (Navigant, 2011 and MHI, January 2012) had already been included in Nalcor's submission for the PUB 2011/12 review and were evaluated as part of the PUB's finding that it could not identify which of the two options was lower cost. Hence, while the government stated that Muskrat Falls was the least-cost option in December 2012 based on recent consulting reports, this finding had not been verified by an independent, expert regulatory review. By relying on these consulting reports, the government thus took a risk that Muskrat Falls was in the fact the lowest-cost option.

6.4 Execution and Oversight

Once a project is sanctioned, project owners bear primary responsibility for implementation according to budget and schedule and to manage its construction in an efficient manner. Recognizing the risk of future cost over-runs, governments and regulators may devise oversight governance mechanisms and attach conditions that incentivize proponents to execute projects prudently. In Ontario, the government designed "off-ramps" for the Darlington nuclear plant refurbishment that enabled the government to cancel the project at specified milestones if cost targets were breached. [48] The government also appointed an advisor to provide independent oversight of the Darlington project, reporting on a quarterly basis directly to the Ministry of Energy, and who sits on the Darlington Refurbishment Committee – an independent committee consisting primarily of external infrastructure experts that reports to Ontario Power Generation's (OPG) board of directors. The Darlington Refurbishment Committee is authorized to retain qualified expert advisors, independent of OPG management, to monitor and report to the Committee on project progress. As a Committee member, the independent advisor has full access to OPG management and Darlington-related information, and reports on the project on a

[48] Financial Accountability Office of Ontario. 2017. *An Assessment of the Financial Risks of the Nuclear Refurbishment Plan.* Available at https://www.fao-on.org/en/Blog/Publications/FAO-NR-Report-Nov-2017#B:%20Details%20of%20Pricing

confidential basis to the Ministry of Energy.[49] As such, the government receives regular, independent, expert information on the project's status, performance and risks – enabling the government to evaluate prudency of expenditures as they are incurred, to take corrective actions with management where needed, and ultimately to reassess and reverse its original sanction decision if deemed necessary.

The NL government also established an independent oversight mechanism, the Muskrat Falls Project Oversight Committee, which operates very differently from Ontario's oversight approach. The Oversight Committee, which first met in April 2014, more than a year after the project was sanctioned and construction had commenced, has a mandate to provide reliable and transparent oversight such that: the project cost and schedule is well managed; the project meets cost and schedule objectives; and risks are reasonably anticipated and managed.[50] The committee originally consisted of nine senior government bureaucrats from the departments of Finance, Natural Resources and Justice, who meet monthly, frequently receiving updates from Nalcor executives.[51] The committee has met four times with Ernst and Young, who provided three reports on the project's cost and schedule status, and once with the Independent Engineer in May 2018.[52] It reports quarterly to the government.

Effective independent oversight during a project's execution stage becomes more critical when there is no final regulatory review of expenditures, which would strengthen incentives on management to maintain strict cost controls. The Muskrat Falls project was exempted by the government from final review by the PUB (see section 6.5), placing more responsibility on the Oversight Committee to monitor and evaluate costs while the project was being constructed.

The effectiveness of the Oversight Committee was questioned, however, by Ernst and Young in its 2017 report, which noted that it did not receive frequent, independent, expert information on the project, and that it operated outside the purview of the Board. The only independent assurance reports were the three provided by Ernst and Young in 2015, 2016 and 2017. The 2017 Ernst and Young report compared the Oversight Committee arrangement to best practice models which would include (i) a dedicated capital projects committee of the Board, comprised of independent directors with experience and knowledge of similar infrastructure projects, and (ii) an independent assurance function that provided regular verification by a qualified independent third party reporting from the project team. Such an arrangement – which was the model adopted by the Ontario government for oversight of the Darlington refurbishment – would increase confidence in the accuracy of reporting provided to the project owner and to the public on project progress. While Ernst and Young concluded that it was too late to implement significant changes to the independent oversight arrangements for the Muskrat Falls project, it recommended that

[49] For details of oversight of the Darlington Refurbishment Project, see Board Staff Interrogatory #222, Exhibit L Tab 10.4 Schedule 1 Staff-222, filed with the Ontario Energy Board, docket number EB-2016-0152. Available at https://www.opg.com/about/regulatory-affairs/Documents/2017-2021/OPG_IRR_Issue_10.0_20161026.pdf

[50] Details of the Oversight Committee's terms of reference and membership are included in the July 2014 Committee Report at https://www.gov.nl.ca/mfoversight/pdf/mfoversight.pdf

[51] As of June 2018, the Oversight Committee had received in-person presentations at monthly Committee meetings from the following parties: Nalcor (30), Ernst and Young (4), Independent Engineer (1), Deloitte (1), Natural Resources Canada (1) and Cassels Brock (1). The Committee held 54 meetings from April 2014 to June 2018.

[52] Oversight Committee meeting minutes and reports are publicly available at https://www.gov.nl.ca/mfoversight/index.html

"*an enhanced independent assurance function performed by a qualified independent third party on a regular basis (e.g. monthly/quarterly) would better enable the OC to fulfill its mandate and meet the expectations of stakeholders*."[53]

6.5 Cost Review and Recovery

In addition to upfront evaluation of the merits of proposed infrastructure projects, regulators play a central role in final review and approval of project expenditures. Proponents are able to recover incurred capital and operating costs once a project is operational by applying to regulators for approval to increase rates charged to consumers. Applications are assessed in the context of open, transparent, evidence-based reviews where the regulator's objective is to determine whether costs were prudently incurred. Costs that are deemed imprudent may not be recovered by the project owner. The prospect of regulatory scrutiny of project costs upon project completion – and the risk of potential disallowances – can exert a powerful discipline on project management to control costs during the construction and operating stages.[54]

Nova Scotia followed best practice in regulatory oversight of the Maritime Link by requiring the proponent, NSPML, to apply for cost recovery from the URB after project completion. Sections 4 and 8 of the Maritime Link regulations state:

"*To obtain a rate, toll, charge of other compensation…an applicant must first obtain an approval of the Maritime Link Project*" … "*Before receiving energy under the Nalcor Transactions, an applicant must set an assessment against Nova Scotia Power Incorporated for the recovery of all the approved Project costs, and must apply to the Review Board for an approval of the assessment under section 64 of the Public Utilities Act. Nova Scotia Power Incorporated is entitled to recover through its rates any assessment approved by the Review Board in respect of the Maritime Link Project*" [55]

In its approval of the Maritime Link in 2013, the Nova Scotia Utilities and Review Board emphasized in its written findings its future role in evaluating the prudency of expenditures, directing the proponent to carefully manage project costs:

"*[The Board] agrees that cost overruns are a serious concern for ratepayers, especially beyond DG3" … "if costs do increase beyond $1.7 billion, NSPML indicated it will apply to the Board for the approval of these additional costs in a timely manner." … "The Board expects NSPML to have strict controls during the design and construction phase of the ML Project to keep its costs within the approved envelope. While the Board will consider any additional request for cost*

[53] Ernst and Young report, Muskrat Falls Project: Assessment of Implementation of EY Interim Report Recommendations. August 31, 2017. Available at https://www.gov.nl.ca/mfoversight/pdf/EY_Muskrat_Falls_Project-Assessment_implementation_EY_Interim_Report_recommendations-31August%202017.pdf

[54] For one of the seminal academic papers on the efficiency impact of cost-of-service regulation, see Gilbert, R. and Newbery, D. 1994. The Dynamic Efficiency of Regulatory Constitutions. *The RAND Journal of Economics*, 25(4): 538-554.

[55] Maritime Link Cost Recovery Process Regulations. Order-in-Council 2012-326 (October 2, 2012), N.S. Reg. 189/2012. Available at https://novascotia.ca/just/regulations/regs/mlcostrecovery.htm

overrun approval, ***the prudency test will be applied in rendering its Decision.***" [emphasis added][56]

Ontario also followed best practice in the $12.8 billion Darlington nuclear power plant refurbishment project by requiring the proponent, Ontario Power Generation (OPG), to apply for cost recovery through rates from the Ontario Energy Board, the independent provincial regulator. Ontario Regulation 53/05 states that OPG is entitled to recover project costs "***if the Board is satisfied that the costs were prudently incurred*** *and that the financial commitments were prudently made*". [emphasis added][57]

In contrast to Nova Scotia and Ontario, in NL the government afforded no role to the PUB to evaluate the prudency of Muskrat Falls expenditures upon completion of the project. In November 2013, the government issued Regulation 120/13 that exempted NL Hydro's costs of power purchased from the Muskrat Falls Corporation, and other costs associated with the Muskrat Falls project, from PUB jurisdiction under the *Electrical Power Control Act, 1994*. Furthermore, under the terms of the federal loan guarantee, NL Hydro is required to recover the costs of Muskrat Falls energy in its regulated rates and revenues.[58] Accordingly, all Muskrat Falls costs will be recovered in consumer rates without first passing an independent, expert regulator test of prudency.[59] One consequence of the removal of this regulatory safeguard is a dulled incentive for Nalcor to manage construction costs as tightly as possible, creating the risk that costs will be higher than under a regime with final regulatory review.

