1 Manitoba Public Utilities Board ("PUB")

1.1 PUB/GSS-GSM-KAP -1

References:

- LEI Evidence Page 8 of 61;
- http://www.gov.mb.ca/asset_library/en/climatechange/climategreenplandiscussionpaper.pdf

Preamble:

"LEI also examined the interplay between carbon pricing and the proposed increases in electricity prices; the proposed price electricity price increases will further diminish agricultural sector competitiveness on top of increasing costs associated with implementing carbon pricing in Manitoba."

It is unclear where in LEI's evidence is its analysis of the interplay between carbon pricing and the proposed electricity prices.

Requests:

a) Please highlight or provide LEI's analysis of the interplay between carbon pricing and the proposed electricity prices.
b) Please explain whether the Manitoba government's Climate and Green Plan and recent pronouncements about carbon pricing, specifically that farm operations will be exempt from the application of the carbon levy and will not be targeted for direct sector reductions, alters LEI's analysis about the impact of carbon pricing.

Response:

a) The Pallister government announced on Friday, October 27th 2017 its plan to introduce a flat $25 carbon tax which will not escalate over the next 5-years.[1] The proposed plan still needs to be voted on in the legislature, but is expected to be passed as Pallister's government holds a large majority. LEI believes that the carbon tax is an additional burden on GSS-GSM customers that will make it more difficult to absorb the proposed rate increases. While LEI excluded the impact of the carbon tax in its analysis of the rate impact on various sample customers, the combined impact of the rate increase and the carbon tax will further reduce the margins for such customers. For those customers who compete with US entities who do not bear the tax, there is the potential for reduced competitiveness. To the extent that relatively low electricity rates are used by customers in their cost structures to offset other aspects of doing business in Manitoba that increase costs, such as the carbon tax, the rate increase will reduce the extent of the offset.

[1] Province of Manitoba. *A Made-in-Manitoba Climate and Green Plan*. October 2017.

Figure 1. Manitoba to have second-lowest carbon price in Canada

2018	2022	
BC = $35	$50	New BC government to raise by $5/tonne each year
AB = $30	$50	Agreed to follow federal plan beginning in 2021
SK = $10	$50	Imposed federal backstop presumed
MB = $25	$25	Made-in-Manitoba Prairie Price
ON = $18	$22 floor price	Cap-and-Trade price forecasted*
QC = $18	$22 floor price	Cap-and-Trade price forecasted*
NB = $10	$50	Agreed to following federal plan beginning in 2018
NS = Under development		Federal equivalency for NS internal cap-and-trade plan
PEI = $10	$50	Agreed to following federal plan beginning in 2018
NL = $10	$50	Agreed to following federal plan beginning in 2018

*Ontario Energy Board Long Term Carbon Price Forecast Report (2017)

Source: Province of Manitoba

b) It does not. Regardless of any exemption from the carbon levy, the impact of the carbon tax on other sectors will be passed through to farm consumers in the prices of all of their inputs. While agricultural producers may be shielded from direct levies, they are unlikely to be shielded from the impact on other sectors. It is important to note, however, that full implementation details have yet to be announced.

1.2 PUB/GSS-GSM-KAP -2

Reference:

- LEI Evidence Page 11 of 61

Preamble:

"For an irrigated potato farm that uses diesel for 40% of the pumping and hydroelectricity for 60% of the pumping, for instance, electricity for irrigation can account for approximately 1.8% of the total annual operating costs."

"In Manitoba, the electricity use on the average dairy farm can account for 2.6% of the total annual operating costs."

Request:

a) Please estimate the proportion of total annual operating costs for an irrigated potato farm that would be attributed to electricity supply in 2024/25 assuming Manitoba Hydro's proposed rate increases of 7.9% are approved. Provide two responses to this request: one assuming all other costs remain constant, the other assuming all other costs escalate by 2% annually.
b) Please estimate the proportion of total annual operating costs for a dairy farm that would be attributed to electricity supply in 2024/25 assuming Manitoba Hydro's proposed rate increases of 7.9% are approved. Provide two responses to this request: one assuming all other costs remain constant, the other assuming all other costs escalate by 2% annually.

Response:

a) Assuming Manitoba Hydro's proposed rate increases of 7.9% up until 2023/24 followed by a rate increase of 4.54% in 2024/25 are approved, LEI estimated the proportion of total operating costs for an irrigated potato farm that would be attributed to electricity supply in 2024/25 under two scenarios.[2] Scenario 1 applies a 7.9% rate increase each year from 2017/18 to 2023/24 followed by a 4.54% rate increase in 2024/25, assuming all costs apart from those associated with electricity remain constant. Scenario 2 also applies a 7.9% rate increase each year from 2017/18 to 2023/24 followed by a 4.54% rate increase in 2024/25, but assumes all costs apart from those associated with electricity escalate at a rate of 2% in each year of the specified timeline. Note that these scenarios, as in the evidence pages, assume that net sales remain constant throughout the specified forecast horizon. The results are outlined in Figure 2.

[2] Manitoba Hydro projects rate increases of 7.9% per year from 2017/18 to 2023/24 and an increase of 4.54% in 2024/25. (Source: *Manitoba Hydro 2017/18 and 2018/19 GRA – First Round Information Requests.* September 5, 2017).

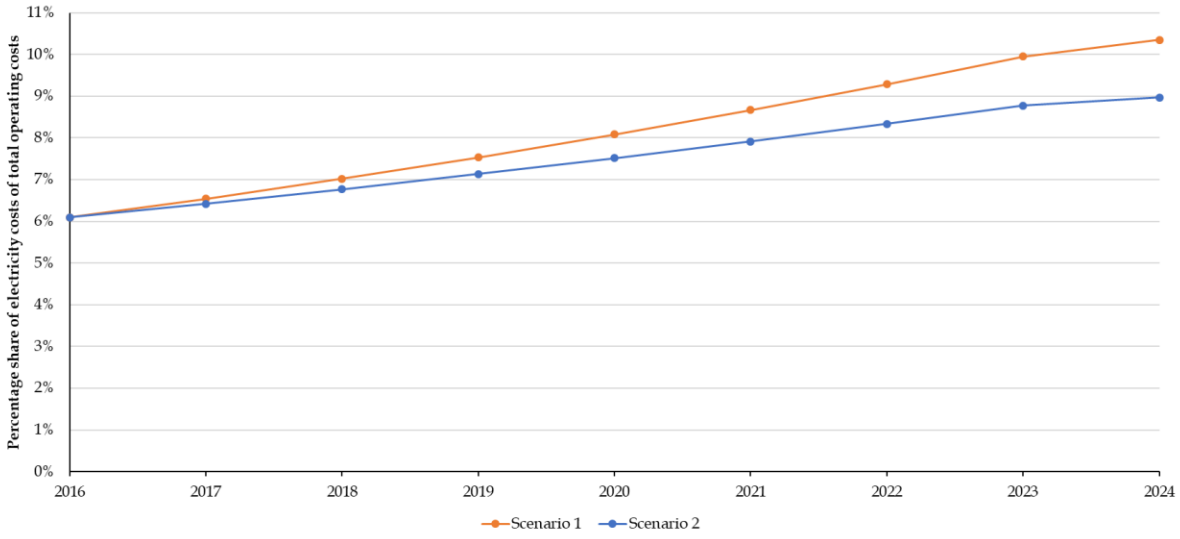
Figure 2. Electricity costs as a proportion of total operating costs of an irrigated potato farm in Manitoba, 2024/25

Scenario	Electricity costs as a proportion of total operating costs in 2024/25
1	10.35%
2	8.97%

Source: *Statistics Canada.*

Furthermore, the percentage shares of electricity costs of total operating costs from the base year of 2016/17 to 2024/25 in both scenarios are presented in Figure 3.

