Cochrane, Marlene EMPR:EX

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 10:22 AM
To: Morton, David BCUC:EX
Subject: Letter from D Nikolejsin and L Wanamaker
Attachments: 102700 BCUC Final_Signed.pdf

Good Morning Mr. Morton,

Please see the attached letter from Mr. Dave Nikolejsin, Deputy Minister, Ministry of Energy, Mines and Petroleum Resources, and Ms. Lori Wanamaker, Deputy Minister, Ministry of Finance, regarding the Inquiry Respecting Site C.

Regards,

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

BRITISH COLUMBIA

November 15, 2017

Ref.: 102700

Mr. David Morton
Chair
BC Utilities Commission

Email: David.Morton@bcuc.com

Re: Inquiry Respecting Site C

The Ministry of Energy, Mines and Petroleum Resources and Ministry of Finance are supporting the government decision process surrounding the future of the Site C project. On behalf of our respective Ministers, we would like to thank the BC Utilities Commission (Commission) for the report *Inquiry Respecting Site C*. Completing an inquiry of this scope over an abbreviated timeframe and with high levels of public and First Nations input is a considerable achievement.

As our ministries analyze the Commission's report, along with other implications associated with government proceeding with or terminating the Site C project, we want to ensure that we fully understand the assumptions and computations that the Commission made in the analysis of potential alternative sources of energy generation and capacity. Accordingly, we are requesting further explanation or additional information on the points listed below and in the Appendix attached to this letter.

1. Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?

   We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not, could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

2. In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects

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Office of the Deputy Minister
Mailing Address: PO Box 9319, Stn Prov Govt Victoria, BC V8W 9N3
Telephone: 250 952-0120
Facsimile: 250 952-0269
Location: 8th Floor, 1810 Blanshard Street Victoria
Website: www.em.gov.bc.ca/

included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?

3. Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?

4. If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?

    - Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?

    - Recently it has been stated that recovering the project's sunk and remediation costs over a 10-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?

5. We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:

    - Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?

    - Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?

We sincerely appreciate the Commission's timely response to these questions and requests for clarification. Government has committed to making a decision on the Site C project before the end of the year. The Commission's responses to our questions will assist our ministries in better understanding the report and the assumptions that underlie it as we prepare advice to support government in making a decision that will be in the best interests of British Columbians.

Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines
and Petroleum Resources

Lori Wanamaker
Deputy Minister
Ministry of Finance

Attachment

Appendix: Detailed Questions for the Commission

We understand that while BC Hydro modelled over 60 scenarios and tested various assumptions, including a number of alternatives requested by the Commission, the alternative portfolio that the Commission included in the final report was not analyzed using BC Hydro's modelling tools. On this basis, government has asked BC Hydro to provide an assessment of the model used to develop the Commission's final alternative portfolio. BC Hydro will provide the Commission with the results of that assessment separately.

In our initial analysis of the report, our ministries have identified several areas that we would appreciate the Commission's feedback on. Several of our questions relate to the impact of certain assumptions made in the report, and how the costs of those assumptions would be recovered from ratepayers.

We understand that BC Hydro follows standards for rate-regulated utilities in its financial statements and in preparing its applications for review by the Commission. This accounting framework follows a number of principles in relation to the amortization of capital assets and the deferral of other costs for the purpose of matching recoveries from ratepayers to periods over which benefits are provided.

It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.

The Commission's process involved some deliberations on the cost of capital. The alternative portfolio presented in the report assumes that BC Hydro will finance all new resources on its balance sheet. However, other than redevelopment of existing sites and Site C, BC Hydro has, for almost three decades, been primarily procuring new supply from competitive processes or bilateral agreements that are benchmarked to competitive processes. This effectively means that BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.

It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio, and the BC Hydro financing assumption should only be used for the Unit Energy Cost (UEC) analysis. However, on pages 167, 170 and Appendix C (Assumption 2), it appears that the

Commission has used BC Hydro financing (100% debt financing at a cost of 3.43%) for the alternative portfolio. If we are interpreting this correctly, we would appreciate clarification on which cost of capital should be used in analysing rate impacts.

BC Hydro has suggested that recovery in rates of sunk costs in a termination scenario should occur over a 10-year period. If the project were to continue as planned, the sunk costs, as part of the overall project costs, will be recovered over a 70-year period, consistent with the amortization of the Site C asset. The Commission model appears to exclude sunk costs in the termination scenario, and has removed those costs from the completion scenario as well. Effectively this assumes that sunk costs will be recovered through rates over 70 years if the project is terminated. Recovering costs in rates over a shorter period has a material impact on the costs of the alternative portfolio. It would be helpful if the Commission could provide an estimate of the impact on rates of using these two timeframes.

The tables on page 17 of the executive summary and page 170 in the main report include a summary of the Commission's sample scenarios showing the effect of modifying one or more variables to the resulting Net Present Value cost to ratepayers. As noted above, the Commission's alternative portfolio does not appear to include sunk costs, and sunk costs have also been removed on the continue scenario. The tables also include UECs. For the Site C scenario, the UECs reflect costs, including sunk costs, of Site C being either $10 billion or $12 billion depending on assumptions. Our review of the Commission report suggests that the alternative portfolio does not include termination costs. It would be helpful if the Commission could confirm this and provide a version of the UEC portion of the table with termination costs included in the alternative portfolio. This would help provide a consistent basis for comparing costs between the scenarios of completing or terminating the project.

It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis?

We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's *Clean Energy Act* energy objectives of:

- Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;
- Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,
- Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.

It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.
It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the *Greenhouse Gas Reduction (Clean Energy) Regulation* under the *Clean Energy Act*. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures.

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

Cochrane, Marlene EMPR:EX

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 10:24 AM
To: Nikolejsin, Dave MNGD:EX
Cc: MacLaren, Les EMPR:EX; Haslam, David GCPE:EX
Subject: Letter from D Nikolejsin and L Wanamaker
Attachments: 102700 BCUC Final_Signed.pdf

Dave, the final letter has been sent to Mr. Morton. (Lori's office is also aware.) Thanks.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

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Sent: Wednesday, November 15, 2017 10:22 AM
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Marlene Cochrane
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Ministry of Energy, Mines
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From: MacLaren, Les EMPR:EX
To: Nikolejsin, Dave EMPR:EX
Subject: RE: BCUC Site C Report
Date: Sunday, November 5, 2017 11:21:05 AM
Attachments: RE Site C BCUC.msg

BCUC staff made their own model, starting with a spreadsheet BCH submitted to NPVs of revenue requirements. It is described in Appendix C of the final report.

On October 11 the BCUC released some alternative portfolios using the model that BCH had issues with. They filed the attached response. Table 1 on pages 2 and 3 summarizes BCH's areas of concern. The final report says BCUC made further adjustments based on feedback from BCH and others. The document I circulated yesterday sets out BCH's ongoing concerns with the revised BCUC model.

Les

From: Nikolejsin, Dave MNGD:EX
Sent: Sunday, November 5, 2017 11:03 AM
To: MacLaren, Les EMPR:EX
Subject: RE: BCUC Site C Report

Can you explain the following to me:

2D
2E
What "model" did the BCUC use? Did they make up their own, or use someone else's (e.g. Deloitte?)

From: MacLaren, Les EMPR:EX
Sent: November 4, 2017 10:06 AM
To: Wright, Don J. PREM:EX <Don.J.Wright@gov.bc.ca>; Meggs, Geoff PREM:EX <Geoff.Meggs@gov.bc.ca>; Wanamaker, Lori FIN:EX <Lori.Wanamaker@gov.bc.ca>; Foster, Doug FIN:EX <Doug.Foster@gov.bc.ca>; Zadravec, Don GCPE:EX <Don.Zadravec@gov.bc.ca>; Lloyd, Evan GCPE:EX <Evan.Lloyd@gov.bc.ca>; Kennedy, Christine PREM:EX <Christine.Kennedy@gov.bc.ca>
Cc: Rowe, Katherine EMPR:EX <Katherine.Rowe@gov.bc.ca>; Nikolejsin, Dave MNGD:EX <Dave.Nikolejsin@gov.bc.ca>
Subject: BCUC Site C Report

Good morning.

s.13

s.13

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy, Mines and Petroleum Resources
NOTE NEW OFFICE PHONE NUMBER: 778-698-7183
Cell: 250-889-3479

Energizing BC—clean, sustainable and productive

From:	Magre, Leela
To:	Haslam, David GCPE:EX
Cc:	Pillon, Lawrence; Zadravec, Don GCPE:EX; Grewar, Colin GCPE:EX; XT:Scott, Mora GCPE:IN; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX; MacLaren, Les EMPR:EX
Subject:	RE: Site C / BCUC
Date:	Thursday, October 19, 2017 8:06:18 AM
Attachments:	2017_10_18_SiteC_BCH_ALT_PRTF.PDF

Good morning,

Here is the filing attached. There is a good summary from page 1 to the top of page 4. In short --

We identified a number of issues with the October 11th alternative portfolio sent around by the Commission for comment, which we discussed at a high level in our Saturday technical presentation. Altogether, these issues would increase the cost of the October 11th portfolio by approximately $4 billion. The main issues are as follows:

- The portfolio assumes BC Hydro is stopping DSM if we build Site C, which is not correct
- It assumes BC Hydro builds and finances all alternative resources, also not correct
- The battery costs in the portfolio incorrectly exclude capital costs other than balance of system, operating costs of approximately $10 million per year (for a 100MW installation) and operating energy losses of approx.7%, effectively understating the costs of batteries

I'm out of the office today, but you can reach me on my cell or email at any time if you have any questions.

Thanks,
Leela

Leela Magre | Manager, Policy & Research

BC Hydro
333 Dunsmuir St, 15th floor
Vancouver, BC V6B 5R3

P 604 623 4008
M 236 993 0338
E leela.magre@bchydro.com

bchydro.com

Smart about power in all we do.

-----Original Message-----
From: Haslam, David GCPE:EX [mailto:David.Haslam@gov.bc.ca]
Sent: 2017, October 19 6:48 AM
To: Magre, Leela
Cc: Pillon, Lawrence; Zadravec, Don GCPE:EX; Grewar, Colin GCPE:EX; Scott, Mora; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX; MacLaren, Les EMPR:EX
Subject: Re: Site C / BCUC

Thx. Including mo staff and Les.

Sent from my iPhone

> On Oct 18, 2017, at 9:10 PM, Magre, Leela <Leela.Magre@bchydro.com> wrote:

>
> Good evening,
>
> Attached is today's filing regarding the October 11th alternative portfolio. It will be posted by the BCUC sometime tomorrow.
>
> Thanks,
> Leela
>
> _____
>
> Leela Magre | Manager, Policy & Research
>
> BC Hydro
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
>
> P 604 623 4008
> M 236 993 0338
> E leela.magre@bchydro.com<mailto:leela.magre@bchydro.com>
>
> bchydro.com<http://www.bchydro.com/>
> Smart about power in all we do.
>
> From: Magre, Leela
> Sent: 2017, October 18 10:32 AM
> To: Pillon, Lawrence; David Haslam (David.Haslam@gov.bc.ca); Zadravec,
> Don GCPE:EX (Don.Zadravec@gov.bc.ca); Grewar, Colin GCPE:EX
> (Colin.Grewar@gov.bc.ca)
> Cc: Scott, Mora
> Subject: RE: Site C / BCUC
>
> Good morning,
>
> As a follow-up to Lawrence's email, we are filing today our comments on the October 11th alternative portfolio that the Commission requested feedback on (you will recall we discussed this in our meeting on Friday). We already addressed this topic with the Commission in our presentation on Saturday, and are providing more detail in writing as requested by the Commission. They have requested feedback from other parties as well.
>
> We've identified a number of issues with the October 11th portfolio, which we highlighted in the Saturday presentation. The main ones are as follows. All would increase the cost of the October 11th portfolio:
>
> * The portfolio assumes BC Hydro is stopping DSM if we build Site C, which is not correct
>
> * It assumes BC Hydro builds and finances all alternative resources, also not correct
>
> * The battery costs in the portfolio incorrectly exclude capital costs of balancing the system, operating costs of approximately $10 million per year and operating energy losses of approx.7%, effectively understating the costs of batteries
>
> We will send along the full filing once it has been submitted to the Commission (likely after close of business today).
>
> Thank you and let me know if you have any questions.
>
> Best,
> Leela

>
> _____
>
> Leela Magre | Manager, Policy & Research
>
> BC Hydro
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
>
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> E leela.magre@bchydro.com<mailto:leela.magre@bchydro.com>
>
> bchydro.com<http://www.bchydro.com/>
>
> Smart about power in all we do.
>
> From: Pillon, Lawrence
> Sent: 2017, October 18 9:57 AM
> To: David Haslam
> (David.Haslam@gov.bc.ca<mailto:David.Haslam@gov.bc.ca>); Zadravec, Don
> GCPE:EX (Don.Zadravec@gov.bc.ca<mailto:Don.Zadravec@gov.bc.ca>);
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> (Colin.Grewar@gov.bc.ca<mailto:Colin.Grewar@gov.bc.ca>)
> Cc: Magre, Leela; Scott, Mora
> Subject: Site C / BCUC
>
> Hi
> Just a heads up that we will be filing another short submission to the
> BCUC later today, a follow-up from Saturday's proceedings. We were asked to provide comments on alternative scenarios. Leela will provide more.
>
> Lawrence
> _____
> This email and its attachments are intended solely for the personal use of the individual or entity named above. Any use of this communication by an unintended recipient is strictly prohibited. If you have received this email in error, any publication, use, reproduction, disclosure or dissemination of its contents is strictly prohibited. Please immediately delete this message and its attachments from your computer and servers. We would also appreciate if you would contact us by a collect call or return email to notify us of this error. Thank you for your cooperation.
> -BCHydroDisclaimerID5.2.8.1541
> <2017_10_18_SiteC_BCH_ALT_PRTF.PDF>

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

October 18, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1598922
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Alternative Portfolios

BC Hydro writes to provide its comments on, and analysis of the BCUC's Alternative Site C Portfolios as requested by the Commission Panel in its letter of October 11, 2017 (**A-22**).

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

fj/ma

Enclosure

Page 021 to/à Page 061

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From:	Haslam, David GCPE:EX
To:	Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX
Cc:	Nikolejsin, Dave EMPR:EX; MacLaren, Les EMPR:EX; Beaupre, Darren GCPE:EX; Grewar, Colin GCPE:EX; Sovka, David GCPE:EX; Zadravec, Don GCPE:EX
Subject:	Letter to BCUC
Date:	Wednesday, November 15, 2017 10:27:17 AM
Attachments:	IB_Questions to BCUC_Nov15_949am_LM_DB.docx KMs-QA_Site C Report_Questions to BCUC_Nov15_955am LM.docx 102700 BCUC Final_Signed.pdf

All – attached are the com products (IB/KM/QA) for the letter to the BCUC – final signed letter attached as well – which was just sent. Note the IB is not going to be distributed – but we have it on hand in case there's a change in direction. The com materials were reviewed by Les yesterday. Minor edits were made this am to reflect minor edits to the letter. Les is monitoring when we can expect the BCUC to post the letter. Probably by tomorrow. The media strategy is reactive with either emailed statements from MMM or interviews if she is available – which is unlikely for the next few days. I've included Don Zadravec. We have a meeting at 11:45 to discuss. We can adjust messaging if necessary.

I note the Hydro Allied Council of BC will be releasing a report today at 1 pm. We will monitor and produce an IN with recommended messaging as following:

- Government is reviewing the report
- The report indicates the level of interest in the government's decision on Site C
- Government will review all the information available to make the best decision in the interests of British Columbians and ratepayers

BRITISH COLUMBIA

November 15, 2017

Ref.: 102700

Mr. David Morton
Chair
BC Utilities Commission

Email: David.Morton@bcuc.com

Re: Inquiry Respecting Site C

The Ministry of Energy, Mines and Petroleum Resources and Ministry of Finance are supporting the government decision process surrounding the future of the Site C project. On behalf of our respective Ministers, we would like to thank the BC Utilities Commission (Commission) for the report *Inquiry Respecting Site C*. Completing an inquiry of this scope over an abbreviated timeframe and with high levels of public and First Nations input is a considerable achievement.

As our ministries analyze the Commission's report, along with other implications associated with government proceeding with or terminating the Site C project, we want to ensure that we fully understand the assumptions and computations that the Commission made in the analysis of potential alternative sources of energy generation and capacity. Accordingly, we are requesting further explanation or additional information on the points listed below and in the Appendix attached to this letter.

1. Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?

   We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not, could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

2. In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects

Ministry of Energy, Mines and Petroleum Resources
Office of the Deputy Minister
Mailing Address: PO Box 9319, Stn Prov Govt Victoria, BC V8W 9N3
Location: 8th Floor, 1810 Blanshard Street Victoria
Telephone: 250 952-0120
Facsimile: 250 952-0269
Website: www.em.gov.bc.ca/

included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?

3. Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?

4. If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?

   - Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?

   - Recently it has been stated that recovering the project's sunk and remediation costs over a 10-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?

5. We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:

   - Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?

   - Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?

We sincerely appreciate the Commission's timely response to these questions and requests for clarification. Government has committed to making a decision on the Site C project before the end of the year. The Commission's responses to our questions will assist our ministries in better understanding the report and the assumptions that underlie it as we prepare advice to support government in making a decision that will be in the best interests of British Columbians.

Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines
and Petroleum Resources

Lori Wanamaker
Deputy Minister
Ministry of Finance

Attachment

Appendix: Detailed Questions for the Commission

We understand that while BC Hydro modelled over 60 scenarios and tested various assumptions, including a number of alternatives requested by the Commission, the alternative portfolio that the Commission included in the final report was not analyzed using BC Hydro's modelling tools. On this basis, government has asked BC Hydro to provide an assessment of the model used to develop the Commission's final alternative portfolio. BC Hydro will provide the Commission with the results of that assessment separately.

In our initial analysis of the report, our ministries have identified several areas that we would appreciate the Commission's feedback on. Several of our questions relate to the impact of certain assumptions made in the report, and how the costs of those assumptions would be recovered from ratepayers.

We understand that BC Hydro follows standards for rate-regulated utilities in its financial statements and in preparing its applications for review by the Commission. This accounting framework follows a number of principles in relation to the amortization of capital assets and the deferral of other costs for the purpose of matching recoveries from ratepayers to periods over which benefits are provided.

It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.

The Commission's process involved some deliberations on the cost of capital. The alternative portfolio presented in the report assumes that BC Hydro will finance all new resources on its balance sheet. However, other than redevelopment of existing sites and Site C, BC Hydro has, for almost three decades, been primarily procuring new supply from competitive processes or bilateral agreements that are benchmarked to competitive processes. This effectively means that BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.

It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio, and the BC Hydro financing assumption should only be used for the Unit Energy Cost (UEC) analysis. However, on pages 167, 170 and Appendix C (Assumption 2), it appears that the

Commission has used BC Hydro financing (100% debt financing at a cost of 3.43%) for the alternative portfolio. If we are interpreting this correctly, we would appreciate clarification on which cost of capital should be used in analysing rate impacts.

BC Hydro has suggested that recovery in rates of sunk costs in a termination scenario should occur over a 10-year period. If the project were to continue as planned, the sunk costs, as part of the overall project costs, will be recovered over a 70-year period, consistent with the amortization of the Site C asset. The Commission model appears to exclude sunk costs in the termination scenario, and has removed those costs from the completion scenario as well. Effectively this assumes that sunk costs will be recovered through rates over 70 years if the project is terminated. Recovering costs in rates over a shorter period has a material impact on the costs of the alternative portfolio. It would be helpful if the Commission could provide an estimate of the impact on rates of using these two timeframes.

The tables on page 17 of the executive summary and page 170 in the main report include a summary of the Commission's sample scenarios showing the effect of modifying one or more variables to the resulting Net Present Value cost to ratepayers. As noted above, the Commission's alternative portfolio does not appear to include sunk costs, and sunk costs have also been removed on the continue scenario. The tables also include UECs. For the Site C scenario, the UECs reflect costs, including sunk costs, of Site C being either $10 billion or $12 billion depending on assumptions. Our review of the Commission report suggests that the alternative portfolio does not include termination costs. It would be helpful if the Commission could confirm this and provide a version of the UEC portion of the table with termination costs included in the alternative portfolio. This would help provide a consistent basis for comparing costs between the scenarios of completing or terminating the project.

It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis?

We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's *Clean Energy Act* energy objectives of:

- Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;
- Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,
- Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.

It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.
It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the *Greenhouse Gas Reduction (Clean Energy) Regulation* under the *Clean Energy Act*. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures.

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

BRITISH COLUMBIA

INFORMATION BULLETIN

Ministry of Energy, Mines and Petroleum Resources

[release number]
[Date]

Province asks Utilities Commission for clarification on Site C report

VICTORIA – The Government of British Columbia has asked the B.C. Utilities Commission (BCUC) to clarify elements of its final report on Site C. The provincial government is taking this action as part of the due diligence necessary to make an informed decision that is in the best interests of ratepayers.