7. Lessons from Major Electricity Infrastructure Projects in Other Provinces

This section describes regulatory and political oversight of several major electricity infrastructure projects that have been completed or commenced in different provinces over the last ten years.[60] The projects are among the largest in Canada's electricity sector (all costing more than $1 billion) and they represent some of the diversity of provincial approaches to evaluating, monitoring and approving new capital projects with significant economic, environmental and social impacts. Conclusions are drawn about the effect of provincial regulatory arrangements on the degree to which project costs and risks were successfully managed. The case study projects include:

- Darlington Nuclear Generating Station Refurbishment, Ontario ($12.8 billion estimate)
- Western Alberta Transmission Line, Alberta ($1.7 billion)

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[56] Nova Scotia Utilities and Review Board. July 22, 2013. *Decision in the Matter of the Maritime Link Act and in the Matter of an Application by NSP Maritime Link Incorporated for Approval of the Maritime Link Project*. Page 111.
[57] Ontario Regulation 53/05, s. 6(2)4. Available at https://www.ontario.ca/laws/regulation/050053
[58] See Schedule A of Federal Loan Guarantee by Her Majesty the Queen in Right of Canada for the Debt Financing of the Lower Churchill River Projects. Available at https://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/05/Terms-and-Conditions-of-the-Federal-Loan-Guarantee.pdf
[59] Newfoundland and Labrador Regulation 120/13, *Muskrat Falls Project Exemption Order*. Available at http://www.pub.nf.ca/applications/NLH2013GRA-Amended/files/information/Information46-2015-11-18.pdf
[60] This section benefitted from research conducted by Adam Fremeth in developing the three case studies.

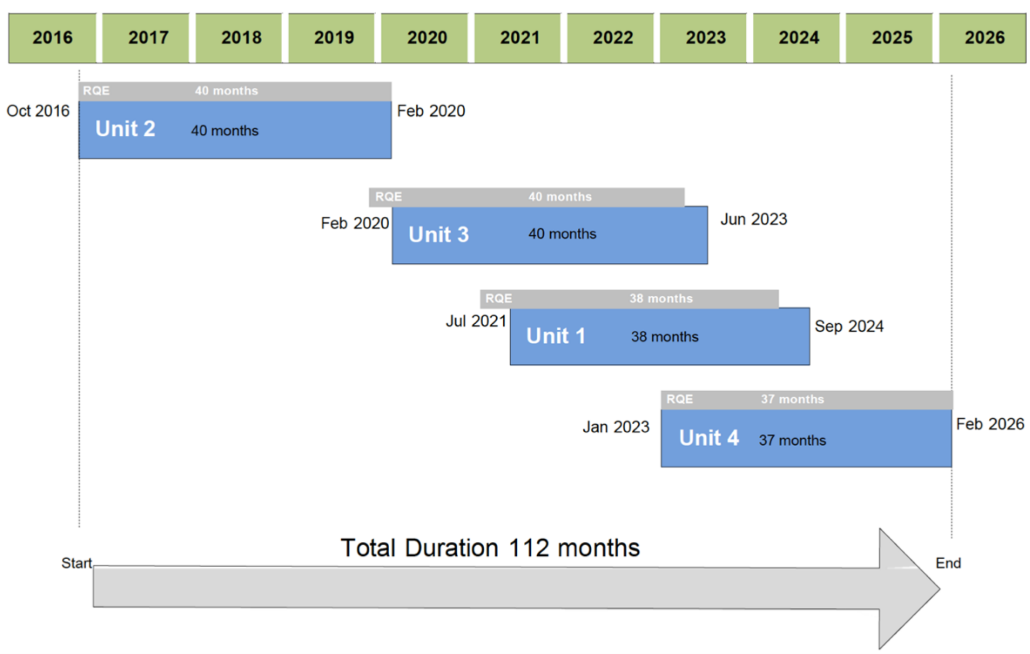
- Keeyask Generation Station, Manitoba ($10.5 billion estimate)

7.1 Darlington Nuclear Generating Station Refurbishment

7.1.1 Overview

The Darlington Refurbishment Project (DRP) represents one of the largest investments in Ontario's electricity infrastructure with an estimated cost of $12.8 billion. The Darlington nuclear generation station, owned by Ontario Power Generation Inc., a corporation established under the *Business Corporations Act* (Ontario) and with its sole shareholder being the Province of Ontario, has a design capacity of approximately 3,500 MW and supplies approximately 20% of Ontario's electricity needs.[61] The four-unit station has approached the mid-point of its initial operating life, and refurbishment will add approximately another 30 years. Project evaluation and planning began in 2007, and the first unit was disconnected from the grid to begin refurbishment in 2016. It is expected that the project to refurbish all four units will be completed by 2026 (see Figure 2).

Figure 2: Darlington Refurbishment Project Timeline



Source: Ontario Energy Board. Decision and Order EB-2016-0152. Ontario Power Generation Application for payment amounts for the period from January 1, 2017 to December 31, 2021.

7.1.2 Project Need Evaluation

The origin of the DRP dates back to the Ontario Power Authority's (OPA) (now the "Independent Electricity System Operator" or "IESO") 2005 Supply Mix Advice Report. The

[61] The Conference Board of Canada. 2015. Refurbishment of the Darlington Nuclear Generating Station.

OPA was established in 2004 through legislation as an independent agency with a mandate to undertake electricity system planning for generation, transmission, conservation, and demand management, and to develop integrated power system plans for the province. [62] In its 2005 report, the OPA outlined a proposal for meeting Ontario's growing electricity needs by 2025, noting that the province would need to add 15,000 MW of new generation capacity to meet future demand. The report recommended that 63%-83% (9,400 to 12,400 MW) of new generation capacity should be nuclear, at an estimated cost of $30-40 billion. The report highlighted nuclear power's ability to provide low cost base-load supply with minimal air emissions.[63] Furthermore, the report recognized how "nuclear generation would provide an excellent alternative to the volatility of price uncertainty of supply that are major drawbacks to gas-fired generation for base load."[64]

Based upon the OPA's advice, on June 13, 2006 Minister of Energy Dwight Duncan issued a directive to the OPA to prepare a 20-year Integrated Power System Plan (IPSP) that would be submitted for approval to the Ontario Energy Board. The IPSP directive contained objectives for Ontario's electricity system that included (1) a target for reducing peak demand through conservation measures by 6,300 MW by 2025, (2) a target for renewable energy capacity of 15,700 MW by 2025, (3) maintaining the use of natural gas capacity, (4) eliminating coal-powered generation, (5) strengthening the transmission system, and (6) developing a "plan for nuclear capacity to meet base-load electricity requirements but limit the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW."[65]

In August 2007, the OPA submitted the IPSP to the OEB, which was required to ensure that it complied with the Minister of Energy's Directives, was economically prudent, and was cost effective. [66] [67] The OEB held public hearings involving 30 intervenors during one week in January of 2008 to identify the key issues for consideration, leading to a set of 34 issues being established by the OEB. Hearings for Phase 2 of the review began in September 2008 and were conducted over nine days, involving 44 intervenors.[68] The review process, however, was

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[62] *Electricity Restructuring Act,* SO *2004,* c 23, s. 25.2.
[63] Ontario Power Authority, 2005. *Supply Mix Advice Report*, page 24.
[64] *Ibid*, page 26.
[65] Dwight Duncan, 'Integrated Power System Plan' [direction to Jan Carr], 13 June 2006.
[66] OEB application EB-2007-0707. The IPSP and associated documentation are available at https://cms.powerauthority.on.ca/integrated-power-system-plan
[67] Electricity Act, SO 1988, c. 15, s., 25.30.
[68] Intervenors in Phase 2 included Alliston & District Environment Watch, Association of Major Power Consumers of Ontario, Association of Power Producers of Ontario, Building and Managers Association, Canadian Chemical Producers Association, Canadian Manufacturers & Exporters, Canadian Solar Industries Association, Canadian Wind Energy Association, City of Thunder Bay, City of Toronto, Consumers Council of Canada, Council of Canadians, Electricity Distributors Association, Energy Probe Research Foundation, First Nations Energy Alliance, Green Energy Coalition, Industrial Gas Users Association, Lake Huron Region Chiefs, Lake Ontario Waterkeeper, Métis Nation of Ontario, Municipality of Port Hope, Assembly of First Nations, New Tecumseth Environment Watch, Nipissing First Nation, Nishnawbe Aski Nation, Northwatch, Northwestern Ontario Municipal Association, Ontario Energy Association, Ontario Federation of Agriculture, Ontario Mining Association, Ontario Sustainable Energy Association, Ontario Waterpower Association, Pembina Institute, Pollution Probe Foundation, Power Workers' Union, Provincial Council of Women of Ontario, Saugeen Ojibway Nations, School Energy Coalition, Seine River First Nation, Serpent River First Nation, Society of Energy Professionals, Toronto Board of Trade, Township of Atikokan, and the Vulnerable Energy Consumers Coalition.