Figure 3. Electricity costs as a proportion of total operating costs of an irrigated potato farm in Manitoba from 2016/17 to 2024/25 for Scenarios 1 and 2



Source: *Statistics Canada.*

b) Assuming Manitoba Hydro's proposed rate increases of 7.9% up until 2023/24 followed by a rate increase of 4.54% in 2024/25 are approved, LEI estimated the proportion of total operating costs for a dairy farm that would be attributed to electricity supply in 2024/25 under two scenarios.[3] Scenario 1 applies a 7.9% rate increase each year from 2017/18 to 2023/24 followed by a 4.54% rate increase in 2024/25, assuming all costs apart from those associated with electricity remain constant. Scenario 2 also applies a 7.9% rate increase each year from 2017/18 to 2023/24 followed by a 4.54% rate increase in 2024/25, but assumes all costs apart from those associated with electricity escalate at a rate of 2% in

[3] Manitoba Hydro projects rate increases of 7.9% per year from 2017/18 to 2023/24 and an increase of 4.54% in 2024/25. (Source: *Manitoba Hydro 2017/18 and 2018/19 GRA – First Round Information Requests.* September 5, 2017).

each year of the specified timeline. Note that these scenarios, as in the evidence pages, assume that net sales remain constant throughout the specified forecast horizon. The results are outlined in Figure 4.

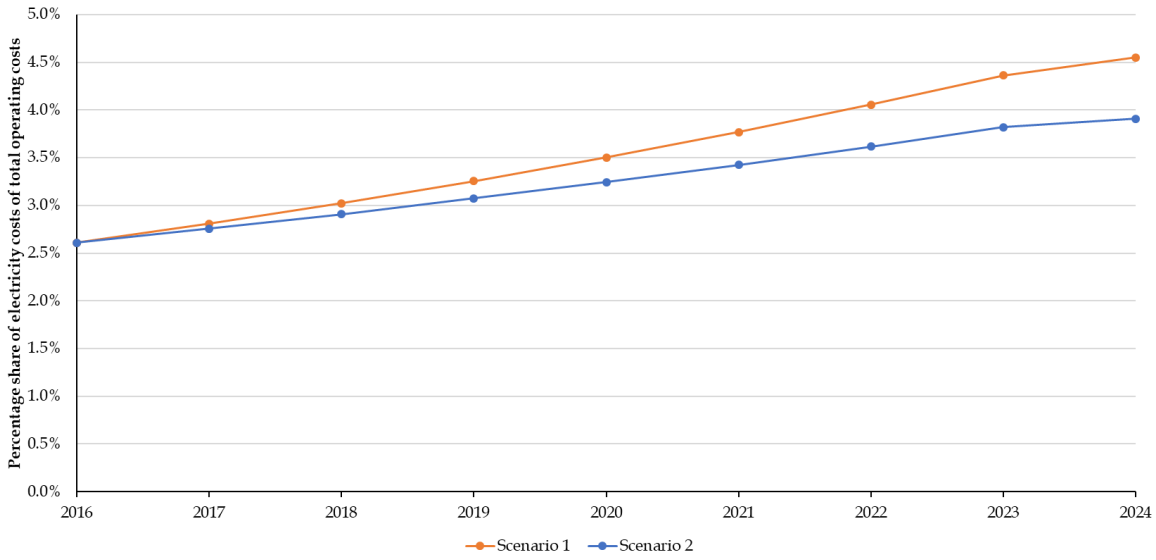
Figure 4. Electricity costs as a proportion of total operating costs of a dairy farm in Manitoba, 2024/25

Scenario	Electricity costs as a proportion of total operating costs in 2024/25
1	4.55%
2	3.91%

Source: *Statistics Canada.*

Furthermore, the percentage shares of electricity costs of total operating costs from the base year of 2016/17 to 2024/25 in both scenarios are presented in Figure 5.

Figure 5. Electricity costs as a proportion of total operating costs of a dairy farm in Manitoba from 2016/17 to 2024/25 for Scenarios 1 and 2



Source: *Statistics Canada.*

1.3 PUB/GSS-GSM-KAP -3

Reference:

- LEI Evidence Page 12 of 61

Preamble:

"In the following sections, LEI examines the bill impact of the proposed increases on an annual and aggregate basis for select customer groups. Manitoba Hydro's use of monthly bill increases obscures the magnitude of their proposal. Next, LEI presents a more in-depth jurisdictional comparison of electricity rates, and assesses the impact on examples of typical agricultural and commercial consumers."

Request:

Given that a primary goal of Manitoba Hydro's asset management goals is to balance the cost of electricity supply with grid reliability, has LEI analysed the cost of reduced electrical grid reliability for typical residential, agricultural and commercial consumers?

i. If yes, please provide this analysis.

ii. If no, please explain why not.

Response:

LEI excluded Bipole III from its analysis of potentially avoidable capital costs because the stated rationale for the investment was reliability; as such, reliability was considered in LEI's recommendations. Customers have not been presented a choice between having an approximately 50% rate increase over a relatively short time period and decreased reliability; indeed, if presented with that choice, some would potentially choose less reliability. Conversely, no evidence has been presented that customers are achieving an increase in reliability proportionate to the rate increase. LEI did not analyze the cost of reduced grid reliability because it does not believe that its recommendations would harm reliability – the rate abeyance would be for a relatively short period, and if a lower rate increase was affirmed, LEI expects that Manitoba Hydro would change its investment profile in ways that would reduce excess supply rather than harming reliability.

1.4 PUB/GSS-GSM-KAP -4

Reference:

- LEI Evidence Pages 19 to 22 of 61

Request:

LEI to repeat the analyses shown in pages 19 to 22 and estimate the changes in operating profits and electricity shares of total operating costs for i) hog farms, ii) irrigated potato farms, and iii) dairy farms based on the proposed electricity rate increases but also escalation of other costs and revenues by 2% annually.

Response:

Hog farms

Assuming Manitoba Hydro's proposed rate increases of 7.9% up until 2023/24 followed by a rate increase of 4.54% in 2024/25 are approved, LEI estimated the proportion of total operating costs for a hog farm that would be attributed to electricity supply in 2024/25 under two scenarios.[4] Scenario 1 applies a 7.9% rate increase each year from 2017/18 to 2023/24 followed by a 4.54% rate increase in 2024/25, assuming all costs apart from those associated with electricity remain constant. Scenario 2 also applies a 7.9% rate increase each year from 2017/18 to 2023/24 followed by a 4.54% rate increase in 2024/25, but assumes all revenues and costs, apart from those associated with electricity, escalate at a rate of 2% in each year of the specified timeline. Figure 6 summarizes the results for farms that use purchased feed and those that use home-mixed feed.