The deputy ministers of Energy, Mines and Petroleum Resources, and Finance have provided a letter to the BCUC asking for further clarification on a number of matters in the report, including the Commission's assumptions and calculations related to:

- The treatment of sunk costs (estimated $2.1 billion already spent on the project) and termination and remediation costs ($1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources.
- Whether BC Hydro or independent power producers (IPPs) would develop and finance projects included in the Commission's proposed alternative portfolio (wind, geothermal), the cost of capital financing applied to the alternative portfolio, and the impact of a higher cost of capital on ratepayers if the alternative portfolio were developed by IPPs rather than BC Hydro.
- The cost of demand side management (conservation) measures included in the alternative portfolio.
- The time period over which sunk, termination and remediation costs (approximately $4 billion) would be recovered in the event the project is cancelled and the impact on ratepayers.
- The use of a low-load forecast instead of a mid-load forecast to assess the need for Site C, and whether the Commission included in its load forecast the potential increased electrical power demand of meeting the province's objectives to reduce greenhouse gas emissions through greater electrification of the economy.

The deputy ministers' letter and the BCUC response will be publicly available on the BCUC's website. *(TBC)*

Government is currently conducting a review of Site C and will consider the BCUC report along with other implications associated with completing or terminating the project.

A decision on the Site C project is anticipated by the end of the year.

BRITISH COLUMBIA

INFORMATION BULLETIN

Learn More: http://www.sitecinquiry.com/

Media contact:
Suntanu Dalal
Media Relations
Ministry of Energy, Mines and Petroleum Resources
250 952-0628

draft

QUESTION AND ANSWERS
SITE C DECISION MAKING PROCESS
Nov. 15, 2017

Ministry of Energy and Mines

- The current uncertainty and division over the Site C project is a direct result of the previous government's irresponsible decision to start construction without proper regulatory oversight.

- It fell to our government to correct that oversight and send the project to the BCUC for review.

- We are now considering the BCUC's final report and other issues as we work towards a final decision on completing or terminating the project that will keep rates affordable for B.C. families and businesses in the long-term.

- We are taking time and care in our decision-making process to ensure the data and analysis we are relying upon is accurate, and that we have a clear understanding of the impacts on ratepayers associated with completing the project or cancelling it.

- That includes working with the Ministry of Finance to conduct an intense economic review of the project over the next few weeks.

Regarding questions to the BCUC and financial analysis:

- As part of its economic review of Site C, Government has asked the BCUC to clarify some elements of its final report on the project delivered November 1, 2017.

- Our request to the BCUC is part of our due diligence as we work towards a final decision on Site C that will keep rates affordable for B.C. families and businesses in the long term.

- In the report the BCUC assesses a large amount of complex data and analysis and we want to make sure we fully understand the Commission's assumptions and calculations.

- Additionally, as part of our decision-making process the Ministry of Finance will be undertaking a financial analysis of BCUC report, including the implications for and risks to the fiscal plan in the event the project is continued or terminated.

Questions and Answers

1. Why are you going back to the BCUC for more information?

After reviewing the BCUC's final report staff in the Ministries of Finance and Energy, Mines and Petroleum Resources had some questions related to the BCUC's methodology, assumptions, calculations and the cost to ratepayers of completing the project, or terminating it and looking to alternative sources of energy and capacity.

Our decision on Site C will ultimately be based on what is best for ratepayers. As we work through that decision we want to make absolute certain that we have a clear understanding of the impact on ratepayers. Our questions to the BCUC will help to clarify some elements of the report.

2. Specifically, what are you asking the BCUC?

The deputy-ministers of Finance, and Energy, Mines and Petroleum Resources have provided a letter to the BCUC asking for further clarification on a number of matters in the report, including the Commission's assumptions and calculations related to:

- The treatment of sunk costs (estimated $2.1 billion already spent on the project) and termination and remediation costs ($1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources.
- Whether BC Hydro or independent power producers (IPPs) would develop and finance projects included in the Commission's proposed alternative portfolio (wind, geothermal), the cost of capital financing applied to the alternative portfolio, and the impact of a higher cost of capital on ratepayers if the alternative portfolio were developed by IPPs rather than BC Hydro.
- The cost of demand side management (conservation) measures included in the alternative portfolio.
- The time period over which sunk, termination and remediation costs (approximately $4 billion) would be recovered in the event the project is cancelled and the impact on ratepayers.
- The use of a low-load forecast instead of a mid-load forecast to assess the need for Site C, and whether the Commission included in its load forecast the potential increased electrical power

demand of meeting the province's objectives to reduce greenhouse gas emissions through greater electrification of the economy.

The full letter can be viewed on the BCUC's website (*TBC*) at http://www.sitecinquiry.com/

3. Does this show you lack confidence in the BCUC's findings or their ability to conduct the review?

Not at all. Given the short time they had the BCUC has conducted a remarkably comprehensive review and produced a report informed by contributions from BC Hydro, stakeholders, energy experts, First Nations and hundreds of concerned British Columbians.

We have full confidence in the BCUC as the province's energy regulator to advise Government on the project, however the final report is – by nature of the subject matter – very complex. As such, we are seeking clarity on some of the BCUC's assumptions and calculations as part of an economic review of the project and our due diligence process as we work towards a final decision that is in the best interests of ratepayers.

4. Does BC Hydro also have questions about the final report?

Staff in the ministries of Finance, and Energy, Mines and Petroleum Resources have discussed the BCUC report with BC Hydro, and government has identified a number of matters it would like the Commission's feedback on. These matters are captured in the deputy-ministers' questions to the Commission.

Government has also asked BC Hydro to provide an assessment of the model the Commission used to develop its illustrative alternative portfolio. We understand that BC Hydro will be providing the Commission with the results of that assessment separately.

5. Why is the Ministry of Finance doing a financial analysis of the report?

This is a multi-billion-dollar project that was started by the previous government without proper regulatory oversight. It fell to our Government to give the project the scrutiny it should have received years ago, including a detailed economic analysis.

Our decision on Site C, whether to proceed or terminate, will have a significant and long-term impact on BC Hydro's debt and financing, and on the Province's books as well. As such, it is the responsibility of the Ministry of Finance to take a close look at the numbers and ensure the impacts on the fiscal plan of continuing or terminating Site C are clearly understood.

6. Does this mean that Government is looking at moving the costs of cancelling Site C from BC Hydro to the provincial debt?

Government is exercising due diligence and working towards a decision on Site C that keeps rates affordable for B.C. families and businesses in the long term.

I don't want to pre-judge that decision in anyway so I cannot provide comment at this time on what Government may or may not do in relation to the costs associated with cancelling the project.

7. Will your requests to the BCUC and the financial analysis delay your decision on Site C?

We have asked the BCUC to respond to Government's questions in a timely manner, and we still anticipate a decision on the project by the end of the year.

From: MacLaren, Les EMPR:EX
To: Nikolejsin, Dave EMPR:EX
Cc: Haslam, David GCPE:EX
Subject: Transcript
Date: Monday, December 11, 2017 5:18:28 PM

Hi Dave:

PJH's comments below with key sections highlighted.

- I don't know where the 70% rate increases since 2001 came from. The correct number validated by BCH over the weekend and reflected in Don's slides is 87.1%. I tried just adding and not compounding and got 59.5% then adding the 5% rate rider gets you to 65%, but not 70%. We can just say "it's even worse than the Premier said ....."
- "reopening the Standing Offer Program" could be a real headache. We have a number of SOP contracts with FNs (Kanaka Bar, Huu-ay-aht, Tsilqhot'in) ready to go that BCH has held off on. We need to discuss whether we try to manage this in the context of the comprehensive BCH review and bump it to next fall as envisioned, or whether faster demonstrable action is required. Hybrid is go with the EPAs in the SOP that are ready, and look at bringing in new projects under a new SOP design post-review. Recall we still have the biomass renewals to deal with and a competitive process including them was contemplated at one point. I don't recall any First Nations biomass plants other than off-grid Tsay Keh.

Les

Media Availability
Horgan press conf on Site C
11-Dec-2017 11:30

Quoted: Reporter, Premier John Horgan, Michelle Mungall

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Page 076 to/à Page 081

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November 23, 2017

Sent via email

Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines and Petroleum Resources
PO Box 9319, Stn Prov Govt
Victoria, BC V8W 9N3
EMPR.Minister@gov.bc.ca

Lori Wanamaker
Deputy Minister
Ministry of Finance
PO Box 9417, Stn Prov Govt
Victoria, BC V8W 9V1
FIN.Minister@gov.bc.ca

Re: British Columbia Hydro and Power Authority - British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922

Dear Dave Nikolejsin and Lori Wanamaker:

The Deputy Ministers' letter of November 15, 2017 poses a series of questions to the Commission regarding its Final Report on the Site C Inquiry, which was initiated by the Lieutenant Governor by Order in Council 244. The Commission thanks the Deputy Ministers for their inquiry and sets out its response below, trusting that any additional clarity or amplification of the messages in the Final Report will assist the government in its decision regarding Site C.

Sincerely,

David Morton
Chair and Chief Executive Officer

DM/kbb
Enclosure

Page 083 to/à Page 108

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From: Wieringa, Paul EMPR:EX
To: MacLaren, Les EMPR:EX
Subject: s.12,s.13
Date: Wednesday, October 25, 2017 1:04:22 PM
Attachments: s.12,s.13

In the comment boxes, I have tried to respond to Selina G's comments.

Page 110 to/à Page 124

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	Sopinka, Amy EMPR:EX
Subject:	FW: Appendix R
Date:	Saturday, October 28, 2017 2:01:00 PM
Attachments:	21_01_01_Site_C_APPX_R.docx ATT00001.htm 20_01_Site_C_APPX_R.pdf ATT00002.htm

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From: Sauer, Darwin [mailto:Darwin.Sauer@bchydro.com]
Sent: Saturday, October 28, 2017 1:59 PM
To: MacLaren, Les EMPR:EX; Rowe, Katherine EMPR:EX; Wieringa, Paul EMPR:EX
Subject: Fwd: Appendix R

Here's the PDF and we will send the excel files as soon as we can.

Thx

Sent from my iPhone

Begin forwarded message:

> **From:** "Magre, Leela" <Leela.Magre@bchydro.com>
> **To:** "Sauer, Darwin" <Darwin.Sauer@bchydro.com>
> **Subject: Appendix R**
>
> Hi Darwin,
> As requested. Excel files to follow from Mike.
> Thanks,
> Leela
>
> _____
> **Leela Magre** | Manager, Policy & Research
> **BC Hydro**
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
> **P** 604 623 4008
> **M** 236 993 0338
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> bchydro.com
> Smart about power in all we do.

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Ratepayer Impact Calculations

1 Approach to Estimating Ratepayer Impact

BC Hydro is using the Regulatory Rate Impact Model (**RRIM**), which has been submitted in previous BCUC applications, to estimate the ratepayer impacts under different scenarios. This is a model with which the BCUC is familiar, and which allows for BC Hydro to compare scenarios under different assumptions.

The RRIM assumes a Base Case, and estimates BC Hydro's total revenue requirement over the fiscal 2018 to fiscal 2094 period. The year fiscal 2094 represents the end of the 70-year economic planning life of Site C. More information on the Base Case is provided below.

For each scenario (e.g., Terminate; or Suspend and Restart; or Suspend and Terminate), BC Hydro estimated the incremental impact on the main components of BC Hydro's total revenue requirement (amortization, finance charges, operating costs and energy costs), compared with the Base Case. This is described in further detail below.

The following documents relating to the three scenarios have been included in Attachment 1 to this document:

- Ratepayer Impact - Terminate & 10 Yr Recovery;
- Ratepayer Impact - Terminate & 5 Yr Recovery;
- Ratepayer Impact - Terminate & 1 Yr Recovery;
- Ratepayer Impact - Suspend and Restart;
- Ratepayer Impact - Suspend and Terminate & 10 Yr Recovery;

- Ratepayer Impact - Suspend and Terminate & 5 Yr Recovery; and
- Ratepayer Impact - Suspend and Terminate & 1 Yr Recovery.

The impact on BC Hydro's total revenue requirement (i.e., cost to ratepayers) under these various scenarios, compared to the Base Case, is estimated on an annual basis over the fiscal 2018 to fiscal 2094 period. This is shown (in $ millions) on Line 8 of the 'Summary' pages in the attached files.

The incremental changes to BC Hydro's revenue requirement are also used to estimate the incremental cumulative rate increases for each scenario. The estimated incremental cumulative rate increases represents the magnitude (in percentages), in a given future year, that cumulative rate increases (compared with current fiscal 2017 rates) would be higher or lower in the scenario than they would have otherwise been in the Base Case, in that same year. This is shown on line 18 of the 'Summary' pages in the attached files.

The methodology and results for each scenario are summarized below.

2 Assumptions

The following key assumptions are used in estimating the ratepayer impacts of scenarios compared to the Base Case.

Financing Costs – costs related to debt incurred to finance capital expenditures, regulatory accounts and incremental DSM expenditures are estimated using BC Hydro's forecast weighted average cost of debt, as shown on Line 37 of the 'Input Data' pages.

Amortization – amortization periods depend on the type of asset, and are shown in the table below:

Expenditure Type	Amortization Period
Base Case Site C Costs (Site C construction costs plus Site C Regulatory Account balance)	70 years
Suspend and Restart Site C Costs (Site C construction costs plus Site C Regulatory Account balance)	70 years
Site C Regulatory Account (related to Project termination)	10, 5 or 1 years
Demand-side management expenditures	15 years
Year 25 Asset	25 years
Year 40 Asset	40 years
Year 45 Asset	45 years
Year 50 Asset	50 years
Year 25 Asset (#2)	25 years

Rate Smoothing - the analysis does not consider potential smoothing of the rate impacts of the Site C Project (in either the Base Case or Suspend and Restart scenario). The review of any such potential mechanisms should occur in the general revenue requirements rate increase context and should not be conducted in isolation for specific scenarios without consideration of other forecast revenue requirement changes. BC Hydro's future revenue requirements applications (i.e., covering test periods after the fiscal 2017 to fiscal 2019 test period) are the most appropriate forums for such an assessment with respect to the potential smoothing the rate impacts related to the Site C Project or any of the scenarios described above.

Base Case – Additional Information

In the Base Case, BC Hydro's total projected revenue requirement over the fiscal 2018 to fiscal 2094 period is estimated by escalating current customer average rates (by customer class) by assumed future rate increases, and then applying these rates to forecast sales (by customer class) volumes subject to rate increases. The result is an estimate of the total revenue requirements subject to rate increases over time.

In the Base Case, rate increases are assumed to increase by 3.5 per cent in fiscal 2018, 3.0 per cent in fiscal 2019, and by 2.6 per cent each year from fiscal 2020 to fiscal 2024, consistent with the 10 Year Rates Plan. For years after fiscal 2024, BC Hydro has assumed for the purposes of this analysis annual rate increases equal to inflation of 2.0 per cent.

The Base Case also assumes that Site C will be placed into service at the end of fiscal 2024, with an estimated cost of approximately $8.335 billion (representing the sum of construction costs and the forecast balance of the Site C Regulatory Account).

BC Hydro's estimated annual revenue requirement over the fiscal 2018 to fiscal 2094 period is not based on a long term forecast of specific annual costs (i.e., it is not a 'bottom-up' forecast of individual costs). Rather, it represents an estimate from the revenue side, making the assumption that customer rates over time will be increasing only in order to recover its total costs (total revenue requirement). And therefore total revenue received from customers in a future year will equal the total costs to be recovered from ratepayer in that same year.

Additionally, BC Hydro's assumed annual rate increases and revenue requirement over the fiscal 2025 to fiscal 2094 period does not represent BC Hydro's view as to future Revenue Requirement Applications (**RRAs**), and any rate increases requested in future RRAs will be based on BC Hydro's assessment of its expected revenues and costs at the time of filing. Similarly, the incremental rate impact assessment of various scenarios related to the Site C Project are not determinative of BC Hydro's view of its future annual rate increases and revenue requirement but gives an indication of the incremental impact to ratepayers under these various scenarios.

3 Scenarios

Terminate

BC Hydro considered the following main items in estimating the ratepayer impact under a termination and remediation scenario:

1. Costs spent to-date on advancing the Project and costs directly related to termination and remediation; and
2. Costs for ratepayers of procuring higher cost energy and capacity that would otherwise have been provided by Site C

These incremental costs are described below and are found on the 'Input Data' pages of the three attached Terminate documents.

Remove:

- Site C costs of $8.335 billion (total Site C construction costs and forecast balance of Site C Regulatory Account) are removed at the end of fiscal 2024;
- Site C operating costs (comprised of water rental costs, operating costs, and taxes) are removed beginning in fiscal 2025; and
- Future sustaining capital expenditures totalling $2.1 billion are removed from the fiscal 2024 to fiscal 2094 period.

Replace with:

- Site C Regulatory Account costs of $3.2 billion (related to Project termination) are added at the end of fiscal 2019. These are comprised of the costs of $3.0 billion shown below at December 31, 2017 (which would increase by interest to $3.2 billion by the end of fiscal 2019):
  - ▶ Project capital costs to termination date ($1.6 billion);
  - ▶ Costs already in the Site C regulatory account ($0.5 billion); and

- Costs directly related to the Project termination and remediation that would be recovered from ratepayers ($0.9 billion); and

- Incremental cost of procuring alternative higher cost energy and capacity that would otherwise have been provided by Site C, including incremental demand-side management efforts. This is comprised of:
  - Incremental energy costs of $105.5 billion; and
  - Incremental demand-side management expenditures of $0.9 billion, which are amortized over 15 years, beginning in the year following the expenditure. BC Hydro has also included the incremental reduction in energy sales, in estimating the incremental impact on future rate increases.

For the changes described above related to capital expenditures, regulatory accounts and demand-side management expenditures, the RRIM model calculates the impact on amortization and financing costs.

The table below shows the estimated incremental impact on cumulative rate increases under the three Termination scenarios, and the estimated incremental impact on revenue requirements (costs to ratepayers). The incremental cumulative rate increase in fiscal 2020 is shown because it is the first year in which the recovery of the Site C Regulatory Account, as a result of termination, will impact customer rates.

	Estimated Incremental Cumulative Rate Increases (%)			Total Estimated Incremental Costs to F2094 ($ Billions)
	in F2020	in F2024	in F2094	Nominal
Terminate Site C – 10 Year Recovery of Site C Regulatory Account	10	9	40	81.4
Terminate Site C – 5 Year Recovery of Site C Regulatory Account	17	15	40	81.2
Terminate Site C – 1 Year Recovery of Site C Regulatory Account	72	1	40	80.9

A chart of the incremental impact on cumulative rate increases is shown on the 'Rate Impact Chart' pages of the three attached Terminate documents.

Suspend and Restart

BC Hydro considered the following main items in estimating the ratepayer impact under a suspend and restart scenario:

1. Costs spent to-date on advancing the Project and costs directly related to suspension and maintenance;
2. Costs of restarting the Project following suspension and completing the Project; and
3. Costs for ratepayers of procuring higher cost energy and capacity that would otherwise have been provided by Site C during the period of suspension and restart.

These incremental costs are described below and are found on the 'Input Data' page of the attached Suspend and Restart document.

Remove:

- Site C costs of $8.335 billion (total Site C construction costs and forecast balance of Site C Regulatory Account) are removed at the end of fiscal 2024;
- Site C operating costs (comprised of water rental costs, operating costs, and taxes) are removed beginning in fiscal 2025; and
- Future sustaining capital expenditures totalling $2.1 billion are removed from the fiscal 2024 to fiscal 2094 period.

Replace with:

- Site C costs of $7.9 billion are added at the end of fiscal 2031;
- Site C operating costs (comprised of water rental costs, operating costs, and taxes) are added beginning in fiscal 2032;
- Future sustaining capital expenditures totalling $2.4 billion are added to the fiscal 2024 to fiscal 2094 period;
- Site C Regulatory Account costs of $5.0 billion are added at the end of fiscal 2031. This comprised of $3.2 billion of costs shown below related to the decision to suspend at December 31, 2017 (increasing by interest to the end of fiscal 2031);
  - ▶ Project capital costs to termination date ($1.6 billion);
  - ▶ Costs already in the Site C Regulatory Account ($0.5 billion); and
  - ▶ Costs directly related to the Project suspension and maintenance that would be recovered from ratepayers ($1.1 billion); and
- Incremental cost of procuring alternative higher cost energy and capacity that would be required in order to meet customer requirements until Site C entered

service at the later date, including incremental demand-side management efforts. This is comprised of:

- Incremental energy costs of $0.5 billion; and
- Incremental demand-side management expenditures of $0.9 billion, which are amortized over 15 years, beginning in the year following the expenditure. BC Hydro has also included the incremental reduction in energy sales, in estimating the incremental impact on future rate increases

For the changes described above related to capital expenditures, regulatory accounts and demand-side management expenditures, the RRIM model calculates the impact on amortization and financing costs.

The table below shows the estimated incremental impact on cumulative rate increases under the Suspend and Restart scenario, and the estimated incremental impact on revenue requirements (costs to ratepayers). The incremental cumulative rate increase in fiscal 2032 is shown because it is the first year in which the costs related to completing the Site C project, under a suspend and restart scenario, will impact customer rates.