subsequently suspended after a new Minister of Energy directed the OPA to revise the IPSP by accelerating the timeframe for conservation and increasing renewable energy capacity targets.[69] Subsequent power system plans – termed 'Long Term Energy Plans' (LTEPs) – built on the 2007 IPSP and were developed by the Ministry of Energy based on analysis and advice from the OPA, the Ontario Energy Board, and Independent System Operator, and restated the central role that nuclear power would play in the province.[70] The first LTEP, released in 2010, committed to "nuclear power remaining at approximately 50 per cent of the province's electricity supply" and the refurbishment of Darlington along with construction of two new nuclear units.[71] The second LTEP, issued in 2013, stated that nuclear power would "continue to be the backbone of Ontario's supply", but that due to a strong supply situation refurbishment would continue without the need for new nuclear generating units.[72] The plan outlined how refurbishment would be subject to the "strictest possible oversight" and would follow guiding principles that included "minimizing commercial risk to the government and the ratepayer, and ensuring that operators and contractors are accountable for refurbishment costs and schedules".[73]

7.1.3 Project Initiation and Implementation

Following the OPA's supply mix advice in 2006, the Minister of Energy issued a directive as controlling shareholder to Ontario Power Generation in June 2006 to "begin feasibility studies on refurbishing its existing nuclear units".[74] Minister Duncan stated at the time that the future of nuclear power in the province would be driven by cost effectiveness and agreements that would limit the risk to ratepayers of cost overruns.[75]

Accordingly, OPG began the Initiation Phase of the project in 2007 to investigate the technical and economic feasibility of refurbishing the Darlington plant. This involved technical assessments of the major systems, a component condition assessment, initial outage planning to determine a reference schedule, and the development of project governance. In November 2009, OPG's Board of Directors approved commencement of the Definition Phase of the DRP. This involved an extensive effort to define the scope of the project, identification of best practices from other nuclear and megaprojects, detailed engineering designs, and construction of a full-scale mock reactor to test tools and train staff. The total expenditures of these activities up to the end of 2015 amounted to $2.2 billion.

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[69] George Smitherman, 'Amendment to Supply Mix Directive Issued June 13, 2006' [directive to Colin Andersen], 17 September 2008. The OEB was not required to approve subsequent Long-Term Energy Plans.
[70] The IESO provides detailed data on electricity system costs, generation supply availability, demand forecast scenarios, bill forecasts, etc. in its 'Ontario Planning Outlook' (OPO) documentation, which form the basis for Long-Term Energy Plans. OPO analyses estimate that nuclear-generated electricity is among the lowest cost in the province.
[71] Ontario Ministry of Energy. 2010. *Long Term Energy Plan*, page 10.
[72] Ontario Ministry of Energy. 2013. *Long Term Energy Plan*, page 3.
[73] *Ibid*, page 5.
[74] Dwight Duncan, 'Government's response to the Supply Mix Report [direction to James Hankinson], 16 June 2006.
[75] Stephen Andrews and Michael Shadbolt. 2006. "Ontario's Integrated Power System Plan". Available online: Borden Ladner Gervais < http://blg.com/en/News-And-Publications/documents/publication687_EN.pdf/>.

The Minister of Energy endorsed the project in January 2015 after it had been approved by OPG's board of directors and P90 cost estimates had been developed. Project execution commenced in October 2016 with disconnection of the first unit (Unit 2) for refurbishment. The cost of refurbishing the first unit is expected to be $5.0 billion and it is forecast to come back online in February 2020. The planned 40-month refurbishment involves four segments, including (1) defueling the reactor and isolating it from the station, (2) preparing the reactor for component removal and removing components, (3) installing reactor components, and (4) loading fuel, testing and restarting the reactor. Following the completion of Unit 2, the refurbishment of the next three generating units will follow sequentially over 112 months until final completion in February 2026. The project is expected to extend the life of the plant to 2055.

7.1.4 Regulatory Oversight and Cost Recovery

Although refurbishment of the Darlington nuclear plant was directed by the government, the Ontario Energy Board has had a central role in approving expenditures by OPG. The OEB's regulatory oversight of OPG is detailed in Section 78.1 of the OEB Act and Ontario Regulation 53/05. This regulation places specific requirements with respect to OPG's recovery of costs related to refurbishing nuclear facilities. Section 6(2)4 of the regulation states that "*The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred … to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to assessment costs and pre-engineering costs and commitments…..**if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made**"* (emphasis added).[76]

The government updated the regulation in January 2016 to clarify that "the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment".[77]

OPG has sought regulatory review and approval of expenditures related to the DRP as they have been incurred. In November 2008, the OEB approved a comprehensive rate case filed by OPG, including approval of $41.2 million in Operation, Maintenance, and Administration costs associated with the DRP (EB-2007-0905). The OEB also approved the creation of OPG's Capacity Refurbishment Variance Account (CRVA) which would accrue a balance approved by the OEB and which could be used should the DRP go over budget. The OEB will review the prudence of any cost overruns before approving disposition of the account's balance. The CRVA is symmetrical in that should the project come in under budget, the excess amount collected in the account will be returned to ratepayers, upon review and approval by the OEB.

Subsequently, the OEB also approved $2.2 billion of costs incurred in the Definition phase of the project. However, the OEB has not been willing to approve forward-looking expenditures outside of the test period. For instance, in a 2011 decision (EB-2010-0008) the OEB did not approve the inclusion of $431.5 million of Construction Work-in-Progress costs within OPG's

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[76] Ontario Regulation 53/05, s 6(2)4.
[77] Ontario Regulation 53/05, s 6(2)12.

rate base, despite a letter from the Minister's office lending support for this approach – which the OEB noted "may be persuasive, [but] it does not bind the authorities that will need to approve the project." Similarly, in a 2014 decision (EB-2013-0321) the OEB would not consider OPG's request for an assessment of the reasonableness of $1.68 billion in forward looking capital expenditures as well as its commercial and contracting strategies.[78] Both these decisions were consistent with the OEB's position that it would only consider costs related to infrastructure included in the agreed test period of analysis, as opposed to future costs outside the test period.

The most significant OEB review to date of DRP expenditures was completed in December 2017 (EB-2016-0152). This was the largest proceeding ever initiated at the OEB in terms of the dollar amount considered and the volume of supporting evidence provided. Nonetheless, the OEB noted that the analysis it applied was "no different than the fundamental considerations the OEB normally uses when considering capital projects." Oral hearings were held over 23 days and 14 intervenors participated in the case.[79] While the case dealt with many issues, such as hydroelectric operations and capital structure, the DRP accounted for a substantial share of the proceeding. After almost a decade of planning, including the Initiation Stage (2007-2009) and the Definition Stage (2009-2015), OPG had begun to implement the Execution Stage. The firm had received authorization for the $12.8 billion budget (see Table 1 for the cost breakdown) and 112-month refurbishment schedule) from its Board of Directors and the Minister of Energy, Bob Chiarelli, who announced that "proceeding with the refurbishment at Darlington will ensure that nuclear continues to be Ontario's single largest source of power".[80] The cost estimates were based on a P90 confidence level, which meant that, based upon statistically modeled forecasts of the risks involved, there would be a 90% chance that the actual project cost would not exceed the estimated amount.

Table 1: Darlington Refurbishment Cost Breakdown (P90 estimates as at November 2015)

Program Component	Cost ($ billion)
Major Work Bundles	5.54
Safety Improvement Opportunities	0.20
Facilities & Infrastructure Projects	0.64
OPG Functional Support	2.23
Early Release Funds	0.11
Contingency	1.71
Interest & Escalation	2.37

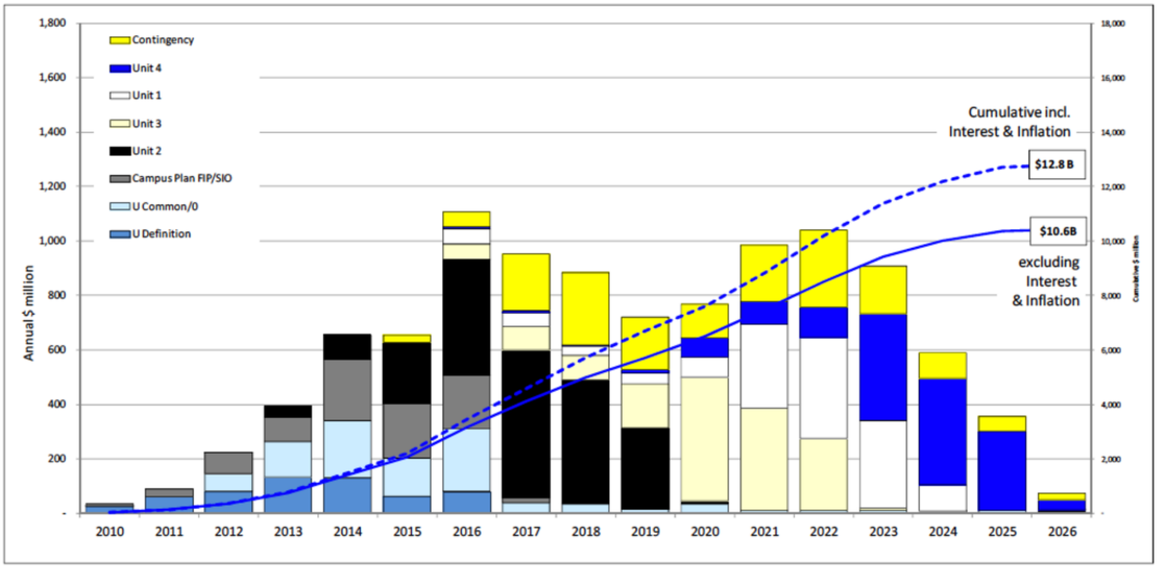
[78] This case involved the same nine intervenors as in EB-2007-0905 as well as Environmental Defense, Haudenosaunee Development Institute, Independent Electricity System Operator, Lake Ontario Waterkeeper, London Property Management Association, Ontario Power Authority, Retail Council of Canada, Society of Energy Professionals and Sustainability-Journal. Oral hearings were held over fourteen days.

