



how
**MEGAPROJECTS
BANKRUPT
POWER UTILITIES**
and
**LEAVE REGULATORS
IN THE DARK**

Brady Yauch

Consumer Policy Institute • Energy Probe

Table of Contents

Executive Summary	2
Part I: What is a megaproject and why you should be scared	4
Part II: Manitoba Hydro, Keeyask and a utility pushed to the brink of financial disaster	8
Part III: Muskrat Falls and a failed nation-building exercise	20
Part IV: Site C – The megaproject that just won't go away	29
Part V: Ontario makes a big bet on nuclear power – regulators and the public be damned	37

Brady Yauch
Economist and Executive Director of Consumer Policy Institute
(416) 964-9223 ext 236
bradyyauch@consumerpolicyinstitute.org
<http://cpi.probeinternational.org>

Cover design by Catharine Solomon

Executive Summary

Across Canada, the provinces' largest public electricity utilities are building ever-larger megaprojects. In just four provinces — Manitoba, Newfoundland and Labrador, British Columbia and Ontario — the current cost of megaprojects in the electricity sector totals \$43 billion and counting. These projects will cause significant rate increases for customers for years — in some cases decades — to come.

Politicians and their appointees running the country's largest public utilities have repeatedly underestimated the costs of these megaprojects, exaggerated the benefits and set unrealistic construction schedules. They have also ignored the financial consequences from the inevitable construction delays and soaring cost estimates that plague all megaprojects, deliberately pushing these projects ahead to a point where they claim they are too far along to stop. The public, in short, has been told that owning a white elephant was better than no elephant at all.

If it weren't for the implicit — or, in most cases, explicit — backing of the public purse in the form of taxpayer-backed bailouts and debt guarantees, these megaprojects would never have gone ahead given the financial risks they impose both on customers and provincial balance sheets. The amount of debt needed to construct a megaproject has left most public utilities almost fully leveraged, contravening their own financial targets and policies, and jeopardizing provincial finances.

In the process of pushing megaprojects ahead, public officials across the country have at various times ignored, handcuffed, circumnavigated or publicly disparaged the regulatory bodies that are there — in most cases established through legislation — to protect the public from the consequences of uneconomic and environmentally destructive megaprojects in the electricity sector. In nearly every case, regulatory bodies or independent commissions have openly questioned whether these megaprojects are the most cost-effective way to produce and deliver power, only to have their powers slashed, their reviews blocked and a truly independent sober second look ended.

The cost to consumers across the country from megaprojects will be severe. In every case, the annual rate increases for electricity customers will be in the double digits. In some cases, the overall increase rates will add up to triple digits.

In **Manitoba**, the public utility has repeatedly underestimated the cost of the \$8.7-billion Keeyask dam — nearly triple the original cost estimate — and oversold its benefits. The utility now admits the dam to be a money-loser until at least the mid 2030s. The public utility also repeatedly downplayed the rate impacts on its electricity customers as a result of its megaproject spending, only to later revise those figures higher once the project hit what it considered a point of no return. In the process, the utility has routinely violated its own stated financial governance policies, leading its newest chairman to warn the public that the utility is a “ticking time bomb.”

In **Newfoundland and Labrador**, the province's regulator was blocked by legislation from performing a thorough cost-benefit analysis of the Muskrat Falls hydroelectric megaproject,

currently estimated to cost \$12.7-billion, or more than double the original price tag. When the regulator said it wasn't provided with the time and resources to determine whether the megaproject was the most cost-effective solution to meet the province's future energy needs, public officials called the regulator's work a waste of time and money. Stan Marshall, the current CEO of the public utility building Muskrat Falls, declared the project a boondoggle and a worse deal for the province's electricity customers than the infamous Churchill Falls power deal signed with Quebec in the 1960s. Nonetheless, the utility says it's too late to stop the megaproject.

In **British Columbia**, the province removed the regulator's power to review the \$8.8-billion Site C hydroelectric project and determine whether it offered good value for money. The province also prohibited the regulator from passing on the real cost to consumers of moving ahead with the project – as is standard practice in good utility regulation – and, instead, used an aggressive accounting trick, among other moves, to keep rates low at the expense of higher rates for future customers. Even though the original forecasts for demand and export markets has proven to be optimistic and the need for the Site C project has been called into question, the province openly admitted that it intended to simply drag the megaproject “past the point of no return.”

And in **Ontario**, the province systematically dismantled the regulatory system that was explicitly put in place in the wake of the 1990s collapse of Ontario Hydro, which was largely caused by cost overruns and poor performance at its nuclear plants. Rather than ensuring the \$12.8-billion refurbishment of the Darlington nuclear station was subject to a public cost-benefit analysis, the project was ultimately pushed through by the power of legislation and blocked from the purview of a public review by the province's regulator. The double-digit rate hikes needed to finance the project have been artificially lowered by legislation, kicking those costs to future ratepayers – in direct contradiction of how rates are normally set in Ontario.

Part I: What is a megaproject and why you should be scared?

Megaprojects — typically classified as infrastructure projects with a price tag greater than \$1 billion — are being pursued by many of Canada's largest publicly owned electricity utilities. Taken as a whole, the cumulative cost of the largest energy projects being built in four of Canada's ten provinces totals \$43 billion (and counting) and includes both nuclear and hydroelectric assets.¹ Many of the projects will require double-digit rate increases for consumers and come at a time when most provinces — and the United States, which remains the largest market for Canadian electricity exports — are experiencing flat or shrinking demand for power.² In many cases, the provinces backstopping these utilities are themselves mired in structural deficits and high debt levels.

The growing body of research on megaprojects is clear: they're bad value for money. The current price tag of these megaprojects masks the much larger risks they will impose on ratepayers, who will be burdened with higher rates to service debts of the public utilities building them, and the taxpayers that will be expected to bail the utilities out from severe cost overruns or subpar performance. Megaprojects have a long and extensive track record of coming in well over budget and years behind schedule. Worse, while the 20th century was a time of significant technological change and improvement, the ability of megaprojects to meet their financial and scheduling forecasts hasn't improved at all.

The megaproject theme song: overbudget and behind schedule, over and over again

Nearly every study on megaprojects has exposed their poor performance, both on cost and construction schedule. One influential study by the world's leading megaproject experts at Oxford University found that nine out of ten megaprojects experienced cost overruns during construction, with the final price tag on many projects coming in at 50% or higher.³ These cost overruns occurred in megaprojects in nearly every sector, including power, IT, public works and transportation projects, among many others. Looking only at large-scale hydro dams,⁴ three out of four dams experienced cost overruns, with the average increase being 96% higher than the initial estimate. In Ontario, the construction and refurbishment of the province's nuclear reactors — a series of megaprojects that eventually bankrupted the country's large public utility Ontario Hydro — cost, on average, 2.5 times more than expected.⁵ The consulting firm EY looked specifically at oil and gas megaprojects from around the world and found that 64% were facing

¹ The six provinces not discussed in this paper are: Alberta, Saskatchewan, Nova Scotia, New Brunswick, Quebec and Prince Edward Island (PEI). Alberta and Nova Scotia are both served by privately run utilities. PEI imports most of its energy from New Brunswick's Point Lepreau nuclear station, which recently completed a refurbishment that was originally forecast to cost \$1.4 billion, but ultimately came in at \$2.4 billion and three years behind schedule. Saskatchewan built the \$1.5 billion Boundary Dam carbon capture project, which was more than \$200 million above its original estimate. Hydro Quebec is currently constructing the \$6.5-billion La Romaine hydroelectric project.

² https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf

³ Bent Flyvbjerg, "What You Should Know About Megaprojects and Why: An Overview," *Project Management Journal*, 45: 6–19, <http://onlinelibrary.wiley.com/doi/10.1002/pmj.21409/abstract>

⁴ Ansar, Atif and Flyvbjerg, Bent and Budzier, Alexander and Lunn, Daniel, "Should We Build More Large Dams? The Actual Costs of Hydropower Megaproject Development," March 10, 2014, *Energy Policy*, March 2014, pp. 1-14, <https://ssrn.com/abstract=2406852>

⁵ Ontario Clean Air Alliance, "The Darlington Re-Build Consumer Protection Plan," September 23, 2010, <http://www.cleanairalliance.org/wp-content/uploads/darlington.pdf>

cost overruns.⁶ PricewaterhouseCoopers found “megaprojects often exceed their budgets by 50% or more.”⁷

Scheduling delays also plague megaprojects. The EY study on oil and gas projects found that 73% were running behind schedule. When it comes to large-scale hydro power projects, eight out of ten suffered a scheduling delay, with the average project taking 44% longer (or 2.3 years) than expected.

Another study put it simply that megaprojects “are well-nigh guaranteed to exceed their budgets and schedules.”⁸

Taxpayers beware

Megaprojects also drag down the valuations and credit ratings of the companies and governments that pursue them. Project delays proved costly for the private companies in the oil and gas sector, for example, with publicly traded companies seeing a 15% decline in their share price in the three months after announcing a delay.⁹ Megaprojects undertaken by government-owned corporations have helped drag down the credit ratings of the governments that are ultimately left to pay the final bill, as happened recently in Newfoundland and Labrador with its Muskrat Falls hydro dam.¹⁰ Ontario’s prized AAA credit rating was lowered once it became clear that the provincial utility had spiralled out of control in its quest to build nuclear plants.

We’re not getting better all the time

Technological advances have done little to improve the performance of megaprojects. Data spanning the last 70 years shows no improvement in the initial estimates on costs and schedules when it comes to megaprojects.¹¹ Over and over again megaproject proponents have continued to get it wrong and failed to realize the mistakes made in previous megaprojects. In the case of hydro dams, cost estimates “today are likely to be as wrong as they were between 1934 and 2007.”¹² The same holds true for mega transportation projects. Nuclear projects, even with decades of experience in building and refurbishing them, suffer the same fate. In Ontario, Pickering A’s return to service cost three times more than expected and took two years longer

⁶ EY, “Spotlight on oil and gas megaprojects”, [http://www.ey.com/Publication/vwLUAssets/EY-spotlight-on-oil-and-gas-megaprojects/\\$FILE/EY-spotlight-on-oil-and-gas-megaprojects.pdf](http://www.ey.com/Publication/vwLUAssets/EY-spotlight-on-oil-and-gas-megaprojects/$FILE/EY-spotlight-on-oil-and-gas-megaprojects.pdf)

⁷ PWC, “Correcting the course of capital projects,” April 2013, <https://www.pwc.com/gx/en/capital-projects-infrastructure/pdf/pwc-correcting-the-course-of-capital-projects-v3-pdf.pdf>

⁸ Matti Siemiatycki, “Cost Overruns on Infrastructure Projects: Patterns, Causes and Cures,” The Institute on Municipal Finance and Governance (IMFG), <http://partnershipsbcc.ca/wp/wp-content/uploads/2017/03/Cost-Overruns-on-Infrastructure-Projects-Patterns-Causes-and-Cures.pdf>

⁹ EY, “Spotlight on oil and gas megaprojects”, [http://www.ey.com/Publication/vwLUAssets/EY-spotlight-on-oil-and-gas-megaprojects/\\$FILE/EY-spotlight-on-oil-and-gas-megaprojects.pdf](http://www.ey.com/Publication/vwLUAssets/EY-spotlight-on-oil-and-gas-megaprojects/$FILE/EY-spotlight-on-oil-and-gas-megaprojects.pdf)

¹⁰ “Power Plant Boondoggle Tests Trudeau’s Green Energy Commitment,” July 22, 2016.

<http://www.bloomberg.com/news/articles/2016-07-22/trudeau-s-muskrat-falls-dilemma-to-test-canada-s-green-pledges>

¹¹ Bent Flyvbjerg, “What You Should Know About Megaprojects and Why: An Overview,” *Project Management Journal*, 45: 6–19, <http://onlinelibrary.wiley.com/doi/10.1002/pmj.21409/abstract>

¹² Ansar, Atif and Flyvbjerg, Bent and Budzior, Alexander and Lunn, Daniel, “Should We Build More Large Dams? The Actual Costs of Hydropower Megaproject Development,” March 10, 2014, *Energy Policy*, March 2014, pp.1-14, <https://ssrn.com/abstract=2406852>

than originally forecast.¹³ The refurbishment of the Bruce reactors came in 75% over budget (as detailed in the Ontario chapter).

Oversell and under deliver

Cost overruns and missed schedules may be excused if the eventual benefits also exceed planners' expectations. Unfortunately, research shows that not only do proponents of megaprojects consistently under-forecast costs, they also over-estimate benefits. For example, forecasts for large-scale dams, on average, include a benefit-to-cost ratio of 1.4, meaning planners believed that future benefits will exceed costs by 40%. But with nearly half of all dams experiencing cost escalations of more than 40%, the benefits — which themselves have been questioned by researchers — were outweighed by the cost of construction.¹⁴ The result is a stranded asset that becomes a financial drain on society, not a net benefit. Transportation megaprojects suffer a similar result, with nine out of ten ridership forecasts on rail projects overestimated compared to when the project is in service.¹⁵ Research on the Euro Tunnel — which came in 80% over budget — has shown many of the predicted wider benefits to the economy and region failed to materialize,¹⁶ with a total loss to the British economy of \$17.8 billion.¹⁷

Megaprojects aren't an honest mistake

Why do megaprojects persist even though their track record is so dismal? Proponents of megaprojects point to factors such as scope changes, disputes among different parties working on the project, inflation of costs and incomplete studies as reasons for the significant cost overruns and delays. These problems, supporters say, can be overcome with the right amount of planning. Yet, megaprojects have been built for more than 70 years and the same problems continue, leaving many to question why those well-known problems haven't been accounted for and factored into initial estimates. Why aren't the estimates on costs, schedule and benefits getting any better, they ask?

Their conclusion? It's not an honest mistake.

In many cases, the planners and supporters of megaprojects manipulate the data to create the appearance of a good deal for ratepayers and taxpayers — leading to what one researcher referred to as the “survival of the unfittest.”¹⁸ One study showed, after extensive interviews with public officials, consultants and planners involved in large transit projects, that cost overruns and optimistic demand forecasts were not the result of “technical errors, honest mistakes, or

¹³ Figures from the “Report of the Pickering ‘A’ review panel.” Unit 4 ultimately cost 5 times its original estimate to bring it back into service. <http://www.ontla.on.ca/library/repository/mon/7000/10317476.pdf>

¹⁴ Ansar, Atif and Flyvbjerg, Bent and Budzier, Alexander and Lunn, Daniel, “Should We Build More Large Dams? The Actual Costs of Hydropower Megaproject Development,” March 10, 2014, Energy Policy, March 2014, pp.1-14, <https://ssrn.com/abstract=2406852>

¹⁵ Bent Flyvbjerg, Hugo Priemus, and Bert van Wee, “Public Planning of Megaprojects: Overestimation of Demand and Underestimation of Costs,” 2008 <https://www.sbs.ox.ac.uk/faculty-research/megaproject-management/publications-0/book-chapters/public-planning-mega-projects-overestimation-demand-and-underestimation-costs>

¹⁶ Alan Hay, Kate Meredith and Roger Vickerman, “The Impact of the Channel Tunnel on Kent and Relationships with Nord-Pas De Calais,” 2004, <https://www.kent.ac.uk/economics/documents/research/seminars/archive/FullReport.pdf>

¹⁷ Bent Flyvbjerg, “What You Should Know About Megaprojects and Why: An Overview,” Project Management Journal, 45: 6–19, <http://onlinelibrary.wiley.com/doi/10.1002/pmj.21409/abstract>

¹⁸ Bent Flyvbjerg, “The lying game,” June 2003, <http://flyvbjerg.plan.aau.dk/Lying%20gamePRINTED.pdf>

inadequate methods.”¹⁹ Rather, the study concluded, in most cases the planners, engineers and others involved in the forecasts were made to “revise” their estimates because the numbers “failed to satisfy their superiors.”