Figure 6. Electricity costs as a proportion of total operating costs of a hog farm in Manitoba, 2024/25

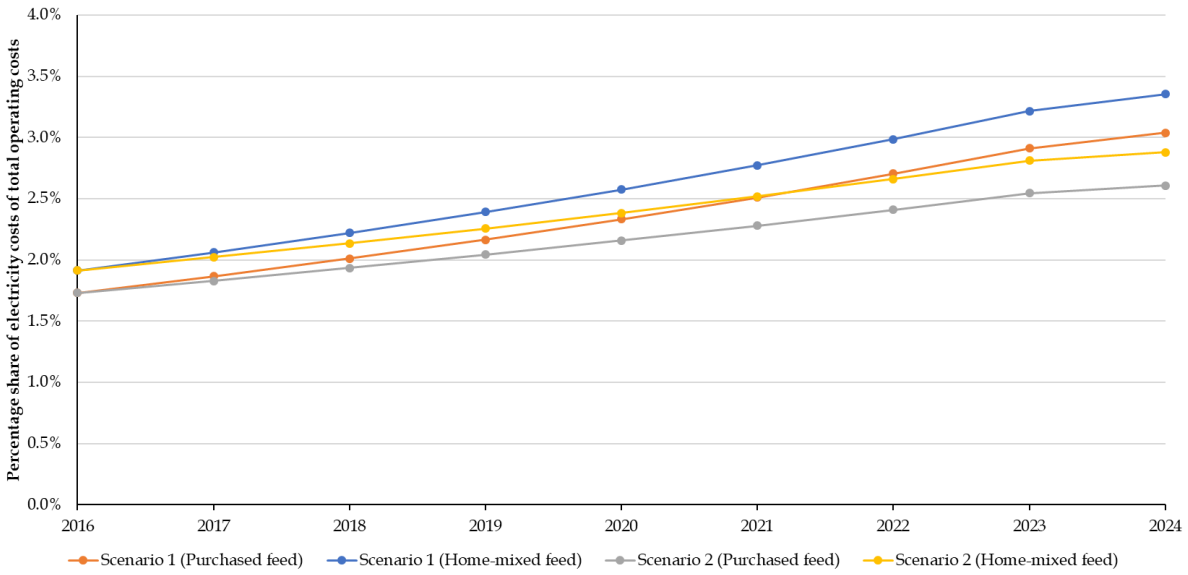
Scenario	Proportion of electricity costs of total operating costs in 2024/25	
	Purchased feed	Home-mixed feed
1	3.04%	3.35%
2	2.61%	2.88%

Source: *Statistics Canada.*

Furthermore, the percentage shares of electricity costs of total operating costs from the base year of 2016/17 to 2024/25 in both scenarios are presented in Figure 7.

[4] Manitoba Hydro projects rate increases of 7.9% per year from 2017/18 to 2023/24 and an increase of 4.54% in 2024/25. (Source: *Manitoba Hydro 2017/18 and 2018/19 GRA – First Round Information Requests.* September 5, 2017).

Figure 7. Electricity costs as a proportion of total operating costs of hog farms (i.e. farms that use purchased feed and those that use home-mixed feed) in Manitoba from 2016/17 to 2024/25 for Scenarios 1 and 2



Source: *Statistics Canada.*

Overall, over the 8-year forecast horizon, hog farms that use purchased feed and those that use home-mixed feed see increases in percentage shares of electricity costs of total operating costs from 1.73% to 3.04% and from 1.91% to 3.35%, respectively (i.e. changes of about 75%) for Scenario 1. For Scenario 2, said percentage share increases from 1.73% to 2.61% and from 1.91% to 2.88%, respectively (i.e. changes of about 50%).

With regards to operating profits, the average Manitoba hog farm that purchases feed and home-mixes feed sees a drop of approximately $211,700 in both cases, or 4.84% and 3.80%, respectively, in the 8-year period for Scenario 1. On the other hand, the average Manitoba hog farm that purchases feed and home-mixes feed sees an increase in operating profits of approximately $585,380 and $791,420, or 13.4% and 14.2%, respectively, in the 8-year period where the rate is applied, and costs and revenues are inflated annually as per Scenario 2.

Irrigated potato farms

Assuming Manitoba Hydro's proposed rate increases of 7.9% up until 2023/24 followed by a rate increase of 4.54% in 2024/25 are approved, LEI estimated the proportion of total operating costs for an irrigated potato farm that would be attributed to electricity supply in 2024/25 under two scenarios mentioned previously.[5] Figure 2 summarizes the results for irrigated potato farms.

[5] Manitoba Hydro projects rate increases of 7.9% per year from 2017/18 to 2023/24 and an increase of 4.54% in 2024/25. (Source: *Manitoba Hydro 2017/18 and 2018/19 GRA – First Round Information Requests.* September 5, 2017).

Furthermore, the percentage shares of electricity costs of total operating costs from the base year of 2016/17 to 2024/25 in both scenarios can be found in Figure 3.

Over the 8-year forecast horizon, an irrigated potato farm sees an increase in percentage share of electricity costs of total operating costs from 6.09% to 10.35%, or a change of approximately 70% for Scenario 1. For Scenario 2, said percentage share increases from 6.09%to 8.97%, or by approximately 47%. Refer to PUB/GSS-GSM-KAP-2 for further details regarding percentage shares of electricity costs of total operating costs of an irrigated potato farm in Manitoba for the two previously mentioned scenarios.

In terms of operating profits, the average Manitoba irrigated potato farm sees a drop of approximately $45,850, or 13%, in the 8-year period for Scenario 1. In Scenario 2, however, the average Manitoba irrigated potato farm sees an increase in operating profits of approximately $24,865, or 7%, in the 8-year period.

Dairy farms

Assuming Manitoba Hydro's proposed rate increases of 7.9% up until 2023/24 followed by a rate increase of 4.54% in 2024/25 are approved, LEI estimated the proportion of total operating costs for a dairy farm that would be attributed to electricity supply in 2024/25 under two scenarios mentioned previously.[6] Figure 4 summarizes the results for dairy farms. Furthermore, the percentage shares of electricity costs of total operating costs from the base year of 2016/17 to 2024/25 in both scenarios can be found in Figure 5.

Over the 8-year forecast horizon, a dairy farm sees an increase in percentage share of electricity costs of total operating costs from 2.61% to 4.55%, or a change of approximately 75% for Scenario 1. For Scenario 2, said percentage share increases from 2.61% to 3.91%, or by approximately 50%. Refer to PUB/GSS-GSM-KAP-2 for details regarding percentage shares of electricity costs of total operating costs of a dairy farm in Manitoba for the two previously mentioned scenarios.

Furthermore, the average Manitoba dairy farm sees a drop in operating profits of approximately $11,850, or approximately 6%, in the 8-year period for Scenario 1. In Scenario 2, the average Manitoba dairy farm sees an increase in operating profits of $24,080, or 12.5%, in the 8-year period.

1.5 PUB/GSS-GSM-KAP -5

Reference:

- LEI Evidence Page 25 of 61

[6] Manitoba Hydro projects rate increases of 7.9% per year from 2017/18 to 2023/24 and an increase of 4.54% in 2024/25. (Source: *Manitoba Hydro 2017/18 and 2018/19 GRA – First Round Information Requests.* September 5, 2017).