[79] Intervenors in this case included Association of Major Power Consumers of Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Environmental Defense, Green Energy Coalition, London Property Management Association, Ontario Association of Physical Plant Administrators, Power Workers Union, Quinte Manufacturers Association, School Energy Coalition, Society of Energy Professionals, Sustainability-Journal, and the Vulnerable Energy Consumers Coalition.

[80] Ministry of Energy, 2004. "Ontario moving forward with nuclear refurbishment at Darlington and pursing continued operations at Pickering to 2024". Available online at https://news.ontario.ca/mndmf/en/2016/1/ontario-moving-forward-with-nuclear-refurbishment-at-darlington-and-pursuing-continued-operations-at.html.

Source: Ontario Energy Board. Decision and Order EB-2016-0152. Ontario Power Generation Application for payment amounts for the period from January 1, 2017 to December 31, 2021.

Figure 3: Darlington Refurbishment Program Anticipated Cash Flow



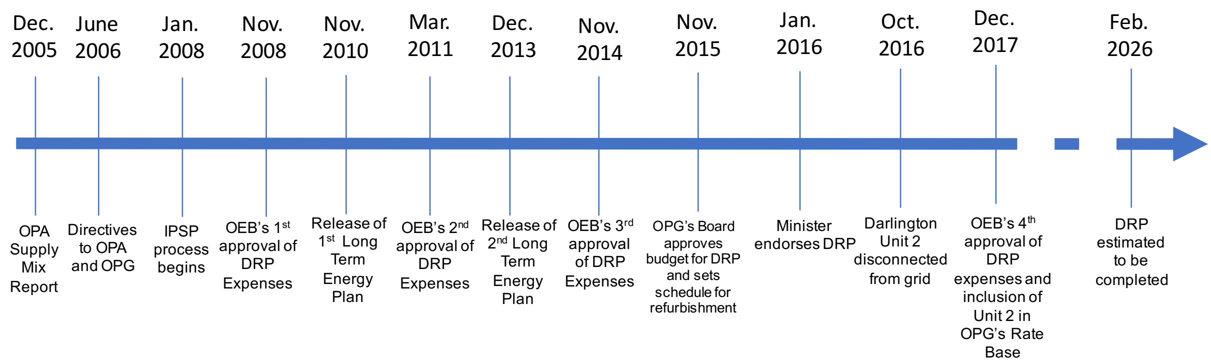
Source: Ontario Energy Board. Decision and Order EB-2016-0152. Ontario Power Generation Application for payment amounts for the period from January 1, 2017 to December 31, 2021.

At this stage, OPG sought approval for the addition of $5.2 billion to its rate base, which included the refurbishment of Unit 2, the first of the four units to be refurbished. OPG advised that it was about $59 million under budget as of February 2017. To support its request, OPG provided evidence regarding the prudence of the planning, contracting, and oversight procedures for the project. Independent experts testified how the firm had employed best practices for planning and contracting for the DRP. It also highlighted the multiple layers of oversight employed in the Execution Phase of the megaproject, including a special Darlington Refurbishment Committee of the Board of Directors of OPG, which engaged its own external expert, OPG's internal audit group, and the Refurbishment Construction Review Board (composed of external members with expertise in megaprojects and nuclear power) that reported to OPG's CEO and Chief Nuclear Officer.[81] The Ministry of Energy further retained an external expert advisor who sat on the Darlington Refurbishment Committee to provide oversight and report directly to the Ministry on the project's status, performance and risks. The OEB considered evidence on OPG's overall planning, project management and oversight for the project, and allowed the request for $5.2 billion of DRP investments to be included in its rate base. The OEB noted that should Unit 2 not be completed on schedule or on budget then OPG would be subject to a prudence review to assess OPG's management of the project.

[81] For details of oversight of the Darlington refurbishment project, see https://www.opg.com/about/regulatory-affairs/Documents/2017-2021/OPG_IRR_Issue_10.0_20161026.pdf

As a further procedural check, the government has designed “off-ramps” after each unit’s refurbishment, which enable to government to stop the project and cease further refurbishment if costs have escalated or if the need for the project has changed due to external factors.[82]

Figure 4: Key Events Timeline



7.1.5 Conclusion

Ontario’s approach to the Darlington plant refurbishment is an example of extensive, deliberate regulatory oversight of a major infrastructure project, with the caveat that the project is yet to be fully completed. While the project was ultimately concurred to by government in 2015, independent regulatory agencies have played a central role in initial assessment and subsequent oversight. Three aspects are notable: first, the need for nuclear plant refurbishment was originally identified as a preferred option by the Independent Electricity System Operator (formerly, the OPA) as one component of a comprehensive power system analysis and plan that sought to achieve economic, reliability and environmental objectives in the supply mix as specified by the Minister of Energy. Second, the Minister approved the project only after 10 years of detailed planning, the development of reliable cost estimates and stringent project governance mechanisms, and continued evaluation by the independent system operator. Third, the province’s utility regulator (the OEB) was explicitly authorised to examine the prudence of expenditures and to deny recovery of any costs deemed imprudent. Expenditures are scrutinized in the context of a public rate case where regulatory staff and multiple intervenors examine and contest proponent requests to recover their costs – the prospect of which sharpens incentives for the proponent to maintain tight cost control as the project unfolds. To date, project expenditures remain within budget and have been deemed reasonable by the regulator.

[82] See Financial Accountability Office of Ontario, 2017. *An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*.

7.2 Western Alberta Transmission Line

7.2.1 Project Overview

The Western Alberta Transmission Line (WATL) is a $1.7 billion, 347 kilometer transmission line situated in the Edmonton-Red Deer-Calgary corridor, which commenced service on December 10, 2015 (see Figure 5 for a timeline of key events). It was constructed and is owned and operated by Altalink Ltd. WATL is one component of Alberta's North-South Transmission Reinforcement (NSTR) plan, which also includes the Eastern Alberta Transmission Line (EATL), developed by ATCO Electric. The NSTR was initiated to address increased demand in southern and central Alberta, improve system reliability, maximize efficiency, and accommodate long term economic growth.[83]

7.2.2 Project Need Evaluation, Initiation and Implementation

The proposal for north-south transmission expansion in Alberta originated in the province's 2004 *10 Year Transmission System Plan*, developed by the Alberta Electric System Operator (AESO), the provincial independent electricity system operator and planner. At the time, there had been no major transmission lines added to the north-south system in more than 20 years, while load and generation capacity had grown significantly, resulting in increasing line losses and constraints on the development of a competitive wholesale electricity market.

In May 2004, the Alberta Electric System Operator submitted a Needs Identification Document (NID) to the Alberta Energy and Utilities Board (EUB), outlining a number of alternatives to develop and reinforce the province's transmission grid.[84] [85] The NID process was the first stage for transmission system additions and, if approved by the EUB, the process would move to the second stage where the AESO would assign the project to a developer who would apply to the EUB for a construction and operation permit. The NID application was approved by the EUB in April 2005 following two weeks of public hearings and participation by 15 intervenors.[86] The approval set in motion the second stage of the process where the AESO directed AltaLink under the *Electric Utilities Act* to submit an application with the EUB for approval to construct one of the lines previously approved in the NID proceeding.[87] AltaLink initiated the second stage of the transmission construction process with its September 2006 application to the EUB. This stage required the EUB to approve the specific location of the transmission line and associated facilities, taking into account social, economic, and environmental impacts.[88]

[83] Transmission Facilities Cost Monitoring Committee, 2015. *Review of the costs Status of Major Transmission Projects in Alberta*, page 32.
[84] *Electric Utilities Act,* SO 2003, cE-5.1, s.34(1).
[85] *Needs Identification Document Application Edmonton-Calgary 500 kV Electric Transmission Facilities, Alberta Electric System Operator* (Decision), Application No. 1346298 (2005) (EUB).
[86] Intervenors involved in the case included AltaLink Management Ltd., AltaGas Power Holdings Partnership, ATCO Electric Ltd., Alberta Department of Energy, Benign Energy Canada, Inc., City of Calgary, EPCOR Utilities Inc., Industrial Power Consumers Association of Alberta/ADC, Independent Power Producers Society of Alberta, Luscar Limited, TransAlta Corporation, TransCanada Energy Ltd./Northern Lights Transmission, City of Lethbridge, and Aboriginal communities.
[87] *Electric Utilities Act,* SO 2003, cE-5.1, s.35(1)(a).
[88] *Hydro and Electric Act*, SO 2000.