A study by a researcher from the U.S. Department of Transportation found that the planning process for large transit infrastructure projects has been reduced to a series of “exaggerated forecasts” in which various jurisdictions competed with one another to make their projects seem reasonable and procure federal funds.²⁰ In another case, Dallas’ transportation agency did its best to “conceal and then to misrepresent” the findings of research showing the agency’s \$2.6-billion transit dream was a bad deal for transit riders and the city’s taxpayers.²¹

But the most telling example of how public officials mislead the public on the true costs of megaprojects comes from San Francisco’s former mayor, Willie Brown. In response to news that a transit project in his city was hundreds of millions of dollars over budget, Mr. Brown wrote:

“In the world of civic projects, the first budget is really just a down payment. If people knew the real cost from the start, nothing would ever be approved. The idea is to get going. *Start digging a hole and make it so big, there's no alternative to coming up with the money to fill it in. [emphasis added]*”²²

Clearly, the risk of megaprojects has consistently — through many decades and hundreds of different projects in a range of sectors — been understated. Consumers and taxpayers have been misled in terms of what these projects cost, how quickly they can be built and what benefit they will bring to society and the overall economy. It’s in this context that we should view the megaprojects currently under construction or being proposed in Canada. Many of the megaprojects have already faced — or are being warned about — the risks they will impose on citizens across the country. In most cases, these risks are being ignored by the politicians in favour of them, as the allure of the megaproject — as it has for so many decades — is too appealing.

¹⁹ Martin Wachs, “Ethics and Advocacy in Forecasting for Public Policy,” *Business and Professional Ethics Journal*, <https://repository.library.georgetown.edu/handle/10822/837561>

²⁰ Don H. Pickrell, “A Desire Named Streetcar: Fantasy and Fact in Rail Transit Planning,” *Journal of the American Planning Association*, 1992, <http://www.tandfonline.com/doi/abs/10.1080/01944369208975791>

²¹ John F. Kain, “Deception in Dallas: Strategic Misrepresentation in Rail Transit Promotion and Evaluation,” *Journal of the American Planning Association*, 1990, <http://www.tandfonline.com/doi/abs/10.1080/01944369008975758?src=recsys>

²² Willie Brown, “When Warriors travel to China, Ed Lee will follow”, *sfgate.com*, July 27, 2013 <http://www.sfgate.com/bayarea/williesworld/article/When-Warriors-travel-to-China-Ed-Lee-will-follow-4691101.php>

Part II: Manitoba Hydro, the Keeyask dam and a utility pushed to the brink of financial disaster

Manitoba Hydro best exemplifies the political tactic of taking a project to the point of no return. The project in question is the \$8.7-billion, 695-megawatt (MW) Keeyask Dam on the Nelson River. A recent review of the dam's construction concluded that it would cost ratepayers more to stop the project than to push ahead, even after the updated price tag for the project was billions of dollars higher than originally forecast and the market for its power has shriveled. Like other energy megaprojects in Canada, the story of the Keeyask is one of continuous cost overruns, optimistic business forecasts and repeated political meddling that allowed a public utility to manage itself in a financially destructive manner.

A price tag that knows no bounds

Like all megaprojects, the price tag for the Keeyask dam has repeatedly been raised and is now billions of dollars more than originally forecast. In 2004, when Manitoba Hydro first presented the Keeyask dam as an option, the crown corporation estimated that the cost to complete the project would be \$1.7 billion.²³

By 2008, the price tag had more than doubled to nearly \$4 billion and would, according to the utility, eliminate a provincial energy deficit that was expected to occur by 2020 — a forecast that was later pushed back by more than 15 years.²⁴ The province's energy regulator, the Public Utilities Board (PUB), warned in 2008 that it was “concerned” that the Keeyask dam — among other capital projects — would ultimately require “substantially higher” costs and put “upward pressure” on electricity rates.²⁵

By 2009, the cost of the Keeyask dam increased to \$4.6 billion.²⁶

By 2011, the price tag had increased by another \$1 billion to \$5.6 billion.²⁷ At that price, Keeyask would produce power at a cost of 10 cents per kwh — or about triple what the utility was receiving in the export market, which was expected to be the primary recipient of the dam's output. At the time, the regulator warned that its previous concerns over Manitoba Hydro's aggressive spending plans — most notably in regards to the Keeyask dam and a multi-billion transmission line (Bipole III) that had, and continues to, experience a similar fate of repeated cost overruns — had only grown. The regulator worried that the crown corporation's forecast for a 70% increase in rates over the next twenty years was optimistic and that the increase would more realistically be 120%. Ultimately, the PUB concluded that the “risk tolerance exhibited by Manitoba Hydro” exceeded that of most of its customers.”²⁸

²³ Board Order 99/11, page 35, <http://www.pubmanitoba.ca/v1/pdf/11hydro/99-11.pdf>

²⁴ <http://www.pubmanitoba.ca/v1/pdf/08hydro/116-08.pdf>, page 145, 215

²⁵ <http://www.pubmanitoba.ca/v1/pdf/08hydro/116-08.pdf>, page 242

²⁶ Board Order 32/09, page 42, http://www.pubmanitoba.ca/v1/pdf/09hydro/32_09.pdf

²⁷ https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_82.pdf, page 11

²⁸ Board Order 99/11, page 7, <http://www.pubmanitoba.ca/v1/pdf/11hydro/99-11.pdf>

By 2013 the cost of the Keeyask dam had jumped once again — this time to \$6.2 billion. At the new price tag, the cost per unit of output would amount to 12.7 cents per KWh. The regulator, in its decision approving the utility’s rates, noted that the expected price of exports would be significantly lower than that figure, meaning ratepayers outside the province wouldn’t be paying the full cost of power produced at the Keeyask dam. Domestic ratepayers would be covering the difference in cost of generating power at the Keeyask dam and later selling it to American electricity customers at a substantial discount.²⁹

Just one-year later, in 2014, Manitoba Hydro added another \$300 million to the price tag of Keeyask — bringing the total to \$6.5 billion.³⁰

By 2015, the magnitude of Manitoba Hydro’s spending spree was on full display when it tabled its annual rate application to the PUB.³¹ While the price tag for Keeyask was \$6.5 billion — that figure would be revised higher at a later date, as detailed below — the financial impact of the Keeyask megaproject and other capital projects were “extremely” concerning to the province’s regulator. In order to cover the cost of these new projects — with Keeyask being the largest — and ignoring operating and other business-as-usual spending that the utility would incur and already forecast in previous rate applications – Manitoba Hydro was asking for a rate increase that would amount to 65% by 2022. Worse, is that even though Manitoba Hydro had already increased the budget for Keeyask by more than 100%, the Board remained “very concerned” about further upward revisions.³²

The Board’s fears were not misplaced. In 2016, after the election of a new government, an independent review of the Keeyask project raised the price tag by another \$700 million to \$7.2 billion. The review concluded that the decision to build Keeyask was “imprudent” and that the dam’s power may not be needed until 2034 — more than 15 years after the dam was supposed to start generating power, although delays have since pushed that date back to the early 2020s from the original forecast of 2019.³³

Nonetheless, the review admitted that, given the billions of dollars already spent on the Keeyask dam, the project had passed the point of no return and, if shut down now, would cost ratepayers more in the long-run. The utility’s new executives would simply have to soldier on, knowing the project was an economic loser.

Manitoba Hydro’s newly appointed chair was more blunt in his criticism, telling the public that there “will be pain, relative to where we are today, suffered by everybody”³⁴, that the utility “built

²⁹ Board Order 43/13, page 30-32, <http://www.pubmanitoba.ca/v1/pdf/13hydro/43-13.pdf>

³⁰ Board Order 49/14, page 10, <http://www.pubmanitoba.ca/v1/pdf/14hydro/49-14.pdf>

³¹ Each year public utilities have to apply to a regulator to set rates. In doing so, they provide detailed evidence on their costs and other expenses. The regulator then determines whether those costs are accurate, prudent and fair to ratepayers and sets rates that allow the utility to recover those costs and, in most cases, earn a regulated level of profit.

³² Board Order 73/15, page 6-7, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

³³ https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_report_bipole_III_keeyask_andt_tie_line_project.pdf

³⁴ <http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-bipole-transmission-line-1.3811316>

a bunch of dams for which we have no use, for the next 15-20 years³⁵ and that, bluntly, “[Manitoba] Hydro is a ticking time bomb.”³⁶

Yet the price tag of the project continues to grow. In Manitoba Hydro’s most recent rate application, the utility admitted that it has added an additional \$1.5 billion to the cost of the project, bringing the new total to complete Keeyask to \$8.7 billion and counting. The utility also admitted that the Keeyask dam will be “cash flow negative”, meaning that each unit of power will cost more to produce than it is worth and will be a drain on the utility’s finances, as far out, potentially, as the late 2030s. Manitoba electricity customers will be subsidizing the operation of the Keeyask dam for, at the minimum, the next two decades, as they will cover the difference between what it costs to produce power at the dam and what power sells for on either the province’s electricity market or markets in the United States.³⁷

Rate hike after rate hike

The growing price of the Keeyask dam — among other capital projects and a workforce that expanded at a double-digit rate over the last decade³⁸ — has resulted in a utility that followed a pattern of low-balling future rate hikes only to revise them higher at a later date.³⁹

In 2008, just as Manitoba Hydro was kicking off its capital spending spree, the utility expected that it would have to increase electricity rates by 2.9% annually until 2017.⁴⁰ By 2009, Manitoba Hydro expected rate increases to remain at 2.9% until 2012, but then bump up to 3.5% annually until 2020.⁴¹

In 2012, Manitoba Hydro increased its rate increase forecast once again. It now expected rates to increase by 3.95% annually — or more than double the rate of inflation — until the beginning of the 2030s.⁴²

By 2017 – Manitoba Hydro’s new management made it clear that improving the dire finances of the utility was a top concern — the company admitted that rates were expected to increase by 7.9% annually until 2023. Such an increase is nearly four times the rate of inflation.⁴³

Worse still is that the new forecast for annual rate increases excludes the cost of a \$10.7 billion hydroelectric project (the Conawapa dam) that was shelved in 2014⁴⁴, but was included in

³⁵ <http://www.winnipegfreepress.com/local/provincial-equity-injection-a-possibility-for-debt-burdened-manitoba-hydro-executives-say-397534131.html>

³⁶ <http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-sandy-riley-rate-increases-1.3970470>

³⁷ Manitoba Hydro 2017/18 and 2018/2019 rate application, tab 2, page 25 and 48,

https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2017_2019/index.shtml

³⁸ Board Order 73/15, page 33, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

³⁹ In nearly every case, the forecast that Manitoba presented to the PUB for rate hikes in years beyond its annual rate application were subsequently raised when the utility came back before the regulator.

⁴⁰ Board Order 90/08, page 3, <http://www.pubmanitoba.ca/v1/pdf/08hydro/90-08.pdf>

⁴¹ IFF-10, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_76.pdf

⁴² IFF-12,

https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/Consolidated_Integrated_Financial_Forecast_IFF12.pdf

⁴³ IFF-16,

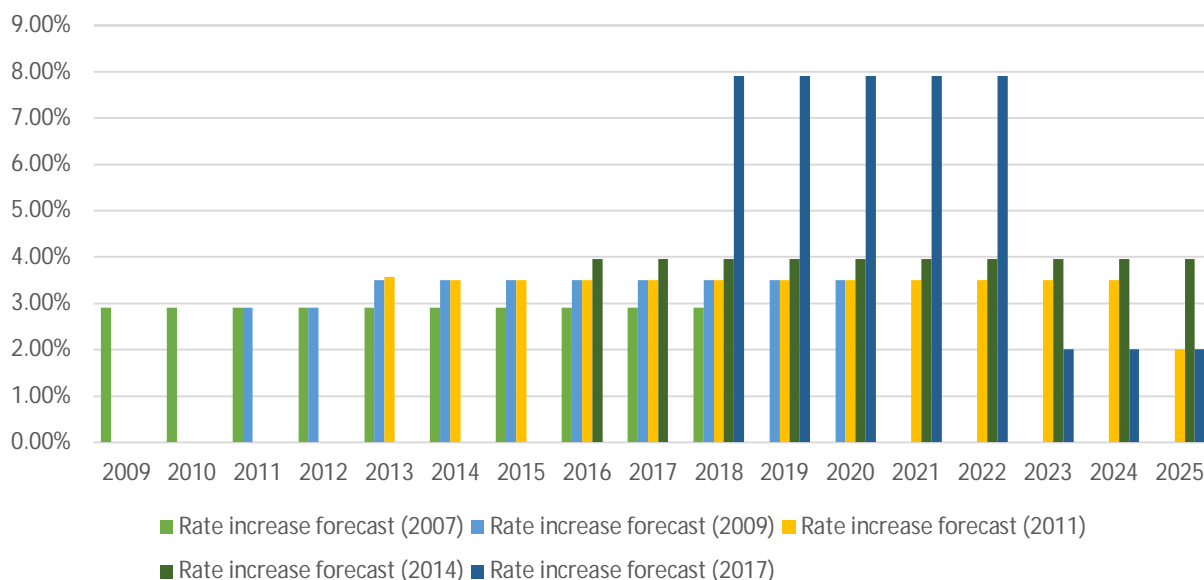
https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/03.1_appendix_3.1_integrated_financial_forecast_iff16.pdf

previous rate increase projections. Manitoba's new management is also pursuing an aggressive cost-cutting plan that it expects will shave \$800 million off operating expenses over the next decade.⁴⁵ Again, those costs were included in the previous rate increase applications, but have been excluded from the current forecast.

Ultimately, when Manitoba Hydro kicked off its capital spending spree in 2008, it told its customers that rates would be increasing at a 2.9% annual clip until 2017. Those rate increases, the utility told the public and its regulator, would pay for the Keeyask dam, the start of construction on the larger \$10-billion Conawapa dam and other projects, while keeping its operating costs, which largely consists of its wage bill, growing by 1% annually. Instead, ratepayers are being asked to pay 7.9% more each year, the Keeyask dam is years behind schedule, the Conawapa dam has been shelved indefinitely and around 900 positions at the company have been eliminated.⁴⁶ Ratepayers have to pay more, but get less in return.

Like other megaprojects, the cost and risk of the Keeyask dam to ratepayers was downplayed while the benefits were vastly exaggerated and now, nearly a decade later, customers are beginning to see the reality of the financial risk of megaprojects such as Keeyask dam.

Manitoba Hydro's Ever-Increasing Annual Rate Forecasts



Digging a financial hole

⁴⁴ Report on the need for and alternatives to (NFAT), Review of Manitoba Hydro's Preferred Development Plan, 2014, http://www.pubmanitoba.ca/v1/nfat/pdf/finalreport_pdp.pdf

⁴⁵ Manitoba Hydro 2017/18 and 2018/2019 rate application, tab 2, page 6. https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2017_2019/index.shtml

⁴⁶ Manitoba Hydro 2017/18 and 2018/2019 rate application, tab 2, page 6, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2017_2019/index.shtml

While Manitoba Hydro's management was intent on pushing ahead with the Keeyask dam (among other billion-dollar capital projects such as the Bipole III transmission line), even as the price to complete the project more than doubled, the company's management was digging a financial hole that would see it lose money for multiple years in row, take on tens of billions of dollars in new debt and become a nearly fully leveraged utility as measured by standard financial metrics.