	Estimated Incremental Cumulative Rate Increases (%)			Total Estimated Incremental Costs to F2094 ($ billion)
	in F2024	in F2032	in F2094	Nominal
Suspend and Restart Site C	1	12	2	9.6

A chart of the incremental impact on cumulative rate increases is shown on the ‘Rate Impact Chart’ page of the attached Suspend and Restart document.

Suspend Site C followed by Terminate

BC Hydro considered the following main items in estimating the ratepayer impact under a suspend and then terminate scenario:

1. Costs spent to-date on advancing the Project and costs directly related to suspension, maintenance and remediation; and
2. Costs for ratepayers of procuring higher cost energy and capacity that would otherwise have been provided by Site C

These incremental costs are described below and are found on the 'Input Data' pages of the three attached Suspend and Terminate documents.

Remove:

- Site C costs of $8.335 billion (total Site C construction costs and forecast balance of Site C Regulatory Account) are removed at the end of fiscal 2024;
- Site C operating costs (comprised of water rental costs, operating costs, and taxes) are removed beginning in fiscal 2025; and
- Future sustaining capital expenditures totalling $2.1 billion are removed from the fiscal 2024 to fiscal 2094 period.

Replace with:

- Site C Regulatory Account costs of $4.2 billion are added at the end of fiscal 2024. This comprised of $3.2 billion of costs shown below related to the decision to suspend at December 31, 2017 (increasing by interest to the end of fiscal 2024) plus additional remediation costs of $0.3 billion that would need to be recovered from ratepayers if the Project were to be terminated:
  - ▶ Project capital costs to termination date ($1.6 billion);
  - ▶ Costs already in the Site C regulatory account ($0.5 billion); and
  - ▶ Costs directly related to the Project suspension and maintenance that would be recovered from ratepayers ($1.1 billion); and

- Incremental cost of procuring alternative higher cost energy and capacity that would be required in order to meet customer requirements until Site C entered service at the later date, including advancing incremental demand-side management efforts. This is comprised of:
  - Incremental energy costs of $105.5 billion; and
  - Incremental demand-side management expenditures of $0.9 billion, which are amortized over 15 years, beginning in the year following the expenditure. BC Hydro has also included the incremental reduction in energy sales, in estimating the incremental impact on future rate increases

For the changes described above related to capital expenditures, regulatory accounts and demand-side management expenditures, the RRIM model calculates the impact on amortization and financing costs.

The table below shows the estimated incremental impact on cumulative rate increases under the three Suspend and Terminate scenarios, and the estimated incremental impact on revenue requirements (costs to ratepayers). The incremental cumulative rate increase in fiscal 2025 is shown because it is the first year in which the recovery of the Site C Regulatory Account, as a result of termination, will impact customer rates.

	Estimated Incremental Cumulative Rate Increases (%)			Total Estimated Incremental Costs to F2094 ($ billions)
	in F2024	in F2025	in F2094	Nominal
Suspend & Terminate Site C – 10 Year Recovery of Site C Regulatory Account	1	12	40	82.6
Suspend & Terminate Site C – 5 Year Recovery of Site C Regulatory Account	1	21	40	82.2
Suspend & Terminate Site C – 1 Year Recovery of Site C Regulatory Account	1	88	40	81.9

A chart of the incremental impact on cumulative rate increases is shown on the 'Rate Impact Chart' pages of the three attached Suspend and Terminate documents.

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BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project

Appendix R

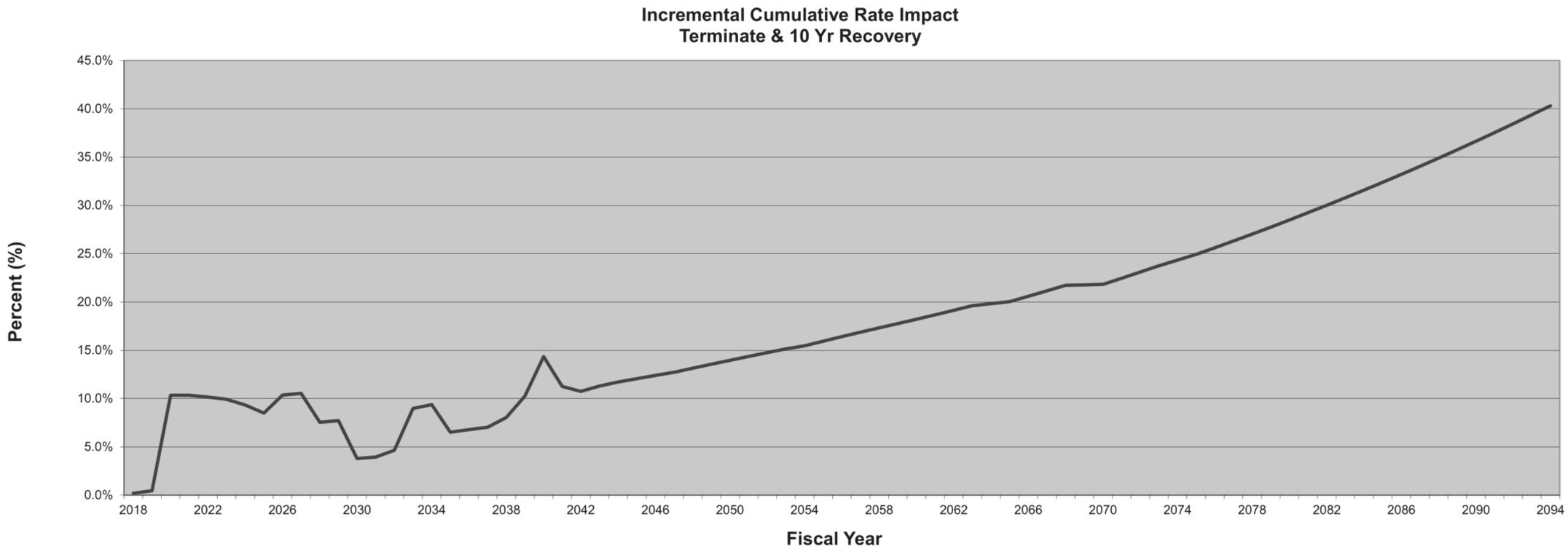
Attachment 1

Ratepayer Impact Calculations - Results and Inputs

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Rate Impact Chart
Page1



BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Summary
Page 2

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	318.6	318.6	318.6	318.6	318.6	199.5	199.5	199.5	199.5	199.5	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	121.4	109.2	94.6	86.7	78.8	(212.8)	(216.8)	(222.7)	(229.4)	(236.9)	(241.0)	(240.1)	(239.8)	(240.0)	(240.9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	433.7	416.7	391.5	364.1	318.2	257.4	342.9	342.0	187.4	196.9	0.3	18.8	70.5	311.3	355.1	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,438	5,635	5,856	6,059	6,262	6,410	6,700	6,901	6,969	7,192	7,220	7,463	7,761	8,244	8,534	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	469.9	475.4	474.4	470.0	448.2	412.4	508.6	522.8	378.9	392.5	194.9	205.7	246.2	480.8	508.8	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	9.46%	9.21%	8.82%	8.41%	7.71%	6.88%	8.21%	8.20%	5.75%	5.77%	2.77%	2.83%	3.28%	6.19%	6.34%	4.32%	4.41%	4.49%	5.03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	119.7	122.6	125.3	128.1	130.5	132.1	136.5	139.2	138.7	141.5	140.3	143.2	146.7	153.8	157.1	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	19.7%	22.6%	25.3%	28.1%	30.5%	32.1%	36.5%	39.2%	38.7%	41.5%	40.3%	43.2%	46.7%	53.8%	57.1%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	10.3%	10.3%	10.2%	9.9%	9.3%	8.5%	10.4%	10.5%	7.5%	7.7%	3.8%	3.9%	4.7%	9.0%	9.4%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Summary
Page 3

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 / 26	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6.82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235.0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395.9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

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Rate Impact Analysis

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Input Data
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Input Data
($ million)

Line		Fiscal Year Column			Total	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**		**Amort. Period (years)**																											
1	Site C Regulatory Account	2019	12	10	3,185.8	0.0	3,185.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024	12	70	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024	12	70	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049	06	25	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064	06	40	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069	06	45	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Year 50 Asset	2074	06	50	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074	06	25	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal				(7,270.0)	0.0	3,185.8	0.0	0.0	0.0	0.0	(8,335.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		15	906.3	69.6	78.4	94.6	110.2	114.8	119.1	128.0	140.9	133.0	42.4	99.0	8.2	(12.0)	(25.8)	(43.1)	(66.7)	(88.7)	(89.7)	(91.0)	(50.9)	(17.0)	(10.3)	(5.7)	(7.1)	12.3	38.6
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential				(13,324.6)	(72.3)	(98.9)	(132.6)	(163.2)	(188.4)	(211.1)	(226.6)	(238.5)	(207.1)	(216.8)	(218.0)	(222.1)	(228.7)	(252.4)	(289.7)	(330.0)	(374.2)	(476.3)	(560.6)	(619.7)	(660.7)	(691.5)	(713.2)	(723.9)	(728.7)	(733.1)
20	Light Industrial and Commercial				(11,421.1)	(42.1)	(73.8)	(127.9)	(200.8)	(261.5)	(325.6)	(394.6)	(467.0)	(498.5)	(552.2)	(595.3)	(602.8)	(558.9)	(499.5)	(468.5)	(441.0)	(402.9)	(402.2)	(388.4)	(363.4)	(335.2)	(331.1)	(355.2)	(370.8)	(367.5)	(355.8)
21	Large Industrial				(6,309.6)	(13.9)	(68.9)	(130.2)	(293.8)	(492.5)	(654.0)	(819.1)	(997.8)	(1,109.6)	(1,166.6)	(1,189.7)	(1,173.8)	(1,168.5)	(1,073.5)	(873.1)	(724.9)	(479.2)	(309.8)	(121.0)	99.7	172.2	232.0	353.2	526.1	644.7	722.1
22	Other				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total				(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $			105,472.5	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
26	Cost of Energy - Item #2	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
	Operating Costs																														
30	Operating Costs	nominal $			(1,479.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.4)	(10.1)	(10.3)	(10.5)	(10.7)	(10.9)	(11.1)	(11.4)	(11.6)	(11.8)	(12.1)	(12.3)	(12.6)	(12.8)	(13.1)	(13.3)	(13.6)	(13.9)	(14.1)
31	Water Rental Costs	nominal $			(6,032.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.3)	(26.7)	(42.2)	(43.0)	(43.9)	(44.8)	(45.6)	(46.6)	(47.5)	(48.4)	(49.4)	(50.4)	(51.4)	(52.4)	(53.5)	(54.6)	(55.6)	(56.8)	(57.9)
32	Grants-in-Lieu / Taxes	nominal $			(462.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	(3.2)	(3.2)	(3.3)	(3.3)	(3.4)	(3.5)	(3.6)	(3.6)	(3.7)	(3.8)	(3.8)	(3.9)	(4.0)	(4.1)	(4.2)	(4.2)	(4.3)	(4.4)
33	Other - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total				(7,974.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(61.5)	(62.7)	(64.0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
37	**Forecast Weighted Average Cost of Debt**	%				3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%				3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Input Data ($ million)

Line			Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
			Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC	In-Service Fiscal Year (YYYY/MM)																													
1	Site C Regulatory Account	2019 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049 06		0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
7	Year 50 Asset	2074 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
18	**DSM additions**	nominal $		56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential			(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial			(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial			665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total			(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $		1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
	Operating Costs																														
30	Operating Costs	nominal $		(14.4)	(14.7)	(15.0)	(15.3)	(15.6)	(15.9)	(16.2)	(16.6)	(16.9)	(17.2)	(17.6)	(17.9)	(18.3)	(18.6)	(19.0)	(19.4)	(19.8)	(20.2)	(20.6)	(21.0)	(21.4)	(21.9)	(22.3)	(22.7)	(23.2)	(23.7)	(24.1)	(24.6)
31	Water Rental Costs	nominal $		(59.0)	(60.2)	(61.4)	(62.7)	(63.9)	(65.2)	(66.5)	(67.8)	(69.2)	(70.6)	(72.0)	(73.4)	(74.9)	(76.4)	(77.9)	(79.5)	(81.1)	(82.7)	(84.3)	(86.0)	(87.7)	(89.5)	(91.3)	(93.1)	(95.0)	(96.9)	(98.8)	(100.8)
32	Grants-in-Lieu / Taxes	nominal $		(4.5)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(5.3)	(5.4)	(5.5)	(5.6)	(5.7)	(5.8)	(5.9)	(6.1)	(6.2)	(6.3)	(6.4)	(6.6)	(6.7)	(6.8)	(7.0)	(7.1)	(7.2)	(7.4)	(7.5)	(7.7)
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)	(127.9)	(130.5)	(133.1)
37	**Forecast Weighted Average Cost of Debt**	%		3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Input Data
Page 7

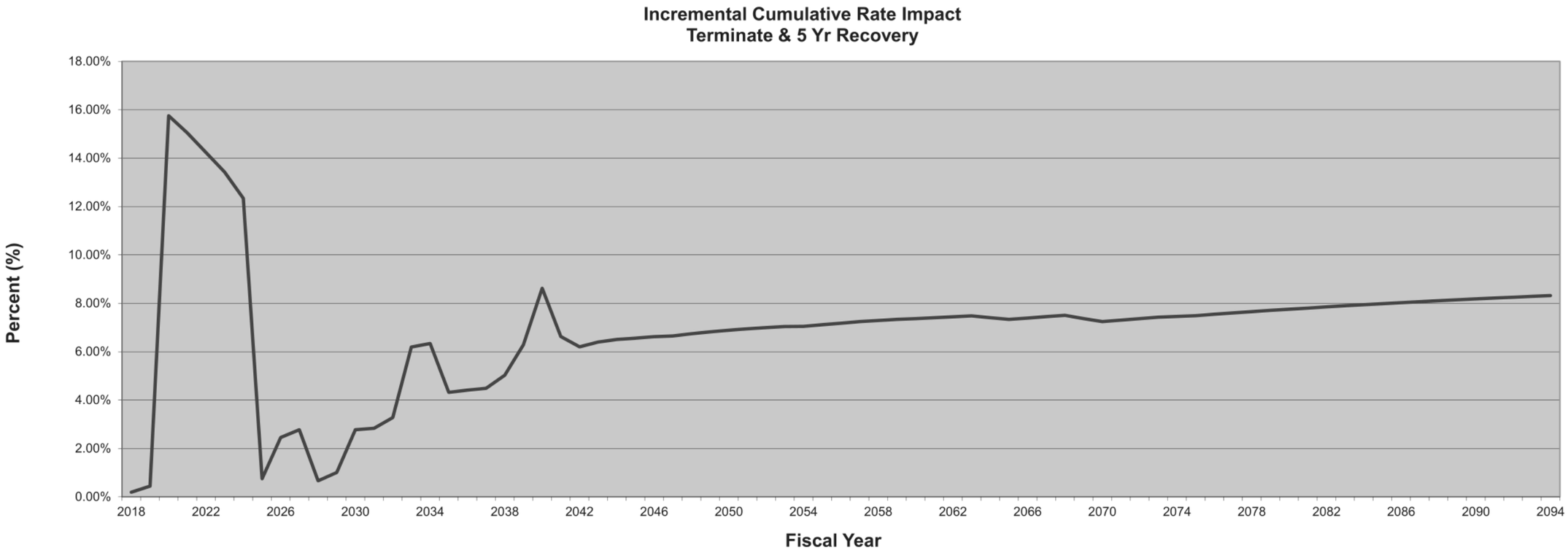
Input Data
($ million)

Line		Fiscal Year / Column	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																							
1	**Site C Regulatory Account**	**2019 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074 06**	0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074 06**	0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	(195.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Increase (Decrease) in Energy Sales (GWh)																								
19	**Residential**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
20	**Light Industrial and Commercial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
21	**Large Industrial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
22	**Other**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																								
25	**Cost of Energy - Item #1**	nominal $	**1,888.1**	**1,925.9**	**1,964.4**	**2,003.7**	**2,043.8**	**2,084.6**	**2,126.3**	**2,168.9**	**2,212.2**	**2,256.5**	**2,301.6**	**2,347.6**	**2,394.6**	**2,442.5**	**2,491.3**	**2,541.2**	**2,592.0**	**2,643.8**	**2,696.7**	**2,750.6**	**2,805.6**	**2,861.8**	**2,919.0**
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
	Operating Costs																								
30	**Operating Costs**	nominal $	**(25.1)**	**(25.6)**	**(26.1)**	**(26.6)**	**(27.2)**	**(27.7)**	**(28.3)**	**(28.8)**	**(29.4)**	**(30.0)**	**(30.6)**	**(31.2)**	**(31.8)**	**(32.5)**	**(33.1)**	**(33.8)**	**(34.5)**	**(35.1)**	**(35.8)**	**(36.6)**	**(37.3)**	**(38.0)**	**(38.8)**
31	**Water Rental Costs**	nominal $	**(102.8)**	**(104.9)**	**(107.0)**	**(109.1)**	**(111.3)**	**(113.5)**	**(115.8)**	**(118.1)**	**(120.4)**	**(122.9)**	**(125.3)**	**(127.8)**	**(130.4)**	**(133.0)**	**(135.6)**	**(138.4)**	**(141.1)**	**(143.9)**	**(146.8)**	**(149.8)**	**(152.8)**	**(155.8)**	**(158.9)**
32	**Grants-in-Lieu / Taxes**	nominal $	**(7.8)**	**(8.0)**	**(8.2)**	**(8.3)**	**(8.5)**	**(8.7)**	**(8.8)**	**(9.0)**	**(9.2)**	**(9.4)**	**(9.6)**	**(9.8)**	**(9.9)**	**(10.1)**	**(10.3)**	**(10.6)**	**(10.8)**	**(11.0)**	**(11.2)**	**(11.4)**	**(11.7)**	**(11.9)**	**(12.1)**
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Terminate & 5 Yr Recovery.xlsx

Rate Impact Chart
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BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 5 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	637.2	637.2	637.2	637.2	637.2	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	115.4	91.7	67.3	48.5	29.6	(262.0)	(255.0)	(250.0)	(245.8)	(242.4)	(241.0)	(240.1)	(239.8)	(240.0)	(240.9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	746.2	717.7	682.8	644.4	587.6	(110.4)	(13.9)	(3.9)	(147.5)	(127.1)	0.3	18.8	70.5	311.3	355.1	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,750	5,937	6,147	6,340	6,532	6,042	6,343	6,555	6,634	6,868	7,220	7,463	7,761	8,244	8,534	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	782.5	776.5	765.7	750.3	717.6	44.7	151.8	176.9	44.0	68.5	194.9	205.7	246.2	480.8	508.8	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	15.75%	15.05%	14.23%	13.42%	12.34%	0.74%	2.45%	2.77%	0.67%	1.01%	2.77%	2.83%	3.28%	6.19%	6.34%	4.32%	4.41%	4.49%	5.03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	126.6	129.1	131.5	134.0	136.2	124.5	129.2	132.2	132.1	135.2	140.3	143.2	146.7	153.8	157.1	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	26.6%	29.1%	31.5%	34.0%	36.2%	24.5%	29.2%	32.2%	32.1%	35.2%	40.3%	43.2%	46.7%	53.8%	57.1%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	17.2%	16.9%	16.4%	15.9%	15.0%	0.9%	3.1%	3.6%	0.9%	1.3%	3.8%	3.9%	4.7%	9.0%	9.4%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 5 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 / 26	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6.82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235.0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 5 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395.9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

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Rate Impact Analysis

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Input Data
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Input Data
($ million)