In 2008, however, the government abruptly dissolved the EUB following concerns about the conduct of public hearings for transmission line proposals, and in late 2009 it enacted Bill 50 which altered the approval process for major new infrastructure.[89] Under the new process, Cabinet would have the power to designate as 'Critical Transmission Infrastructure' (CTI) any projects included in AESO system plans or those deemed critical solely by Cabinet. The rationale for this new authority was to expedite several projects that had been delayed by the disbandment of the EUB and which had become critical. The newly formed Alberta Utilities Commission (AUC), which replaced the EUB as the electricity sector regulator, would approve the siting of transmission lines but would not determine need. Bill 50 also listed four transmission projects that were designated as CTI, including WATL.[90] Mindful of potential concerns about cost escalation, the government established a Transmission Facilities Cost Monitoring Committee (TFCMC) by Ministerial Order in 2010, in order to increase transparency about the cost of transmission.[91]

AltaLink submitted a 'Proposal to Provide Service' (PPS) to the AESO on January 20 2011, with a cost estimate of $1.4 billion, and subsequently filed an application with the AUC on March 1, 2011 to initiate a proceeding. PPS cost estimates are intended to have an accuracy level of +20%/-10% and are updated once the permit and license are received, the final route is confirmed, and access to lands is granted. The AUC determines whether a transmission project is (1) consistent with the technical solution identified in the Cabinet's Needs approval, and (2) is in the public interest with regards to social, economic, and environmental effects. The Alberta Utilities Commission considered the province-wide improvements in electricity reliability, performance and access that the WATL project would provide against the impacts on individuals who reside or own land along the route. The AUC approved AltaLink's application on December 6, 2012, noting that the project was critical infrastructure as defined in the amended *Electric Utilities Act*, that participant involvement and consultation programs were consistent with AUC requirements[92], and that the preferred route, subject to some changes and conditions imposed by the AUC, would be in the public interest. Public hearings in Red Deer involved appearances from 18 intervening groups and 80 witnesses between June and August.[93] Permits and licenses were issued on December 20, 2012, which marked the start of the execution stage of the project.

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[89] Bill 50, *Electric Statutes Amendment Act*, 2nd Session, 27th Legislature, Alberta, 2009 (Assented 9 December 2009), SO 2009.

[90] The Alberta government has not designated any other projects as Critical Transmission Infrastructure since Bill 50 was enacted. In fact, in late 2012 the government removed its authority to designate Critical Transmission Infrastructure in Bill 8, the Electric Utilities Amendment Act, 2012, returning authority to the AUC, which determines the public interest for proposed transmission lines, as specified in AESO needs identification documents. See http://www.auc.ab.ca/pages/electric-industry.aspx

[91] *Ministerial Order*, 64/2010.

[92] AUC Rule 007 outlines the application process for constructing new electricity infrastructure. Appendix A of Rule 007 details the participant involvement requirements that must be followed to intervene in an application proceeding.

[93] Intervenors involved in the case included 566 Corridor group, Chinook Country group, J.M. Chudobiak, West to East Alternate Protesters, Kathyrn School Council, Westcott/Hainstock Landowner group, Gleniffer Lake Landowner group, A. Cunningham, J. and V. Safronovich, Landowners opposed to the Langdon Alternate, Midway group, Medicine Valley Landowners group, L. and M. Black, A. Heinrich, H. Tanner, Langdon group, ENMAX Corporation, and the Peacock Linder Halt group.

7.2.3 Regulatory Oversight and Cost Recovery

The execution stage of the WATL project was implemented under the oversight of the AESO, which had initially directed AltaLink to construct the line, subject to AUC approval. The details of the monitoring program are set out in ISO Rule 9.1.3 and 9.1.5 and include cost reporting, monthly reports, change order processes, and approved systems for procurement of materials, services, and equipment.[94] AltaLink senior executives met with the AESO monthly while project managers met weekly with the AESO to discuss the project's progress. The project was also monitored by the Transmission Facilities Cost Monitoring Committee which published semi-annual reports tracking project progression, Project Change Proposals (PCPs) approved by the AESO, and updates to the authorized budget and estimated completion costs. For instance, the December 2013 report from the TFCMC noted how AltaLink's decision to establish a turnkey contract for a converter station with Siemens was effective in reducing costs. Siemens would later state in their annual report how they absorbed €298 million (approximately $454 million) in additional charges as a result of increased labour and input costs related to the project.[95] TFCMC information and reports are used in AUC General Tariff Applications (GTAs) as evidence about the prudency of project costs, scope, schedules and variances.

Upon completion in 2015, the project was within the 20% cost overrun threshold that was defined when the PPS was originally filed in 2011. Thirteen changes totaling $290 million had been approved by the AESO through the Project Change Proposals process, increasing the authorized budget to almost $1.7 billion. Table 2 presents the PPS estimates and the total costs for the project. The greatest variances in the project's costs were related to labour, which was 145% over budget. AltaLink cited market escalation, right of way access, clearing and brushing, site preparation and scope changes as the major causes for the variance.[96]

Table 2: WATL Project Costs

	Cost Estimate ($ million): January 2011	**Final Cost ($ million): December 2015**
Transmission Line:		
Material	203.8	141.7
Labour	308.6	628.3
Substation:		
Material	420.7	241.9
Labour	78.3	326.4
Telecommunication:		
Material	5.5	2.5
Labour	3.7	5.9

[94] *ISO Rules, Part Two – Market Participant Rules* (2018). online: https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/
[95] *Deferral Accounts Reconciliation Application – 2014 and 2015 Projects, AltaLink Management Ltd.* (Application), Proceeding No. 22542 (2017) (AUC).
[96] *2015 Deferral Accounts Reconciliation Application.* Project Summary Report – Western Alberta Transmission Line Project.

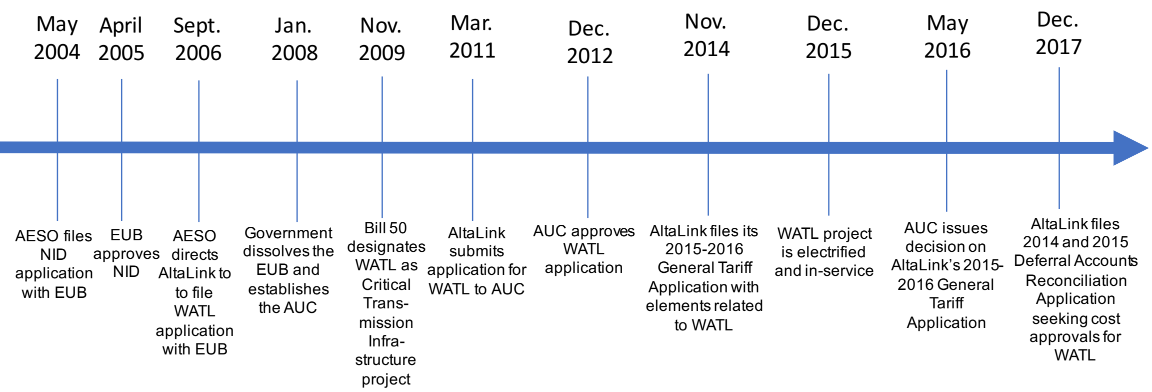
Owner Costs:		
Proposal to Provide Service	11.9	13.4
Facility Applications	35.1	43.7
Land Rights – Easements	39.8	50.6
Land – Damage Claims	2.8	2.5
Land – Acquisitions	16.6	24.8
Distributed Costs:		
Procurement	3.5	10.2
Project Management	22.2	57.2
Construction Management	29.4	59.9
Escalation	65.3	0
Contingency	95.8	0
Other Costs:		
Engineering and Supervision	54.8	55.7
Allowance for Funds Used During Construction	3.0	3.2
Total	**1400.8**	**1667.8**

Source: AltaLink Management Ltd. *2015 Deferral Accounts Reconciliation Application.* Project Summary Report – Western Alberta Transmission Line Project.

As of 2018, cost recovery of the WATL project through the AUC is still underway. AltaLink's 2015-2016 General Tariff Application (GTA), which sought consecutive 23.5% increases in its annual revenue requirement for 2015 and 2016, stated that a significant share of the request was due to the $2.9 billion in projects directed to the firm by the AESO and completed in those years. While the AUC approved a 13.5% revenue increase in 2015 and 13% in 2016, the AUC deferred explicit evaluation of WATL expenditures to a later hearing.[97] Such consideration is currently being considered in AltaLink's 2014 and 2015 Deferral Accounts Reconciliation Application for its Direct Assign Capital Deferral Account (DACDA). A DACDA proceeding "assesses costs that have been actually incurred by a Transmission Facility Owner according to mandatory directions received from the AESO".[98] The DACDA proceeding allows for a true-up of costs that were previously approved for capital additions in the GTA. As part of this application, AltaLink is seeking final approval for 110 transmission capital projects totaling $2.949 billion to be included in its rate base. The largest component of this application is the $1.7 billion WATL project. Hearings on this proceeding are scheduled for September 2018.

[97] *Deferral Accounts Reconciliation Application – 2014 and 2015 Projects, AltaLink Management Ltd.* (Application), Proceeding No. 22542 (2017) (AUC).
[98] *Ibid.*

Figure 5: Timeline of Key Events



7.2.4 Conclusion

As with the Darlington nuclear power plant refurbishment, regulatory oversight of the Western Alberta Transmission Line project exhibits favourable practices that have contributed to successful implementation. The original needs evaluation was undertaken by the electricity system operator and approved by the independent regulator after a public review, though the government since assumed the authority to approve new critical infrastructure projects. Development of the project was closely monitored by the system operator, which had to approve engineering and cost deviations from the original proposal, as well as by a separate provincial transmission oversight committee. Once completed, the proponent was required to apply to the regulator for cost recovery in transmission rates, initiating administrative review and public hearings to assess the prudency of expenditures. The final cost of the project was $1.7 billion, within the tolerance limits of the estimate at the time of the initial application.