Preamble:

"With the requested rate increases over a 5-year period, electricity bills are expected to increase from $1,957 to $2,862. Assuming that all other costs and revenue remain in equal, gross margins will fall by 4%, from 21% to 17%."

Request:

Please recalculate the change in Manitoba convenience store gross margins assuming all other costs except electricity as well as revenues increase by 2% annually, while electricity rates increase by Manitoba Hydro's proposed 7.9% annual increase.

Response:

Assuming Manitoba Hydro's rate increase of 7.9% up until 2023/2024 followed by a rate increase of 4.54% in 2024/2025 are approved, and all other costs except electricity as well as revenue increase by 2% annually, LEI estimates that the operating revenues and operating expenses amount to $82,569.36 and $66.420.54, respectively. This translates to a gross operating margin for convenience stores of 19%, indicating a 2% drop from the previous gross operating margin of convenience stores of 21%.[7]

[7] NACS. *NACS State of Industry Summit 2015.* 2016.

1.6 PUB/GSS-GSM-KAP -6

Reference:

- LEI Evidence Page 31 of 61

Preamble:

"In Manitoba Hydro's 2016 electric load forecast, the utility estimated that a one-time 1% in real electricity price would result in a 0.18% decrease in consumption by GSS and GSM customers." [Footnote Omitted]

Request:

What reduction in grid reliability would result in a similar 0.18% decrease in GSS and GSM customer consumption?

Response:

The concept of decline in consumption due to changes in price (elasticity) is unrelated to the involuntary decrease in consumption which occurs due to a decline in reliability. While LEI has performed some indicative calculations regarding the extent to which reliability would need to deteriorate in order to match the level of decline related to a price increase, no evidence has been presented to suggest that modifying Manitoba Hydro's capital investment program in response to changes in demand and market conditions would reduce reliability.

In Appendix 2 of Manitoba Hydro's GRA filing, GSS and GSM customers consumed a total of 8,035 GWh/year. Should GSS and GSM consumption fall by 0.18% due to outages, this would amount to a reduction of 14.46 GWh of GSS and GSM consumption or an outage of 946 minutes, or 15.78 hours. Relating this disruption to Manitoba Hydro's latest SAIDI would see values increase from 2.62 in Manitoba Hydro's 66th Annual Report to 18.38, or a percentage increase of 601%. LEI caveats that actual usage is not average, but has an hourly profile, and that the experience of commercial customers may differ from the system as a whole.

1.7 PUB/GSS-GSM-KAP -7

References:

- LEI Evidence Page 35 of 61;
- GSSGSM/MH I-5;
- Coalition/MH I-50;
- 2016/17 Interim Application Attachment 17 Resource Planning Assumptions and Analysis p.2 of 28

Preamble:

LEI may have misinterpreted the response to GSS-GSM/MH I-5, which identifies the need date for new resources after Keeyask enters service.

The need-date for resources if Keeyask is cancelled is not 2040, but is closer to 2034/35 assuming the Minnesota Power 250MW contract is also cancelled (based on the supply and demand tables from Coalition/MH I-50).

Request:

Please confirm whether analysis of gas generation alternatives changes if the need for new resources absent Keeyask is in the mid-2030s instead of 2040.

Response:

In its response to GSS-GSM/MH I-5 part a, MH states *"Using the 2016 MH16 Update assumptions, the need for new generation changes to 2039/40."* LEI notes that there is no mention of Minnesota Power.

LEI's analysis does not change if the need for new resources is in the mid-2030s. Natural gas plants are relatively cheap to build compared to large-scale hydro, and have less potential cost volatility. In addition, the gestation time for a natural gas plant is much shorter – 2 to 3 years from conceptualization to completion depending on the permitting process. An additional key factor is granularity – natural gas plants can be built in smaller sizes, with their online dates better synchronized with load. This additional optionality is valuable, particularly in a situation where load is falling and technologies are changing rapidly. Even if the actual need date is in the mid-2030s – and it is unclear whether current demand forecasts fully factor in the impact of the proposed and projected rate increases on suppressing demand – the decision on whether to build the new plants could be delayed until at least 2030.

1.8 PUB/GSS-GSM-KAP -8

Reference:

- LEI Evidence Page 38 of 61

Request:

Please provide LEI's view as to the most appropriate real discount rate to use in the analysis of whether to continue with or cease work on Keeyask. Provide LEI's analysis to support the recommended real discount rate.

Response:

It is an established tenet of financial valuation that the appropriate discount rate should be matched to the risk of the project being considered, rather than to the nature of the investor. When considering an appropriate real discount rate for Keeyask, it is important to note that the risk profile of Keeyask is very different from that of Manitoba Hydro as a whole, or more generally of any vertically integrated utility. A large proportion of Keeyask output will be merchant for the foreseeable future. This exposes the asset to substantial market risk. Furthermore, the plant is only partially built, and may suffer additional schedule delays and cost overruns. Consequently, it is inappropriate to use a cost of capital based on Manitoba Hydro's generalized risk profile. This means that the 4.4% real discount rate described on page 557 of 615 of the BCG study is irrelevant for the purposes of investment decision-making, as is the discussion on page 560 which focuses on approved returns for various utilities.[8]

Instead, the most appropriate points of consideration include the nominal post-tax project IRR discussed on page 561, and the WACC and ROE matrix on page 558 of the BCG study. The 10-12 percent nominal post-tax project IRR is linked to merchant gas plant in an energy-only market; the higher capital cost per kW and the longer gestation period for large-scale hydro like Keeyask would suggest that the appropriate IRR target would be 12% or potentially above. This is consistent with the positioning of the marking for US Renewable Power Producers on page 558, which shows a nominal pre-tax WACC of approximately 7.5% and nominal return on equity of 12%. Given that US interest rates have risen 0.76% since the BCG material was prepared, and that Keeyask faces additional construction risk relative to the US Renewable Power Producers, we believe that this would result in a nominal pre-tax WACC of 9-10%; adjusted to real by deducting 1.7% (consistent with the BCG deduction for inflation) would result in a real discount rate of 7.3%-

[8] Manitoba Hydro. *MFR-72 - Attachment.* 2017.

8.3%.[9] As a result, we believe that the 8% rate used by BCG in its alternative case should in fact be used as the reference case.[10]

[9] Federal funds rate increased from 0.40 in October 2016 to 1.16 as of November 2017, an increase of 0.76%.

[10] For example, assuming a 12% cost of equity and 6.16% cost of debt (5.4% cost of debt estimated by BCG plus 0.76% increase in US interest rates), and a capital structure consisting of 55% debt and 45% equity, nominal WACC is around 8.78%. Adjusting to real by deducting the 1.7% inflation factor used by BCG gives a real WACC of 7.09%.

1.9 PUB/GSS-GSM-KAP -9

Reference:

- LEI Evidence Pages 44 to 48 of 61

Requests:

a) Please explain whether LEI used numbers of employees, numbers of full time equivalent employees based on straight time, numbers of full time equivalent employees based on straight time plus overtime, or some other measure in its benchmarking analysis.

b) Please confirm whether LEI removed the numbers of employees performing work for Manitoba Hydro's subsidiaries, including the gas utility Centra Gas, from its benchmarking analysis. If not, please re-file the analysis removing these numbers of employees.

c) Please provide the Annual Reports or links to the reports referenced in LEI's evidence.