Line		Fiscal Year			Total	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		Column				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**		**Amort. Period (years)**																											
1	**Site C Regulatory Account**	**2019**	**12**	**5**	3,185.8	0.0	**3,185.8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024**	**12**	**70**	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(7,750.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024**	**12**	**70**	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(585.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049**	**06**	**25**	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064**	**06**	**40**	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069**	**06**	**45**	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074**	**06**	**50**	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074**	**06**	**25**	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal				(7,270.0)	0.0	3,185.8	0.0	0.0	0.0	0.0	(8,335.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		**15**	906.3	**69.6**	**78.4**	**94.6**	**110.2**	**114.8**	**119.1**	**128.0**	**140.9**	**133.0**	**42.4**	**99.0**	**8.2**	**(12.0)**	**(25.8)**	**(43.1)**	**(66.7)**	**(88.7)**	**(89.7)**	**(91.0)**	**(50.9)**	**(17.0)**	**(10.3)**	**(5.7)**	**(7.1)**	**12.3**	**38.6**
	Increase (Decrease) in Energy Sales (GWh)																														
19	**Residential**				(13,324.6)	**(72.3)**	**(98.9)**	**(132.6)**	**(163.2)**	**(188.4)**	**(211.1)**	**(226.6)**	**(238.5)**	**(207.1)**	**(216.8)**	**(218.0)**	**(222.1)**	**(228.7)**	**(252.4)**	**(289.7)**	**(330.0)**	**(374.2)**	**(476.3)**	**(560.6)**	**(619.7)**	**(660.7)**	**(691.5)**	**(713.2)**	**(723.9)**	**(728.7)**	**(733.1)**
20	**Light Industrial and Commercial**				(11,421.1)	**(42.1)**	**(73.8)**	**(127.9)**	**(200.8)**	**(261.5)**	**(325.6)**	**(394.6)**	**(467.0)**	**(498.5)**	**(552.2)**	**(595.3)**	**(602.8)**	**(558.9)**	**(499.5)**	**(468.5)**	**(441.0)**	**(402.9)**	**(402.2)**	**(388.4)**	**(363.4)**	**(335.2)**	**(331.1)**	**(355.2)**	**(370.8)**	**(367.5)**	**(355.8)**
21	**Large Industrial**				(6,309.6)	**(13.9)**	**(68.9)**	**(130.2)**	**(293.8)**	**(492.5)**	**(654.0)**	**(819.1)**	**(997.8)**	**(1,109.6)**	**(1,166.6)**	**(1,189.7)**	**(1,173.8)**	**(1,168.5)**	**(1,073.5)**	**(873.1)**	**(724.9)**	**(479.2)**	**(309.8)**	**(121.0)**	**99.7**	**172.2**	**232.0**	**353.2**	**526.1**	**644.7**	**722.1**
22	**Other**				0.0	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total				(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																														
25	**Cost of Energy - Item #1**	nominal $			105,472.5	**(5.3)**	**(10.0)**	**(16.2)**	**(27.3)**	**(45.1)**	**(72.4)**	**(118.3)**	**238.4**	**343.1**	**355.0**	**205.4**	**216.9**	**343.5**	**363.2**	**417.4**	**662.6**	**717.6**	**575.5**	**610.5**	**654.0**	**727.1**	**864.8**	**1,121.1**	**965.3**	**958.9**	**1,006.4**
26	Cost of Energy - Item #2	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
	Operating Costs																														
30	**Operating Costs**	nominal $			(1,479.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(5.4)**	**(10.1)**	**(10.3)**	**(10.5)**	**(10.7)**	**(10.9)**	**(11.1)**	**(11.4)**	**(11.6)**	**(11.8)**	**(12.1)**	**(12.3)**	**(12.6)**	**(12.8)**	**(13.1)**	**(13.3)**	**(13.6)**	**(13.9)**	**(14.1)**
31	**Water Rental Costs**	nominal $			(6,032.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(8.3)**	**(26.7)**	**(42.2)**	**(43.0)**	**(43.9)**	**(44.8)**	**(45.6)**	**(46.6)**	**(47.5)**	**(48.4)**	**(49.4)**	**(50.4)**	**(51.4)**	**(52.4)**	**(53.5)**	**(54.6)**	**(55.6)**	**(56.8)**	**(57.9)**
32	**Grants-in-Lieu / Taxes**	nominal $			(462.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(1.7)**	**(3.2)**	**(3.2)**	**(3.3)**	**(3.3)**	**(3.4)**	**(3.5)**	**(3.6)**	**(3.6)**	**(3.7)**	**(3.8)**	**(3.8)**	**(3.9)**	**(4.0)**	**(4.1)**	**(4.2)**	**(4.2)**	**(4.3)**	**(4.4)**
33	Other - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total				(7,974.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(61.5)	(62.7)	(64.0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
37	**Forecast Weighted Average Cost of Debt**	%				3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%				3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Input Data ($ million)

Line		Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
		Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC	In-Service Fiscal Year (YYYY/MM)																												
1	Site C Regulatory Account	2019 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049 06	0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
7	Year 50 Asset	2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
18	**DSM additions**	nominal $	56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																													
19	Residential		(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial		(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial		665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total		(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																													
25	Cost of Energy - Item #1	nominal $	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
	Operating Costs																													
30	Operating Costs	nominal $	(14.4)	(14.7)	(15.0)	(15.3)	(15.6)	(15.9)	(16.2)	(16.6)	(16.9)	(17.2)	(17.6)	(17.9)	(18.3)	(18.6)	(19.0)	(19.4)	(19.8)	(20.2)	(20.6)	(21.0)	(21.4)	(21.9)	(22.3)	(22.7)	(23.2)	(23.7)	(24.1)	(24.6)
31	Water Rental Costs	nominal $	(59.0)	(60.2)	(61.4)	(62.7)	(63.9)	(65.2)	(66.5)	(67.8)	(69.2)	(70.6)	(72.0)	(73.4)	(74.9)	(76.4)	(77.9)	(79.5)	(81.1)	(82.7)	(84.3)	(86.0)	(87.7)	(89.5)	(91.3)	(93.1)	(95.0)	(96.9)	(98.8)	(100.8)
32	Grants-in-Lieu / Taxes	nominal $	(4.5)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(5.3)	(5.4)	(5.5)	(5.6)	(5.7)	(5.8)	(5.9)	(6.1)	(6.2)	(6.3)	(6.4)	(6.6)	(6.7)	(6.8)	(7.0)	(7.1)	(7.2)	(7.4)	(7.5)	(7.7)
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)	(127.9)	(130.5)	(133.1)
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 5 Yr Recovery.xlsx

Input Data
Page 7

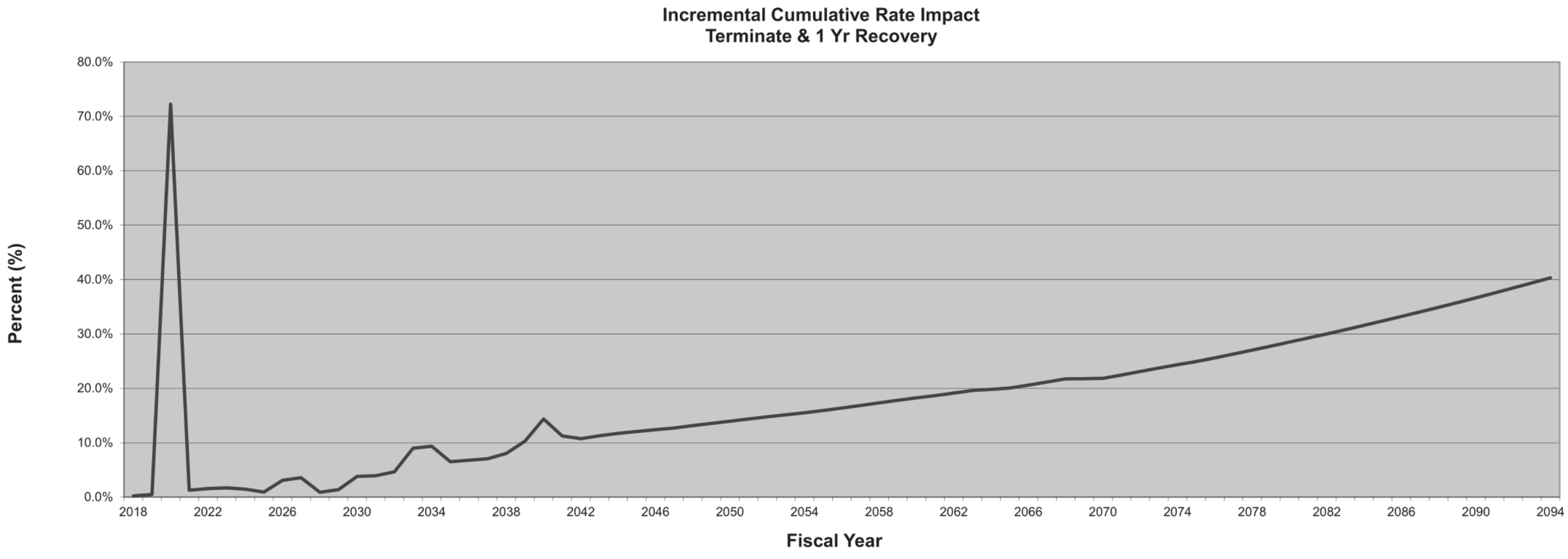
Input Data
($ million)

Line		Fiscal Year / Column	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																							
1	**Site C Regulatory Account**	**2019 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074 06**	0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074 06**	0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	(195.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Increase (Decrease) in Energy Sales (GWh)																								
19	**Residential**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
20	**Light Industrial and Commercial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
21	**Large Industrial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
22	**Other**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																								
25	**Cost of Energy - Item #1**	nominal $	**1,888.1**	**1,925.9**	**1,964.4**	**2,003.7**	**2,043.8**	**2,084.6**	**2,126.3**	**2,168.9**	**2,212.2**	**2,256.5**	**2,301.6**	**2,347.6**	**2,394.6**	**2,442.5**	**2,491.3**	**2,541.2**	**2,592.0**	**2,643.8**	**2,696.7**	**2,750.6**	**2,805.6**	**2,861.8**	**2,919.0**
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
	Operating Costs																								
30	**Operating Costs**	nominal $	**(25.1)**	**(25.6)**	**(26.1)**	**(26.6)**	**(27.2)**	**(27.7)**	**(28.3)**	**(28.8)**	**(29.4)**	**(30.0)**	**(30.6)**	**(31.2)**	**(31.8)**	**(32.5)**	**(33.1)**	**(33.8)**	**(34.5)**	**(35.1)**	**(35.8)**	**(36.6)**	**(37.3)**	**(38.0)**	**(38.8)**
31	**Water Rental Costs**	nominal $	**(102.8)**	**(104.9)**	**(107.0)**	**(109.1)**	**(111.3)**	**(113.5)**	**(115.8)**	**(118.1)**	**(120.4)**	**(122.9)**	**(125.3)**	**(127.8)**	**(130.4)**	**(133.0)**	**(135.6)**	**(138.4)**	**(141.1)**	**(143.9)**	**(146.8)**	**(149.8)**	**(152.8)**	**(155.8)**	**(158.9)**
32	**Grants-in-Lieu / Taxes**	nominal $	**(7.8)**	**(8.0)**	**(8.2)**	**(8.3)**	**(8.5)**	**(8.7)**	**(8.8)**	**(9.0)**	**(9.2)**	**(9.4)**	**(9.6)**	**(9.8)**	**(9.9)**	**(10.1)**	**(10.3)**	**(10.6)**	**(10.8)**	**(11.0)**	**(11.2)**	**(11.4)**	**(11.7)**	**(11.9)**	**(12.1)**
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Rate Impact Chart
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BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	3,185.8	0.0	0.0	0.0	0.0	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	67.2	10.1	12.6	15.7	18.7	(262.0)	(255.0)	(250.0)	(245.8)	(242.4)	(241.0)	(240.1)	(239.8)	(240.0)	(240.9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	3,246.7	(1.0)	(9.0)	(25.5)	(60.5)	(110.4)	(13.9)	(3.9)	(147.5)	(127.1)	0.3	18.8	70.5	311.3	355.1	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	8,251	5,218	5,455	5,670	5,884	6,042	6,343	6,555	6,634	6,868	7,220	7,463	7,761	8,244	8,534	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	3,282.9	57.7	73.9	80.4	69.5	44.7	151.8	176.9	44.0	68.5	194.9	205.7	246.2	480.8	508.8	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	66.08%	1.12%	1.37%	1.44%	1.20%	0.74%	2.45%	2.77%	0.67%	1.01%	2.77%	2.83%	3.28%	6.19%	6.34%	4.32%	4.41%	4.49%	5.03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	181.7	113.5	116.7	119.8	122.7	124.5	129.2	132.2	132.1	135.2	140.3	143.2	146.7	153.8	157.1	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	81.7%	13.5%	16.7%	19.8%	22.7%	24.5%	29.2%	32.2%	32.1%	35.2%	40.3%	43.2%	46.7%	53.8%	57.1%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	72.3%	1.3%	1.6%	1.7%	1.4%	0.9%	3.1%	3.6%	0.9%	1.3%	3.8%	3.9%	4.7%	9.0%	9.4%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 / 26	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6.82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235.0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395.9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Input Data
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Input Data
($ million)

Line		Fiscal Year			Total	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
		Column				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**		**Amort. Period (years)**																											
1	Site C Regulatory Account	2019	12	1	3,185.8	0.0	3,185.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024	12	70	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024	12	70	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049	06	25	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064	06	40	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069	06	45	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Year 50 Asset	2074	06	50	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074	06	25	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal				(7,270.0)	0.0	3,185.8	0.0	0.0	0.0	0.0	(8,335.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		15	906.3	69.6	78.4	94.6	110.2	114.8	119.1	128.0	140.9	133.0	42.4	99.0	8.2	(12.0)	(25.8)	(43.1)	(66.7)	(88.7)	(89.7)	(91.0)	(50.9)	(17.0)	(10.3)	(5.7)	(7.1)	12.3	38.6
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential				(13,324.6)	(72.3)	(98.9)	(132.6)	(163.2)	(188.4)	(211.1)	(226.6)	(238.5)	(207.1)	(216.8)	(218.0)	(222.1)	(228.7)	(252.4)	(289.7)	(330.0)	(374.2)	(476.3)	(560.6)	(619.7)	(660.7)	(691.5)	(713.2)	(723.9)	(728.7)	(733.1)
20	Light Industrial and Commercial				(11,421.1)	(42.1)	(73.8)	(127.9)	(200.8)	(261.5)	(325.6)	(394.6)	(467.0)	(498.5)	(552.2)	(595.3)	(602.8)	(558.9)	(499.5)	(468.5)	(441.0)	(402.9)	(402.2)	(388.4)	(363.4)	(335.2)	(331.1)	(355.2)	(370.8)	(367.5)	(355.8)
21	Large Industrial				(6,309.6)	(13.9)	(68.9)	(130.2)	(293.8)	(492.5)	(654.0)	(819.1)	(997.8)	(1,109.6)	(1,166.6)	(1,189.7)	(1,173.8)	(1,168.5)	(1,073.5)	(873.1)	(724.9)	(479.2)	(309.8)	(121.0)	99.7	172.2	232.0	353.2	526.1	644.7	722.1
22	Other				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total				(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $			105,472.5	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
26	Cost of Energy - Item #2	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
	Operating Costs																														
30	Operating Costs	nominal $			(1,479.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.4)	(10.1)	(10.3)	(10.5)	(10.7)	(10.9)	(11.1)	(11.4)	(11.6)	(11.8)	(12.1)	(12.3)	(12.6)	(12.8)	(13.1)	(13.3)	(13.6)	(13.9)	(14.1)
31	Water Rental Costs	nominal $			(6,032.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.3)	(26.7)	(42.2)	(43.0)	(43.9)	(44.8)	(45.6)	(46.6)	(47.5)	(48.4)	(49.4)	(50.4)	(51.4)	(52.4)	(53.5)	(54.6)	(55.6)	(56.8)	(57.9)
32	Grants-in-Lieu / Taxes	nominal $			(462.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	(3.2)	(3.2)	(3.3)	(3.3)	(3.4)	(3.5)	(3.6)	(3.6)	(3.7)	(3.8)	(3.8)	(3.9)	(4.0)	(4.1)	(4.2)	(4.2)	(4.3)	(4.4)
33	Other - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total				(7,974.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(61.5)	(62.7)	(64.0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
37	**Forecast Weighted Average Cost of Debt**	%				3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%				3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Input Data
Page 6

Input Data
($ million)

Line			Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
			Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																													
1	Site C Regulatory Account	2019 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049 06		0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
7	Year 50 Asset	2074 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
18	**DSM additions**	nominal $		56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential			(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial			(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial			665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total			(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $		1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
	Operating Costs																														
30	Operating Costs	nominal $		(14.4)	(14.7)	(15.0)	(15.3)	(15.6)	(15.9)	(16.2)	(16.6)	(16.9)	(17.2)	(17.6)	(17.9)	(18.3)	(18.6)	(19.0)	(19.4)	(19.8)	(20.2)	(20.6)	(21.0)	(21.4)	(21.9)	(22.3)	(22.7)	(23.2)	(23.7)	(24.1)	(24.6)
31	Water Rental Costs	nominal $		(59.0)	(60.2)	(61.4)	(62.7)	(63.9)	(65.2)	(66.5)	(67.8)	(69.2)	(70.6)	(72.0)	(73.4)	(74.9)	(76.4)	(77.9)	(79.5)	(81.1)	(82.7)	(84.3)	(86.0)	(87.7)	(89.5)	(91.3)	(93.1)	(95.0)	(96.9)	(98.8)	(100.8)
32	Grants-in-Lieu / Taxes	nominal $		(4.5)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(5.3)	(5.4)	(5.5)	(5.6)	(5.7)	(5.8)	(5.9)	(6.1)	(6.2)	(6.3)	(6.4)	(6.6)	(6.7)	(6.8)	(7.0)	(7.1)	(7.2)	(7.4)	(7.5)	(7.7)
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)	(127.9)	(130.5)	(133.1)
37	**Forecast Weighted Average Cost of Debt**	%		3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 1 Yr Recovery.xlsx

Input Data
Page 7

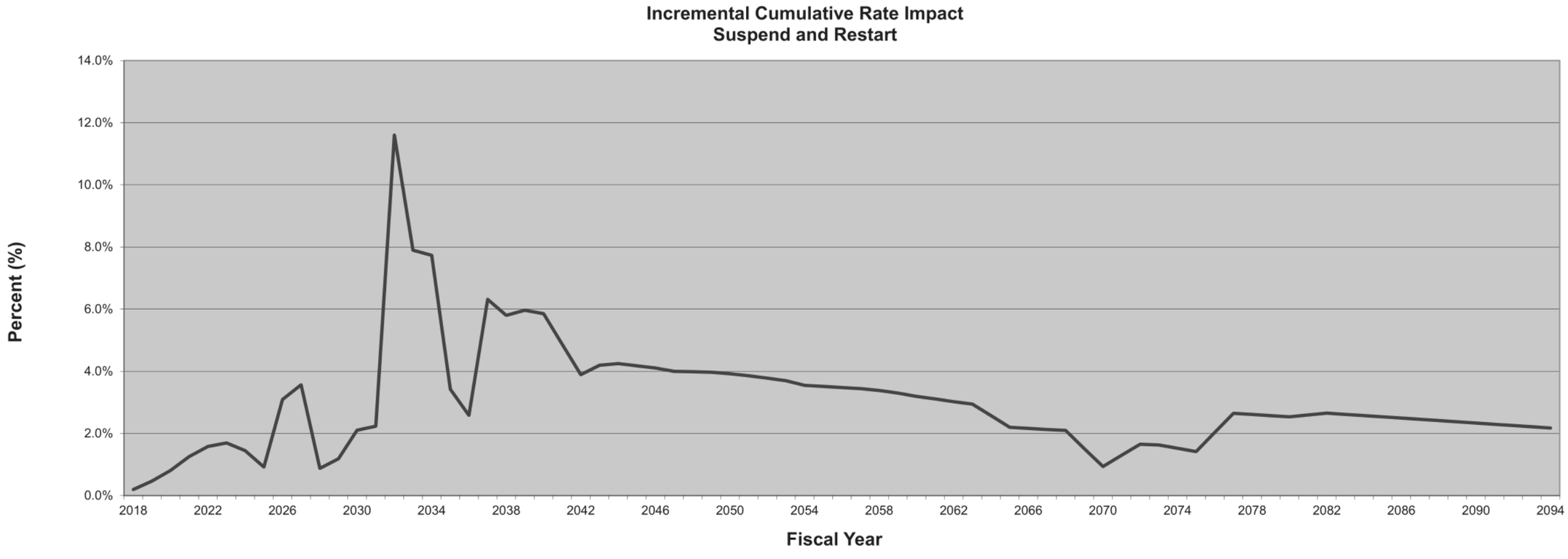
Input Data
($ million)

Line		Fiscal Year / Column	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																							
1	**Site C Regulatory Account**	**2019 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074 06**	0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074 06**	0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	(195.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Increase (Decrease) in Energy Sales (GWh)																								
19	**Residential**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
20	**Light Industrial and Commercial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
21	**Large Industrial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
22	**Other**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																								
25	**Cost of Energy - Item #1**	nominal $	**1,888.1**	**1,925.9**	**1,964.4**	**2,003.7**	**2,043.8**	**2,084.6**	**2,126.3**	**2,168.9**	**2,212.2**	**2,256.5**	**2,301.6**	**2,347.6**	**2,394.6**	**2,442.5**	**2,491.3**	**2,541.2**	**2,592.0**	**2,643.8**	**2,696.7**	**2,750.6**	**2,805.6**	**2,861.8**	**2,919.0**
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
	Operating Costs																								
30	**Operating Costs**	nominal $	**(25.1)**	**(25.6)**	**(26.1)**	**(26.6)**	**(27.2)**	**(27.7)**	**(28.3)**	**(28.8)**	**(29.4)**	**(30.0)**	**(30.6)**	**(31.2)**	**(31.8)**	**(32.5)**	**(33.1)**	**(33.8)**	**(34.5)**	**(35.1)**	**(35.8)**	**(36.6)**	**(37.3)**	**(38.0)**	**(38.8)**
31	**Water Rental Costs**	nominal $	**(102.8)**	**(104.9)**	**(107.0)**	**(109.1)**	**(111.3)**	**(113.5)**	**(115.8)**	**(118.1)**	**(120.4)**	**(122.9)**	**(125.3)**	**(127.8)**	**(130.4)**	**(133.0)**	**(135.6)**	**(138.4)**	**(141.1)**	**(143.9)**	**(146.8)**	**(149.8)**	**(152.8)**	**(155.8)**	**(158.9)**
32	**Grants-in-Lieu / Taxes**	nominal $	**(7.8)**	**(8.0)**	**(8.2)**	**(8.3)**	**(8.5)**	**(8.7)**	**(8.8)**	**(9.0)**	**(9.2)**	**(9.4)**	**(9.6)**	**(9.8)**	**(9.9)**	**(10.1)**	**(10.3)**	**(10.6)**	**(10.8)**	**(11.0)**	**(11.2)**	**(11.4)**	**(11.7)**	**(11.9)**	**(12.1)**
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Suspend and Restart.xlsx