7.3 Keeyask Generating Station

7.3.1 Project Overview

The Keeyask Generating Station is a 695 megawatt hydroelectric power generation project being developed by Manitoba Hydro (MH) and four First Nations[99]. The station is located on the lower Nelson River, 725 kilometres north of Winnipeg, and involves more than two kilometres of dams across Gull Rapids and a seven-unit powerhouse complex. Independent experts estimate the in-service date will be November 2022 with a final cost of $10.5 billion, a 70% premium over the initial cost estimate outlined in MH's 2013 Preferred Development Plan (see Figure 6 for a

[99] First Nations own 25% of the equity in the project and include Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation.

timeline of key events).[100] The Keeyask project is one of several large scale infrastructure projects that have been identified by MH as necessary to "further improve electrical system reliability, to meet the future energy needs of the province and to take advantage of export opportunities".[101] Together, these projects include $20 billion of capital expenditures in a mix of new generation and transmission assets.

7.3.2 Project Need Evaluation, Initiation and Implementation

The project's potential was identified by MH in the early 1990s but development began in earnest in October 2000 when an agreement in principle was signed between MH and the Tataskweyak Cree Nation, which outlined the basis for negotiating the Joint Keeyask Development Agreement (JKDA). The JKDA set out understandings related to accommodation for development and for equity ownership of the project. The final agreement and related Adverse Effects Agreements were signed in 2009, which set in motion more advanced engineering and environmental studies required for regulatory approval of the project.

The regulatory evaluation of need began with a January 2011 letter from the Minister responsible for Manitoba Hydro, a portfolio then held by the Minister of Finance, to the Chair of the MH board informing it of the Minister's intention to request that an independent body undertake a Needs For and Alternatives To (NFAT) assessment of the Keeyask project.[102] A few months later, Premier Selinger announced a $4 billion dollar export deal to sell 475 megawatts of hydro power from the yet-to-be approved project to utilities in Minnesota and Wisconsin. The announcements of the NFAT assessment and the export deal coincided with an ongoing regulatory proceeding at the Public Utilities Board to assess MH's application to increase rates 2.9% in 2010 and again in 2011. As part of the proceeding, MH had submitted plans for a 'decade of investment', including the Keeyask project, which the PUB considered as part of the utility's strategy of building new infrastructure in expectation of exports until needed by Manitoba consumers. The PUB ruled against MH for this part of its application in its January 2012 decision, stating that "the utility's business plan is incomplete, lacks required detail and has not been tested through what has been promised as a "Needs For and Alternatives To" (NFAT) review by an independent tribunal that will have full access to the economic and financial assumptions that underpin MH's business plan."[103] Despite this ruling and the lack of a NFAT review, MH had already spent millions of dollars on the development of the Keeyask project and, according to its Annual Reports, had incurred $85 million in 2010 and $108 million in 2011 in capital expenditures related to the Keeyask and Conawapa projects.[104]

In November 2012 the Minister of Innovation, Energy, and Mines directed the PUB to conduct the NFAT review for the Keeyask and Conawapa Generating Stations and their associated transmission facilities, jointly known as the Preferred Development Plan (PDP) (see Table 3).

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[100] Delays and cost overruns have been attributed to the contractor's productivity performance and indirect costs related to labour and the remoteness of the project site. An independent report commissioned by the Manitoba Public Utilities Board noted that "project management and control effectiveness is low".
[101] Manitoba Hydro-Electric Board, 2010. *Annual Report*.
[102] Rosann Wowchuk, "To Victor H. Schroeder." 13 January, 2011.
[103] *A Final Order with respect to Manitoba Hydro's Application for Increased 2010/11 and 2011/12 Rates and Other Related Matters,* Board Order 5/12 (2012) (PUB).
[104] Manitoba Hydro-Electric Board, 2011. *Annual Report*.

Table 3: Manitoba Hydro's Preferred Development Plan (June 2014)

Component	**Description**	**Estimated Cost**
Keeyask Project	695 MW hydro dam with a planned in-service date of 2019	$6.5 billion
Conawapa Project	1,485 MW hydro dam with a planned in-service date of 2026	$10.7 billion
North-South Transmission Upgrade Project	Domestic AC line associated with Keeyask and Conawapa	$0.5 billion
U.S. Transmission Interconnection Project	750 MW line terminating near Duluth, MN with a planned in-service date of 2020	$1.0 billion

Source: The Public Utilities Board. *2014. Report on the Needs For and Alternatives To (NFAT).* Review of Manitoba Hydro's Preferred Development Plan.

The Minister stated that the projects represented a major economic development opportunity for Manitoba and that they would need an independent assessment in comparison to the alternative of natural gas generation.[105] This direction was formalized in April 2013 by Order in Council 128/2013, which set out the terms of reference for the review and set a deadline of June 20, 2014 for submitting its report. The Order in Council first directed the PUB to assess whether the need for the PDP was "thoroughly justified and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate". It also asked "whether the Plan is justified as superior to potential alternatives that could fulfill the need."[106] However, the Order in Council excluded specific elements from the scope of the NFAT review, including the planned 1,384 kilometre Bipole III transmission line[107], which would expand north-south transmission capacity by 2,000 MW and which was needed to accommodate Keeyask. The Order in Council also prevented the PUB from considering the Pointe Du Bois 78MW spillway replacement project, commercial arrangements between MH and its Aboriginal partners for the proposed projects, environmental reviews of proposed projects, issues surrounding Aboriginal consultation, any past MH development proposals or government assessments (including NFATs of past proposals), and historic environmental costs.[108]

[105] Ministry of Innovation, Energy and Mines. (November 16 2012) *Manitoba Asks Independent Board to Review Major Hydro Capital Projects.* [Press release].
[106] *Order in Council*, 128/2013.
[107] The Bipole III Transmission line was completed in July 2018 at a cost of $5 billion, and was designed to improve reliability beyond that provided by the Bipole I and II lines as well as to increase transmission capacity to satisfy the needs of the Keeyask project. The siting of the line generated significant controversy as the decision to route the line along a more circuitous route to the west of Lake Winnipeg, which was 455 kilometers longer than an eastern route, added $1 billion to its cost but avoided sensitive ecosystems and First Nations communities. MH had been directed by the Minister responsible for Manitoba Hydro not to pursue the more direct eastern route option.
[108] *Ibid*.

The NFAT review was conducted over thirteen months, involving five intervenors and expert testimony from eight independent consultants. [109] The PUB conducted 43 days of oral evidentiary hearings between March and May 2013. The PUB assessed five pathways that MH had presented for development of the projects, including alternative timelines, interconnections, export contracts to the U.S., and the role of natural gas generation. The PUB filed its report with the Minister on June 20, 2014, finding that "Manitoba Hydro has not justified the need for its Preferred Development Plan and has not shown it to be superior to alternatives".[110] As a result, while the PUB recommended the need for the Keeyask Project and the U.S. transmission project, it recommended termination of the Conawapa project and North-South transmission line. The report also went on to recommend that MH divest its demand-side management responsibilities to an independent agency and that the government should not approve any further generation or transmission projects (or approve the commencement of spending on such projects), unless they had been examined through a comprehensive and regularly occurring integrated resource planning process. The decision made note of the fact that MH had already incurred $1.2 billion of expenditures on the Keeyask project when the NFAT process began.[111] The basis for the decision was that the Panel determined that no new generation would be needed until 2024, but that there were "compelling economic, financial, and commercial reasons to advance the Keeyask Project to 2019". These included the need for new resources in the future, construction expenditures already undertaken, the socio-economic and environmental benefits of the project, commercial relations established with First Nations and committed export contracts. The rejected projects, on the other hand, were deemed to be too speculative in light of rapidly changing conditions in North American electricity markets and rapid technological innovation.

The project officially broke ground on July 16, 2014 shortly after the conclusion of the NFAT review. The quick ramp up to construction was made possible by the significant investment that MH had already made in anticipation of the NFAT approval; during 2012 it had constructed roads, a bridge and a work camp that would be required for the dam's construction. Similarly, the single largest contract for the project, the General Civil Contract (GCC), had been finalized in March 2014, prior to the NFAT decision. The GCC, awarded to BBE Hydro Constructors, was wide ranging and included river management, earthworks to build the dykes, concrete structures such as the powerhouse and spillway, and electrical and mechanical work. The decision to award such a large contract to a single counterparty and to structure it in a cost-plus manner would later be closely scrutinized for the risk it conferred on MH. [112]

3.3 Regulatory Oversight and Cost Recovery

The PUB has oversight responsibility over for the electricity sector in its assessment of the prudence of utility costs and the reasonableness of including them in rates. This statutory responsibility is derived from The Public Utilities Board Act, the Crown Corporations

[109] The intervenors in the NFAT Review were Consumers' Association of Canada (Manitoba) Inc., the Green Action Centre, the Manitoba Industrial Power Users Group, the Manitoba Metis Federation, and the Manitoba Keewatinowi Okimakanak Inc.
[110] *Report on the Needs for and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plant*. (June 2014) (PUB).
[111] *Ibid.*
[112] *Final Order with respect to Manitoba Hydro's Application for Increased 2017/18 and 2018/19 General Rate Application,* Order No. 59/18 (2018) (PUB).