Responses:

a) LEI's definition of employees was based on the number of employees reported by the various entities. The analysis was illustrative; a more in-depth analysis would be needed to assess details of how full time equivalents ("FTEs") are categorized at each entity.

b) Manitoba Hydro's 5,511 employees (i.e. 6,411 full-time employees minus 900 employees, as per their workforce reduction plan) include Centra Gas Manitoba Inc.'s employees as these were not differentiated in Manitoba Hydro's annual report. The Manitoba Hydro-Electric Board 66th Annual Report does not differentiate employees from that of its subsidiaries. LEI notes that these calculations were illustrative and further detailed categorization could be performed in a more exhaustive analysis.

c) The following annual reports were referenced in LEI's evidence:

Avista. *2016 Annual Report.* <http://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_AVA_2016.pdf>

British Columbia Hydro and Power Authority. *2016/17 Annual Service Plan Report.*<https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2016-17-annual-service-plan-report.pdf>

Emera. *2016 Annual Report.* <http://investors.emera.com/Cache/1500098124.PDF?Y=&O=PDF&D=&fid=1500098124&T=&iid=4072693>

Enérgie NB Power. *Annual Report 2016/17.* <https://www.nbpower.com/media/759035/2016-2017-annualreport-en_web_ready.pdf>

Hydro Quebec. *Annual Report 2016.* <http://www.hydroquebec.com/publications/en/docs/annual-report/annual-report-2016.pdf>

IDACORP. *Idaho Power Annual Report.* 2016. <http://www.idacorpinc.com/~/media/Files/I/IDACorp/investor-docs/annual-reports/ar2016.pdf>

Manitoba Hydro. *Manitoba Hydro-Electric Board 66th Annual Report for the Year Ended March 31, 2017.* <https://www.hydro.mb.ca/corporate/ar/pdf/annual_report_2016_17.pdf>

SaskPower. *2016-17 Annual Report.* <http://www.saskpower.com/wp-content/uploads/2016_17_Annual_Report.pdf>

1.10 PUB/GSS-GSM-KAP -10

Reference:

- LEI Evidence Pages 52 of 61

Preamble:

"LEI believes that Manitoba Hydro's request for a rate increase should be held in abeyance until the following analysis is performed and submitted to the Board for its review:

• Properly conducted macroeconomic analysis which appropriately addresses full impacts of all of the projected rate increases on the Manitoba economy in an integrated fashion, including the impact on employment, economic growth, and per capita incomes."

Requests:

a) Please identify where, in authoritative sources, consideration of macroeconomic impacts is a principle of setting electricity or other utility rates, specifically for governmentally owned utilities such as Crown Corporations where return on equity considerations are not present.

b) If the PUB were to take into consideration LEI's recommendation, where does LEI suggest a Crown Corporation whose sole owner is the government obtain necessary funding to meet revenue shortfalls from Board-approved revenue requirements resulting from an abeyance of the rate application?

c) LEI to provide examples of Crown Corporations where rate applications similar to that filed by Manitoba Hydro were held in abeyance and the requests were deferred. Please cite the specific circumstances including:

   i. The size of the applications;

   ii. What, if any, interim rate relief was provided to the utilities while the applications was held in abeyance;

   iii. The ratemaking principles cited in granting the abeyances;

   iv. The factors considered during the macroeconomic analyses;

   v. The ultimate results achieved.

Responses:

a) One authoritative source come from *The Regulation of Public Utilities*, *Theory and Practice* by Charles F. Phillips, Jr. – an excerpt of which is provided in the textbox below.

> "At the state level, in addition to providing rate relief for low-income customers, special or discount rates have been proposed to prevent bypass, to promote economic development and, in a few instances, to replace tariffed interruptible rates. To prevent the loss of commercial or industrial load (where a customer has a financially viable option of self-generation or the ability to obtain electricity from another source or to switch fuel types), several commissions have permitted electricity utilities to negotiate noncost-based rates, commonly known as "antibypass" rates or "anticogeneration" rates (sometimes as "incentive" or "load retention" rates). To increase commercial or industrial load, due to surplus and/or excess capacity, some commissions have approved experimental or limited special discount rates, known as "economic development" rates, to customers who locate in the state or who expand either their production or facilities (and thereby hire new employees). To provide added flexibility, electric utilities commonly offer interruptible service to customer willing to have their service interrupted, if necessary, by the utility. In all three cases, the commissions have generally held that the rates must be above the utilities' marginal or avoided costs of serving such customers, thereby making some contribution to fixed costs. Such rates often raise issues of undue discrimination, from a statutory standpoint, but have been found "in the public interest" since they promote specific economic and social objectives."
>
> Source: Phillips, C. F. Jr. *The Regulation of Public Utilities: Theory and Practice*. Public Utilities Reports, Inc. Arlington, Virginia, United States. 1993. p. 469.

It appears that MH also recognizes the relevance of the broad economic consequences of the rates that customers are required to pay. For example, MH states *"Manitoba Hydro's long term plans are to avoid short-term rate increases and fluctuations that would cause undue shocks to ratepayers and/or interfere with MH's own financial planning and budgeting"* among its primary objectives in its financial planning process. Further, in Tab 2 of its GRA filing, MH notes *"establishing the time frame for the achievement of its minimum equity target at 10 years strikes an appropriate balance between what is reasonable for customers and what is necessary to ensure the long-term financial health of Manitoba Hydro"* as one its key reasons for the rate increase. Given that virtually all residential and business customers are impacted by the macroeconomic consequence of MH's rates, it would be inconsistent to exclude macroeconomic effects from consideration of the impact MH's proposals have on its customers.

b) LEI does not oppose an interim 3.36% increase while the overall application is held in abeyance, consistent with the current trajectory of rates. Furthermore, LEI does not believe that abeyance necessarily results in shortfalls, as LEI believes that part of the impetus for the abeyance is that Manitoba Hydro can reduce its cash needs through changes to the speed at which it increases its equity cushion, reconsideration of Keeyask, and changes to operations. Additionally, the abeyance would be time-limited, consistent with the time needed to perform appropriate in-depth analysis of alternative approaches to Keeyask.

c) LEI notes the following cases as examples of rate abeyance: BC Hydro, SaskPower, NB Power, ENMAX (owned by the city of Calgary). The table below summarizes some of the features and details available and/or applicable. Additional colour is provided in subsections 0 to 0.