Rate Impact Chart
Page1



BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Restart.xlsx

Summary
Page 2

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	208.8	256.8	274.1	143.9	(57.9)	(46.3)	(264.4)	(287.8)	(46.5)	(55.5)	(31.8)	(20.3)	(52.7)	(87.5)
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(86.9)	(83.6)	(88.7)	(89.7)	(91.0)	(50.9)	(17.0)	(10.3)	(5.7)	(7.1)	12.3
3	**Amortization**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2
4	**Finance Charges**		1.4	4.1	7.0	10.1	12.6	15.7	18.7	(262.0)	(255.0)	(250.0)	(245.8)	(242.4)	(241.0)	(240.1)	199.6	193.0	185.9	178.7	171.8	166.1	162.0	159.0	156.5	154.4	152.9
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	0.7	(1.0)	(9.0)	(25.5)	(60.5)	(110.4)	(13.9)	(3.9)	(147.5)	(135.2)	(86.5)	(70.3)	438.3	254.0	266.2	29.8	(12.8)	209.3	185.2	196.8	196.6	152.4	106.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,005	5,218	5,455	5,670	5,884	6,042	6,343	6,555	6,634	6,859	7,134	7,374	8,129	8,187	8,445	8,465	8,693	9,170	9,428	9,737	10,068	10,334	10,628
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	36.9	57.7	73.9	80.4	69.5	44.7	151.8	176.9	44.0	60.4	108.2	116.6	614.1	423.5	419.9	188.0	143.7	355.1	330.2	343.8	342.2	288.2	233.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	0.74%	1.12%	1.37%	1.44%	1.20%	0.74%	2.45%	2.77%	0.67%	0.89%	1.54%	1.61%	8.17%	5.45%	5.23%	2.27%	1.68%	4.03%	3.63%	3.66%	3.52%	2.87%	2.25%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	110.2	113.5	116.7	119.8	122.7	124.5	129.2	132.2	132.1	135.0	138.6	141.5	153.6	152.8	155.5	154.1	156.3	163.1	165.7	169.1	172.2	174.6	177.0
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	10.2%	13.5%	16.7%	19.8%	22.7%	24.5%	29.2%	32.2%	32.1%	35.0%	38.6%	41.5%	53.6%	52.8%	55.5%	54.1%	56.3%	63.1%	65.7%	69.1%	72.2%	74.6%	77.0%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	0.8%	1.3%	1.6%	1.7%	1.4%	0.9%	3.1%	3.6%	0.9%	1.2%	2.1%	2.2%	11.6%	7.9%	7.7%	3.4%	2.6%	6.3%	5.8%	6.0%	5.9%	4.9%	3.9%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Restart.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 / 26	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(56.8)	(56.3)	(31.3)	(21.2)	(30.7)	(24.0)	(13.1)	(9.5)	(11.7)	(15.9)	(10.1)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Operating Costs**		38.6	56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Amortization**		65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.1	65.1	65.1	65.1	65.1	65.1	65.2	65.3	65.3	65.3	65.3	65.3	65.3	65.3	56.7	48.1	48.1	48.1	48.1
4	**Finance Charges**		152.4	152.7	153.1	153.2	153.0	152.2	150.7	148.9	146.9	144.5	141.9	139.2	136.4	133.6	130.8	128.0	125.2	122.5	119.9	117.4	115.0	101.1	87.5	85.8	84.1	82.4
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		134.9	131.8	160.4	174.1	168.9	180.2	194.8	203.2	205.6	205.6	212.4	221.2	219.0	216.7	214.5	210.8	205.4	199.0	193.6	188.3	183.5	160.1	137.1	134.7	132.6	130.7
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,012	11,333	11,574	11,819	12,069	12,318	12,575	12,831	13,086	13,344	13,614	13,890	14,162	14,438	14,720	15,007	15,297	15,593	15,895	16,204	16,519	16,823	17,133	17,471	17,815	18,167
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	255.5	261.3	257.4	253.5	247.3	247.1	246.1	243.5	239.6	234.8	229.9	221.2	219.0	216.7	214.5	210.8	205.4	199.0	193.6	188.3	183.5	160.1	137.1	134.7	132.6	130.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	2.37%	2.36%	2.27%	2.19%	2.09%	2.05%	2.00%	1.93%	1.86%	1.79%	1.72%	1.62%	1.57%	1.52%	1.48%	1.42%	1.36%	1.29%	1.23%	1.18%	1.12%	0.96%	0.81%	0.78%	0.75%	0.72%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	180.8	184.4	187.9	191.5	195.1	198.9	202.8	206.7	210.7	214.8	218.9	223.1	227.5	231.9	236.4	241.0	245.7	250.4	255.3	260.3	265.3	270.2	275.2	280.6	286.1	291.8
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	80.8%	84.4%	87.9%	91.5%	95.1%	98.9%	102.8%	106.7%	110.7%	114.8%	118.9%	123.1%	127.5%	131.9%	136.4%	141.0%	145.7%	150.4%	155.3%	160.3%	165.3%	170.2%	175.2%	180.6%	186.1%	191.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	4.2%	4.3%	4.2%	4.1%	4.0%	4.0%	4.0%	3.9%	3.9%	3.8%	3.7%	3.6%	3.5%	3.5%	3.4%	3.4%	3.3%	3.2%	3.1%	3.0%	2.9%	2.6%	2.2%	2.2%	2.1%	2.1%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Restart.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 52	2070 53	2071 54	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Operating Costs**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Amortization**		34.4	20.7	30.5	40.4	40.4	38.4	36.5	52.3	68.0	68.0	68.0	68.0	70.2	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
4	**Finance Charges**		59.8	37.7	50.4	62.7	61.3	56.6	51.9	74.7	97.0	94.6	92.3	90.0	91.5	92.9	90.4	87.9	85.4	82.9	80.4	78.0	75.5	73.0	70.5	68.0	65.5	63.0
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		94.2	58.4	80.9	103.0	101.7	95.0	88.4	127.0	165.0	162.7	160.3	158.0	161.7	165.4	162.9	160.4	157.9	155.4	152.9	150.4	147.9	145.5	143.0	140.5	138.0	135.5
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	18,491	18,823	19,221	19,626	20,015	20,407	20,806	21,259	21,720	22,149	22,586	23,032	23,493	23,964	24,437	24,920	25,413	25,916	26,428	26,951	27,485	28,029	28,584	29,151	29,728	30,318
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	94.2	58.4	80.9	103.0	101.7	95.0	88.4	127.0	165.0	162.7	160.3	158.0	161.7	165.4	162.9	160.4	157.9	155.4	152.9	150.4	147.9	145.5	143.0	140.5	138.0	135.5
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.51%	0.31%	0.42%	0.53%	0.51%	0.47%	0.43%	0.60%	0.77%	0.74%	0.71%	0.69%	0.69%	0.69%	0.67%	0.65%	0.63%	0.60%	0.58%	0.56%	0.54%	0.52%	0.50%	0.48%	0.47%	0.45%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	297.0	302.3	308.7	315.2	321.5	327.8	334.2	341.4	348.8	355.7	362.8	369.9	377.3	384.9	392.5	400.2	408.2	416.2	424.5	432.9	441.4	450.2	459.1	468.2	477.5	486.9
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	197.0%	202.3%	208.7%	215.2%	221.5%	227.8%	234.2%	241.4%	248.8%	255.7%	262.8%	269.9%	277.3%	284.9%	292.5%	300.2%	308.2%	316.2%	324.5%	332.9%	341.4%	350.2%	359.1%	368.2%	377.5%	386.9%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	1.5%	0.9%	1.3%	1.7%	1.6%	1.5%	1.4%	2.0%	2.6%	2.6%	2.6%	2.5%	2.6%	2.7%	2.6%	2.6%	2.5%	2.5%	2.5%	2.4%	2.4%	2.3%	2.3%	2.3%	2.2%	2.2%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Restart.xlsx

Input Data
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Input Data
($ million)

Line		Fiscal Year Column		Total	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**	**Amort. Period (years)**																										
1	**Site C Construction**	**2031 12**	**70**	7,921.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**7,921.6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Site C Regulatory Account**	**2031 12**	**70**	4,980.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**4,980.3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Year 25 Asset**	**2056 06**	**25**	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 40 Asset**	**2071 06**	**40**	788.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 45 Asset**	**2076 06**	**45**	1,418.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 50 Asset**	**2081 06**	**50**	216.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 25 (#2) Asset**	**2081 06**	**25**	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Original Site C Construction**	**2024 12**	**70**	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(7,750.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Original Site C Regulatory Account**	**2024 12**	**70**	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(585.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Year 25 Asset**	**2049 06**	**25**	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Year 40 Asset**	**2064 06**	**40**	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Year 45 Asset**	**2069 06**	**45**	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Year 50 Asset**	**2074 06**	**50**	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Year 25 (#2) Asset**	**2074 06**	**25**	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			4,882.2	0.0	0.0	0.0	0.0	0.0	0.0	(8,335.0)	0.0	0.0	0.0	0.0	0.0	0.0	12,901.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $	**15**	906.3	**69.6**	**78.4**	**94.6**	**110.2**	**114.8**	**119.1**	**128.0**	**140.9**	**133.0**	**42.4**	**99.0**	**8.2**	**(12.0)**	**(25.8)**	**(43.1)**	**(66.7)**	**(88.7)**	**(89.7)**	**(91.0)**	**(50.9)**	**(17.0)**	**(10.3)**	**(5.7)**	**(7.1)**	**12.3**	**38.6**
	Increase (Decrease) in Energy Sales (GWh)																												
19	**Residential**			(13,324.6)	**(72.3)**	**(98.9)**	**(132.6)**	**(163.2)**	**(188.4)**	**(211.1)**	**(226.6)**	**(238.5)**	**(207.1)**	**(216.8)**	**(218.0)**	**(222.1)**	**(228.7)**	**(252.4)**	**(289.7)**	**(330.0)**	**(374.2)**	**(476.3)**	**(560.6)**	**(619.7)**	**(660.7)**	**(691.5)**	**(713.2)**	**(723.9)**	**(728.7)**	**(733.1)**
20	**Light Industrial and Commercial**			(11,421.1)	**(42.1)**	**(73.8)**	**(127.9)**	**(200.8)**	**(261.5)**	**(325.6)**	**(394.6)**	**(467.0)**	**(498.5)**	**(552.2)**	**(595.3)**	**(602.8)**	**(558.9)**	**(499.5)**	**(468.5)**	**(441.0)**	**(402.9)**	**(402.2)**	**(388.4)**	**(363.4)**	**(335.2)**	**(331.1)**	**(355.2)**	**(370.8)**	**(367.5)**	**(355.8)**
21	**Large Industrial**			(6,309.6)	**(13.9)**	**(68.9)**	**(130.2)**	**(293.8)**	**(492.5)**	**(654.0)**	**(819.1)**	**(997.8)**	**(1,109.6)**	**(1,166.6)**	**(1,189.7)**	**(1,173.8)**	**(1,168.5)**	**(1,073.5)**	**(873.1)**	**(724.9)**	**(479.2)**	**(309.8)**	**(121.0)**	**99.7**	**172.2**	**232.0**	**353.2**	**526.1**	**644.7**	**722.1**
22	**Other**			0.0	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total			(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																												
25	**Cost of Energy - Item #1**	nominal $		499.5	**(5.3)**	**(10.0)**	**(16.2)**	**(27.3)**	**(45.1)**	**(72.4)**	**(118.3)**	**238.4**	**343.1**	**355.0**	**205.4**	**208.8**	**256.8**	**274.1**	**143.9**	**(57.9)**	**(46.3)**	**(264.4)**	**(287.8)**	**(46.5)**	**(55.5)**	**(31.8)**	**(20.3)**	**(52.7)**	**(87.5)**	**(56.8)**
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	208.8	256.8	274.1	143.9	(57.9)	(46.3)	(264.4)	(287.8)	(46.5)	(55.5)	(31.8)	(20.3)	(52.7)	(87.5)	(56.8)
	Operating Costs																												
30	**Operating Costs**	nominal $		(74.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(5.4)**	**(10.1)**	**(10.3)**	**(10.5)**	**(10.7)**	**(10.9)**	**(11.1)**	**(5.2)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	**Water Rental Costs**	nominal $		(308.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(8.3)**	**(26.7)**	**(42.2)**	**(43.0)**	**(43.9)**	**(44.8)**	**(45.6)**	**(37.0)**	**(16.8)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	**Grants-in-Lieu / Taxes**	nominal $		(23.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(1.7)**	**(3.2)**	**(3.2)**	**(3.3)**	**(3.3)**	**(3.4)**	**(3.5)**	**(1.6)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(405.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(43.8)	(16.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	**Forecast Weighted Average Cost of Debt**	%			3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%			3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%			2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Input Data ($ million)

Line		Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
		Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC	In-Service Fiscal Year (YYYY/MM)																												
1	Site C Construction	2031 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Site C Regulatory Account	2031 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Year 25 Asset	2056 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 40 Asset	2071 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	788.1
5	Year 45 Asset	2076 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 50 Asset	2081 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Year 25 (#2) Asset	2081 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Original Site C Construction	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Original Site C Regulatory Account	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Year 25 Asset	2049 06	0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Year 40 Asset	2064 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Year 45 Asset	2069 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
13	Year 50 Asset	2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Year 25 (#2) Asset	2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	788.1
18	**DSM additions**	nominal $	56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																													
19	Residential		(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial		(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial		665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total		(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																													
25	Cost of Energy - Item #1	nominal $	(56.3)	(31.3)	(21.2)	(30.7)	(24.0)	(13.1)	(9.5)	(11.7)	(15.9)	(10.1)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			(56.3)	(31.3)	(21.2)	(30.7)	(24.0)	(13.1)	(9.5)	(11.7)	(15.9)	(10.1)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Operating Costs																													
30	Operating Costs	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Water Rental Costs	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Grants-in-Lieu / Taxes	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

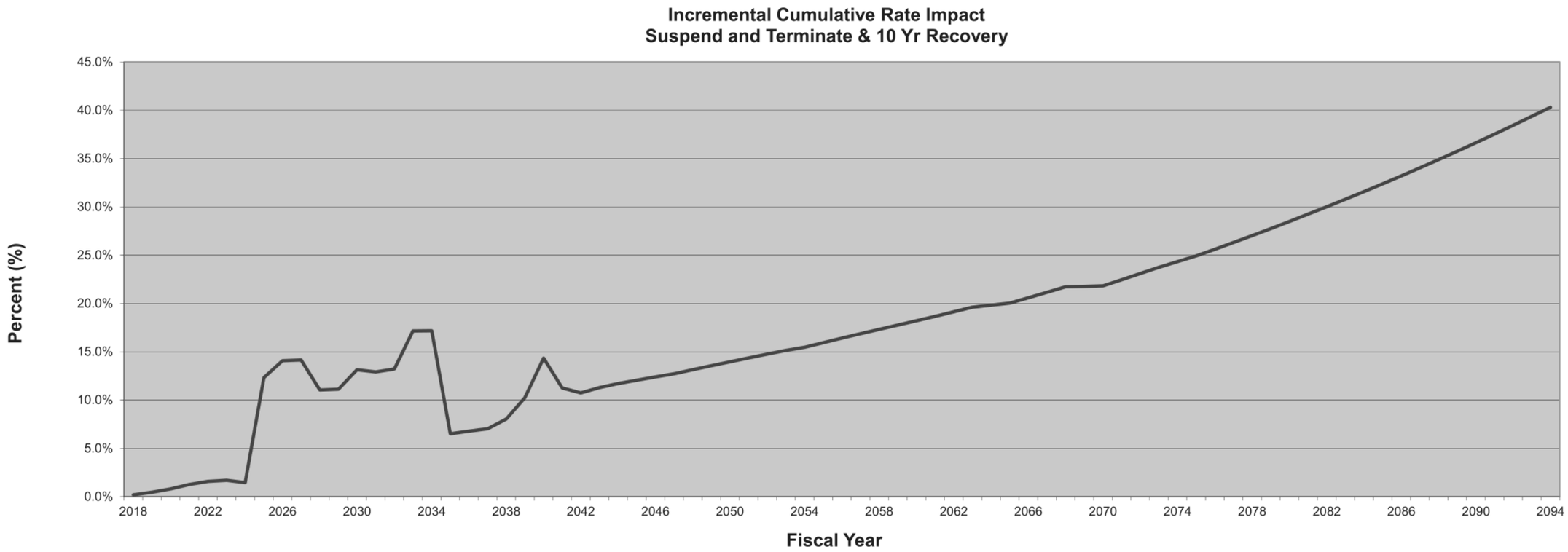
Input Data ($ million)

Line		Fiscal Year / Column	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																							
1	Site C Construction	2031 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Site C Regulatory Account	2031 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Year 25 Asset	2056 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 40 Asset	2071 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 45 Asset	2076 06	0.0	0.0	0.0	0.0	1,418.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 50 Asset	2081 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Year 25 (#2) Asset	2081 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Original Site C Construction	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Original Site C Regulatory Account	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Year 25 Asset	2049 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Year 40 Asset	2064 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Year 45 Asset	2069 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Year 50 Asset	2074 06	0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Year 25 (#2) Asset	2074 06	0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	(195.8)	0.0	1,418.2	0.0	0.0	0.0	0.0	224.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																								
19	Residential		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																								
25	Cost of Energy - Item #1	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Operating Costs																								
30	Operating Costs	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Water Rental Costs	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Grants-in-Lieu / Taxes	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Suspend and Terminate & 10 Yr Recovery.xlsx

Rate Impact Chart
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Rate Impact Analysis

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Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	298.5	298.5	298.5	298.5	298.5	298.5	298.5	298.5	298.5	298.5	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	7.0	10.1	12.6	15.7	18.7	(125.9)	(133.3)	(142.6)	(152.7)	(163.6)	(176.5)	(190.0)	(203.9)	(218.5)	(233.7)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	0.7	(1.0)	(9.0)	(25.5)	(60.5)	443.3	525.4	521.1	363.2	369.2	482.3	486.5	523.9	750.4	779.9	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,005	5,218	5,455	5,670	5,884	6,596	6,883	7,080	7,145	7,364	7,703	7,931	8,214	8,684	8,959	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	36.9	57.7	73.9	80.4	69.5	598.3	691.1	701.9	554.7	564.8	676.9	673.4	699.6	919.8	933.5	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	0.74%	1.12%	1.37%	1.44%	1.20%	9.98%	11.16%	11.00%	8.42%	8.31%	9.64%	9.28%	9.31%	11.85%	11.63%	4.32%	4.41%	4.49%	5.03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	110.2	113.5	116.7	119.8	122.7	136.0	140.2	142.8	142.2	144.9	149.6	152.1	155.2	162.0	164.9	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	10.2%	13.5%	16.7%	19.8%	22.7%	36.0%	40.2%	42.8%	42.2%	44.9%	49.6%	52.1%	55.2%	62.0%	64.9%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	0.8%	1.3%	1.6%	1.7%	1.4%	12.3%	14.1%	14.2%	11.0%	11.1%	13.2%	12.9%	13.2%	17.2%	17.2%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

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Rate Impact Analysis

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Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 / 26	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6.82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235.0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 10 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395.9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 10 Yr Recovery.xlsx

Input Data
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Input Data
($ million)