Governance and Accountability Act, and the Manitoba Hydro Act. The Crown Act states that "No changes in rates for services can be made and no new rates for services can be introduced without the approval of the Board". However, the Board's jurisdiction over MH is limited by subsection 2(5) of the Board Act, such that the Board's primary authority over MH is the review and approval of rates, and it does not have statutory authority to approve capital project plans or associated expenditures.

The first review of costs related to Keeyask was filed six months after the NFAT decision as part of MH's 2014/15 and 2015/16 General Rate Application (GRA). In its application, MH indicated that in order to recover capital expenditures related to Keeyask and other projects, it would need 3.95% in annual rate increases for the next 15 years. This would provide a smoothed series of rate increases and avoid short-term shocks to ratepayers. The PUB agreed with this phased-in approach and allowed MH its requested increase for 2014/15 and 2015/16. However, it also directed the utility to file quarterly progress reports outlining budget changes and how any increases would impact domestic revenue requirements and MH's financial forecasts and targets.[113]

The Keeyask project featured in the run-up to the 2016 provincial election when Brian Pallister, then leader of the Progressive Conservative party, promised to halt its construction if elected Premier. Soon after his victory in April 2016, Pallister's government appointed a new Board of Directors for MH who initiated an evaluation of the prudency and risk of building the Keeyask project and two transmission lines. This was undertaken by Boston Consulting Group (BCG), who assessed whether the original decisions were reasonable, whether there was further downside risk, and if the projects could be stopped or paused without undue cost or risk. BCG found that the decision to pursue the Keeyask project was an "imprudent one due to a failure to fully assess the risks associated with moving forward".[114]

A key finding in the BCG report was that the NFAT was hamstrung by the Terms of Reference, which excluded consideration of on-going projects (such as the Bipole III transmission project) or prior development proposals and NFATs. Keeyask would not be able to operate without the Bipole III transmission line, which was treated as a sunk cost. Excluding it from the NFAT effectively underestimated the overall cost of the Keeyask project and tilted economic analysis of the NFAT in favour of the PDP.[115] The report highlighted how acceleration of the Keeyask project for a 2019 in-service date was based on unrealistic assumptions about a short window of opportunity for export and meant that the project would commence prior to receiving the necessary approvals for the transnational transmission line. However, given the current state of execution and the costs involved in cancelling the project, BCG recommended continuing the project to completion.

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[113] *Final Order with respect to Manitoba Hydro's Application for Increased 2014/15 and 2015/16 General Rate Application,* Order No. 73/15 (2015) (PUB).

[114] Boston Consulting Group, 2016. "Review of Bipole III, Keeyask and Tie-Line Project". Available online at https://www.hydro.mb.ca/corporate/news_media/pdf/bcg_report_bipole_III_keeyask_and_tie_line_project.pdf

[115] As the NFAT panel commented, "There are realities of the Keeyask Project over which the Panel had no influence. Approximately $1.2 billion has already been spent on the Keeyask Project. The $3.2 billion Bipole III transmission line, which was not subject to the NFAT Review, has already received regulatory approval and will be constructed to carry northern electricity to southern Manitoba. Both of these were treated by Manitoba Hydro as "sunk costs", and therefore excluded from the economic analysis."

While MH's first rate proceeding with issues related to Keeyask was relatively straightforward, the next was more challenging. It was also the first proceeding after the government's Order in Council 92/2017 in April 2017, which charged the PUB with reviewing MH's capital expenditures, and compelled MH to provide information and documents related to capital expenditures, project justifications, and revenue and income records.[116] MH filed its 2017/18 and 2018/19 GRA in May 2017, requesting a 3.36% increase to rates in each of 2016 and 2017 and then a 7.9% increase in 2018. The 7.9% increase request represented a significant departure from the 15-year plan which had been approved in the previous rate application. MH proposed a new 10-year plan that would involve a rate path of six years of 7.9% increases, followed by a one-year increase of 4.54% and then two years at 2%. Underlying this change was concern about the utility's financial health due to escalating costs of the Keeyask project and the Bipole III Transmission Project and the debt burden that MH would need to maintain.[117]

The 2017/18 and 2018/19 GRA proceeding attracted significant media attention and involved nine intervenors, some of whom had never participated in rate proceedings before. [118] There were 31 days of oral hearings, which included testimony also from five independent expert consultants retained to assist the PUB's consideration of the Order-in-Council's direction. Of particular note was the report by MGF Project Services who reviewed MH's major capital expenditures. MGF's lengthy report identified serious deficiencies in contracting practices and oversight of the GCC which led to cost overruns borne by MH and poor productivity performance of the contractor. The report argued that the final cost of the Keeyask project would approach $10.5 billion, close to a 70% premium over the 2013 cost estimate, and would likely be in-service in late 2022 (see Table 4). As a result, the PUB denied MH's requested 7.9% rate increase in 2018, approving only a 3.6% increase as determined in the previous GRA.[119] The PUB also directed MH to consider the recommendations of its independent expert consultants and to report back at the next GRA on the extent to which it had implemented them, along with the estimated costs savings and schedule impacts.

Government oversight of the Keeyask project also seems to have been limited since it did not appear to have created an independent, expert oversight governance mechanism specifically for the project. Instead, oversight fell to the Manitoba Crown Corporations Council, a civilian board

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[116] Order in Council 92/2017 was made by the Minister of Finance on April 5, 2017 and stated that "The Public Utilities Board (the "PUB") is assigned the duty of considering capital expenditures by The Manitoba Hydro-Electric Board ("Manitoba Hydro") as a factor in reaching a decision regarding rates for services under Part IV of The Crown Corporation Public Review and Accountability Act to support setting rates for services in a manner that balances the interests of ratepayers and the financial health of Manitoba Hydro".

[117] *Final Order with respect to Manitoba Hydro's Application for Increased 2017/18 and 2018/19 General Rate Application,* Order No. 59/18 (2018) (PUB).

[118] Intervenors in this case included the Assembly of Manitoba Chiefs, Business Council of Manitoba, Consumers Coalition, Representative of the General Service Small and General Service Medium Customer Classes, Green Action Centre, Keystone Agricultural Producers, Manitoba Industrial Power Users Group, Manitoba Keewatinowi Okimakanak, and the City of Winnipeg. Among the first-time intervening parties were the Business Council of Manitoba and Keystone Agricultural Producers who were concerned about the impact of the requested rate increase on the Manitoban economy.

[119] *Final Order*, supra note 115, page 17.

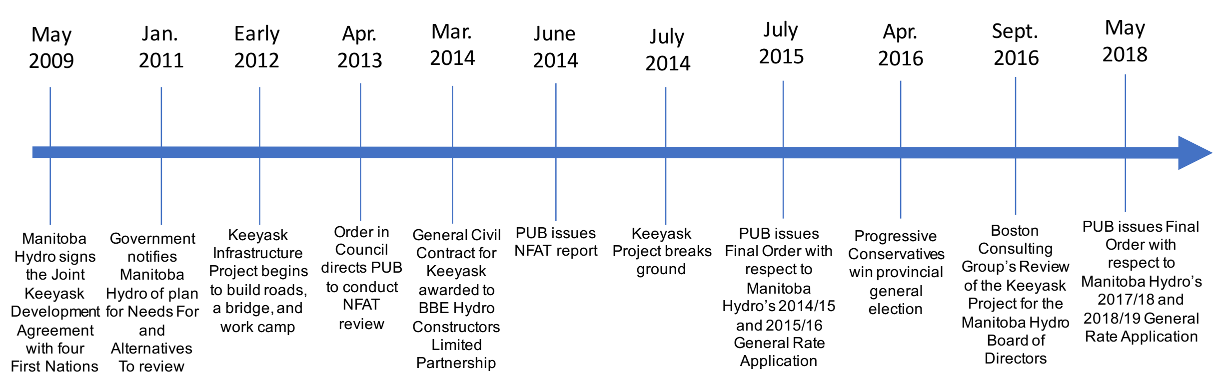
that was dismantled in 2016, the Crown Corporations Standing Committee of the legislature, and the Auditor General of Manitoba.[120]

Table 4: Cost and In-Service Date Estimates

	Cost Estimate	Projected In-Service Date	Source
August 2013	$6.2 billion	November 2019	*Manitoba Hydro* – Business Case Submission to NFAT
September 2016	$7.8 billion	June 2022	*Boston Consulting Group* – Review of Bipole III, Keeyask and Tie-line Projects
March 2017	$8.7 billion	August 2021	*Manitoba Hydro* Press Release
December 2017	$10.5 billion	November 2022	*MGF Project Services Inc.* – Report to PUB