Figure 8. Details on selected Crown Corporation's abeyance rate cases

Specific Circumstances	BC Hydro	SaskPower	NB Power	ENMAX (owned by the city of Calgary)
Applicable period of application	1993-2003	2011-2013	2011-2013	2012-2013
The size of the applications	No applications were filed (BC Utilities Commission did not regulate BC Hydro rates in this period)	No applications were filed	No applications were filed	No applications were filed
What, if any, interim rate relief was provided to the utilities while the applications was held in abeyance	no interim relief	no interim relief	no interim relief	no interim relief
The ratemaking principles cited in granting the abeyances	Rates were capped in 1996 by the Tax and Consumer Rate Freeze Act; rates were frozen in 1998 by the BC Hydro and Power Authority Rate Freeze and Profit Sharing Act	Average ROE exceeded target ROE over the 2011-2013 period	In January 2011, the Shareholder's mandate letter which directed NB Power to implement a three year rate freeze ending September 2013	In 2012, the Alberta Minister of Energy issued a mandate to freeze electricity rates pending a review of regulated electricity charges by an independent committee. On January 30, 2013, the government announced its findings of the review and lifted the rate freeze
The factors considered during the macroeconomic analyses	n/a	n/a	n/a	n/a
The ultimate results achieved	BC Hydro deferred capital spending and resource acquisition in this period	Subsequent rate increases have been relatively high (5%+)		EPC's was allowed to true up the difference between the interim rates in place and the final rates requested for the effective period of the 2012 annual rates

Sources: Utility filings and reports

BC Hydro

- "During the 1990s, new and amended directions, Ministers' exemption orders, and **legislation limited BCUC jurisdiction to regulate BC Hydro. Rates were capped in 1996 by the Tax and Consumer Rate Freeze Act.** After customer groups asked BC Hydro to apply for rate reductions, rates were frozen in 1998 by the BC Hydro and Power Authority

Rate Freeze and Profit Sharing Act. BC Hydro deferred capital spending and resource acquisition during this time."[11]

- "BC Hydro's rates were legislatively frozen from 1996 until the rate freeze ended effective March 31, 2003. The end of the rate freeze allowed the implementation of Policy Action #5 of the 2002 Energy Plan, which provided that "the BC Utilities Commission will once again regulate BC Hydro rates."[12]

SaskPower

- SaskPower did not apply for rate increases in 2011 or 2012 (and have since referred to it as a rate freeze). Average ROE exceeded target ROE over the 2011-2013 period.

NB Power

- Following the provincial elections, In January 2011, the NB Power Board of Directors received the Shareholder's mandate letter which included a number of specific directives, one of which directed NB Power to implement a three-year rate freeze ending September 2013.

ENMAX

ENMAX had applied for a distribution tariff (DT) rate increase just before the province-wide rate freeze, and was allowed to recover the shortfall after the rate freeze was lifted.

- "The Commission acknowledges that, due to the timing of EPC's application with respect to its 2011 annual rates and technical report for DT rates for the period July 1, 2011 to June 30, 2012 (which were approved as final in Decision 2013-074); and its 2012 annual rates and technical report for proposed DT rates for the period July 1, 2012 to June 30, 2013 (which are approved as final in this decision), EPC has remained on interim rates approved in Decision 2011-260 during this time.

- **The Commission accepts EPC's proposal to true up the difference between the interim rates currently in place and the final rates requested for the effective period of the 2012 annual rates and technical report (July 1, 2012 to June 30, 2013) in its 2013 annual rates** and technical report, which the Commission observes has been filed under Proceeding ID No. 2657. EPC will seek approval in that proceeding to commence collecting or refunding the aforementioned trueups. Accordingly, the Commission directs EPC to continue to

[11] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/iepr/ministry_discussion_paper_iepr.pdf

[12] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/ regulatory-planning-documents/regulatory-matters/bcuc-order-g-130-07-and-reasons-for-decision.pdf

apply the current DT Tariff on an interim basis until such time as the Commission issues a decision on EPC's 2013 annual rates and technical report (Proceeding ID No. 2657)."

1.11 PUB/GSS-GSM-KAP -11

Reference:

- LEI Evidence Page 16 of 61 - Figure 8 & 9

Preamble:

To account for five years of rate increases out to 2021, LEI escalated the average commercial rates in competing jurisdictions with inflation of 2% while Manitoba's rate increased at a rate of 7.9 annually. This is similar to the approach taken by Manitoba Hydro.

MH provided a historical comparison of rates in Tab 9 Page 14 Figure 9.4.

Request:

Please indicate where MH escalated the rates in other jurisdictions by inflation of 2% for rate comparison purposes.

Response:

In Figure 2.34 entitled, "*Residential Monthly Bill Comparisons (1,000 kWh per month),*" on page 56 of its Tab 2 submission, MH notes *"Winnipeg bill reflects 7.9% rate increase in 2017/18 and 2018/19. Where published information is available, projected rate increases have been reflected in the bill calculations for other cities, and where not available, annual rate increases of 2% have been assumed. [Emphasis added.] Analysis does not consider the impact that the implementation of a carbon tax may have on electricity prices in the future."*

1.12 PUB/GSS-GSM-KAP -12

Reference:

- LEI Evidence Page 28 IMPLAN Model

Requests:

a) Please explain the calibration done to use the IMPLAN model for Manitoba.

b) Please indicate where the IMPLAN model has been used in Canada in other jurisdictions with respect to economic analysis.

c) Please indicate what additional data was available from Stats Canada post 2012.

Responses:

a) For this analysis, LEI used IMPLAN's proprietary input-output model for the province Manitoba. The primary sources for the Canadian provincial data include a symmetric input-output table, released by Statistics Canada in 2012. This table provides the basis for the purchasing patterns for industries in all provinces.

IMPLAN obtained data on regional employment and compensation from Statistics Canada, and estimated values for missing or non-disclosed cells by using various interpolation methods and data from Dunn and Bradstreet.

The regional employment and compensation data also serve to distribute national industry value-added, intermediate expenditures, output, and transfer payments to provinces.

b) IMPLAN has been used to conduct economic analysis in the following studies in jurisdictions across Canada:

The Brattle Group. *Employment and Economic Benefits and Transmission Infrastructure Investment in the U.S. and Canada.* 2011. <http://www.capx2020.com/media/WIRES_study/WIRES_jobs_study_05.2011.pdf>

Bureau of Business and Economic Research. *Enbridge Pipeline Construction Economic Impact Study.* April 18, 2017. <http://www.apexgetsbusiness.com/media/userfiles/subsite_159/files/Enbridge%20Line%203%20Impact%20Study%20-%20April%202017(2).pdf>

Canadian Energy Research Institute. *Economic Impacts of New Oil Sand Projects in Alberta (2010-2035).* May 2011. <http://www.americanpetroleuminstitute.net/~/media/Files/News/2011/Economic_Impacts_of_New_Oil_Sands_Projects_Alberta.pdf>

Chen, Xi. *Economic and Environmental Impacts of Biofuel Policy in Canada: An Application of Input-Output Modelling.* July 2015. <http://digitool.library.mcgill.ca/webclient/StreamGate?folder_id=0&dvs=1510704718628~251>

Deloitte. *Economic Impact Study on the Ontario Veterinary College at the University of Guelph.* 2014. <https://ovc.uoguelph.ca/doc/economic/OVC-Economic-Impact-Study.pdf>

Frank, Rimerman + Co. LLP. *The Economic Impact of the wine and grape industry in Canada.* 2015. <http://www.canadianvintners.com/wp-content/uploads/2017/06/Canada-Economic-Impact-Report-2015.pdf>

Ontario Corn Producers' Association. *The Economic Importance of Ontario's Corn Sector.* December 2005. <https://www.ridgetownc.com/research/documents/vyn_Impact_of_Corn_Report.pdf>

Across North America more broadly, the following sample of reports use IMPLAN.