Nowhere was the utility's move towards financial instability more evident than in its 2015 and 2016 rate application to the Public Utilities Board. On nearly every front, the utility's executives proposed pushing Manitoba Hydro to the brink of financial ruin, even admitting in their application that their proposal meant it would "barely" be capable of absorbing the shock of a drought and would leave it unable to "mitigate the potential financial impacts of the considerable array of risks the Corporation faces in fulfilling its mandate."⁴⁷

It's easy to see why the utility's executives would say that given the evidence it presented to the Public Utilities Board.

For starters, Manitoba Hydro was forecasting that the annual cost of running the utility would increase by 100% over the next decade, from \$1.5 billion to nearly \$3.0 billion.⁴⁸ To deal with that run-up in costs, the utility was asking the regulator to approve annual rate increases of 3.95%. Yet, even with those rate increases, Manitoba Hydro would post net income losses of around \$900 million between 2018 and 2023, or an average annual loss of \$180 million — more than 6 times Manitoba Hydro's net income of \$37 million in 2015.⁴⁹⁵⁰ That's a far cry from the utility's net income forecasts in 2009 when it expected to post a profit of between \$235 and \$276 million through 2018 to 2020.⁵¹

⁴⁷ 2015/16 & 2016/2017 rate application, Tab 2, page 18, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/index.shtml

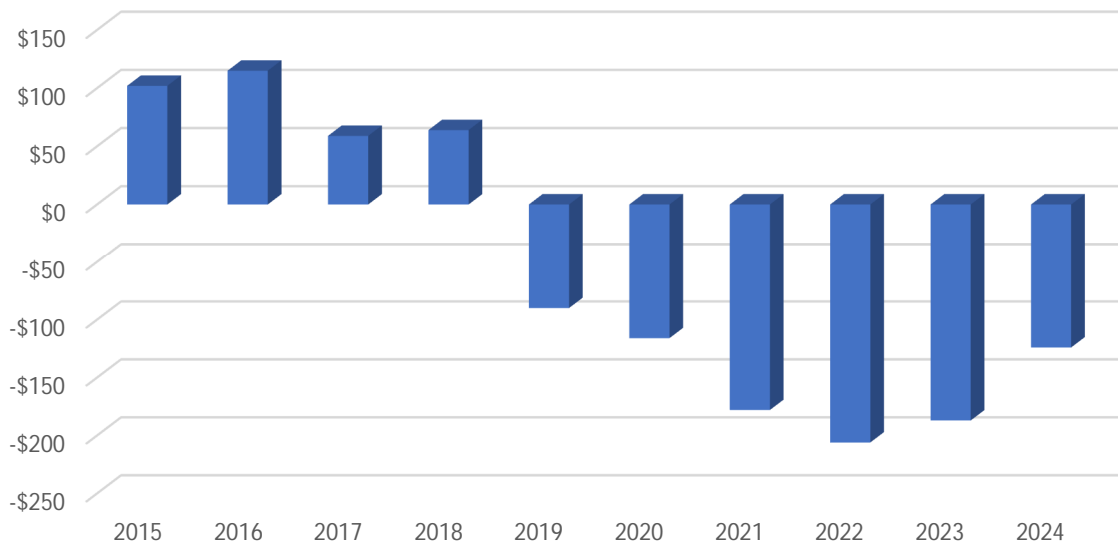
⁴⁸ 2015/16 & 2016/2017 rate application, Tab 2, page 20, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/index.shtml

⁴⁹ 2015/16 & 2016/2017 rate application, Tab 2, page 21, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/index.shtml

⁵⁰ IFF16, page 5, https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/03.1_appendix_3.1_integrated_financial_forecast_iff16.pdf

⁵¹ IFF09, page 34, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_5_2.pdf

Manitoba Hydro's Forecasted Net Income (\$ million)

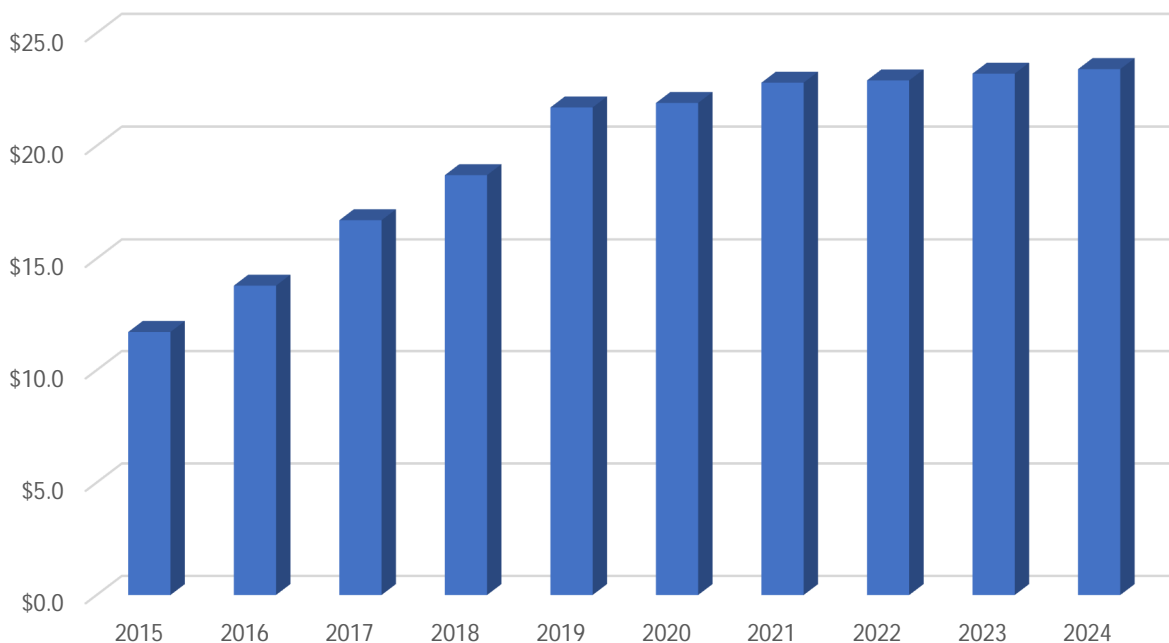


Led by the cost of the Keeyask dam, Manitoba Hydro also forecast a doubling of its long-term debt. In 2015, Manitoba Hydro had \$11 billion in long-term debt and predicted that amount to grow to \$23.4 billion by 2024.⁵² The annual interest costs alone of servicing that debt would nearly triple, growing from their current level \$495 million and hitting nearly \$1.3 billion by 2024.⁵³

⁵² IFF14, page 38, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/pdf/appendix_3_3.pdf

⁵³ IFF14, page 36, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/pdf/appendix_3_3.pdf

Manitoba Hydro's Long-Term Debt (\$ billion)



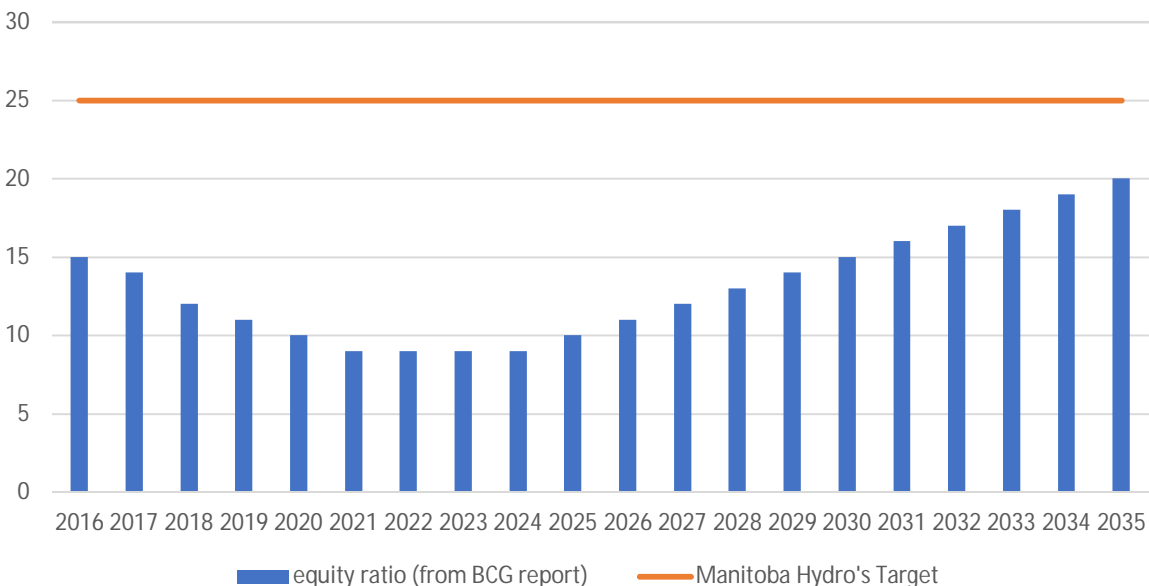
The company's debt-to-equity ratio, a standard financial metric used to measure a company's leverage (the more debt, the more leveraged the company), was forecast to hit 91:09 by 2021.⁵⁴ Not only is that type of leverage well above other Canadian crown corporations, but it's significantly above the company's own target of 75:25.⁵⁵ It's also far higher than investor-owned utilities. The Ontario Energy Board, for example, pushes for a 60:40 debt-to-equity ratio in an effort to mimic the financial targets of private utilities. In the United States, many utilities have debt-to-equity ratios lower than 50:50 (less debt than equity).

⁵⁴ Boston Consulting Group (BCG) report, page 18,

https://www.hydro.mb.ca/corporate/news_media/pdf/bcg_bipoleIII_keeyask_and_tie_line_review.pdf

⁵⁵ See the independent Boston Consulting Group (BCG) report, page 19, for a look at the debt-to-equity ratio for other corporations, both in Canada and the United States.

Manitoba Hydro's Debt-to-Equity Ratio (%)



Manitoba Hydro would also be so leveraged that it would be forced to borrow simply to pay interest costs. The utility's interest coverage ratio, where anything below 1.0 means that it can't pay its interest obligations from its annual earnings, was forecast to fall below that threshold for six of the next ten years. Similarly, its capital coverage ratio, where anything below 1.0 means the company can't afford to maintain its current assets from its annual earnings, was also expected to fall below that threshold in six of the next 10 years — meaning the company would have to issue debt simply to perform basic maintenance.⁵⁶

By 2016, one credit ratings agency admitted that Manitoba Hydro was no longer self-supporting and its dire finances could drag down the province's credit rating.⁵⁷

In short, Manitoba Hydro was admitting that it planned to become highly leveraged — far higher than any investor-owned utility could imagine — while being unable to pay the interest costs on its debt or afford the necessary investments required to maintain or upgrade its assets. Worse still, this was all part of the utility's plan, not the result of forces beyond its control, as it repeatedly laid out to the PUB each year in its rate applications its plan to become a highly leveraged utility.

The financial hole that Manitoba Hydro had willingly dug itself was in sharp contrast to its forecasts in 2009, when the Keeyask dam was still in its infancy. First off, at that time the utility expected the Keeyask dam to cost just \$4.6 billion, or nearly 50% of the \$8.7 billion (and counting) that it's now forecasting. Nevertheless, Manitoba Hydro expected that annual net

⁵⁶ 2015/16 & 2016/2017 rate application, Tab 2, page 22, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/index.shtml

⁵⁷ <http://mytoba.ca/featured/manitoba-hydro-debt-doubling-25-billion/>

income would consistently come in above \$200 million in the years 2016 to 2020 (later revised to years of losses), that long-term debt levels would peak at \$16.4 billion (revised to \$23.4 billion, even though it excluded the cost of the now shelved \$10-billion Conawapa dam), its debt-to-equity ratio would fall to 80:20 by 2019 and then recover “strongly thereafter” (revised later to years of a 91:09 debt-to-equity ratios) and its interest and capital coverage ratios would never fall below 1.0, meaning the company would be able to pay its interest costs and maintenance costs from annual earnings (revised later to years of issuing debt to pay those costs).⁵⁸

On every single measure, Manitoba Hydro’s initial forecasts that its aggressive capital spending — notably with the megaproject Keeyask dam — would have little negative impact on the company’s finances proved to be misguided or negligent.

The company’s most recent rate application provides a sobering reassessment. In asking for annual rate increases of nearly 8% over the next five years, the utility’s new management said the company’s current and future financial situation “represents an untenable risk to both the financial sustainability of the corporation and the overall economic health of the Province of Manitoba.” It added that the “previous financial plans did not adequately prepare Manitoba Hydro to absorb the significant increase in operating and borrowing costs that result from the completion of major capital projects currently underway while still ensuring the continued financial strength of the corporation.”⁵⁹

Publicly, the company’s new chair said the company may need an “equity injection” — a fancy term for a taxpayer-funded bailout — to “moderate” the significant rate increases that are necessary to improve the company’s finances.⁶⁰

Now that the Keeyask dam is apparently beyond the point of no return, the utility’s management is finally being honest with the public on the real price and financial risk that the project entails.

Selling power at a loss

Like almost all megaprojects, the management at Manitoba Hydro relied on optimistic forecasts regarding the future demand for Keeyask’s output. In Manitoba Hydro’s case, that demand largely revolved around exporting generation from the Keeyask dam to electricity markets in the United States. Unfortunately for Manitoba Hydro’s ratepayers, demand for power in the United States from the Keeyask dam and the price expected to be paid for it has fallen drastically over the last decade. The result will be a dam that sells power on export markets at a loss with domestic ratepayers left to pick up the tab.

Manitoba Hydro prefers to construct large, multi-billion dams such as Keeyask on the argument that they are cheaper in the long-run. In order to fund those investments, the utility will sell that

⁵⁸ IFF 09, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_5_2.pdf

⁵⁹ Manitoba Hydro 2017/18 and 2018/2019 rate application, tab 2, page 2,

https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2017_2019/index.shtml

⁶⁰ <http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-sandy-riley-rate-increases-1.3970470>

excess power — it admits that big dams like Keeyask will create a surplus, sometimes for more than a decade — in an effort to help finance megaprojects. Export sales, according to the utility, are a key financial resource in its push to big build dams like Keeyask, rather than smaller, incremental generation projects, which wouldn't require large export markets to be financially viable.

Unfortunately, Manitoba Hydro's forecasts for the price it will receive for surplus power have proven to be optimistic. The result is that domestic ratepayers, rather than seeing a rate reduction because of export sales, will actually be subsidizing those exports.