Sources: Manitoba Hydro, *2013. NFAT Business Case*; Boston Consulting Group, 2016. *Review of Bipole III, Keeyask, and Tie-Line Project*; Manitoba Hydro, 2017. Control budget for Keeyask Generating Station revised; MGF Project Services, 2017. Report for Manitoba Hydro, *Capital Expenditure Review for the Keeyask Hydroelectric Dam, the Bipole III, Manitoba-Minnesota and GNTL Transmission Lines.*

Figure 6: Timeline of Key Events



7.3.3 Conclusion

Compared to regulatory oversight of the Darlington nuclear plant refurbishment and the Western Alberta Transmission line projects, regulatory review and oversight of Keeyask has been less comprehensive and rigorous. While the government directed the PUB to conduct an independent needs review to determine whether Keeyask would be a prudent decision compared to alternative options, it handcuffed the PUB's analysis by limiting the scope of the review and by excluding related transmission infrastructure from consideration. The government also committed to major electricity export contracts, and the proponent incurred significant sunk costs on the project,

[120] See Manitoba Hydro August 2013 submission to Needs for And Alternatives To Review, available at http://www.greatnortherntransmissionline.com/assets/documents/CertificateNeed/Appendix_E.pdf

before the review commenced, further 'stacking the deck' towards a more favourable initial economic assessment of Keeyask. Final regulatory oversight of utilities has also been weaker in Manitoba than in Ontario and Alberta, largely due to the restriction that the PUB did not have authority to question or (dis)approve Manitoba Hydro's capital expenditure plans or projects. The incentive for Manitoba Hydro to control costs on capital projects is thus expected to be weaker than, for example, in Ontario, where the Ontario Energy Board has jurisdiction to assess the prudency of all utility expenditures. Consistent with the effect of a weak regulatory regime, it is notable that the final cost of the Keeyask project is predicted to escalate to 70% over budget (at $10.5 billion), resulting in rapidly escalating electricity rates for consumers, and contributing to credit rating agency concerns about the level of Manitoba Hydro's debt.

8. Conclusion

Effective regulatory oversight is particularly important for protecting ratepayer interests in the case of megaprojects due to the scale of the impacts and risks involved – and more so since infrastructure sector projects such as power generation stations are irreversible investments and have long-term impacts for multiple generations. Regulatory due diligence and scrutiny reduce the risk of making policy decisions that can have negative economic consequences.

A key advantage of independent regulatory oversight is improved information – open, transparent, evidence-based decision-making procedures can tackle the inherent complexity of megaprojects by yielding more reliable information about benefits, costs, impacts and risks. Regulatory due process thereby enables the relative merits and disadvantages of alternatives to be better assessed, reducing the probability of selecting uneconomic projects, and increasing the probability of identifying and choosing beneficial ones. Effective regulation also creates incentives for proponents to manage projects within approved budgets and to implement appropriate project governance mechanisms, lowering the probability of experiencing major cost over-runs. When a government elects to make the final sanction decision on a proposed project, allowing independent regulators to undertake comprehensive evaluation and to make recommendations beforehand ensures the government has the best information possible before making its decision.

Regulatory agencies in Alberta, Ontario, and Nova Scotia have played central roles in evaluating, approving, monitoring and reviewing large electricity infrastructure projects such as the Western Alberta Transmission Line, Darlington nuclear power plant refurbishment, and Maritime Link. To date, these projects have largely been completed on budget and on schedule. By contrast, in Manitoba, where the Public Utility Board has had a much more restricted role in evaluating and overseeing the Keeyask generation project, the project is significantly over budget, three years behind schedule, and the focus of political controversy.

The Newfoundland and Labrador government's approach to regulatory oversight of Muskrat Falls has not met the high standard that other provinces such as Alberta, Ontario and Nova Scotia have adopted in regulatory oversight of megaprojects, as described in this report. By requiring the PUB to commence its review in 2011, by restricting the scope of the review, and by limiting the time available, the Newfoundland and Labrador government was ultimately not as informed as it could have been at the time of sanction about the costs and risks of the Muskrat Falls project relative to other alternatives had it instead waited until reliable cost estimates were ready and had it given the PUB full latitude to carefully assess all possible options. DG3 cost estimates, which were released shortly before project sanction, were not scrutinized by an independent regulator in the context of an open, transparent, evidence-based review process; and other potential supply and demand-side options were not investigated by the PUB at all. Although the government released several consulting reports that supported the Interconnected Option after March 2012, they were not tested or validated by the PUB's review process. Consequently, in the absence of a positive recommendation from an independent, expert regulator, the government took a significant risk when it sanctioned Muskrat Falls that it would be the lowest-cost approach to securing the province's electricity future. By exempting Muskrat Falls costs from PUB review upon project completion, the government also took a risk that Nalcor would prudently manage construction of the project without the prospect of future regulatory disallowance, and that the Oversight Committee would satisfactorily monitor progress and hold Nalcor to account.

While it is necessarily hypothetical as to what might have happened if the PUB had had unrestricted regulatory oversight responsibilities, it is possible that the PUB would not have approved or recommended Muskrat Falls if a review had commenced in 2013, after the DG3 cost estimates were released in late 2012. If the review had occurred during 2013 and 2014 (allowing up to an 18-month duration), new information and events could have made the Interconnected option less attractive as compared to the 2011/12 review analysis for several reasons. First, the PUB would have had the freedom to assess a range of potential supply and demand-side options beyond the two specific alternatives defined by the government. The PUB could also have considered a shorter planning time horizon to 2041, which is when Upper Churchill power will become available, and also the option of developing new capacity to meet just domestic needs rather than to also serve export markets. Detailed scrutiny of all plausible options may have yielded a lower-cost solution than Muskrat Falls.

Second, in 2013 the PUB would have had the benefit of new load information, which would have shown that total Island load grew more slowly in 2011 and 2012 than originally forecast by Nalcor in 2010.[121] The effect of lower load growth may have strengthened the PUB's concern that "*there is not an immediate need for the large incremental supply associated with the Interconnected Option and that Island electricity needs could be met in the short to medium term with available renewable sources on the Island and/or additional thermal generation*".[122]

Third, in July 2013 the Nova Scotia UARB approved the Maritime Link project but required Emera to negotiate an energy access agreement – which ultimately led to a commitment by Nalcor to provide an average of 1.2 TWh of non-firm energy per year over a 24-year period. The

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[121] The 2010 Planning Load Forecast predicted Total Island load of 7,709 GWh in 2011, 7,850 GWh in 2012 and 8,214 GWh in 2013. Actual load in these years was, respectively, 7,652 GWh, 7,686 GWh, and 7,996 GWh (as reported in Power Advisory's 2015 report, page 274).

[122] Board of Commissioners of Public Utilities, March 30, 2012. *Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067*, page 41. The Joint Review Panel also questioned the need for the project. In its report, the JRP stated it "did not accept that developing the hydroelectric potential of the lower Churchill River was a "need" … the Panel concluded that Nalcor had not demonstrated the justification of the Project as a whole in energy and economic terms" (pages xii-xiii, Report of the Joint Review Panel, Lower Churchill Hydroelectric Generation Project. August 2011).

UARB approved the energy access agreement in November 2013. Nalcor's concession could have altered the economics of the Muskrat Falls project and hence its economic value relative to other options. It is likely that the PUB would have wanted to conduct its own investigation after the UARB's approval in November 2013 in order to understand the implications for the Muskrat Falls project.

Fourth, the new cost estimates for the Interconnected option released in October 2012 were almost 20% higher than the estimates the PUB received for its 2011/12 review (DG3 $7.4bn versus DG2 $6.2bn), which would probably have reduced the attractiveness of the Interconnected option relative to other potential alternatives that the PUB could analyze in an unrestricted review (but which were excluded from the original review).[123]

Fifth, had the PUB review occurred during 2014, it would have coincided with the dramatic collapse in global oil prices that occurred during 2014. As a result of increased U.S. shale oil and non-OPEC production, global oil prices approximately halved, causing sector analysts to reassess their market price forecasts.[124] The estimated difference in cumulative present worth between the Interconnected and Isolated Island options was quite sensitive to the oil price forecast used, making the timing of the PUB review potentially consequential.[125]

It is not possible to know with certainty how any of these factors, or combination of them, would have influenced the PUB's overall evaluation of whether Muskrat Falls was the preferred option compared to other alternatives in the context of a hypothetical review – but they could have reduced the probability of the PUB finding in favour of the project. If the PUB had publicly concluded after a comprehensive review that Muskrat Falls was not needed at that time or was not the lowest-cost alternative, it would have been more difficult for the government to justify a sanction decision. Even if the government had still decided to proceed, allowing the PUB to review project costs and to assess prudency could have contributed to better cost containment and on-time delivery during the construction stage.

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[123] MHI stated in its October 2012 report for the government that the estimated costs of the Isolated Island option had increased since its January 2012 report for the PUB (the base case cumulative present worth was estimated at $8.8bn in January 2012 versus $10.8bn in October 2012).

[124] See https://www.eia.gov/todayinenergy/detail.php?id=19451

[125] Analysis presented during the PUB review in 2011-12 showed that forecast Holyrood fuel costs had a significant impact on the estimate of which option was least cost. The PUB reported that a 44% reduction in the forecast oil fuel price would make the Isolated Island option a similar cost to the Interconnected option, all else equal. Reducing the oil fuel price by 20% while increasing the Interconnected Option capital cost by 20% would have a similar effect.