Bureau of Business and Economic Research. *The Economic Impact of the Canada/Northeastern Minnesota Relationship on the Arrowhead Region of Minnesota.* June 30, 2016. <https://lsbe.d.umn.edu/sites/lsbe.d.umn.edu/files/canada_minnesota_connection_report_final.pdf>

Henneberry, S., Whitacre, B., and Agustini, H. *An Evaluation of the Economic Impacts of Oklahoma Farmers Markets.* 2008. <http://ageconsearch.umn.edu/bitstream/99760/2/Evaluation%20pg%2064-78.pdf>

Massachusetts Energy Storage Initiative Study. *State of Charge.* 2016. <http://energystorage.org/system/files/attachments/ma_storage_study.final_w5768299x7ac2e.pdf>

Midcontinent Independent System Operator. *Economic Impact of MTEP In-service Projects from 2002-2015.* July 2015. <https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Economic%20Impact%20of%20MTEP%20In-Service%20Projects.pdf>

Minnesota Power. *Minnesota Power/Manitoba Hydro Great Northern Transmission Line Economic Impact on Northern Minnesota.* July 2013. <http://www.greatnortherntransmissionline.com/files/3713/7882/6435/MN_Power_Manitoba_Hydro_FINAL_July_2013.pdf.pdf>

National Renewable Energy Laboratory. *National Economic Value Assessment of Plug-In Electric Vehicles*. December 2016. <https://www.nrel.gov/docs/fy17osti/66980.pdf>

c) Since the "*2009 Input-Output Structure of the Canadian Economy in Current Prices*", was released in November 2012, Statistics Canada has released the following updates:

- 2010 Input-Output Structure of the Canadian Economy in Current Prices (2013)
- 2011 Input-Output Structure of the Canadian Economy in Current Prices (2014)
- 2012 Input-Output Structure of the Canadian Economy in Current Prices (2015)
- 2013 Input-Output Structure of the Canadian Economy in Current Prices (2016)
- 2014 Input-Output Structure of the Canadian Economy in Current Prices (2017)

LEI notes that it given the limited time, it was not able to update this analysis using the IMPLAN. Nevertheless, the proposed rate increases will still likely to result in material (or substantial) job losses, labor income reduction, and decline in value added, and lower output level.

1.13 PUB/GSS-GSM-KAP -13

Reference:

- LEI Evidence Page 32 Economic Impacts

Request:

Please provide the definition of each of the economic impacts set out in Figure 20 and provide an illustrative description if appropriate to describe the factor.

Response:

In Figure 20, LEI examines the employment, labor income, value-added and output impacts associated with a consumption reduction.

Employment is defined as the annual average of monthly jobs in the industries included in this economic impact study. One job in IMPLAN is defined as 1 job lasting 12 months, or 2 jobs lasting 6 months, or 3 jobs lasting 4 months each.

Labor income refers to all employment income, including wages and benefits, and income by self-employed individuals and unincorporated business owners.

Value added is a measure of the contribution to GDP made by the industry or industries. It is defined as the difference between and industry's total output and the cost of its intermediate inputs. The Value added consists of employee compensation, taxes on production, and imports excluding subsidies, and a gross operating surplus.

Output represents the value of industry production. For manufacturers, this would mean sales ± net inventory changes. For service sectors its representative of Sales. For retail and wholesale trade sectors, output is defined as the gross margin.

1.14 PUB/GSS-GSM-KAP -14

Reference:

- LEI Evidence Page 32 Economic Impacts

Request:

a) Please indicate the direct, indirect and induced impacts on employment, labour income, value added and gross output based on the current proposed rate impacts through 2024/25.

b) Please provide the related income tax revenue impacts related to the job losses.

c) Please explain why there are no direct impacts related to the proposed rate increases in terms of employment, labour income, value added or gross output.

Response:

a)

The direct, indirect, and induced impacts on employment, labour income, value added, and gross output are presented in the figure below, utilizing a 7.9% difference in revenue case.

Figure 9. Summary of the impact of the annual 7.9% rate increase

	Employment			Labor Income ($ M)			Value Added ($ M)			Output ($ M)		
	Direct Effect	Indirect Effect	Induced Effect	Direct Effect	Indirect Effect	Induced Effect	Direct Effect	Indirect Effect	Induced Effect	Direct Effect	Indirect Effect	Induced Effect
Residential												
0% savings usage	(321.1)	(128.0)	(117.0)	($16.5)	($8.5)	($6.6)	($36.2)	($13.9)	($13.4)	($64.2)	($29.3)	($25.1)
10% savings usage	(239.5)	(95.4)	(87.2)	($10.9)	($5.6)	($4.4)	($24.0)	($9.2)	($8.9)	($41.4)	($19.0)	($16.2)
20% savings usage	(157.8)	(62.9)	(57.5)	($7.2)	($3.7)	($2.9)	($15.8)	($6.0)	($5.9)	($27.3)	($12.5)	($10.7)
GSS & GSM	0.0	(340.6)	(104.1)	$0.0	($22.2)	($5.9)	$0.0	($35.0)	($12.0)	$0.0	($70.5)	($22.4)

b)

The indicative impact to the income tax revenue for the associated job losses in each case is listed below. The income tax revenue loss was calculated using an average annual salary of $46,203[13] and a blended income tax rate of 20.69%.[14]

[13] The average weekly earnings in Manitoba for 2016 was $888.52. Source: Statistics Canada. *Average weekly earning (including overtime), by province and territory.* <https://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/labr79-eng.htm>

[14] EY. *Tax calculators and rates (2016).* <http://www.ey.com/ca/en/services/tax/tax-calculators-2016-personal-tax>

Figure 10. Impact of rate increase on residential income tax revenues

	Employment loss	Income tax revenue loss ($ M)
Case I: 7.9%		
0% savings usage	(566.0)	($5.4)
10% savings usage	(422.1)	($4.0)
20% savings usage	(278.2)	($2.7)
Case II: 3.36%		
0% savings usage	(451.4)	($4.3)
10% savings usage	(307.5)	($2.9)
20% savings usage	(163.5)	($1.6)

Figure 11. Impact of rate increase on business income tax revenues

	Employment loss	Income tax revenue loss ($ M)
Case I: 7.9%	(444.7)	($4.3)
Case II: 3.36%	(375.9)	($3.6)

c)

LEI designed the inputs to provide conservative configuration impacts. An alternative or more aggressive configuration could result in larger direct impacts.

1.15 PUB/GSS-GSM-KAP -15

Reference:

- LEI Evidence Pages 17 to 26, 32 of 61 Sector economic impacts

Preamble:

It is not clear whether LEI modelled the incremental impact of two different rate trajectories versus a global increase as proposed based on a 7.9% rate increase.

Request:

a) Please indicate the direct, indirect and induced impacts on employment, labour income, value added and gross output based on the difference between the proposed 7.9% rate trajectory and or a 3.36% or 3.95% rate trajectory.

b) Please comment on the impact by industry on the incremental impact a rate trajectory at 7.9% as proposed by MH for the next six years with a 3.95% rate indication from the last GRA.

Response:

a)

The five figures below present the difference between the impact of the 7.9% rate trajectory and the 3.36% rate trajectory. The positive results indicate that the 3.36% rate trajectory will result in **lower** employment, income, value added, and output losses in comparison to the 7.9% trajectory. The 7.9% rate increase then is more harmful to the economy.