For example, in 2007 Manitoba Hydro expected to earn \$645 million and \$679 million in export sales in 2017 and 2018, respectively.⁶¹ By 2016, it lowered that amount by hundreds of millions of dollars to \$468 and \$454 over the two year period.⁶² Looking out over a twenty-year period, in 2011, the utility expected to earn \$12 billion on exports, but then just two years later, slashed that forecast in half to \$6 billion.⁶³

The utility's financial reports show that the value of export sales into the U.S. market have fallen by hundreds of millions of dollars. In 2008, Manitoba Hydro sold \$515 million worth of power into the United States, but by 2016, that figure had fallen to \$385 million.⁶⁴ In its most recent rate application, the utility has lowered its export revenue forecast more dramatically, expecting that figure to remain below \$200 million annually until 2021.⁶⁵

The price the utility expected to receive when selling power into the U.S. market also proved to be optimistic. Manitoba Hydro's forecasts in 2009 for export prices in 2015 were nearly double what it was actually receiving that year.⁶⁶ The PUB noted in its 2015 decision that "successive Manitoba Hydro export price forecasts have been revised downward and consistently overestimate actual results."⁶⁷

Furthermore, the cost to produce each unit of power at Keeyask is significantly higher than the price that unit of power will fetch in U.S. wholesale markets. The last estimate of the per-unit cost of generation at Keeyask was done in 2013, when the cost of the dam was forecast to be \$6.2 billion. At the time, the utility expected that figure to be 12.7 cents per kwh. Since that time, the price tag of Keeyask has increased by 40% to \$8.7 billion — meaning the cost of each unit of generation from Keeyask may be as much as 17 cents per kwh.

⁶¹ IFF07, page 38, https://www.hydro.mb.ca/regulatory_affairs/electric/gra_08_09/information_requests/Appendix_22-Integrated_Financial_Forecast_IFF07-1.pdf

⁶² IFF16, page 57,

https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/03.1_appendix_3.1_integrated_financial_forecast_iff16.pdf

⁶³ Board Order 43/13, page 2, <http://www.pubmanitoba.ca/v1/pdf/13hydro/43-13.pdf>

⁶⁴ 57th annual report, page 68 and 65th annual report, page 28

⁶⁵ Manitoba Hydro 2017/18 and 2018/2019 rate application, tab 2, page 5,

https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2017_2019/index.shtml

⁶⁶ Board Order 73/15, page 86, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

⁶⁷ Board Order 73/15, page 87, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

Contrast that with the market price in the U.S. market neighbouring Manitoba where the average price has ranged from 2 to 4 cents per kwh over the last two years.⁶⁸

Other export markets, such as Ontario and Saskatchewan either have their own surplus of power (Ontario) or are considering constructing gas plants given the long-term forecasts for lower natural gas prices due to the increase in fracking (Saskatchewan). There simply isn't a financially viable market for Keeyask's output.

A regulator's concerns repeatedly ignored

Over the past decade, the Public Utilities Board repeatedly raised its concerns over what Manitoba Hydro's aggressive spending plans would do to its financial health. The utility repeatedly ignored those concerns.

As early as 2004, the PUB warned that it was "concerned about the Corporation's overall debt levels in relation to its equity levels." The PUB also noted that it was concerned with the "substantial growth in capital expenditures and accompanying debt", adding that, while many of the large capital projects the utility was planning may be justified "individually," when considered "collectively" they place "increased strain on the financial stability of Manitoba Hydro" and add "additional risk for ratepayers."⁶⁹

In 2007 the PUB noted it has repeatedly called for "quicker progress" to hit the 75:25 debt-to-equity target, but the utility had ignored those concerns and, instead, was proposing to delay the date to achieve that target by five years to 2017 (it later pushed it out by more than a decade into the 2030s).⁷⁰

By 2011, the PUB once again reiterated its concerns over the "scale of capital expenditure and new debt". But this time, the PUB stated that Manitoba Hydro had "either refused or failed to provide the Board information that the Board considers critical to it reaching a comprehensive and final perspective on the prudence of Manitoba Hydro's actions and plans, and the implications for domestic rates of Manitoba Hydro's operations and plans." The regulator and the utility ended up in court to try and settle the matter. Ultimately, the PUB concluded that it was concerned that the "consequences" of the utility's current capital spending plans would result in rates "much higher" than its currently forecasting.⁷¹ It warned that rates could more than double over the next 20 years — yet the utility was predicting a rate increase of about half that amount.

The PUB also noted that the utility had repeatedly ignored its concerns over ever-escalating operating costs.⁷²

⁶⁸ <http://www.pjm.com/~media/committees-groups/committees/mc/20170221-webinar/20170221-item-06a-markets-report.ashx>

⁶⁹ Board Order 143/04, page 92-95, <http://www.pubmanitoba.ca/v1/pdf/04hydro/143-04.pdf>

⁷⁰ Board Order 20/07, page 27, <http://www.pubmanitoba.ca/v1/pdf/07hydro/020-07.pdf>

⁷¹ Board Order 99/11, page 3-6, <http://www.pubmanitoba.ca/v1/pdf/11hydro/99-11.pdf>

⁷² Board Order 99/11, page 84, <http://www.pubmanitoba.ca/v1/pdf/11hydro/99-11.pdf>

By 2013, the PUB once again highlighted Manitoba Hydro's "deteriorating financial condition...in the face of pending significant major capital expenditures." The utility had also completely abandoned any push to achieving its own 75:25 debt-to-equity ratio, as it now forecast that ratio to hit 90:10. It also warned that Manitoba Hydro's growing debt levels could potentially drag down the credit rating of the entire province.⁷³

In 2015, the PUB raised its alarm, admitting that it was "extremely concerned about the impact of successive and significant rate increases on ratepayers."⁷⁴ Even though the price tag of Keyask and other major capital projects had already increased by billions of dollars, the PUB maintained that it was worried about further "cost escalations."⁷⁵ It also called on the province — Manitoba Hydro's sole shareholder — to allow the PUB the "statutory jurisdiction to review and approve Manitoba Hydro's major capital projects."⁷⁶ To date, the regulator still has no authority to review the utility's billions of dollars in proposed capital spending.

In 2017, Manitoba Hydro eventually admitted its financial standing created an "untenable risk to both the financial sustainability of the corporation and the overall economic health of the Province of Manitoba." Nearly a decade later, the utility was finally prepared to acknowledge the risks and warnings repeatedly raised by its regulator. Unfortunately for ratepayers, the admission also came with a request for near 8% annual rate increases. Ratepayers finally have a more realistic look at the cost of the utility's megaproject.

⁷³ Board Order 43/13, page 9-10, 24, <http://www.pubmanitoba.ca/v1/pdf/13hydro/43-13.pdf>

⁷⁴ Board Order No. 73/15, page 5, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

⁷⁵ Board Order No. 73/15, page 7, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

⁷⁶ Board Order No. 73/15, page 8, <http://www.pubmanitoba.ca/v1/pdf/15hydro/73-15.pdf>

Part III: Muskrat Falls and a failed nation-building exercise

The politics of energy are front and centre in Newfoundland and Labrador. As such, the decision to build the multi-billion Muskrat Falls hydro dam, officially announced in November of 2010 by then Premier Danny Williams, was initially as much a political statement as it was a financial and economic one. But, as has occurred during the construction of so many other megaprojects, the economics of the project have gone bust, with the utility's new CEO officially calling the project a boondoggle. Worse still, the majority of the public, which for years backed the project as a source of provincial pride, no longer supports it and the original government that pushed the project through has been voted out of office.⁷⁷

Just like the other energy megaprojects in Canada, Muskrat Falls has been plagued by cost overruns, optimistic revenue and demand forecasts and the systematic sidelining of the province's regulator.

What is Muskrat Falls?

The Muskrat Falls hydroelectric project sits on the Churchill River in Labrador. The project consists of two dams with a total capacity of 824 Megawatts (MW), making it the second largest hydroelectric generator in the province, behind the 5,428 MW Churchill Falls dam.⁷⁸

Due to Muskrat Falls' remote location, bringing power from the dam to Newfoundland and Labrador's largest city, St. John's, and beyond, will require the construction of more than 1,100 kilometers of transmission lines.

The first leg of the 1,100 kilometers of transmission lines will move power from Muskrat Falls to St. John's via 35 kilometers of underwater cable across the Strait of Belle Isle, which separates Labrador (mainland Canada) from the island of Newfoundland.⁷⁹

But because Muskrat Falls will produce more power than Newfoundland and Labrador will need, another transmission line is also being built to send a portion of Muskrat's power to Nova Scotia. The Maritime Link, as the inter-provincial line is called, consists of 300 kilometres of transmission lines in Newfoundland, 170 kilometres of subsea transmission lines from the island of Newfoundland to Cape Breton Nova Scotia — the longest subsea cable in North America — and an additional 50 kilometres of transmission lines in Nova Scotia. In exchange for constructing the Maritime Link, the Nova Scotia-based utility Emera was originally to receive 20% of Muskrat Falls' output for 35 years, but that deal was later revised at the request of Nova Scotia's regulator.⁸⁰ Nova Scotia will now receive between 44% and 57% of power produced at Muskrat Falls.⁸¹

Righting an historical “wrong”

⁷⁷ <http://www.cbc.ca/news/canada/newfoundland-labrador/muskrat-falls-poll-1.3920950>

⁷⁸ <https://muskratfalls.nalcorenergy.com/project-overview/muskrat-falls-hydroelectric-generation-facility/>

⁷⁹ <https://muskratfalls.nalcorenergy.com/project-overview/labrador-island-link-and-transmission-assets/>

⁸⁰ <http://www.emeranl.com/en/home/themaritimelink/infrastructure.aspx>

⁸¹ <https://www.pressreader.com/canada/the-telegram-st-johns/20131211/281633893046045>

From the outset, the Muskrat Falls project was presented as a way to end a decades-long grievance that has, in many ways, shaped Newfoundland and Labrador's political life: the Churchill Falls contract.

The contract, signed in 1969 and beginning in 1972, ensured that almost all of the 5,428 MW of power from the Churchill Falls dam flows to Hydro Quebec at rock bottom prices for the next 40 years.⁸² Worse still for the residents of Newfoundland and Labrador is that the contract contained an automatic renewal in 2016 that extended it until 2041.

So, what's wrong with the contract? Hydro Quebec currently receives nearly all of the output from the Churchill Falls generating station for \$2 per MWh, which is so low that it's essentially free. For context, the "peak" electricity rate in Ontario is \$180 per MWh.⁸³ Or, for example, Hydro Quebec has a contract with neighbouring Vermont to sell the state power at a cost starting at \$58 per MWh.⁸⁴ If Hydro Quebec were to export the 31,000,000 MWh of annual power that it, on average, receives from Churchill Falls for that price, it would profit by more than \$1.7 billion annually. Newfoundland and Labrador, on the other hand, earns a pittance on the dam's output.

One report suggests that, to date, the contract signed between Hydro Quebec and Newfoundland and Labrador has earned the Quebec utility \$27.5 billion, compared to just \$2 billion for the home province.⁸⁵ In 1984, Premier Brian Peckford told prime minister Pierre Trudeau that the province was losing \$2 million a day because of the Churchill contract.⁸⁶

Newfoundland and Labrador politicians have railed against the contract for decades — with one recently calling it "one of the greatest public policy disasters entered into by any province or government in the history of Canada."⁸⁷ The province's previous Premier, Danny Williams, once said that the Churchill falls contract was "part of the reason I got involved in politics."⁸⁸ Disputes over the contract have also made their way to the courts, with the Supreme Court hearing two appeals in the 1980s from actions launched by the Newfoundland government. In both cases, the Supreme Court ruled against the Newfoundland government.⁸⁹ In 2010, the Newfoundland government launched yet another legal challenge to the contract, but to date, no court in Quebec has sided with the province, though the Supreme Court says it will once again review the contract.⁹⁰

In 2010, when then Premier Danny Williams officially launched the Muskrat Falls project, he assured Newfoundlanders that this was the solution to ending years of anger over the Churchill falls contract.

⁸² <http://www.ucs.mun.ca/~feehan/CF.pdf>

⁸³ This was the rate prior to the province introducing the Fair Hydro Plan, which will see Ontario issue debt to lower rates in the short term.

⁸⁴ <http://psb.vermont.gov/sites/psbnew/files/orders/2011/7670FinalOrder.pdf>

⁸⁵ <http://montrealgazette.com/news/quebec/supreme-court-to-review-hydro-quebecs-churchill-falls-energy-deal-with-newfoundland-and-labrador>

⁸⁶ <http://theindependent.ca/2011/08/31/a-look-into-the-history-of-the-churchill/>

⁸⁷ <https://www.theglobeandmail.com/opinion/revenge-is-a-bad-business-plan-newfoundland/article13464882>

⁸⁸ <http://www.cbc.ca/news/canada/newfoundland-labrador/muskrat-falls-cheerleaders-1.3657564>

⁸⁹ <http://policyoptions.irpp.org/magazines/making-parliament-work/the-churchill-falls-contract-and-why-newfoundlanders-cant-get-over-it/>

⁹⁰ <http://www.cbc.ca/news/canada/newfoundland-labrador/supreme-court-canada-review-churchill-falls-energy-deal-1.4077258> and <http://www.cbc.ca/news/canada/newfoundland-labrador/nalcor-hydro-quebec-churchill-falls-court-challenge-1.3960079>

"This is a day of great historic significance to Newfoundland and Labrador as we move forward with development of the Lower Churchill project, *on our own terms and free of the geographic stranglehold of Quebec* which has for too long determined the fate of the most attractive clean energy project in North America," Premier Williams announced to the public (emphasis added).⁹¹ He went on to say the Muskrat Falls project marks a "new era" for Atlantic Canada, while Newfoundland would enjoy the "enormous" benefits of the project that would include "thousands" of jobs and "billions of dollars of economic activity."

Enormous so-called "benefits" at an enormous price

The price tag for the Muskrat falls project has more than doubled from when it was first unveiled. The current CEO warns that the price increases may not be over.

When Danny Williams announced the Muskrat falls project, the official press release said the "total cost" of the project would be \$6.2 billion.⁹² By early 2014, the publicly owned utility overseeing the project, Nalcor, maintained that the project would still cost \$6.2 billion, but admitted that figure "excluded" interest and other financing costs.⁹³

By June of 2014, Nalcor admitted that after completing "98%" of the "detailed engineering" needed to move ahead with the project — although that detailed engineering, as is the case with so many other megaprojects, eventually proved inadequate — the new price tag for the project was \$6.99 billion (interest and other financing costs were still excluded).⁹⁴

In September of 2015, Nalcor increased the cost of the Muskrat Falls project to \$7.6 billion and, at the same time, informed the public that the financing costs would total more than \$1.3 billion. In total, the new price tag for the project was now \$9.05 billion.⁹⁵ The utility also admitted that the dam wouldn't start producing power in 2017 as previously forecast — that date had now been pushed back to 2018.

With the appointment of a new CEO and the election of a new government, the real financial and economic impact of the Muskrat Falls project became clearer. In June 2016, Nalcor's new CEO, Stan Marshall, admitted that Muskrat Falls was a "boondoggle" and "not the right choice for the power needs of this province."⁹⁶ In saying those remarks, he also added the new price for the project had jumped to \$11.4 billion — which includes \$9.13 billion in base construction costs and an additional \$2.3 billion in interest and other financial costs. When compared to the original, publicly announced price of \$6.2 billion by Premier Williams, the updated forecast marked an 83% increase in the cost of Muskrat Falls. Even if financing costs were added to the original \$6.2 billion estimate — bringing that forecast to \$7.4 billion — the new estimate is \$4 billion greater (and, as shown below, the price has gone up since then).