Line		Fiscal Year / Column			Total	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**		**Amort. Period (years)**																											
1	Site C Regulatory Account	2024	12	10	4,175.9	0.0	0.0	0.0	0.0	0.0	0.0	4,175.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024	12	70	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024	12	70	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049	06	25	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064	06	40	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069	06	45	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Year 50 Asset	2074	06	50	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074	06	25	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal				(6,279.9)	0.0	0.0	0.0	0.0	0.0	0.0	(4,159.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		15	906.3	69.6	78.4	94.6	110.2	114.8	119.1	128.0	140.9	133.0	42.4	99.0	8.2	(12.0)	(25.8)	(43.1)	(66.7)	(88.7)	(89.7)	(91.0)	(50.9)	(17.0)	(10.3)	(5.7)	(7.1)	12.3	38.6
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential				(13,324.6)	(72.3)	(98.9)	(132.6)	(163.2)	(188.4)	(211.1)	(226.6)	(238.5)	(207.1)	(216.8)	(218.0)	(222.1)	(228.7)	(252.4)	(289.7)	(330.0)	(374.2)	(476.3)	(560.6)	(619.7)	(660.7)	(691.5)	(713.2)	(723.9)	(728.7)	(733.1)
20	Light Industrial and Commercial				(11,421.1)	(42.1)	(73.8)	(127.9)	(200.8)	(261.5)	(325.6)	(394.6)	(467.0)	(498.5)	(552.2)	(595.3)	(602.8)	(558.9)	(499.5)	(468.5)	(441.0)	(402.9)	(402.2)	(388.4)	(363.4)	(335.2)	(331.1)	(355.2)	(370.8)	(367.5)	(355.8)
21	Large Industrial				(6,309.6)	(13.9)	(68.9)	(130.2)	(293.8)	(492.5)	(654.0)	(819.1)	(997.8)	(1,109.6)	(1,166.6)	(1,189.7)	(1,173.8)	(1,168.5)	(1,073.5)	(873.1)	(724.9)	(479.2)	(309.8)	(121.0)	99.7	172.2	232.0	353.2	526.1	644.7	722.1
22	Other				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total				(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $			105,472.5	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
26	Cost of Energy - Item #2	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
	Operating Costs																														
30	Operating Costs	nominal $			(1,479.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.4)	(10.1)	(10.3)	(10.5)	(10.7)	(10.9)	(11.1)	(11.4)	(11.6)	(11.8)	(12.1)	(12.3)	(12.6)	(12.8)	(13.1)	(13.3)	(13.6)	(13.9)	(14.1)
31	Water Rental Costs	nominal $			(6,032.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.3)	(26.7)	(42.2)	(43.0)	(43.9)	(44.8)	(45.6)	(46.6)	(47.5)	(48.4)	(49.4)	(50.4)	(51.4)	(52.4)	(53.5)	(54.6)	(55.6)	(56.8)	(57.9)
32	Grants-in-Lieu / Taxes	nominal $			(462.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	(3.2)	(3.2)	(3.3)	(3.3)	(3.4)	(3.5)	(3.6)	(3.6)	(3.7)	(3.8)	(3.8)	(3.9)	(4.0)	(4.1)	(4.2)	(4.2)	(4.3)	(4.4)
33	Other - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total				(7,974.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(61.5)	(62.7)	(64.0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
37	**Forecast Weighted Average Cost of Debt**	%				3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%				3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 10 Yr Recovery.xlsx

Input Data
Page 6

Input Data
($ million)

Line		Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
		Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																												
1	Site C Regulatory Account	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049 06	0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
7	Year 50 Asset	2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
18	**DSM additions**	nominal $	**56.8**	**41.5**	**42.3**	**36.4**	**13.8**	**11.7**	**9.7**	**6.9**	**3.9**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Increase (Decrease) in Energy Sales (GWh)																													
19	Residential		(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial		(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial		665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total		(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																													
25	Cost of Energy - Item #1	nominal $	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
	Operating Costs																													
30	Operating Costs	nominal $	(14.4)	(14.7)	(15.0)	(15.3)	(15.6)	(15.9)	(16.2)	(16.6)	(16.9)	(17.2)	(17.6)	(17.9)	(18.3)	(18.6)	(19.0)	(19.4)	(19.8)	(20.2)	(20.6)	(21.0)	(21.4)	(21.9)	(22.3)	(22.7)	(23.2)	(23.7)	(24.1)	(24.6)
31	Water Rental Costs	nominal $	(59.0)	(60.2)	(61.4)	(62.7)	(63.9)	(65.2)	(66.5)	(67.8)	(69.2)	(70.6)	(72.0)	(73.4)	(74.9)	(76.4)	(77.9)	(79.5)	(81.1)	(82.7)	(84.3)	(86.0)	(87.7)	(89.5)	(91.3)	(93.1)	(95.0)	(96.9)	(98.8)	(100.8)
32	Grants-in-Lieu / Taxes	nominal $	(4.5)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(5.3)	(5.4)	(5.5)	(5.6)	(5.7)	(5.8)	(5.9)	(6.1)	(6.2)	(6.3)	(6.4)	(6.6)	(6.7)	(6.8)	(7.0)	(7.1)	(7.2)	(7.4)	(7.5)	(7.7)
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)	(127.9)	(130.5)	(133.1)
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

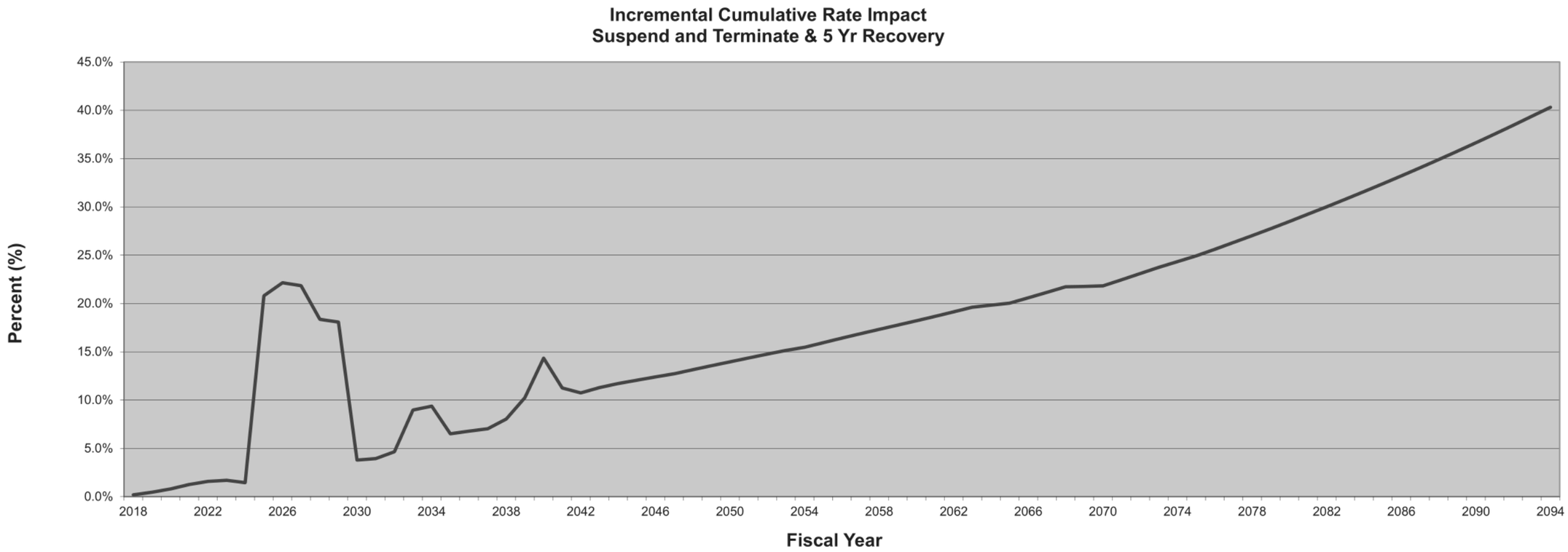
Input Data
($ million)

Line		Fiscal Year		2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082	2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094
		Column		55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																								
1	**Site C Regulatory Account**	**2024**	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024**	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024**	**12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049**	**06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064**	**06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069**	**06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074**	**06**	0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074**	**06**	0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			0.0	0.0	(195.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Increase (Decrease) in Energy Sales (GWh)																									
19	**Residential**			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
20	**Light Industrial and Commercial**			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
21	**Large Industrial**			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
22	**Other**			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																									
25	**Cost of Energy - Item #1**	nominal $		**1,888.1**	**1,925.9**	**1,964.4**	**2,003.7**	**2,043.8**	**2,084.6**	**2,126.3**	**2,168.9**	**2,212.2**	**2,256.5**	**2,301.6**	**2,347.6**	**2,394.6**	**2,442.5**	**2,491.3**	**2,541.2**	**2,592.0**	**2,643.8**	**2,696.7**	**2,750.6**	**2,805.6**	**2,861.8**	**2,919.0**
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
	Operating Costs																									
30	**Operating Costs**	nominal $		**(25.1)**	**(25.6)**	**(26.1)**	**(26.6)**	**(27.2)**	**(27.7)**	**(28.3)**	**(28.8)**	**(29.4)**	**(30.0)**	**(30.6)**	**(31.2)**	**(31.8)**	**(32.5)**	**(33.1)**	**(33.8)**	**(34.5)**	**(35.1)**	**(35.8)**	**(36.6)**	**(37.3)**	**(38.0)**	**(38.8)**
31	**Water Rental Costs**	nominal $		**(102.8)**	**(104.9)**	**(107.0)**	**(109.1)**	**(111.3)**	**(113.5)**	**(115.8)**	**(118.1)**	**(120.4)**	**(122.9)**	**(125.3)**	**(127.8)**	**(130.4)**	**(133.0)**	**(135.6)**	**(138.4)**	**(141.1)**	**(143.9)**	**(146.8)**	**(149.8)**	**(152.8)**	**(155.8)**	**(158.9)**
32	**Grants-in-Lieu / Taxes**	nominal $		**(7.8)**	**(8.0)**	**(8.2)**	**(8.3)**	**(8.5)**	**(8.7)**	**(8.8)**	**(9.0)**	**(9.2)**	**(9.4)**	**(9.6)**	**(9.8)**	**(9.9)**	**(10.1)**	**(10.3)**	**(10.6)**	**(10.8)**	**(11.0)**	**(11.2)**	**(11.4)**	**(11.7)**	**(11.9)**	**(12.1)**
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
37	**Forecast Weighted Average Cost of Debt**	%		3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Suspend and Terminate & 5 Yr Recovery.xlsx

Rate Impact Chart
Page1



BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 5 Yr Recovery.xlsx

Summary
Page 2

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	716.1	716.1	716.1	716.1	716.1	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	7.0	10.1	12.6	15.7	18.7	(133.1)	(154.8)	(178.4)	(202.9)	(228.1)	(241.0)	(240.1)	(239.8)	(240.0)	(240.9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	0.7	(1.0)	(9.0)	(25.5)	(60.5)	853.7	921.5	902.9	730.6	722.4	0.3	18.8	70.5	311.3	355.1	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,005	5,218	5,455	5,670	5,884	7,006	7,279	7,462	7,512	7,717	7,220	7,463	7,761	8,244	8,534	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	36.9	57.7	73.9	80.4	69.5	1,008.7	1,087.2	1,083.7	922.1	917.9	194.9	205.7	246.2	480.8	508.8	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	0.74%	1.12%	1.37%	1.44%	1.20%	16.82%	17.56%	16.99%	13.99%	13.50%	2.77%	2.83%	3.28%	6.19%	6.34%	4.32%	4.41%	4.49%	5.03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	110.2	113.5	116.7	119.8	122.7	144.4	148.2	150.5	149.6	151.9	140.3	143.2	146.7	153.8	157.1	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	10.2%	13.5%	16.7%	19.8%	22.7%	44.4%	48.2%	50.5%	49.6%	51.9%	40.3%	43.2%	46.7%	53.8%	57.1%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	0.8%	1.3%	1.6%	1.7%	1.4%	20.8%	22.1%	21.9%	18.4%	18.1%	3.8%	3.9%	4.7%	9.0%	9.4%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 5 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 26	2044 27	2045 28	2046 29	2047 30	2048 31	2049 32	2050 33	2051 34	2052 35	2053 36	2054 37	2055 38	2056 39	2057 40	2058 41	2059 42	2060 43	2061 44	2062 45	2063 46	2064 47	2065 48	2066 49	2067 50	2068 51
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6.82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235.0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 5 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395.9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

BC Hydro
Rate Impact Analysis

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Input Data
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Input Data
($ million)

Line		Fiscal Year / Column			Total	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**		**Amort. Period (years)**																											
1	**Site C Regulatory Account**	**2024**	**12**	**5**	4,175.9	0.0	0.0	0.0	0.0	0.0	0.0	**4,175.9**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024**	**12**	**70**	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(7,750.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024**	**12**	**70**	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(585.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049**	**06**	**25**	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064**	**06**	**40**	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069**	**06**	**45**	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074**	**06**	**50**	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074**	**06**	**25**	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal				(6,279.9)	0.0	0.0	0.0	0.0	0.0	0.0	(4,159.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		**15**	906.3	**69.6**	**78.4**	**94.6**	**110.2**	**114.8**	**119.1**	**128.0**	**140.9**	**133.0**	**42.4**	**99.0**	**8.2**	**(12.0)**	**(25.8)**	**(43.1)**	**(66.7)**	**(88.7)**	**(89.7)**	**(91.0)**	**(50.9)**	**(17.0)**	**(10.3)**	**(5.7)**	**(7.1)**	**12.3**	**38.6**
	Increase (Decrease) in Energy Sales (GWh)																														
19	**Residential**				(13,324.6)	**(72.3)**	**(98.9)**	**(132.6)**	**(163.2)**	**(188.4)**	**(211.1)**	**(226.6)**	**(238.5)**	**(207.1)**	**(216.8)**	**(218.0)**	**(222.1)**	**(228.7)**	**(252.4)**	**(289.7)**	**(330.0)**	**(374.2)**	**(476.3)**	**(560.6)**	**(619.7)**	**(660.7)**	**(691.5)**	**(713.2)**	**(723.9)**	**(728.7)**	**(733.1)**
20	**Light Industrial and Commercial**				(11,421.1)	**(42.1)**	**(73.8)**	**(127.9)**	**(200.8)**	**(261.5)**	**(325.6)**	**(394.6)**	**(467.0)**	**(498.5)**	**(552.2)**	**(595.3)**	**(602.8)**	**(558.9)**	**(499.5)**	**(468.5)**	**(441.0)**	**(402.9)**	**(402.2)**	**(388.4)**	**(363.4)**	**(335.2)**	**(331.1)**	**(355.2)**	**(370.8)**	**(367.5)**	**(355.8)**
21	**Large Industrial**				(6,309.6)	**(13.9)**	**(68.9)**	**(130.2)**	**(293.8)**	**(492.5)**	**(654.0)**	**(819.1)**	**(997.8)**	**(1,109.6)**	**(1,166.6)**	**(1,189.7)**	**(1,173.8)**	**(1,168.5)**	**(1,073.5)**	**(873.1)**	**(724.9)**	**(479.2)**	**(309.8)**	**(121.0)**	**99.7**	**172.2**	**232.0**	**353.2**	**526.1**	**644.7**	**722.1**
22	**Other**				0.0	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total				(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																														
25	**Cost of Energy - Item #1**	nominal $			105,472.5	**(5.3)**	**(10.0)**	**(16.2)**	**(27.3)**	**(45.1)**	**(72.4)**	**(118.3)**	**238.4**	**343.1**	**355.0**	**205.4**	**216.9**	**343.5**	**363.2**	**417.4**	**662.6**	**717.6**	**575.5**	**610.5**	**654.0**	**727.1**	**864.8**	**1,121.1**	**965.3**	**958.9**	**1,006.4**
26	Cost of Energy - Item #2	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
	Operating Costs																														
30	**Operating Costs**	nominal $			(1,479.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(5.4)**	**(10.1)**	**(10.3)**	**(10.5)**	**(10.7)**	**(10.9)**	**(11.1)**	**(11.4)**	**(11.6)**	**(11.8)**	**(12.1)**	**(12.3)**	**(12.6)**	**(12.8)**	**(13.1)**	**(13.3)**	**(13.6)**	**(13.9)**	**(14.1)**
31	**Water Rental Costs**	nominal $			(6,032.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(8.3)**	**(26.7)**	**(42.2)**	**(43.0)**	**(43.9)**	**(44.8)**	**(45.6)**	**(46.6)**	**(47.5)**	**(48.4)**	**(49.4)**	**(50.4)**	**(51.4)**	**(52.4)**	**(53.5)**	**(54.6)**	**(55.6)**	**(56.8)**	**(57.9)**
32	**Grants-in-Lieu / Taxes**	nominal $			(462.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(1.7)**	**(3.2)**	**(3.2)**	**(3.3)**	**(3.3)**	**(3.4)**	**(3.5)**	**(3.6)**	**(3.6)**	**(3.7)**	**(3.8)**	**(3.8)**	**(3.9)**	**(4.0)**	**(4.1)**	**(4.2)**	**(4.2)**	**(4.3)**	**(4.4)**
33	Other - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total				(7,974.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(61.5)	(62.7)	(64.0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
37	**Forecast Weighted Average Cost of Debt**	%				3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%				3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Input Data ($ million)

Line			Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
			Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC		In-Service Fiscal Year (YYYY/MM)																												
1	Site C Regulatory Account		2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction		2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account		2024 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset		2049 06	0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset		2064 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset		2069 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
7	Year 50 Asset		2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset		2074 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16		2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
18	**DSM additions**	nominal $		56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential			(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial			(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial			665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total			(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $		1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
	Operating Costs																														
30	Operating Costs	nominal $		(14.4)	(14.7)	(15.0)	(15.3)	(15.6)	(15.9)	(16.2)	(16.6)	(16.9)	(17.2)	(17.6)	(17.9)	(18.3)	(18.6)	(19.0)	(19.4)	(19.8)	(20.2)	(20.6)	(21.0)	(21.4)	(21.9)	(22.3)	(22.7)	(23.2)	(23.7)	(24.1)	(24.6)
31	Water Rental Costs	nominal $		(59.0)	(60.2)	(61.4)	(62.7)	(63.9)	(65.2)	(66.5)	(67.8)	(69.2)	(70.6)	(72.0)	(73.4)	(74.9)	(76.4)	(77.9)	(79.5)	(81.1)	(82.7)	(84.3)	(86.0)	(87.7)	(89.5)	(91.3)	(93.1)	(95.0)	(96.9)	(98.8)	(100.8)
32	Grants-in-Lieu / Taxes	nominal $		(4.5)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(5.3)	(5.4)	(5.5)	(5.6)	(5.7)	(5.8)	(5.9)	(6.1)	(6.2)	(6.3)	(6.4)	(6.6)	(6.7)	(6.8)	(7.0)	(7.1)	(7.2)	(7.4)	(7.5)	(7.7)
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)	(127.9)	(130.5)	(133.1)
37	**Forecast Weighted Average Cost of Debt**	%		3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

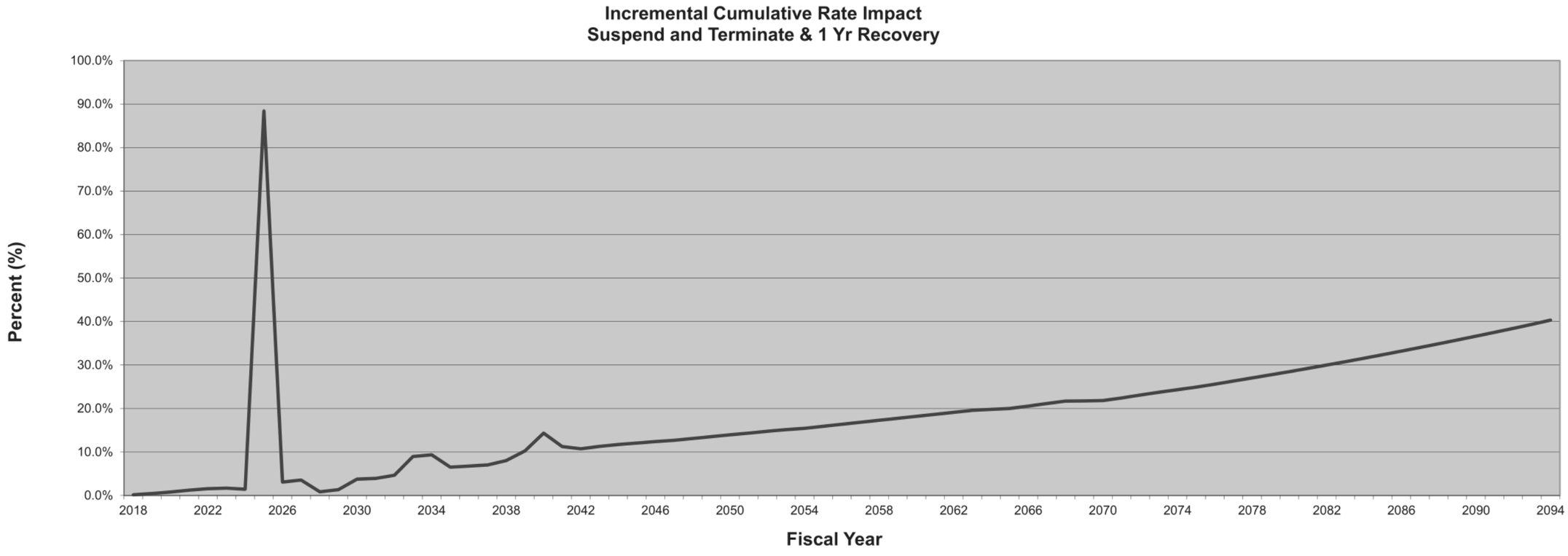
Input Data
($ million)