Figure 12. Difference in impact on the agricultural sector

Impact Type	Employment	Labor Income ($)	Value Added ($)	Output ($)
Direct Effect	-	-	-	-
Indirect Effect	2.36	135,316	235,245	579,463
Induced Effect	0.64	35,852	72,898	136,253
Total Effect	**3.00**	**171,168**	**308,143**	**715,716**

Figure 13. Difference in economic impact on the GSS-GSM sector

Impact Type	Employment	Labor Income ($)	Value Added ($)	Output ($)
Direct Effect	-	-	-	-
Indirect Effect	52.73	3,437,969	5,416,541	10,916,881
Induced Effect	16.12	910,841	1,852,001	3,461,579
Total Effect	**68.85**	**4,348,810**	**7,268,542**	**14,378,460**

Figure 14. Difference in economic impact on the residential sector - 0% saving rate

Impact Type	Employment	Labor Income ($)	Value Added ($)	Output ($)
Direct Effect	65.03	4,803,105	10,557,237	19,983,589
Indirect Effect	25.91	2,464,041	4,034,224	9,067,421
Induced Effect	23.69	1,925,294	3,914,674	7,819,969
Total Effect	**114.62**	**9,192,440**	**18,506,135**	**36,870,978**

Figure 15.Difference in economic impact on the residential sector - 10% saving rate

Impact Type	Employment	Labor Income ($)	Value Added ($)	Output ($)
Direct Effect	65.03	2,967,945	6,523,550	11,238,948
Indirect Effect	25.91	1,522,585	2,492,836	5,150,052
Induced Effect	23.69	1,189,682	2,418,963	4,393,551
Total Effect	**114.62**	**5,680,211**	**11,435,350**	**20,782,550**

Figure 16. Difference in economic impact on the residential sector - 20% saving rate

Impact Type	Employment	Labor Income ($)	Value Added ($)	Output ($)
Direct Effect	65.03	2,967,945	6,523,550	11,238,948
Indirect Effect	25.91	1,522,585	2,492,836	5,150,052
Induced Effect	23.69	1,189,682	2,418,964	4,393,551
Total Effect	**114.62**	**5,680,211**	**11,435,350**	**20,782,550**

b)

based on the analysis in part a, LEI expects the 3.9% rate increase to have a less negative impact compared to the 7.9% case, but a more negative impact when compared to the 3.36% case. In ranking then, the 7.9% rate increase is the most harmful to the economy; the 3.9% rate increase is less harmful to the economy and; the 3.36% rate increase is the least harmful to the economy.

1.16 PUB/GSS-GSM-KAP -16

Reference:

- LEI Evidence Page 36 of 61 Sector economic impacts

Request:

LEI indicates that applying the unspent cost overruns to BCG's calculation suggests the project cancellation is a more viable option.

a) Each of the cited examples on page 37, please indicate the financial reporting impact of the decision on the reporting entity.

b) Please explain how LEI proposes on handling $3.35 billion in sunk costs from a financial reporting and regulatory rate recovery basis in the analysis presented in canceling Keeyask versus mothballing.

c) To what extent are such costs (sunk and break up costs) relevant for rate setting for MH if the project is cancelled?

Response:

a) V.C. Summer Nuclear expansion project is owned jointly by South Carolina Electric & Gas ("SCE&G") and Santee Cooper (66.3% and 33.3% respectively). Due to the abandonment of the project, SCE&G estimates capital expenditures over 2017 to 2019 to be $1.62 billion, $859 million and $847 million respectively. In addition to capital expenditure costs, SCE&G estimated the carrying costs, during the three and six months ended June 30, 2017, at $4.3 million and $8.6 million respectively. According to the SCEG's 10-Q filed on August 4th, 2017, the company seeks to recover those costs under the abandonment provisions of South Carolina's Base Load Review Act. [15]

   Bellefonte Nuclear Plant was originally owned by Tennessee Valley Authority, which was mothballed in 2013. According to their 2014 10-Q annual report, TVA was seeking to recover previous construction costs, regulatory asset- construction costs and remaining amounts included in deferred nuclear generating unit, totaling to $6 billion. The TVA board accepted recovery of the plant in future rates at an amount of $237 million per year until fully recovered.[16]

   The Tazi Twe Hydro Project was deferred by SaskPower on September 25, 2017 due to a decline in projected demand in northern Saskatchewan. SaskPower has invested an

[15] SCANA. *Quarterly report which provides a continuing view of a company's financial position*. August 2017.

[16] Tennessee Valley Authority. *2015 Annual Report on Form 10-K*. September 2015.

estimated amount of $34 million dollars over the past five years. The company has yet to report any financial implications in the deferral of the Tazi Twe Hydro Project. [17]

b) In the case of cancellation of Keeyask, LEI would suggest handling the sunk costs in a manner similar to Conawapa, and amortizing them over 30 years as proposed on page 19 of Manitoba Hydro's Integrated Financial Forecast. In the case of mothballing, LEI would suggest including only the cost of funds in rates for the period up until the plant becomes operational. From an intergenerational equity perspective, this would allow for current ratepayers to pay for the embedded value of the optionality that a mothballed plant provides, while future ratepayers pay for the total costs of the plant (including sunk costs) once they begin to benefit from it.

c) In a traditional cost of service proceeding, imprudently incurred costs would normally not be recovered from ratepayers; this means shareholders absorb the losses through a reduction in retained earnings. In the case of Manitoba Hydro, this would leave the government, and ultimately taxpayers, responsible for sunk and break up costs. However, it is important not to be overly proscriptive in applying the benefit of hindsight to past decisions. While sunk costs should not be taken into account for the purposes of going forward decisions, if we believe that at least a portion of these costs were incurred using the best available information at the time, then as noted in 16b, it would be appropriate to recover that portion of the costs over time from ratepayers. In many cases, the outcome is the result of a negotiation between the utility, intervenors, and the regulator, with shareholders bearing a portion of the burden through write-downs, and ratepayers paying a portion of the costs through rates.

[17] SaskPower. *SaskPower Defers Tazi Twe Hydro Project*. September 2017.

1.17 PUB/GSS-GSM-KAP -17

Reference:

- LEI Evidence Page 45 of 61 Key Performance Indicator Analysis

Request:

LEI states its Key Performance Indicators exercise is intended to be illustrative, consistent with the scope of intervenor budgets and timescales; the purpose of the presentation is to demonstrate that further analysis is necessary rather than to suggest that the results are exhaustive and conclusive.

a) Please describe how the KPI exercise could be improved upon and further analysis that would be required to improve the utility of the benchmarking exercise.

b) Please indicate what extent, the measures per employee excluded natural gas operations.

c) To what extent did the comparative analysis take into consideration the number of operating employees vs. capital employees?

Response:

a) LEI believes that the best approach to addressing trends in operating expenses is to perform a total factor productivity ("TFP") analysis. Such an analysis would take into account the way in which factors of production are used together to produce specified outputs.

b) Please refer to LEI's response to PUB/GSS-GSM-KAP-9 part b.

c) The analysis presented did not explore this question; in fact, this is one of the areas that would be captured through TFP analysis.