⁹¹ <http://www.releases.gov.nl.ca/releases/2010/exec/1118n06.htm>

⁹² <http://www.releases.gov.nl.ca/releases/2010/exec/1118n06.htm>

⁹³ <https://muskratfalls.nalcorenergy.com/wp-content/uploads/2014/03/Muskrat-Falls-January-2014-Monthly-Report-Final-compressed.pdf>

⁹⁴ <http://muskratfalls.nalcorenergy.com/wp-content/uploads/2014/08/June-2014-LCP-Monthly-Project-Report-final.pdf>

⁹⁵ <https://www.gov.nl.ca/mfoversight/pdf/December-Report-2015.pdf>

⁹⁶ <http://www.cbc.ca/news/canada/newfoundland-labrador/stan-marshall-muskrat-falls-update-1.3649540>

Nalcor's new CEO also predicted that Muskrat Falls wouldn't hit full production until 2020 — nearly two full years behind schedule.

As is the case with so many other megaprojects, Nalcor's CEO said the project couldn't be stopped now. When asked whether it would be better to simply pull the plug on the project, Stan Marshall said that wasn't a "practical option," as the utility has already spent billions of dollars and made future plans based on generation from Muskrat Falls. He added that canceling the project would add "billions more" to the price tag and the province would have nothing to show for it.

Nonetheless, the cost increases have continued to pile up. In December 2016, Nalcor admitted that it had approved a new deal with a key contractor on the project, adding an additional \$300 million to the total costs — bringing that figure to \$11.7 billion.⁹⁷

CEO Stan Marshall said he also couldn't rule out more cost increases.⁹⁸

His warnings become a reality in June of 2017, when Nalcor added an additional \$1 billion to the cost of Muskrat falls. The total is now \$12.7 billion.⁹⁹ When announcing the new cost increase, Marshall admitted that the Muskrat Falls project is now a "hell of a lot worse" deal for Newfoundland electricity customers than the infamous Churchill contract — pointing out that contract didn't cost electricity customers a cent, it simply sent the profits to Quebec. Marshall also said that "intentionally or otherwise," the costs of the project were initially vastly "underestimated."

Worse still for electricity customers, Nalcor also added an additional \$75 million in annual operating costs, bringing that total to \$109 million each year — nearly triple the 2012 forecast of annual operating costs of \$34 million.¹⁰⁰

"I knew this was a boondoggle ... It should never have been built," he said, "How many times do I have to say that? But it's too late to stop. We couldn't go and get a refund."

On the same day that Stan Marshall admitted that Muskrat Falls should have never been built, the province released a 2013 report by engineering firm SNC-Lavalin that warned of the risk of cost overruns and delays. Marshall says the report was presented to Nalcor executives, but "wasn't accepted."¹⁰¹

⁹⁷ https://www.gov.nl.ca/mfoversight/pdf/report_dec_2016.pdf

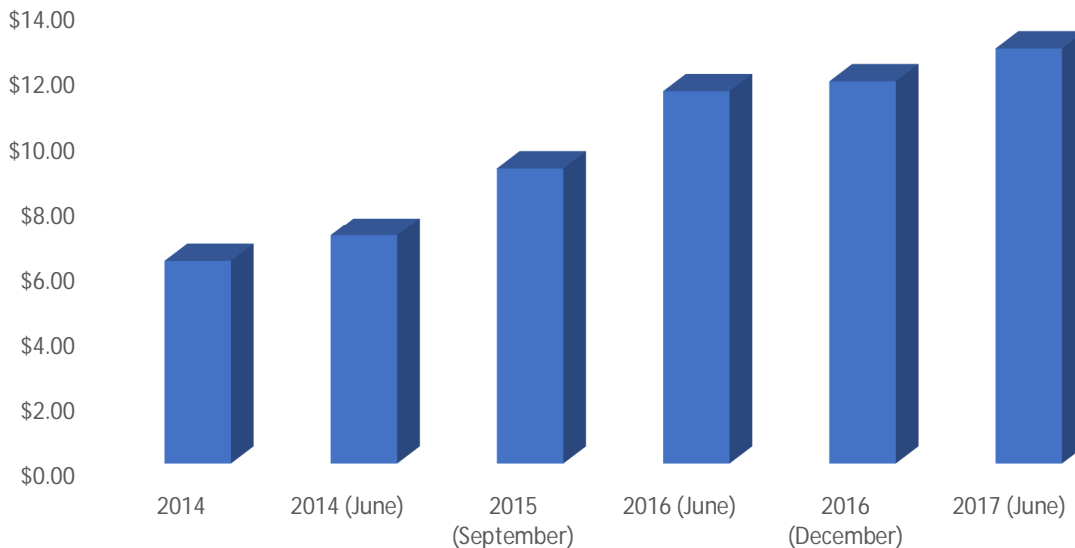
⁹⁸ <https://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/new-deal-hikes-costs-at-troubled-muskrat-falls-project-to-almost-117-billion/article33399611/>

⁹⁹ <http://www.cbc.ca/news/canada/newfoundland-labrador/stan-marshall-muskrat-falls-nupdate-1.4174569>

¹⁰⁰ http://muskratfalls.nalcorenergy.com/wp-content/uploads/2017/06/Muskrat-Falls-Project-Update-Presentation-June-23_Final.pdf

¹⁰¹ <http://www.cbc.ca/news/canada/newfoundland-labrador/danny-williams-boondoggle-1.4181633>

Cost Estimate of Muskrat Falls (\$ billion)



A rate increase here, there and everywhere

The rate impacts on households and businesses across the province are for more severe than when the project was first approved. In 2012, Muskrat Falls was expected to add \$38 per month to the average customer's electricity bill — with Nalcor noting that without Muskrat Falls, that increase would be \$82 per month, as the province would continue to rely on an aging oil generating plant for its power. As detailed below, that \$82 projection was based on an oil price forecast that has turned out to be more than double today¹⁰² By 2014, as the price of the project began to soar higher, the average monthly electricity bill increase was expected to be \$46 per month.

As the cost of Muskrat Falls grew by the billions, so too did the forecast monthly costs for electricity customers. By the time the new CEO called the project a “boondoggle,” the average monthly cost was expected to increase by \$150 — a level that the CEO admitted “was unaffordable.”¹⁰³ With the additional \$1 billion added to the cost of the project in June of 2017, that figure is now even higher and more than double Nalcor's own estimate in 2012 that without Muskrat Falls, monthly electricity bills would increase by \$82.

The original estimate that Nalcor submitted on the cost per kwh that electricity customers would pay once Muskrat Falls was completed was 15.2 cents (a preliminary study done in 2011 estimated the cost to be 14.3 cents per kwh).¹⁰⁴¹⁰⁵ The utility now expects that figure to be 23.3 cents per kwh — or more than double their current level of 11.7 cents per kwh.¹⁰⁶ It would also

¹⁰² <http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/Technical-Briefing-Electricity-Rate-Forecasting-Nov-2012.pdf>

¹⁰³ <http://www.cbc.ca/news/canada/newfoundland-labrador/stan-marshall-muskrat-falls-update-1.3649540>

¹⁰⁴ <http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/Decison-Gate-3-Electricity-Rates.pdf>

¹⁰⁵ <http://www.pub.nf.ca/applications/MuskratFalls2011/files/corresp/RF1-KPL125-KPL156-Nalcor-questions.pdf>

¹⁰⁶ http://muskratfalls.nalcorenergy.com/wp-content/uploads/2017/06/Muskrat-Falls-Project-Update-Presentation-June-23_Final.pdf

leave Newfoundland and Labrador with the highest electricity rates in the country, according to its own forecasts.¹⁰⁷ Without a loan guarantee from the federal government, the utility expects electricity customers to be pay 25 cents per kwh.

No need and a regulator straightjacket

Unlike many other megaprojects that received rubber stamp approval from government-appointed review boards and compliant regulators, the supposed “need” for the Muskrat Falls project has repeatedly been questioned by these bodies and never received their full support. The provincial leaders pushing the project have simply ignored these warnings.

In 2011, a joint federal and provincial review panel tasked with reviewing the environmental impact of the Muskrat falls project (as well as another much larger hydro dam nearby) and determining whether it was needed and the most cost-effective way to meet future energy demand, failed to throw its support behind Muskrat Falls. The panel concluded that the utility’s evidence showing Muskrat Falls to be the “least-cost” way to meet future energy demand was “inadequate.”¹⁰⁸ The panel recommended that a new, “independent” analysis be undertaken.

The joint review panel also questioned whether the Public Utilities Board (PUB) would allow the utility to pass on all of the costs associated with the Muskrat Falls project. The province ultimately removed the PUB’s ability to set rates for power from Muskrat Falls

In 2012, after significant public criticism, the province announced that it would allow the PUB to do a very limited and narrow review of the project. The only reason the PUB was blocked from doing a review in the first place was the province passed an order-in-council explicitly preventing it from doing so and in direct contradiction of legislation that ensured the PUB reviewed all major capital expenditures undertaken by utilities (public and private) operating in the province. Rather than allow a full review of all options that would consider Muskrat against a range of alternatives — including gas plants, conservation, buying power from Hydro Quebec or any combination of these and other alternatives — the province narrowed the review to two narrow options: Muskrat Falls or the continued operation of an aging oil-fired generator.

In its final report, the PUB noted that the terms of reference established by the province were “very specific” and made it so that the review “excluded many issues” raised by a number of parties throughout the proceeding.¹⁰⁹

Nonetheless, even within the narrow review afforded it by the province, the PUB still couldn’t support Muskrat Falls and publicly called the whole process “torturous” and Nalcor’s refusal to cooperate with the regulator “inexplicable.”¹¹⁰ In its final report, the regulator noted the many problems and delays it faced in doing the review, saying that “difficulties were encountered from the beginning with the receipt of timely and complete information from Nalcor.” It detailed, at length, the various deadlines missed by Nalcor — often with no reason provided by the utility — and the many shortcomings with data that was provided.

¹⁰⁷ http://muskratfalls.nalcorenergy.com/wp-content/uploads/2017/06/Muskrat-Falls-Project-Update-Presentation-June-23_Final.pdf

¹⁰⁸ http://www.mae.gov.nl.ca/env_assessment/projects/Y2010/1305/lower_churchill_panel_report.pdf

¹⁰⁹ https://www.gov.nl.ca/lowerchurchillproject/muskrat_falls_pub_final_report.pdf

¹¹⁰ <http://www.cbc.ca/news/canada/newfoundland-labrador/pub-says-not-enough-time-for-full-muskrat-review-1.1252647?cmp=rss>

When the PUB and the Consumer Advocate, which was appointed to represent the view of consumers in the proceeding, asked for an extension to complete the review, the province declined. The PUB admitted that such delays “significantly impacted” its ability to adequately complete the review.

Ultimately, the Board concluded it couldn’t support the project as it was currently presented, as the information provided by Nalcor was not “detailed or complete or current enough” to determine whether Muskrat Fall was the “least cost option for the supply of power.”

More telling are the many concerns that the PUB highlighted in its report. It noted that the utility was relying on outdated data, optimistic forecasts, that there were gaps in the cost estimates presented by Nalcor and concern over the utility’s decision to build transmission lines to transmit power from Muskrat Falls that would fail to meet standards already in place across North America.

Similar to other megaprojects that failed to pass a regulator’s review, Newfoundland and Labrador’s then Premier Kathy Dunderdale attempted to discredit the PUB, calling the review a waste of nine months and \$2 million.¹¹¹

Optimistic forecasts

A number of Nalcor’s key forecasts have also proven to be optimistic.

In 2012, when Nalcor officially sanctioned the Muskrat Falls project, it expected electricity demand to grow 0.8% annually after 2016. By 2031, the utility was forecasting that total electricity demand in Newfoundland and Labrador would reach almost 10 TWh.¹¹²

Yet, by 2016, along with updated figures on the price of the project came a new, more realistic forecast for future demand. The utility’s previous forecast for electricity demand in 2020 now wouldn’t be hit until 2036 — a full sixteen years later than it originally planned when it moved ahead with Muskrat Falls in 2012. Rather than an 0.8% annual increase from 2016 and beyond, the utility now forecast that electricity demand would decline until almost the middle of the next decade.¹¹³ The power from Muskrat Falls is simply not needed.

The utility’s forecast on oil prices has also proven to be wildly optimistic. The reason the future price of oil is so central to the justification of Muskrat Falls is that the province repeatedly justified the project when comparing it to the ongoing operation of the Holyrood generating station in Newfoundland, which runs on oil. With oil prices rising dramatically between 2000 and 2010, Nalcor used that increase to make the economics of the Muskrat Falls project look more attractive. Nalcor predicted the long-term price of oil would be well over \$100 per barrel.¹¹⁴ In 2012, the utility admitted that if oil prices fell to \$60, the cost of generation from Holyrood and Muskrat Falls would be roughly the same.¹¹⁵ The current price of oil is well below the \$60 mark

¹¹¹ <http://thechronicleherald.ca/business/80659-danny-williams-blasts-board-over-muskrat-falls-review>

¹¹² <http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/Technical-Briefing-Electricity-Demand-Nov-2012.pdf>

¹¹³ http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/News-Conference-Presentation_MF-Project-Update_Web_24Jun2016.pdf

¹¹⁴ <http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/Technical-Briefing-Electricity-Rate-Forecasting-Nov-2012.pdf>

¹¹⁵ <http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/Technical-Briefing-Decisoin-Gate-3-Oct-2012.pdf>

(in the mid \$40 range) and some significant market players are expecting it to stay that way, potentially, well into the next decade.¹¹⁶

A broken culture

While Nalcor pushes ahead with the Muskrat Falls project at any cost, its subsidiary and owner of the controversial hydro dam has repeatedly been taken to task by the province's regulator for its lax attitude to blackouts and their impact on the utility's customers.¹¹⁷ In the wake of severe and prolonged blackouts in 2013, 2014 and 2015, the PUB launched an investigation into the operations of Newfoundland and Labrador Hydro, a fully owned subsidiary of Nalcor. The PUB ultimately concluded that the blackouts were a "result of multiple failures by Hydro...over the course of a number of years" and that the utility "failed to meet the standard of generally accepted sound public utility practice and failed to fulfil its obligation to provide an adequate reliable supply of power to customers."¹¹⁸

It's not the first time the PUB has criticized the utility for the way it maintains and operates its assets. The PUB performed what is known in regulatory circles as a "prudence review" in which it reviews the utility's spending and operations to determine whether the utility acted "prudently" in carrying out its duties. The PUB found the utility's management sorely lacking, noting "imprudence by Hydro are significant and reflect failure on the part of Hydro's management to exercise the reasonable standard of care expected in certain aspects of its operations." The PUB added that the "consequences of this imprudence for customers are significant, both in terms of impact on service adequacy and reliability, as was shown during the outages of January 2013 and January 2014, and in terms of cost."¹¹⁹

The regulator is not alone in criticizing the culture and performance of the utility. An independent consultant tasked to investigate the blackouts said the company's "operating culture continues to comprise a matter of concern" and that the utility "has not accepted changing that culture as a priority." Ultimately it found that the company's operating culture directly led to blackouts and "continues to adversely influence Hydro's decision making and contributes to operational incidents."¹²⁰

In a later report the same consultant concluded that the blackouts suffered by the utility's customers were "as much or more due to organizational issues as they were due to system inadequacies."¹²¹

Muskrat Falls is all of Canada's problem now

Unlike the other megaprojects in Canada reviewed in this report, the financial fallout of the Muskrat Falls project could extend well beyond Canada's most eastern province, as the federal

¹¹⁶ <http://www.marketwatch.com/story/oil-at-50-may-be-what-sparks-a-rebalance-of-crude-market-goldman-says-2017-05-30>

¹¹⁷ While Newfoundland and Labrador Hydro is a subsidiary of Nalcor, it has the exact same board of directors as Nalcor. Nalcor is essentially a holding company with Hydro being its main asset.