Line		Fiscal Year	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082	2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094
		Column	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																							
1	**Site C Regulatory Account**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024 12**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069 06**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074 06**	0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074 06**	0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		0.0	0.0	(195.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	Increase (Decrease) in Energy Sales (GWh)																								
19	**Residential**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
20	**Light Industrial and Commercial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
21	**Large Industrial**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
22	**Other**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																								
25	**Cost of Energy - Item #1**	nominal $	**1,888.1**	**1,925.9**	**1,964.4**	**2,003.7**	**2,043.8**	**2,084.6**	**2,126.3**	**2,168.9**	**2,212.2**	**2,256.5**	**2,301.6**	**2,347.6**	**2,394.6**	**2,442.5**	**2,491.3**	**2,541.2**	**2,592.0**	**2,643.8**	**2,696.7**	**2,750.6**	**2,805.6**	**2,861.8**	**2,919.0**
26	Cost of Energy - Item #2	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
	Operating Costs																								
30	**Operating Costs**	nominal $	**(25.1)**	**(25.6)**	**(26.1)**	**(26.6)**	**(27.2)**	**(27.7)**	**(28.3)**	**(28.8)**	**(29.4)**	**(30.0)**	**(30.6)**	**(31.2)**	**(31.8)**	**(32.5)**	**(33.1)**	**(33.8)**	**(34.5)**	**(35.1)**	**(35.8)**	**(36.6)**	**(37.3)**	**(38.0)**	**(38.8)**
31	**Water Rental Costs**	nominal $	**(102.8)**	**(104.9)**	**(107.0)**	**(109.1)**	**(111.3)**	**(113.5)**	**(115.8)**	**(118.1)**	**(120.4)**	**(122.9)**	**(125.3)**	**(127.8)**	**(130.4)**	**(133.0)**	**(135.6)**	**(138.4)**	**(141.1)**	**(143.9)**	**(146.8)**	**(149.8)**	**(152.8)**	**(155.8)**	**(158.9)**
32	**Grants-in-Lieu / Taxes**	nominal $	**(7.8)**	**(8.0)**	**(8.2)**	**(8.3)**	**(8.5)**	**(8.7)**	**(8.8)**	**(9.0)**	**(9.2)**	**(9.4)**	**(9.6)**	**(9.8)**	**(9.9)**	**(10.1)**	**(10.3)**	**(10.6)**	**(10.8)**	**(11.0)**	**(11.2)**	**(11.4)**	**(11.7)**	**(11.9)**	**(12.1)**
33	Other - Item #4	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
37	**Forecast Weighted Average Cost of Debt**	%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Suspend and Terminate & 1 Yr Recovery.xlsx

Rate Impact Chart
Page1



BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 1 Yr Recovery.xlsx

Summary
Page 2

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49.8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,056.8	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	7.0	10.1	12.6	15.7	18.7	(190.4)	(255.0)	(250.0)	(245.8)	(242.4)	(241.0)	(240.1)	(239.8)	(240.0)	(240.9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8.2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75.3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	0.7	(1.0)	(9.0)	(25.5)	(60.5)	4,137.1	(13.9)	(3.9)	(147.5)	(127.1)	0.3	18.8	70.5	311.3	355.1	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,005	5,218	5,455	5,670	5,884	10,290	6,343	6,555	6,634	6,868	7,220	7,463	7,761	8,244	8,534	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	36.9	57.7	73.9	80.4	69.5	4,292.1	151.8	176.9	44.0	68.5	194.9	205.7	246.2	480.8	508.8	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	0.74%	1.12%	1.37%	1.44%	1.20%	71.56%	2.45%	2.77%	0.67%	1.01%	2.77%	2.83%	3.28%	6.19%	6.34%	4.32%	4.41%	4.49%	5.03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133.8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	110.2	113.5	116.7	119.8	122.7	212.1	129.2	132.2	132.1	135.2	140.3	143.2	146.7	153.8	157.1	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	10.2%	13.5%	16.7%	19.8%	22.7%	112.1%	29.2%	32.2%	32.1%	35.2%	40.3%	43.2%	46.7%	53.8%	57.1%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.2%	0.5%	0.8%	1.3%	1.6%	1.7%	1.4%	88.5%	3.1%	3.6%	0.9%	1.3%	3.8%	3.9%	4.7%	9.0%	9.4%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 1 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 / 26	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963.5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6.82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219.5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235.0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 1 Yr Recovery.xlsx

Summary
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Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774.3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484.8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395.9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

BC Hydro
Rate Impact Analysis

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Input Data
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Input Data
($ million)

Line		Fiscal Year / Column			Total	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**		**Amort. Period (years)**																											
1	**Site C Regulatory Account**	**2024**	**12**	**1**	4,175.9	0.0	0.0	0.0	0.0	0.0	0.0	**4,175.9**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**Original Site C Construction**	**2024**	**12**	**70**	(7,750.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(7,750.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Original Site C Regulatory Account**	**2024**	**12**	**70**	(585.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(585.0)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Year 25 Asset**	**2049**	**06**	**25**	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Year 40 Asset**	**2064**	**06**	**40**	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Year 45 Asset**	**2069**	**06**	**45**	(1,234.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Year 50 Asset**	**2074**	**06**	**50**	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Year 25 (#2) Asset**	**2074**	**06**	**25**	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018	06	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal				(6,279.9)	0.0	0.0	0.0	0.0	0.0	0.0	(4,159.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		**15**	906.3	**69.6**	**78.4**	**94.6**	**110.2**	**114.8**	**119.1**	**128.0**	**140.9**	**133.0**	**42.4**	**99.0**	**8.2**	**(12.0)**	**(25.8)**	**(43.1)**	**(66.7)**	**(88.7)**	**(89.7)**	**(91.0)**	**(50.9)**	**(17.0)**	**(10.3)**	**(5.7)**	**(7.1)**	**12.3**	**38.6**
	Increase (Decrease) in Energy Sales (GWh)																														
19	**Residential**				(13,324.6)	**(72.3)**	**(98.9)**	**(132.6)**	**(163.2)**	**(188.4)**	**(211.1)**	**(226.6)**	**(238.5)**	**(207.1)**	**(216.8)**	**(218.0)**	**(222.1)**	**(228.7)**	**(252.4)**	**(289.7)**	**(330.0)**	**(374.2)**	**(476.3)**	**(560.6)**	**(619.7)**	**(660.7)**	**(691.5)**	**(713.2)**	**(723.9)**	**(728.7)**	**(733.1)**
20	**Light Industrial and Commercial**				(11,421.1)	**(42.1)**	**(73.8)**	**(127.9)**	**(200.8)**	**(261.5)**	**(325.6)**	**(394.6)**	**(467.0)**	**(498.5)**	**(552.2)**	**(595.3)**	**(602.8)**	**(558.9)**	**(499.5)**	**(468.5)**	**(441.0)**	**(402.9)**	**(402.2)**	**(388.4)**	**(363.4)**	**(335.2)**	**(331.1)**	**(355.2)**	**(370.8)**	**(367.5)**	**(355.8)**
21	**Large Industrial**				(6,309.6)	**(13.9)**	**(68.9)**	**(130.2)**	**(293.8)**	**(492.5)**	**(654.0)**	**(819.1)**	**(997.8)**	**(1,109.6)**	**(1,166.6)**	**(1,189.7)**	**(1,173.8)**	**(1,168.5)**	**(1,073.5)**	**(873.1)**	**(724.9)**	**(479.2)**	**(309.8)**	**(121.0)**	**99.7**	**172.2**	**232.0**	**353.2**	**526.1**	**644.7**	**722.1**
22	**Other**				0.0	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
23	Total				(31,055.3)	(128.4)	(241.6)	(390.7)	(657.7)	(942.3)	(1,190.7)	(1,440.4)	(1,703.3)	(1,815.2)	(1,935.5)	(2,003.1)	(1,998.8)	(1,956.2)	(1,825.4)	(1,631.3)	(1,495.9)	(1,256.3)	(1,188.3)	(1,070.1)	(883.3)	(823.7)	(790.5)	(715.2)	(568.6)	(451.5)	(366.8)
24	**Increase (Decrease) in Cost of Energy**																														
25	**Cost of Energy - Item #1**	nominal $			105,472.5	**(5.3)**	**(10.0)**	**(16.2)**	**(27.3)**	**(45.1)**	**(72.4)**	**(118.3)**	**238.4**	**343.1**	**355.0**	**205.4**	**216.9**	**343.5**	**363.2**	**417.4**	**662.6**	**717.6**	**575.5**	**610.5**	**654.0**	**727.1**	**864.8**	**1,121.1**	**965.3**	**958.9**	**1,006.4**
26	Cost of Energy - Item #2	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					0.0	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9	1,006.4
	Operating Costs																														
30	**Operating Costs**	nominal $			(1,479.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(5.4)**	**(10.1)**	**(10.3)**	**(10.5)**	**(10.7)**	**(10.9)**	**(11.1)**	**(11.4)**	**(11.6)**	**(11.8)**	**(12.1)**	**(12.3)**	**(12.6)**	**(12.8)**	**(13.1)**	**(13.3)**	**(13.6)**	**(13.9)**	**(14.1)**
31	**Water Rental Costs**	nominal $			(6,032.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(8.3)**	**(26.7)**	**(42.2)**	**(43.0)**	**(43.9)**	**(44.8)**	**(45.6)**	**(46.6)**	**(47.5)**	**(48.4)**	**(49.4)**	**(50.4)**	**(51.4)**	**(52.4)**	**(53.5)**	**(54.6)**	**(55.6)**	**(56.8)**	**(57.9)**
32	**Grants-in-Lieu / Taxes**	nominal $			(462.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**(1.7)**	**(3.2)**	**(3.2)**	**(3.3)**	**(3.3)**	**(3.4)**	**(3.5)**	**(3.6)**	**(3.6)**	**(3.7)**	**(3.8)**	**(3.8)**	**(3.9)**	**(4.0)**	**(4.1)**	**(4.2)**	**(4.2)**	**(4.3)**	**(4.4)**
33	Other - Item #4	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total				(7,974.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(15.4)	(39.9)	(55.7)	(56.8)	(57.9)	(59.1)	(60.3)	(61.5)	(62.7)	(64.0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
37	**Forecast Weighted Average Cost of Debt**	%				3.93%	3.83%	3.78%	3.66%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%				3.5%	3.0%	2.6%	2.6%	2.6%	2.6%	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%				2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Input Data ($ million)

Line			Fiscal Year	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071
			Column	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
	Capital Expenditures Including IDC	In-Service Fiscal Year (YYYY/MM)																													
1	Site C Regulatory Account	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049 06		0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
7	Year 50 Asset	2074 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			0.0	0.0	0.0	0.0	0.0	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(686.1)	0.0	0.0	0.0	0.0	(1,234.6)	0.0	0.0
18	**DSM additions**	nominal $		56.8	41.5	42.3	36.4	13.8	11.7	9.7	6.9	3.9	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																														
19	Residential			(741.2)	(627.2)	(529.5)	(455.1)	(390.9)	(329.5)	(267.4)	(202.6)	(135.2)	(67.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial			(350.1)	(278.5)	(234.6)	(202.7)	(175.0)	(139.9)	(105.7)	(76.5)	(50.3)	(25.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial			665.5	674.8	606.5	443.8	398.6	377.9	312.8	208.3	88.2	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total			(425.7)	(230.9)	(157.6)	(214.0)	(167.3)	(91.5)	(60.3)	(70.8)	(97.3)	(69.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																														
25	Cost of Energy - Item #1	nominal $		1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744.3	1,779.2	1,814.8	1,851.1
	Operating Costs																														
30	Operating Costs	nominal $		(14.4)	(14.7)	(15.0)	(15.3)	(15.6)	(15.9)	(16.2)	(16.6)	(16.9)	(17.2)	(17.6)	(17.9)	(18.3)	(18.6)	(19.0)	(19.4)	(19.8)	(20.2)	(20.6)	(21.0)	(21.4)	(21.9)	(22.3)	(22.7)	(23.2)	(23.7)	(24.1)	(24.6)
31	Water Rental Costs	nominal $		(59.0)	(60.2)	(61.4)	(62.7)	(63.9)	(65.2)	(66.5)	(67.8)	(69.2)	(70.6)	(72.0)	(73.4)	(74.9)	(76.4)	(77.9)	(79.5)	(81.1)	(82.7)	(84.3)	(86.0)	(87.7)	(89.5)	(91.3)	(93.1)	(95.0)	(96.9)	(98.8)	(100.8)
32	Grants-in-Lieu / Taxes	nominal $		(4.5)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(5.3)	(5.4)	(5.5)	(5.6)	(5.7)	(5.8)	(5.9)	(6.1)	(6.2)	(6.3)	(6.4)	(6.6)	(6.7)	(6.8)	(7.0)	(7.1)	(7.2)	(7.4)	(7.5)	(7.7)
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)	(127.9)	(130.5)	(133.1)
37	**Forecast Weighted Average Cost of Debt**	%		3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Suspend and Terminate & 1 Yr Recovery.xlsx

Input Data
Page 7

Input Data
($ million)

Line			Fiscal Year	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082	2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094
			Column	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77
	Capital Expenditures Including IDC	**In-Service Fiscal Year (YYYY/MM)**																								
1	Site C Regulatory Account	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Original Site C Construction	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Original Site C Regulatory Account	2024 12		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Year 25 Asset	2049 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Year 40 Asset	2064 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Year 45 Asset	2069 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Year 50 Asset	2074 06		0.0	0.0	(188.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Year 25 (#2) Asset	2074 06		0.0	0.0	(7.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Asset #9	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Asset #10	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Asset #11	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Asset #12	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Asset #13	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Asset #14	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Asset #15	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Asset #16	2018 06		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal			0.0	0.0	(195.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**DSM additions**	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Increase (Decrease) in Energy Sales (GWh)																									
19	Residential			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Light Industrial and Commercial			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Large Industrial			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Other			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Increase (Decrease) in Cost of Energy**																									
25	Cost of Energy - Item #1	nominal $		1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
26	Cost of Energy - Item #2	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Cost of Energy - Item #3	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Cost of Energy - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Cost of Energy - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212.2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919.0
	Operating Costs																									
30	Operating Costs	nominal $		(25.1)	(25.6)	(26.1)	(26.6)	(27.2)	(27.7)	(28.3)	(28.8)	(29.4)	(30.0)	(30.6)	(31.2)	(31.8)	(32.5)	(33.1)	(33.8)	(34.5)	(35.1)	(35.8)	(36.6)	(37.3)	(38.0)	(38.8)
31	Water Rental Costs	nominal $		(102.8)	(104.9)	(107.0)	(109.1)	(111.3)	(113.5)	(115.8)	(118.1)	(120.4)	(122.9)	(125.3)	(127.8)	(130.4)	(133.0)	(135.6)	(138.4)	(141.1)	(143.9)	(146.8)	(149.8)	(152.8)	(155.8)	(158.9)
32	Grants-in-Lieu / Taxes	nominal $		(7.8)	(8.0)	(8.2)	(8.3)	(8.5)	(8.7)	(8.8)	(9.0)	(9.2)	(9.4)	(9.6)	(9.8)	(9.9)	(10.1)	(10.3)	(10.6)	(10.8)	(11.0)	(11.2)	(11.4)	(11.7)	(11.9)	(12.1)
33	Other - Item #4	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Other - Item #5	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Other - Item #6	nominal $		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total			(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
37	**Forecast Weighted Average Cost of Debt**	%		3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%	3.43%
38	**Annual Forecast Rate Increases (nominal)**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
39	**Annual Inflation Rate**	%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

From:	Wieringa, Paul EMPR:EX
To:	Cutler, Scott EMPR:EX; Buchanan, Jack EMPR:EX; Dias, Oswald EMPR:EX
Subject:	FW: BC"S Energy, Climate and Investment Future
Date:	Monday, November 20, 2017 11:28:00 AM
Attachments:	image003.jpg ATT00001.htm 2017-Honorable John Horgan Site C and Prosperity.pdf ATT00002.htm

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fyi

From: MacLaren, Les EMPR:EX
Sent: Saturday, November 18, 2017 6:34 AM
To: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX
Subject: FW: BC'S Energy, Climate and Investment Future

Good letter. Interesting the e-mail addressees do not match the cc: s in the letter.

Les

From: Nikolejsin, Dave MNGD:EX
Sent: Friday, November 17, 2017 7:42 PM
To: Lloyd, Evan GCPE:EX; MacLaren, Les EMPR:EX; Sanderson, Melissa EMPR:EX; Haslam, David GCPE:EX
Subject: Fwd: BC'S Energy, Climate and Investment Future

Dave Nikolejsin
Deputy Minister
Energy, Mines and Petroleum Resources

Begin forwarded message:

> **From:** "Greg D'Avignon" <greg.davignon@bcbc.com>
> **Date:** November 17, 2017 at 10:37:25 AM PST
> **To:** "premier@gov.bc.ca" <premier@gov.bc.ca>
> **Cc:** "bobbi.plecas@gov.bc.ca" <bobbi.plecas@gov.bc.ca>, "Dave Nikolejsin (dave.nikolejsin@gov.bc.ca)" <dave.nikolejsin@gov.bc.ca>, "Don.J.Wright@gov.bc.ca" <Don.J.Wright@gov.bc.ca>, "ken.peterson@bchydro.com" <ken.peterson@bchydro.com>, "dm.env@gov.bc.ca" <dm.env@gov.bc.ca>, "andrew.weaver.mla@leg.bc.ca" <andrew.weaver.mla@leg.bc.ca>, "mem.minister@gov.bc.ca" <mem.minister@gov.bc.ca>
> **Subject: BC'S Energy, Climate and Investment Future**
>
> Dear Premier Horgan
> Please find the attached letter from the Business Council of BC, with respect to our position on Site C, and BC's Energy, Climate and Investment Future.
> Respectfully,
> Greg D'Avignon
> President & Chief Executive Officer
> Business Council of BC
> Direct: 604.696.6580

Business Council of British Columbia
Est. 1966

Suite 810
1050 West Pender Street
Vancouver BC V6E 3S7

Telephone: 604-684-3384
info@bcbc.com
www.bcbc.com

November 17, 2017

The Honorable John Horgan
Premier of British Columbia
Government of British Columbia
P.O. Box 9041, Stn. Prov. Govt.
Victoria, BC; V8W 9E1

Dear Premier Horgan:

Re: BC's Energy, Climate and Investment Future

The Business Council of BC and our 250 members spanning every part of the province's economy write today to communicate our views on the future of the Site C project.

British Columbia is at a crossroads in terms of the prosperity of our province. Our ability to deliver equality of opportunity for citizens and to address climate change in a manner that creates the conditions for competitiveness and investment are at risk. Addressing these challenges relates directly to your cabinet's pending decision on Site C. We recognize that this is a complex matter, not least because the previous government failed to undertake a proper independent review of the economic and business case for the project. Nonetheless, the decision now rests with you and your colleagues.

Having considered the evidence, including the BC Utilities Commission's (BCUC) recent report, our reputational risk and the anticipated significant electricity demand as we accelerate into the digital age and low carbon economy, we offer our support for completing the project, for several reasons – some of which are also referenced in a recent submission from the BC Building Trades unions.

First, in reviewing Site C, the BCUC was given a narrow mandate and a very short timeframe. While we recognize that the Commission worked under tight constraints, its report does not reflect a comprehensive examination of the trends shaping the outlook for electricity demand over the medium- and longer-term. Therefore, the BCUC's default to the low load forecast is suspect and inadequate given the reality of our need for energy in the coming decades, let alone the potential of the contribution that reliable firm power can make to a lower carbon future.

.../2

While actual demand growth has underperformed BC Hydro's projections over the last few years, there are reasons to anticipate stronger demand over the next two decades. Apart from a steadily rising provincial population, we anticipate significant growth in the digital economy, healthcare, film production, e-commerce, gaming, mixed reality technologies, financial services, fintech, tourism, the Gateway transportation sector, and segments of advanced manufacturing. Additional demand will arise through shifting regulatory realities touching everything from marijuana legalization (requiring electricity, substations and transmission for cultivation) to increased use of electric vehicles, server farms and carbon sequestration facilities. In addition, electrification transitions are either under way or possible in areas like port terminal operations, mining and metals production[1], value added forest manufacturing, and industrial robotics. Then too, in the medium-term there may be opportunities to sell BC renewable power to Alberta as that province moves away from coal.

Also worth noting in this regard is the City of Vancouver's Renewable City Strategy, part of its Sustainable City plan, which targets 100% renewable energy consumption in Vancouver before 2050. The City's plans, analysed in their October 2017 report,[i] call for 50-75% growth in electricity use within a jurisdiction that accounts for 14% of the provincial population. It is conceivable that more BC municipalities will follow an energy path similar to Vancouver's in the years ahead.

In total, none of these sources of future electricity demand is considered in detail in BCUC's analysis.

As an added point, we would note that cancellation of Site C will stop any future investment and climate gains from upstream electrification in the natural gas and oil sector, while also complicating the situation for other BC industries looking to transition to lower carbon sources of energy. This includes LNG projects that may be developed in British Columbia. Our understanding is that one large LNG project would require all of the power from Site C to support two trains of electrified compression at the facility. As another example, Encana earlier this summer operationalized the electrification of new gas plants in the northeast that draw 200 MWH of firm power. The switch from gas fired operations reduced greenhouse gas emissions by ~ 900,000 tonnes of carbon dioxide equivalent (CO_2e) on an annual basis -- the equivalent of taking 191,000 cars off the road.[ii] Within the upstream industry, there is further scope to dampen emissions via electrification. These kinds of transition projects in BC – along with future electricity demand that may stem from Alberta's shift away from coal-fired power – are overlooked in BCUC's low load forecast.