¹¹⁸ <http://www.pub.nf.ca/applications/IslandInterconnectedSystem/files/reports/PUB-FinalReport-Sept29-16.pdf>

¹¹⁹ <http://pub.nf.ca/orders/order2016/pu/PU13-2016.pdf>

¹²⁰ <http://www.pub.nl.ca/applications/March4thPowerOutage/files/reports/Liberty-Report-Oct22-15.pdf>

¹²¹ <http://www.pub.nf.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/TheLibertyConsultingGroup-PhaseTwoReport-2016-08-19.pdf>

government has promised to guarantee the debt of the project. If Newfoundland and Labrador ratepayers or taxpayers can't afford to pay the costs of the Muskrat Falls project and the utility defaults on its debt payments, the rest of Canada will have to pony up.

The original debt guarantee was made by then Prime Minister Stephen Harper and amounted to \$5 billion. At the time, the loan guarantee was expected to save Newfoundland and Labrador ratepayers \$1 billion.¹²²

But as the cost of the project continued to creep higher, so too did the loan guarantee. In November of 2016, the federal government — now headed by Prime Minister Justin Trudeau — said it was increasing the debt guarantee by \$2.9 billion, bring the total amount of debt backed by Canadians to \$7.9 billion.^{123 124}

¹²² <http://www.releases.gov.nl.ca/releases/2013/exec/1210n07.htm>

¹²³ <http://www.newswire.ca/news-releases/government-of-canada-announces-additional-loan-guarantee-support-for-lower-churchill-projects-599879831.html>

¹²⁴ Other critics of the project, notably Tom Adams, an energy consultant in Toronto that has been looking at the project for years, have pointed to issues such as competing water rights between Muskrat Falls and Hydro Quebec's upriver Churchill Falls dam. Adams points out that Muskrat Falls will likely never operate as planned, making the project even more of an economic albatross for the province than current forecasts. <http://www.tomadamsenergy.com/> Cabot Martin, a St. John's lawyer, says the dam is being built at an unstable site and is putting the lives of those living downstream at risk. <http://www.muskratmadness.ca/>

Part IV: Site C – the megaproject that just won’t go away¹²⁵

Sometimes it takes many attempts for a particular megaproject to come to fruition. BC Hydro – British Columbia’s public utility responsible for generating and delivering power across the province – has been trying to get the massive Site C dam built for decades. In each of its previous attempts, the crown corporation faced a critical utilities commission, less-than-forecasted demand to justify the project, or such intense public scrutiny – or a combination of all three – that it had to shelve the endeavor and wait patiently for the right opportunity (or government) to again push ahead. Opposition to the dam has come from a range of groups, including environmentalists, politicians, First Nations, farmers and the province’s own regulator.

Yet the utility has never fully put the project to bed.

So, in 2016 when then Premier Christy Clark said she would get the project “past the point of no return,”¹²⁶ it became clear that the public utility – backed by the province relying on the power of legislation to push the project along — was finally about to win the war.

Decades in the making

In the 1950s, energy planners proposed four dams to be constructed in the Peace River valley in the northeast corner of British Columbia. Two of them — the W.A.C. Bennett Dam and Peace Canyon Dam — were built in 1967 and 1980, respectively.

Plans to construct Site C — the third of the four dams — kicked off at the end of 1979, with BC Hydro formally submitting an application to the province in 1980. By 1981, the application was referred to the British Columbia Utilities Commission (BCUC) for review, which established a special committee to oversee the process.

In 1983, the commission ruled against Site C. In its decision, the BCUC argued that BC Hydro was overestimating future demand, that it wasn’t clear that Site C “was the best possible project from a provincial point of view” and that, ultimately, the application didn’t clearly demonstrate that “construction must or should start immediately.”¹²⁷ Later that year, the government — BC Hydro’s sole shareholder — formally pulled the application.

Over the following two decades, the project was never completely put to bed. In 1989 through 1991, the utility once again considered the project¹²⁸, but decided not to move ahead, as other solutions, such as gas-fired generation and conservation, “appeared to be more attractive ways to meet demand.”¹²⁹

¹²⁵ During the publication of this report, the recently elected NDP government announced a BCUC-led review of the Site C project. The previous government used legislation to block the regulator from undertaking such a review.

¹²⁶ <http://www.news1130.com/2016/01/31/former-b-c-premier-bill-bennetts-accomplishments-celebrated-at-memorial/>

¹²⁷

<https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf>

¹²⁸

<https://www.sitecproject.com/sites/default/files/19910300%20Peace%20River%20Site%20C%20Summary%20Status%20Report%20-%20BCH.pdf>

¹²⁹ <https://www.sitecproject.com/sites/default/files/20071200-Site-C-Feasibility-Review-Stage-1-Completion-Report.pdf>

In 2006, the utility once again included Site C in its Integrated Electricity Plan as a “resource option.” At the start of 2007, the province released its Energy Plan, which directed the utility to “enter into initial discussions” with groups that may be impacted by the construction of Site C — essentially paving the way for the utility to move ahead with the project. In 2008, the utility completed an early feasibility study, concluding that Site C was an “attractive” option for meeting future demand.

By 2010, the province formally declared that it was directing BC Hydro to move ahead with the project, yet at the same time, admitting that the final cost of the project was undetermined.¹³⁰ To avoid the thorny process of a detailed examination of the project by regulators, the province passed Bill 17 (2010), the Clean Energy Act, which exempted Site C from oversight and review from the BCUC.¹³¹ Energy Minister Bill Bennett scoffed at the idea of having “a group of unelected bureaucrats and lawyers” decide the future of the project.¹³²

Remember, it was the regulator that determined the dam wasn’t needed when it was first proposed in the 1980s.

Pump it up: Site C’s price tag continues to increase

The cost estimate of the Site C dam has grown since its inception — above and beyond inflation — and, if research on 70 years of megaprojects¹³³ is anything to go by, it will increase, in percentage terms, by double digits, possibly even triple digits, by the time the project begins producing power. Yet, even the publicly stated price tag of the project underestimates the real cost of building Site C; the province has afforded the company a number of hidden subsidies to keep the price tag lower than it would be if the project were to be undertaken by a private utility that can’t rely on the province’s credit rating and the pockets of millions of taxpayers to bail it out.

When Site C was first proposed by BC Hydro in the early 1980s, the utility expected it to cost \$3.2 billion (in nominal dollars) to construct. When adjusted for inflation, that amounts to \$7.9 billion in 2016 dollars, which is the same amount BC Hydro expected Site C to cost in 2010.¹³⁴ Yet, that figure has continued to rise. By 2014 the price tag increased to \$8.3 billion and then, later, to \$8.8 billion after the province decided the utility should set up a “project reserve” fund to “account for events outside of BC Hydro’s control” that will occur during construction.¹³⁵ The new “final” price tag of nearly \$8.8 billion is \$1 billion more than the original cost when adjusted for inflation — and, given that the dam is in the early stages of construction, that figure is likely to grow.

Hidden subsidies, soaring debt levels and accounting tricks at BC Hydro

¹³⁰ <https://issuu.com/northeastnews/docs/042210>

¹³¹ <http://www.millerthomson.com/en/publications/communiques-and-updates/environotes/may-2010-bc-client-alert/bc-introduces-new-clean-energy-act/>

¹³² <https://www.theglobeandmail.com/news/british-columbia/bc-ignored-calls-for-oversight-in-site-c-dam-ruling/article22422910/>
¹³³ Bent Flyvbjerg, “What You Should Know About Megaprojects and Why: An Overview,” *Project Management Journal*, 45: 6–19, <http://onlinelibrary.wiley.com/doi/10.1002/pmj.21409/abstract>

¹³⁴ https://www.sitecproject.com/sites/default/files/backgrounder-site-c-cost-estimate_0.pdf

¹³⁵ https://www.sitecproject.com/sites/default/files/backgrounder-site-c-cost-estimate_0.pdf

The real cost of Site C and the risk that it entails for the province's largest public utility are hidden by subsidies and accounting maneuvers that mask the utility's leveraged balance sheet.

First, there's the implicit promise that if the billions of dollars in debt needed to finance the construction of Site C becomes unmanageable — and starts pushing the company into insolvency — taxpayers will bail it out. That means that BC Hydro borrows at interest rates below the market — and uses those lower rates to improve the economics of the project. BC Hydro admits as much when it says that the reason it employs a lower discount rate when running cost analyses on Site C is that its debt "is guaranteed by the government, and the Company may also borrow directly from the Province."¹³⁶ Eliminate that provincial guarantee and the cost of constructing Site C increases.

That guarantee keeps borrowing costs low for the utility even as it has nearly tripled its long-term debt over the last ten years — and expects to add billions more while it constructs Site C. In 2006, BC Hydro's long-term debt stood at \$5.7 billion.¹³⁷ By 2016, that figure had increased to \$15.8 billion¹³⁸ — amounting to an increase of more than 177% and \$2.6 billion more than it forecast in its 2014 application to the BCUC. BC Hydro now expects its long-term debt to increase by an additional \$3.2 billion to more than \$19 billion by the end of 2019.¹³⁹

By 2019, the total amount of BC Hydro's short and long-term debt will total \$21.8 billion, while the value of its regulated assets will be less than that at \$21.6 billion. Every dollar of assets is backed by more than one dollar in debt.¹⁴⁰

The utility's debt financing will come at a cost to ratepayers. Since 2006, the annual cost of that debt for ratepayers will nearly double by 2019, even though interest rates have declined over the period. In 2006, BC Hydro paid \$493 annually to cover the interest on its long-term debt, while in 2019 it expects that figure to increase to \$825.8 million.¹⁴¹

The double-digit growth in debt at BC Hydro could drag down the province's credit rating. Moody's, the debt ratings agency, warned that such an increase in debt levels could "pressure the province's rating, since it raises the contingent liability of (the B.C. government)." The agency added that should BC Hydro's "financial position deteriorate" it may require a bailout from the province's taxpayers.¹⁴²

BC Hydro's ability to rely on a provincial bailout allows it to be far more leveraged than its private sector counterparts — both inside and outside the province. Utilities in the private sector typically maintain a 60/40 debt-to-equity ratio. BC Hydro currently has a debt-to-equity ratio of 80/20, meaning it is more highly leveraged than most utilities — in Ontario, for example, the

¹³⁶ <https://www.sitecproject.com/sites/default/files/synapse-energy-economics-inc-letter.pdf>

¹³⁷ https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/2006_annual_report_annual_report.pdf

¹³⁸ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 707

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf,

¹³⁹ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 707

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

¹⁴⁰ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 708

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

¹⁴¹ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 708

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

¹⁴² <http://www.alaskahighwaynews.ca/regional-news/site-c/moody-s-upholds-bc-hydro-credit-rating-but-debt-concerns-loom-1.2230511>

province's regulator prefers publicly owned utilities to maintain a 60/40 ratio in order to more closely align with the private sector — and more at risk from a financial setback.¹⁴³ On a standalone basis — without the backing the province and its taxpayers with a bailout — investors would demand a higher interest rate when purchasing BC Hydro bonds.

The utility is also using a 70-year time frame to finance Site C, which is decades longer than the federal government is using to finance the controversial — and massively over budget and delayed — Muskrat Falls project in Newfoundland. When asked whether the 70-year time frame and 100% debt financing meant the project would neither be paid for until 2094 or earn a return for the company over that time, the utility confirmed that was the case. A 2014 joint provincial-federal review panel questioned the utility's decision to finance the dam over such a long time period, saying a 40-year time period would be more appropriate.¹⁴⁴

A highly leveraged balance sheet — backed by the province — isn't the only financial maneuver helping BC Hydro. The utility is also relying on an accounting sleight of hand to make its balance sheet look better in the short-term through an aggressive use of what are known as “deferral accounts” or “regulatory assets.” These accounts, essentially, defer current expenses to later years in order to “smooth” rates — and keep them artificially low in the near term. A “regulatory asset,” then, is money that the company expects to earn in future years from ratepayers (through future rate increases). The result is that current expenses are lowered by deferring them to future ratepayers — a move which ultimately boosts the utility's current net income and increases the amount of dividends it can provide to its sole shareholder (the province).

Unlike most utilities, which rely on small deferral accounts to help offset minor variations in costs and revenues and are typically cleared within a couple of years, BC Hydro — at the behest of the province — has allowed its deferral accounts to grow into the billions of dollars. Doing so means that future ratepayers will be on the hook for the billions of dollars to cover the costs that the company has deferred — all in an effort to reduce rates in the short term and delay the day of reckoning for ratepayers.

In 2011, the province's Auditor General warned that the utility's increased use of these accounts was “unsustainable.” Yet, since that report — when the amount of deferred expenses amounted to \$2.2 billion — the utility now has \$5.9 billion¹⁴⁵ sitting in “regulatory assets” that it now plans to collect from future ratepayers and it expects that figure to increase by another \$100 million. Worse still, that figure is \$1 billion more than it forecast in its last rate application.¹⁴⁶ Rather than establish a clear plan to tackle the amounts in the deferral accounts — as the Auditor General recommended in 2011 — BC Hydro has allowed them to grow at a faster rate than previously forecasted.

¹⁴³ <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf> , page 18

¹⁴⁴ <http://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf> , page 312

¹⁴⁵ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 498

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

¹⁴⁶ <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/RRRA-2015-2016-regulatory-accounts-report.PDF>

The "rate smoothing" deferral account alone will increase by nearly \$800 million over the next three years. BC Hydro — and the BCUC, which sets its rates — are bound by legislation to cap rate increases over the next three years at 4%, 3.5% and 3%, respectively. Yet, the utility's costs will be increasing by significantly more over that time. In order to deal with that difference, the province directed BC Hydro to establish a "rate smoothing" deferral account to record that amount with future ratepayers on the hook to pay that money back to BC Hydro.

The province eventually realized that deferring costs to future ratepayers while taking hundreds of millions of dollars in dividends from BC Hydro made little sense and so, beginning in 2018, the province has lowered the dividend by \$100 million annually. Notwithstanding, the province admits that the dividends BC Hydro will pay the province between 2016 and 2018 will be financed by debt.¹⁴⁷ The province has also admitted that a large percentage of the utility's dividend to the province since 1992 has been borrowed money — a policy the Energy Minister admitted is "unsustainable."¹⁴⁸

The need for Site C is far from clear

Ignoring the impact of a highly leveraged utility and the billions of dollars in deferred accounts that future ratepayers will be left paying back, the question remains: is Site C even needed? Ever since Site C was first proposed in 1979, BC Hydro has repeatedly tabled optimistic demand forecasts to justify its construction. In 1979, for example, BC Hydro expected that by 1991, domestic demand would total 54,770 GWh.¹⁴⁹ Domestic demand in the province didn't hit that level until 2005¹⁵⁰ and was at that same level in 2015.¹⁵¹

The last ten years have been no exception to the past when it comes to optimistic forecasts from BC Hydro. In its 2013-2023 load forecast, for example, the utility expected that by 2016, total energy sales in the province would amount to 56,315 GWh.¹⁵² Yet, in its most recent rate application to the BCUC, BC Hydro admits that domestic load in 2016 was 51,023 GWh — or nearly 10% lower than it expected and largely level with demand at the time.¹⁵³ The utility has also lowered its demand forecasts going forward.

¹⁴⁷ <http://vancouversun.com/news/local-news/bc-hydro-borrows-millions-more-to-pay-government-dividend>

¹⁴⁸ <http://www.timescolonist.com/news/b-c/b-c-hydro-s-dividend-policy-unsustainable-energy-minister-says-1.1729303>

¹⁴⁹

<https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf> , page 51

¹⁵⁰ https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/2006_annual_report_annual_report.pdf

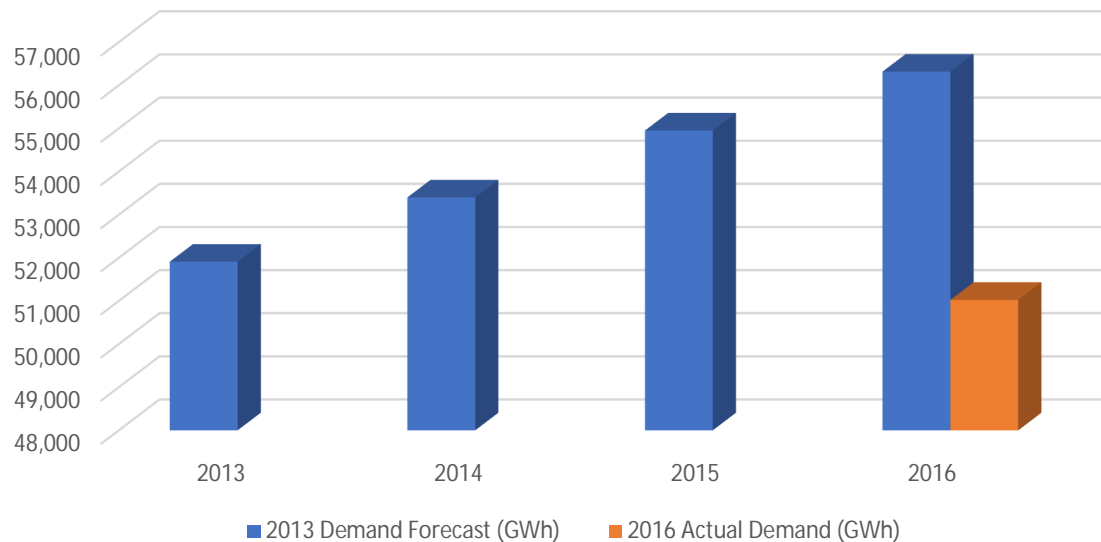
¹⁵¹ <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf>

¹⁵² <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf>, page 113.

¹⁵³ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 313

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

BC Hydro's Demand Forecast



If we compare domestic demand in 2016 — 51,023 GWh as detailed in its rate application — to demand a decade earlier, 52,440 GWh, it's clear that, rather than growing, electricity demand is largely stagnant. Peak demand — or the amount of power consumed during the busiest hours — has also remained flat over the last decade, coming in at 9,317 MWh in 2006 and 9,602 MWh in 2016.¹⁵⁴ Looking back to 2004, peak demand was actually higher than it was in 2016, so over the last 12 years, it's actually declined.

Nonetheless, BC Hydro continues to adhere to its optimistic forecasts and is expecting demand in the province to increase by more than 8% over the next three years — a rate of increase that the utility hasn't experienced for nearly two decades and is contrary to what is happening across North America where electricity demand is largely flat or declining.

Overly optimistic forecasts aren't a new problem at BC Hydro. A recent study on the Site C dam found that 85% of the demand forecasts made by BC Hydro since the 1980s have been overestimates.¹⁵⁵ Sometimes the overestimates have been extreme. For example, in 1981, when BC Hydro was proposing to construct Site C and the BCUC was reviewing the project, its load forecast at the time for 1992 has still not been reached.¹⁵⁶

BC Hydro also juiced its demand forecasts leading up to the approval of the Site C project. In 2009, the utility's forecast for demand in 2024 was nearly at the same level as the actual amount of power consumed in the province in 2009. But by the next year, the utility began ramping up those forecasts and by 2013 expected demand by 2024 to be 18,000 GWh higher than its 2009 assessment. Coincidentally, the Site C project was undergoing an environmental

¹⁵⁴ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 1-5

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

¹⁵⁵ <https://watergovernance.ca/wp-content/uploads/2017/03/1-Site-C-Economics-Report-19042017.pdf>

¹⁵⁶ See the 1981 report and the figures from its 2017-2019 rate application, found on page 3-13 of the BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application.

assessment between 2010 and 2013 and by 2014, once it had been approved, the 2024 demand forecasts were lowered by nearly 15,000 GWh.¹⁵⁷

The cost to the utility and its customers of those optimistic forecasts is already becoming clear. In its current rate application, BC Hydro admits that lower demand — particularly from large industrial customers — means the utility will bring in \$3.5 billion less over the next decade than it previously forecast.¹⁵⁸

Review panel skeptical that Site C is needed

A 2014 provincial-federal review panel tasked with examining the project noted that a growing economy will one day require more energy, but it was far from certain when that day would arrive. It concluded that it wasn't clear that Site C was "needed on the schedule presented" by the utility. The panel also questioned whether Site C will even be the best option when that day arrives, pointing out that even BC Hydro has admitted that large sources of geothermal generation may be available at "competitive prices" to meet much of the demand growth.¹⁵⁹

Harry Swain, the chair of the review panel — and now outspoken critic of the project — said that while the panel originally feared BC Hydro's forecasts were optimistic, those fears have "now come to pass." Contrary to claims from BC Hydro that demand will once again pick up, Swain says there is no "indication that there is any huge load-growth lurking out there. In fact, quite the contrary."¹⁶⁰

The review ultimately recommended that, should the BC government decide to go ahead with the Site C project, it should bring BC Hydro's load forecasts, electricity prices and conservation plans before the BCUC to address the uncertainties surrounding those issues and the impact they have on determining whether the project is needed or not.¹⁶¹ The recently elected NDP government has since ordered an independent review of the project.¹⁶²

Exporting at a loss

The economics of exporting any surplus power from Site C — if the project turns out to be unnecessary to meet provincial demand — are also dire. While in the past BC Hydro has largely recovered the cost of exporting its surplus power (and at times profited from it), changing market conditions mean that exporting Site C's power will be subsidized by the province's ratepayers. The utility admits as much, saying that in the first four years of operation, exporting Site C's power will cost the company \$800 million — a cost that will eventually be paid by ratepayers.¹⁶³ While BC Hydro believes that those costs will be offset by future lower rates, the joint review

¹⁵⁷ <https://watergovernance.ca/wp-content/uploads/2017/03/1-Site-C-Economics-Report-19042017.pdf> page 23

¹⁵⁸ BC Hydro Fiscal 2017 to 2019 Revenue Requirements Application, page 30

http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf

¹⁵⁹ <http://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf>, page 308

¹⁶⁰ <http://www.alaskahighwaynews.ca/regional-news/site-c/q-a-dr-harry-swain-former-site-c-panel-chair-becomes-outspoken-opponent-1.2296875>

¹⁶¹ <https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf> page 325

¹⁶² <http://vancouver.sun.com/news/politics/ndp-government-sends-site-c-dam-for-independent-review>

¹⁶³ <https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf> page 298

panel warned that relying on exports to absorb surplus power “would likely be very expensive.”¹⁶⁴

Another review of the project estimated that the losses on selling the dam’s surplus power could total as much as \$2.7 billion by 2036 and continue for years afterwards.¹⁶⁵

A “significant” impact on the environment

While the province repeatedly says that Site C will provide “clean” power for the next 100 years, the federal-provincial joint review panel offered a much more stark assessment.¹⁶⁶ One study found that the joint review panel noted that the Site C dam would have more “significant” negative impacts on the environment than any other project ever assessed by the Canada Environmental Assessment Agency (CEAA). The number of “significant” environmental impacts from the Site C dam are four times the level of those of another megaproject dam, the Muskrat Falls project in Newfoundland and Labrador.

The “significant” environmental impacts, according to the joint review panel are wide-ranging and affect fish, wetlands, plant life, migratory birds and birds of prey, among others.

The panel also found that the project would have a significant impact on the use of the lands surrounding the dam of First Nations and that some of these impacts “cannot be mitigated.”

¹⁶⁴ <http://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf>

¹⁶⁵ <https://watergovernance.ca/wp-content/uploads/2017/03/1-Site-C-Economics-Report-19042017.pdf> page 70

¹⁶⁶ <https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power>

Part V: Ontario makes another big bet on nuclear power – regulators and the public be damned

Nuclear power debt, and the double-digit rate increases needed to pay for it, pushed Ontario Hydro into insolvency in the late 1990s. Now, the successor company to Ontario Hydro is once again putting its faith — and the monthly bills of future electricity customers — behind a nuclear megaproject.

In the wake of the financial collapse of Ontario Hydro — once the largest public utility in North America — Ontario attempted to create a competitive electricity sector. The goal was to reduce the power of government monopolies, limit the risk to taxpayers when those utilities run into financial trouble and provide greater choice and lower prices for electricity consumers. As part of that move, the province broke Ontario Hydro into pieces, with Ontario Power Generation (OPG) taking ownership of the province's nuclear and hydroelectric generating stations. OPG continues to be the province's dominant generator, producing around 50% of Ontario's electricity each day. It remains publicly owned.¹⁶⁷

Yet, over the last decade, the province has steadily eroded the many agencies and policies put in place to avoid a repeat of the financial and economic follies that Ontario Hydro imposed on electricity customers and taxpayers alike. Nowhere is that more evident than in OPG's decision to refurbish the Darlington nuclear plant, sitting on the shores of Lake Ontario. As with many other megaprojects, the province has had to use the legislature to overrule the many checks and balances that were put in place explicitly to protect electricity customers and taxpayers from the financial risk of these types of megaprojects. As result, ratepayers can now expect triple-digit rate increases and billions of dollars in costs kicked to future customers — the very scenario that brought down Ontario Hydro.

What is the Darlington Refurbishment Program (DRP)

The DRP is a decade-long megaproject to refurbish the four nuclear reactors at the plant. The DRP officially began in October 2016 — although \$2.2 billion has been spent over the last decade on planning and early construction projects associated with the DRP — and will last until February 2026, according to the public utility's forecasted schedule. The refurbished units at the Darlington nuclear station will remain in-service until 2055.

The total cost — including interest and \$1.7 billion in “contingency” amounts (\$2.1 billion if the contractors' contingency levels are included) — of the DRP is currently expected to be \$12.8 billion.¹⁶⁸

Due to its size and complexity, the DRP has been “broken” down into a series of large infrastructure projects, ranging from the replacement of pressure tubes and feeder pipes to an array of safety projects required as a result of new regulations. Many of these “mini” projects are themselves megaprojects and come with a price tag of more than \$1 billion.

¹⁶⁷ <http://www.opg.com/about/Pages/about.aspx>

¹⁶⁸ EB-2016-0152, Exhibit D2, Tab 2, Schedule 1, pages 1-13 and Transcript Volume 3

Unlike previous nuclear refurbishments — in Ontario and elsewhere — the province has ensured that the refurbishment of the first nuclear reactor is done in isolation before OPG moves onto refurbishing later units.¹⁶⁹ The province — OPG's sole shareholder — has explicitly established so-called off-ramps that require the utility to obtain its approval before moving onto the refurbishment of later units.¹⁷⁰ In theory, if the cost of refurbishing the first reactor is significantly higher or severely delayed before coming back into service, the province could block OPG from moving ahead with the refurbishment of the next three units and avoid the experience of many other megaprojects, in Canada and elsewhere, of taking a project to the point of no return. OPG, as detailed in its rate application before the Ontario Energy Board (OEB), says it can cancel the planned refurbishment of later units at minimal cost to ratepayers and taxpayers that would bail it out if the project became a financial albatross to the company.¹⁷¹

Ontario's track record on nuclear megaprojects is abysmal

Ontario's track record when it comes to nuclear refurbishments is consistent: they're overbudget and behind schedule, time and time again. While nearly all nuclear projects have significant problems in their original construction — when they also came in overbudget, behind schedule and failed to meet forecasted reliability metrics — this report will only focus on the more recent refurbishments in Ontario and at other CANDU reactors in Canada.

- **Bruce A units 1 and 2:** In 2005 the province announced that Bruce Power, a consortium of private companies holding a long-term lease to operate the nuclear plant, would refurbish units 1 and 2 at a cost of \$2.75 billion. Bruce Power said it could have the two reactors back online by late 2009 or early 2010. An independent review in 2008 revealed that the cost of the project had climbed by \$350 million and could increase by as much as \$650 million. A year later, Transcanada, one of the consortium companies, announced publicly that the project would cost at least \$3.4 billion, but that figure could increase by an additional \$340 million, or \$1 billion over the original estimate. By the end of 2010, it was announced that the final price tag for the refurbishment was \$4.8 billion, marking a 75% increase over the first estimate. The reactors didn't enter commercial service until 2012, more than two years behind schedule.¹⁷²
- **Pickering (return to service) Unit 1 and 4:** After laying up the four units at Pickering A in 1997, Ontario Hydro's Board announced in August of that year that it could bring the units back into service by 2000 at a cost of \$780 million. In May 1999, the utility revised that estimate to \$840 million. In August of that year, that figure was once again revised higher to \$1.1 billion, with Unit 4 (and shared systems) expected to cost \$457 million, while Unit 1 would cost \$213 million. By the time Unit 4 came back online in 2003, three years behind schedule, the price tag for just that one unit had increased to \$1.25 billion, or a 173% increase. Unit 1 was brought back online in 2005 with a final price tag

¹⁶⁹ The first unit to be refurbished is actually Unit 2.

¹⁷⁰ While the nature of these off-ramps has never been disclosed, the idea is that neither OPG nor the province is fully locked in to refurbishing all four units at Darlington. If the cost of the first unit is too extreme or the delays too severe, one, or both, of the province or OPG can cancel the remainder of the project.

¹⁷¹ EB-2016-0152, Transcript volume 1.

¹⁷² EB-2016-0152, Exhibit L, Schedule 15 SEC 033, Attachment 3, page 5 and https://www.thestar.com/business/2010/11/04/bruce_nuclear_refit_2_billion_over_budget.html

of \$996 million, or nearly five times the original budget.¹⁷³ OPG ultimately decided not to proceed with the return to service of units 2 and 3.

- **Point Lepreau:** In July 2005, the government of New Brunswick announced that it would go ahead with the refurbishment of the Point Lepreau nuclear plant — going against the advice of its own regulator that looked at the project and concluded there was “no significant economic advantage to the proposed refurbishment project.”¹⁷⁴ Nonetheless, the project went ahead in 2008 with an estimated price tag of \$1.4 billion. By the time the nuclear reactor was back in service in November 2012, it was more than three years behind schedule and \$1 billion overbudget. The final cost of the refurbishment is currently pegged at \$2.4 billion.¹⁷⁵ A recent news report based on a memo from the Prime Minister’s Office suggests that the price tag could hit \$3.3 billion.¹⁷⁶

Tear down the regulatory body tasked to protect electricity customers

Similar to other megaprojects being pursued by crown corporations, OPG’s shareholder (the province) has used the legislature to push the project through and avoid the hassle of having outside regulatory bodies or agencies determine whether it’s the best option for ratepayers. Electricity consumers — who will ultimately be left picking up the tab for the nuclear project — have been blocked from having their say on whether the DRP really is the best way forward to meet the province’s future energy needs.

To understand how the province has used the legislature to push the DRP ahead without restraint, one has to go back to the regulatory and oversight functions established in the wake of the breakup of Ontario Hydro. By 1998, in the wake of the release of a report on how to transition to a competitive electricity sector¹⁷⁷ and a government white paper on competition¹⁷⁸, the province passed the Energy Competition Act, which provided the legislative framework for a competitive electricity sector. As part of the Energy Competition Act, the legislation governing the OEB was revised and enhanced, providing the independent regulator with the responsibility of regulating and setting prices for the transmission and distribution sector, among a number of other significant changes.¹⁷⁹

In 2002, four years after the move towards a competitive electricity sector began, the market officially opened and the successor companies to Ontario Hydro — OPG (generation) and Hydro One (transmission and distribution) — were now operated independently of one another and were run as for-profit businesses. Just as the market opened in May of 2002, Ontario experienced a hot summer that coincided with unexpected delays at the return to service of

¹⁷³ <http://www.ontla.on.ca/library/repository/mon/7000/10317476.pdf> and http://www.opg.com/about/finance/Documents/Q3_05all.pdf

¹⁷⁴

<http://142.166.3.251/Documents/Decisions/Electricity/E/Decision%20Pt%20Lepreau%20GS%20Refurbishment%20Sep%2024%202%20E.pdf>

¹⁷⁵ <http://www.agnb-vqnb.ca/content/dam/agnb-vqnb/pdf/Reports-Rapports/2014V2/Chap2e.pdf>

¹⁷⁶ <http://www.cbc.ca/news/canada/new-brunswick/point-lepreau-costs-could-hit-3-3b-pmo-memo-says-1.1344861>

¹⁷⁷ A Framework for Competition, <http://www.ontla.on.ca/library/repository/mon/3000/10258213.pdf>

¹⁷⁸ Direction For Change: Charting a course for competitive electricity and jobs in Ontario,

<https://archive.org/details/directionforchan00ontauoft>

¹⁷⁹ The Energy Competition Act also introduced the Electricity Act, which, when combined with the OEB, continues to layout the legislative framework for the province’s electricity sector.

reactors at the Pickering nuclear plant.¹⁸⁰ Electricity prices immediately shot higher. Just as quickly as the market opened, the government became so spooked by the public outcry of increasing hydro rates that by December of 2002, it implemented a four-year price freeze and offered hundreds of millions of dollars in rebates to quell the outrage.¹⁸¹ Taxpayers were once again subsidizing hydro bills.

By 2004, with a new government in power, the price freeze was adjusted slightly higher and, more importantly, a new so-called “hybrid” model — and subsequent legislation — for the electricity sector was introduced. As part of the reforms, the province passed legislation that separated the market operator — now called the Independent Electricity System Operator (IESO) — from planning issues and, in its place, created the Ontario Power Authority (OPA).

The OPA would file, once every three years, a system supply plan to the OEB. The OEB would then assess whether the plan was “economically prudent and cost effective” after hearing from the various parties. Consumer and industry groups and other experts could (and did) challenge those forecasts and assumptions in a public forum. The OPA — and subsequent review of its plans by the OEB — was put in place to protect electricity consumers and ratepayers from the overbuilding and uneconomic energy projects often pursued by public utilities like Ontario Hydro. All energy plans would now be created by energy experts and debated in an open, transparent hearing at the province’s regulator to determine if they pass the economic smell test. The OEB would determine whether they offered good value for money.

Yet, just as quickly as the province passed legislation to protect consumers, it began to ignore — and eventually repeal — it. While the OPA did submit a supply plan to the OEB in 2007, the review process was eventually shelved in the middle of the hearing after a directive from the Ministry of Energy overruled the application, calling for — among other things — more renewable energy and the premature closing of the province’s coal plants. Both decisions, as it turned out, would be extremely costly.¹⁸²

By 2011, while the Ministry of Energy publicly directed the planning agency to again develop and submit its long-term plan to the OEB, that plan never saw the light of day. Instead, the Ministry of Energy began releasing its own Long-Term-Energy Plans detailing what types and how much energy should be procured in Ontario. To date, no independent supply plan has been issued by the OPA and reviewed by the OEB. In 2015, the province’s auditor general concluded that the “power system planning process has essentially broken down” and the Ministry of Energy was “operating outside the checks and balances of the legislated planning process.”¹⁸³

In 2016 the province ended the charade of having an “independent” planning agency by passing legislation that formally transferred all planning responsibilities to the Ministry of Energy (the OPA by then had been merged with the system operator). All planning is now overseen and

¹⁸⁰ <https://www.pembinafoundation.org/reports/appendix2.pdf>

¹⁸¹ <http://www.statcan.gc.ca/pub/13-605-x/2003001/concept/4151943-eng.htm> and <https://www.theglobeandmail.com/news/national/eves-freezes-power-prices/article25425877/> and <http://www.nytimes.com/2002/11/13/business/outcry-in-ontario-over-energy-prices.html>

¹⁸² <http://www.auditor.on.ca/en/content/annualreports/arreports/en11/303en11.pdf> and <http://www.auditor.on.ca/en/content/annualreports/arreports/en15/3.05en15.pdf>

¹⁸³ <http://www.auditor.on.ca/en/content/annualreports/arreports/en15/3.05en15.pdf>

rubber-stamped by the Minister of Energy, not the agencies that were created for that purpose.¹⁸⁴ The Ministry of Energy is now the sole decision maker in all energy-related matters.

Ultimately, the need for the DRP — one of the largest energy infrastructure projects the province has ever seen — has never been independently verified by any regulatory body or independent agency in a public forum. The only document detailing the “need” for the DRP is the province’s Long-Term Energy Plan and subsequent press releases, both of which are written by the Ministry of Energy without being independently reviewed for their cost effectiveness.¹⁸⁵ In January 2016, the province explicitly included the DRP in a regulation and legislated that the OEB “accept the need for the Darlington Refurbishment Project.”¹⁸⁶

Like other megaprojects, the DRP will proceed because the province says so and because it has destroyed the checks and balances needed to protect electricity customers from white elephants and other unnecessary investments.

Triple digit rate increases ahead

Similar to other megaprojects, the DRP will require mega rate increases. OPG expects the \$12.8-billion DRP will produce a triple digit increase in rates to be paid by consumers over the next two decades.

The current “base” nuclear rate paid to OPG by electricity customers in Ontario is \$59.29 per MWh. This rate excludes a number of “rate riders” that are added to base nuclear rates to account for past variances in the amount of revenue paid to OPG by ratepayers. By 2025, according to OPG’s most recent application to the OEB, it expects its base nuclear rate will increase from \$59 to a \$165 — amounting to 178% increase over ten years.¹⁸⁷

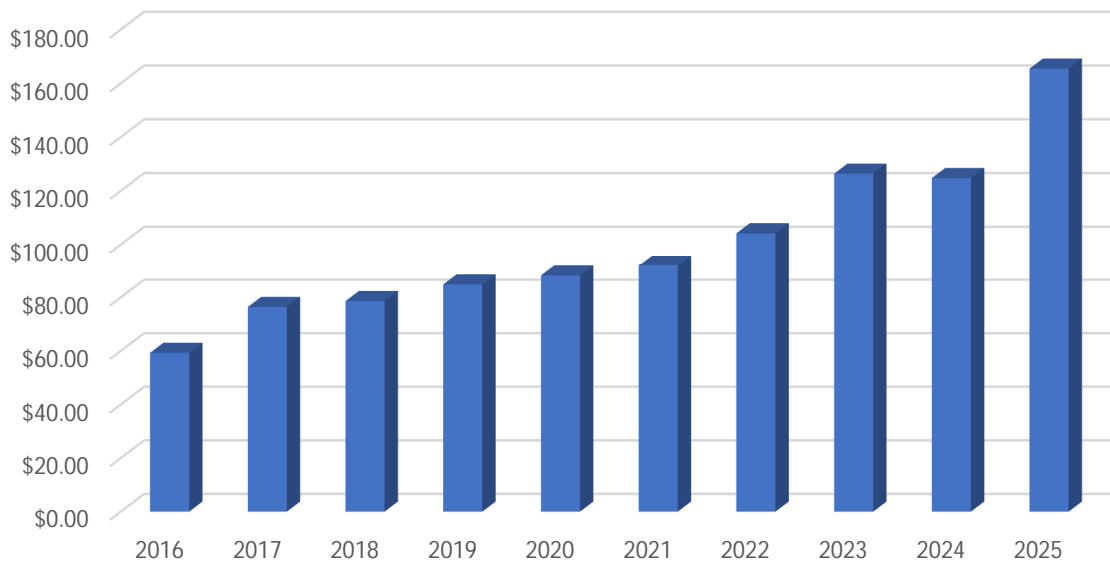
¹⁸⁴ http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=3539

¹⁸⁵ <http://www.ieso.ca/corporate-ieso/media/news-releases/2016/01/ont-moving-forward-with-nuclear-refurb-at-dar-and-pursuing-continued-ops-at-pickering-to-2024>

¹⁸⁶ <https://www.ontario.ca/laws/regulation/050053/v9>

¹⁸⁷ EB-2016-0152, Exhibit N3 Tab 1, Schedule 1, Attachment 2, Table 14

OPG's Nuclear Base Rate (\$/MWh)



Give it a rate smoothing subsidy to hide the real cost

The triple digit rate increases needed to fund the DRP must have been too high for OPG’s shareholder — the politicians — to stomach and, ultimately, pass on to electricity customers.

So, instead of setting nuclear rates over the next five years using traditional regulatory oversight, nuclear rates will be “mitigated” through financial maneuvering that will ultimately cost ratepayers an additional \$1 billion. Under standard regulatory practice, a utility begins earning a return on its asset once it “comes into service,” or more simply, starts producing power or contributing in some way to the generation or delivery of electricity. Once an asset — a nuclear or natural gas plant — starts producing power, the regulator can set a rate that consumers pay for that power that ensures the utility covers its operating costs as well as earns a “return” on the capital invested to construct the plant.

In the case of the DRP, once the first of the four units comes into service in 2020, it would cause a double-digit “jump” in rates paid to the utility. According to OPG’s application before the OEB, under traditional regulation, the utility’s base nuclear rate would jump from its current level of \$59.29 to \$101.28 in 2020, marking a 70% increase in nuclear rates charged to electricity customers, or more than 17% annually.¹⁸⁸

Given the political backlash in Ontario over already soaring hydro rates, which at one point put hydro rates as the number one concern among Ontarians, OPG’s shareholder (the province) introduced legislation blocking the OEB from approving such a rate increase.¹⁸⁹ The legislation explicitly directs the OEB to set up an account which records the difference between what OPG

¹⁸⁸ EB-2016-0152 Exhibit N3 Tab 11.6, Schedule 1 Attachment 2, Table 18

¹⁸⁹ <https://www.theglobeandmail.com/news/national/why-does-electricity-cost-so-much-in-ontario/article33453270/>

collects from customers and the actual cost of generating power.¹⁹⁰ The province and OPG call this “rate smoothing”, and the goal, according to OPG, is to provide customers with “rate stability” by smoothing the year-over-year rate increases — and, doubly, to keep the rate increases below the utility’s actual costs.

Instead of regulating OPG in a similar manner that it regulates other utilities in Ontario, the OEB has been explicitly legislated by the province to pursue a different type of rate-setting methodology that, ultimately, defers today’s costs to future electricity customers. This type of “rate smoothing” is the exact opposite of the OEB’s standard regulatory procedures, as outlined in its Renewed Regulatory Framework for Electricity (RRFE). In that document, the OEB explicitly states that it only requires utilities to “consider” some form of “mitigation” when the impact on a customer’s *total* bill is more than 10%.¹⁹¹ OPG admitted, when asked during the hearing in its rate application, that the rate impact of the DRP would not be above that threshold.¹⁹²

OPG also reiterated that it had “no option” when it came to rate smoothing, as the province legislated that the utility do it. In fact, in the past, when the province didn’t require it by legislation, OPG has actually argued against rate smoothing proposals, specifically noting that the 10% threshold had “not been reached.”¹⁹³ The province’s legislation works against both the OEB’s rate-setting policies and previous arguments by its own company.

Nonetheless, the cost of “rate smoothing” is significant. Over the next five years, if the OEB approves OPG’s application as it’s currently proposed, the public utility would “defer” \$1 billion in order to “smooth” its nuclear rate.¹⁹⁴ The interest costs to be paid on the \$1 billion being deferred over the next five years will total, according to OPG’s own calculations, as much as \$470 million.¹⁹⁵ This is just the tip of the iceberg. Over the next ten years, as the DRP is completed, OPG plans to “defer” to future ratepayers as much as \$2.9 billion in costs. The interest on that amount of money, which the province has legislated to be set at OPG’s long-term borrowing rate — a much higher interest rate than the OEB typically applies to deferral accounts — will cost future ratepayers as much as \$1.4 billion in interest costs.¹⁹⁶

The “implicit” provincial guarantee is what makes the DRP possible

The underlying reason for why a megaproject like the DRP — and others across Canada and the around the world — is able to go ahead is that the province (taxpayers) provides OPG with a near unlimited source of bailout funds. Multiple witnesses at OPG’s rate application — one of them OPG’s own witness — concluded that without provincial support, a project like the DRP couldn’t proceed.

¹⁹⁰ <https://www.ontario.ca/laws/regulation/050053>

¹⁹¹ The “total bill” threshold is, itself, problematic. While that rate paid by customers to OPG for nuclear power will increase by triple digits, that only makes up one portion of the total bill — excluding the cost of other forms of generation, taxes and delivery charges.

¹⁹² EB-2016-0152 Transcript Volume 22

¹⁹³ See EB-2013-0321 — 2014/15 Payment Amounts Application, OPG’s Argument-in-Chief and Reply Argument

¹⁹⁴ EB-2016-0152 Exhibit N3, Tab 1, Schedule 1, Page 14

¹⁹⁵ EB-2016-0152 Undertaking J22.2

¹⁹⁶ EB-2016-0152 Exhibit N3, Tab 1, Schedule 1 Attachment 2, Table 7

OPG's witness, for example, noted at the outset that the DRP was, without doubt, the biggest financial and economic risk facing the company going forward. He then admitted that the "provincial commitment" to the DRP in the form of legislation detailing its need and other regulatory support offered through deferral accounts and rate smoothing regulations — mixed with the "implicit" guarantee that taxpayers will bail the company out — are the only reasons why the company can move forward with the megaproject. Without those commitments, it would be "impossible" to move ahead, he concluded.

OPG's witness also confirmed that without the "implicit" guarantee that taxpayers will support OPG in the event of a significant cost overrun, the public utility's credit rating — which measures how risky the company's debt and is and what interest rate investors would demand to purchase its debt — is "very close to junk." Without provincial support, he admitted, OPG would "struggle" to raise debt for a capital-intensive megaproject like the DRP.¹⁹⁷

Another witness at the hearing also confirmed that if OPG was an independent, private generator and had no provincial support, it likely wouldn't be able to finance a project as risky as the DRP. The witness noted that other nuclear projects in the United States have also had to rely on government guarantees to move forward. Ultimately, the witness concluded that if OPG were treated like a private generator, the OEB would have to approve a level of return beyond what it currently allows and finds reasonable — meaning it would, essentially, have to change its regulatory principles for OPG.¹⁹⁸

Like other megaprojects, the DRP needs the backing of taxpayers to move ahead, as private investors would avoid investing in such a risky endeavor.

¹⁹⁷ EB-2016-0152 Transcript Volume 18

¹⁹⁸ EB-2016-0152 Transcript Volume 19