.../3

[1] We note that the Commission assumes aggressive measures by metal mining operators to reduce energy demand at peak times; we believe this assumption to be dubious.

Second, the BCUC review suggests that the power to be produced by Site C can be replaced with a portfolio of additional renewable projects that are not in existence, and which would be challenging to develop in a timely manner given the delays experienced in advancing all types of energy, industrial and infrastructure projects in BC (and Canada).

Third, the BCUC report does not consider how cancelling Site C mid-way through the construction work would impact BC's and Canada's already eroding reputation as a place to invest. Outside of the real estate sector and the advanced technology industry, BC today is viewed, globally, as an increasingly uncertain, complex and costly place to invest compared to many other jurisdictions, including the United States but also – in some industry sectors – Australia and some emerging economies. The weakness of capital spending and the paucity of greenfield investment in manufacturing and some key natural resource industries are signs of the province's diminished competitiveness. Terminating Site C is likely to compound the problem.

Lastly, the BCUC review was undertaken absent the province having adopted a new energy policy framework that the Business Council believes is urgently needed. An updated and retooled provincial energy strategy is required given the opportunities available in BC to stimulate low-carbon economic growth, advance reconciliation with Indigenous peoples, and remain in the forefront of efforts to tackle climate change. We believe BC can be a leader in supplying relatively low-carbon goods and services, including energy, to the world. A revamped provincial energy policy framework can create conditions that allow this to happen and attract new investments by companies and entrepreneurs in sectors like light tight oil and condensate, LNG, hydro, and wind as well as digital technologies, clean technology, and manufacturing.

We stand ready to work with your Ministers and senior officials in developing a renewed energy strategy for the province.

In summary, our conclusion is that BCUC's Site C review falls short of the mark in some important respects. It ignores the difficulties of developing other sources of power if Site C is terminated. It underestimates the future growth in electricity demand in a global context, where electricity is destined to play a larger role in the overall energy system. Further, the BCUC review overlooks opportunities to export BC-produced renewable energy to other provinces committed to reducing their own carbon emissions.

.../4

Finally, unlike the Commission, cabinet must consider the consequences of its decision in terms of the province's reputation in capital markets and in the eyes of investors and corporate managers. Despite our size, bounty of resources, diverse pools of talent and demonstrated innovative capacity, we are at risk of squandering our riches and advantages while competitors benefit from our inaction and confused policies. The climate, reconciliation with Indigenous peoples and middle class incomes and jobs will all suffer unnecessarily if we abandon thoughtful policy approaches, innovation and foundational investment decisions.

Our prosperity will be greater and the global environment healthier if BC and Canada work together to pursue cogent and integrated climate and energy policies that leverage our strengths and keep us in the vanguard of innovation and efficient regulation.

Respectfully submitted,

Greg D'Avignon
President and CEO

Copies to:
Right Honorable Justin Trudeau; Prime Minister of Canada
Honorable James Carr; Minister, Natural Resources Canada
Honorable Catherine McKenna; Minister, Environment and Climate Change Canada
Honorable Michelle Mungall; Minister, Energy, Mines and Petroleum Resources
Honorable George Heyman; Minister, Environment & Climate Change Strategy
Honorable Dr. Andrew Weaver; Leader, Green Party of British Columbia
Mr. Don Wright; Deputy Minister to the Premier
Mr. Dave Nikolejsin; Deputy Minister; Ministry of Energy, Mines and Petroleum Resources
Ms. Bobbi Plecas; Deputy Minister, Climate Change, Ministry of Environment & Climate Change Strategy
Dr. Mark Zacharias, Deputy Minister, Environment, Ministry of Environment & Climate Change Strategy
Mr. Ken Peterson; Executive Chairman of the Board, B.C. Hydro and Power Authority

---

[i] City of Vancouver Energy and Emissions Forecast Oct 10, 2017
[ii] "Greenhouse gas emissions from a typical passenger vehicle" EPA-420-F-14-040a May 2014

From:	Wieringa, Paul EMPR:EX
To:	Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX; Buchanan, Jack EMPR:EX
Subject:	FW: CAS Request - Response to Hendriks GHG report
Date:	Friday, November 10, 2017 8:23:00 AM
Attachments:	CAS Request - Response to Hendriks GHG report v2.docx 7997 1-site-c-comparative-ghg-analysis-report-final2.pdf

---

From: Bell, Warren [mailto:Warren.Bell@bchydro.com]
Sent: Friday, November 10, 2017 7:02 AM
To: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Cc: Lesiuk, Tim ENV:EX; Magre, Leela; Savidant, Michael
Subject: FW: CAS Request - Response to Hendriks GHG report

Les and Paul,

Attached is our response, requested by Tim, to a report titled "Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives", released by the UBC Program on Water Governance in July 2016. The original report is also attached.

Warren

From: Bell, Warren
Sent: 2017, November 09 8:12 PM
To: 'Lesiuk, Tim ENV:EX'
Cc: Savidant, Michael; Jackson, Siobhan; Reimann, Randy; Bridget Gilbride (bgilbride@fasken.com) (bgilbride@fasken.com)
Subject: FW: CAS Request - Response to Hendriks GHG report

Hi Tim,

Attached is BC Hydro's response to Hendrik's GHG report.

Warren

This email and its attachments are intended solely for the personal use of the individual or entity named above. Any use of this communication by an unintended recipient is strictly prohibited. If you have received this email in error, any publication, use, reproduction, disclosure or dissemination of its contents is strictly prohibited. Please immediately delete this message and its attachments from your computer and servers. We would also appreciate if you would contact us by a collect call or return email to notify us of this error. Thank you for your cooperation.

Page 194 to/à Page 226

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From:	Wieringa, Paul EMPR:EX
To:	Les.MacLaren@gov.bc.ca
Cc:	Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	FW: Offer of Support
Date:	Thursday, November 9, 2017 4:31:00 PM

Les: we like to farm out some of the work on GHG emissions. (Karthik has been in touch with Jack.) On GHG emissions, we think that CAS could provide information on the emissions from Site C, and on the alternative portfolio. Bakker, Hendriks and Rafael made a submission to the BCUC suggesting that emissions (on a 20 year lifecycle) from Site C are much higher than the alternative portfolio. Having some research on this would be helpful.
Secondly, it would be helpful if CAS could also give us an indication of how electrification fits in with meeting the province's GHG targets.

From: Rowe, Katherine EMPR:EX
Sent: Thursday, November 9, 2017 11:32 AM
To: Sopinka, Amy EMPR:EX
Cc: Wieringa, Paul EMPR:EX
Subject: FW: Offer of Support
Something else we can touch on this afternoon?

From: MacLaren, Les EMPR:EX
Sent: Thursday, November 9, 2017 10:59 AM
To: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: FW: Offer of Support
Any pieces we would want to farm out?
Les

From: Plecas, Bobbi ENV:EX
Sent: Thursday, November 9, 2017 10:56 AM
To: MacLaren, Les EMPR:EX
Cc: Laaksonen-Craig, Susanna ENV:EX; Nikolejsin, Dave MNGD:EX
Subject: Offer of Support
Les
I am aware of the amount of Site C work you have on your plate. If there is any work our CAS folks can do to support you, please don't hesitate to let us know.
Bobbi

From:	Wieringa, Paul EMPR:EX
To:	Cutler, Scott EMPR:EX; Buchanan, Jack EMPR:EX; Dias, Oswald EMPR:EX; Davison, Jennifer EMPR:EX; Craig, Shannon MEM:EX
Cc:	Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	FW: Site C Final Report
Date:	Tuesday, October 31, 2017 3:30:00 PM
Attachments:	Site C Executive Summary.pdf Site C Final Report_Nov 1 2017.pdf
Sensitivity:	Confidential

Happy reading. Do not distribute.

From: Haslam, David GCPE:EX
Sent: Tuesday, October 31, 2017 2:59 PM
To: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX; Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Cc: Howlett, Tim GCPE:EX; Zadravec, Don GCPE:EX; Beaupre, Darren GCPE:EX; Grewar, Colin GCPE:EX; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX
Subject: FW: Site C Final Report
Sensitivity: Confidential

Report and executive summary attached. Bottom – It Depends. Nothing definitive.

From: Hamilton, Erica BCUC:EX
Sent: Tuesday, October 31, 2017 1:58 PM
To: Haslam, David GCPE:EX
Subject: Site C Final Report
Sensitivity: Confidential

Hi David,

As promised, here is a pre-release of the final Site C Report and executive summary. Both documents will be published tomorrow at 10am.

Best regards,

Erica Hamilton

Director, Communications

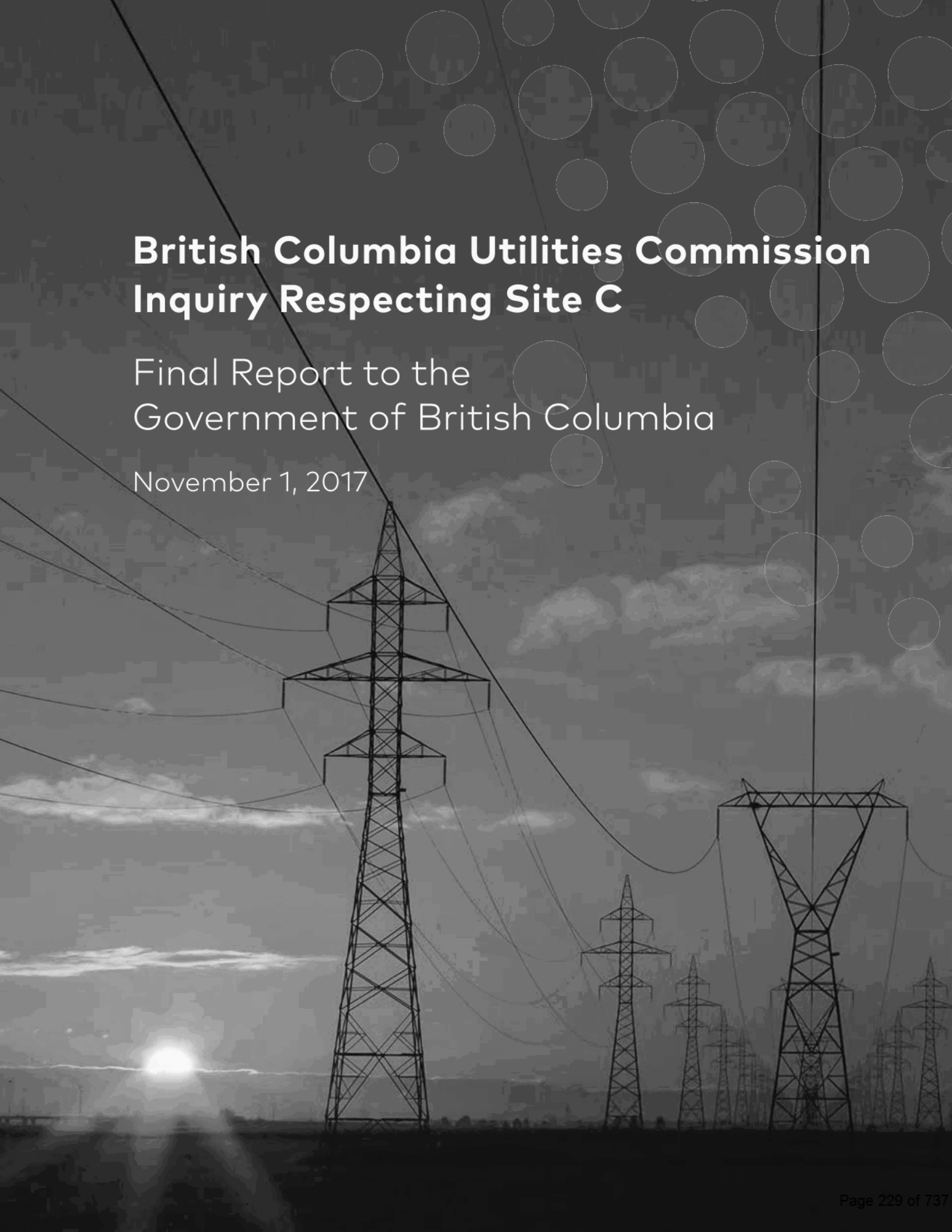
British Columbia Utilities Commission

P: 604.660.4727 **C:** 604.314.6203

BC Toll Free: 1 800.663.1385 **F:** 604.660.1102

bcuc.com

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British Columbia Utilities Commission Inquiry Respecting Site C

Final Report to the Government of British Columbia

November 1, 2017

Page 230 to/à Page 525

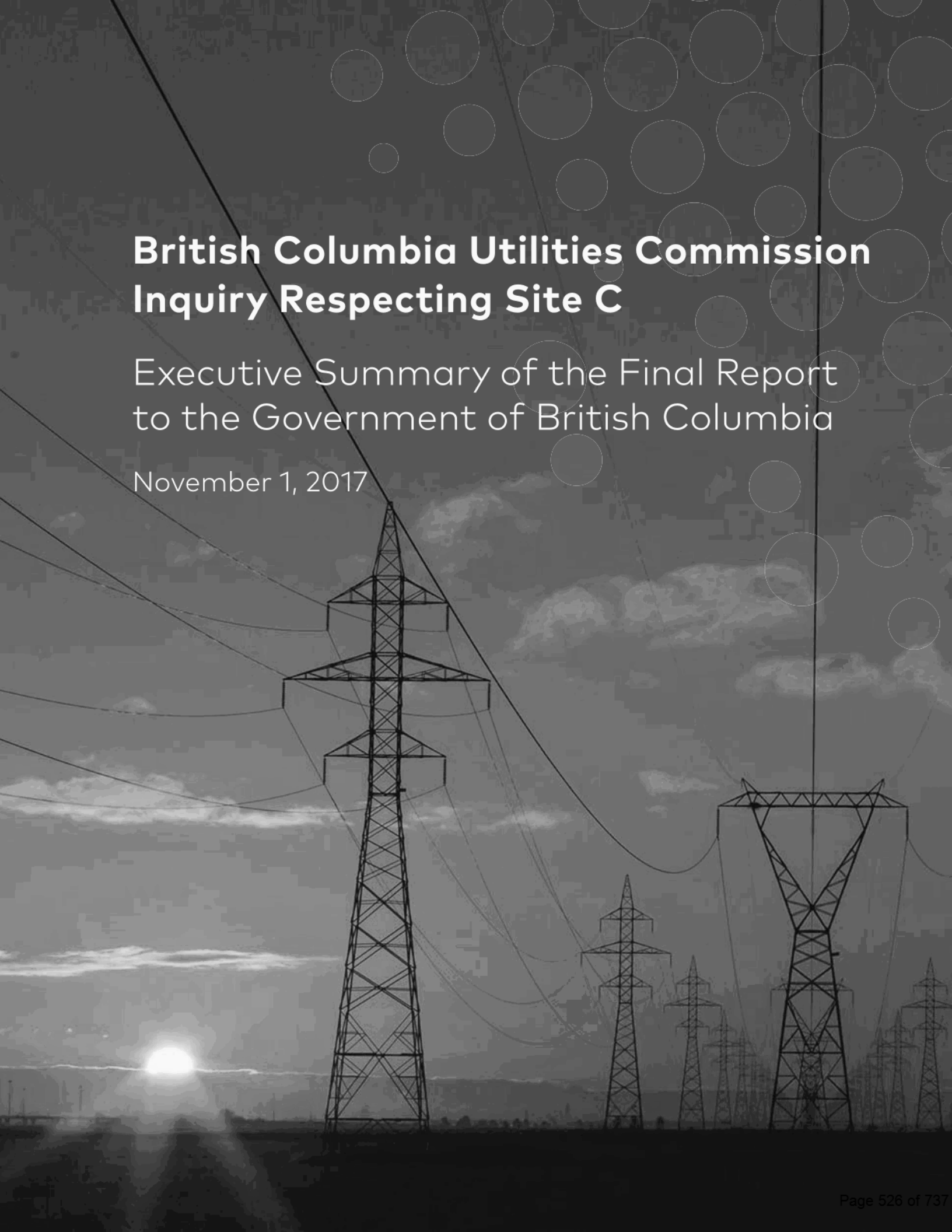
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British Columbia Utilities Commission Inquiry Respecting Site C

Executive Summary of the Final Report to the Government of British Columbia

November 1, 2017



Page 527 to/à Page 544

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From:	Wieringa, Paul EMPR:EX
To:	Muncaster, Katherine EMPR:EX; Buchanan, Jack EMPR:EX
Subject:	Fwd: Bch letter
Date:	Thursday, November 16, 2017 6:39:23 AM
Attachments:	FILE_1922.docx ATT00001.htm

See reference to DSM

Sent from my iPhone

Begin forwarded message:

> **From:** "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>
> **Date:** November 15, 2017 at 6:25:55 PM PST
> **To:** "Wieringa, Paul EMPR:EX" <Paul.Wieringa@gov.bc.ca>, "Rowe, Katherine EMPR:EX" <Katherine.Rowe@gov.bc.ca>, "Sopinka, Amy EMPR:EX" <Amy.Sopinka@gov.bc.ca>
> **Subject: Fwd: Bch letter**
>
> Latest version of BC Hydro's computation letter. It refers to running BCUC assumptions through BC Hydro models coming separately. Mike S indicates that work should be completed tomorrow and is expected to show a ~$1B difference.
>
> Les
>
> Begin forwarded message:
>
> > **From:** "Haslam, David GCPE:EX" <David.Haslam@gov.bc.ca>
> > **Date:** November 15, 2017 at 5:47:03 PM PST
> > **To:** "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>
> > **Subject: Bch letter**

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

November 10, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

s.13

s.13

s.13

s.13

s.13

s.13

s.13

Yours sincerely,

Fred James
Chief Regulatory Officer

fj/ma

From:	Wieringa, Paul EMPR:EX
To:	Dias, Oswald EMPR:EX
Subject:	Job numbers
Date:	Wednesday, October 18, 2017 10:00:00 AM
Attachments:	image001.png

https://energeticcity.ca/2017/10/site-c-sees-local-hiring-boom-august-total-job-numbers-fall/

Paul Wieringa
Executive Director
Energy Policy and Regulations
Ministry of Energy, Mines and Petroleum Resources
Telephone: 250-952-0651
Facsimile: 250-952-0258

Energizing BC—clean, sustainable and productive

cid:image003.png@01D1E405.FEB4DB90



From: Wieringa, Paul EMPR:EX
To: Les.MacLaren@gov.bc.ca
Cc: Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject: s.12,s.13
Date: Thursday, October 26, 2017 1:44:37 PM
Attachments: s.12,s.13

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s.12,s.13

Page 555 to/à Page 562

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	Cutler, Scott EMPR:EX; MacLaren, Les EMPR:EX
Cc:	Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	s.12,s.13
Date:	Thursday, October 26, 2017 10:20:00 AM
Attachments:	s.12,s.13

s.12,s.13

Page 564 to/à Page 578

Withheld pursuant to/removed as

s.12;s.13

DRAFT

Via E-mail

David Morton
Chair
BC Utilities Commission

Re: Inquiry Respecting Site C

We would like to thank the BC Utilities Commission (Commission) for the report on the Inquiry Respecting Site C that you delivered to the Minister of Energy, Mines and Petroleum Resources on November 1, 2017. Completing the report in a short time frame with such high levels of public and First Nations input and transparency is a significant achievement.

Our Ministries are supporting government's decision making on the future of Site C, which will consider the Commission's report along with other implications associated with proceeding or terminating the Project. In considering the Commission's report, w~~W~~e want to be sure that we fully understand the Commission's assumptions and computations in its analysis of Site C and the Commission's Illustrative Alternative Portfolio.

We note that the Commission has stated in the report that the "alternative portfolio developed by Commission staff are not a substitute for BC Hydro's planning processes." We understand that BC Hydro modelled over 60 scenarios testing various assumptions, including a number of alternatives requested by the Commission, but that the Alternative Portfolio in the final report was not analyzed using BC Hydro's modelling tools. We have therefore asked BC Hydro to provide an assessment of the Commission's final Alternative Portfolio and would like the Commission's response to a number of matters that BC Hydro has identified in its initial analysis.

Our understanding is that t~~T~~he Alternative Portfolio is modelled using a nominal dollar market price, with discounting at a nominal dollar discount rate. Site C is modelled using a 2018 real dollar market price, with discounting at a nominal dollar discount rate. Please confirm that t~~T~~he discount rate should be consistent with the dollar basis of prices. Please also confirm that t~~T~~he effect of using a nominal dollar market price and discount rate results ~~this~~ in the Commission staff model ~~is to~~ undervalueing the Site C surplus on a present value basis. BC Hydro's modelling shows for the Low Load Case used in Table 40 that the impact is a $336 million higher net present value (NPV) cost for Site C. Please advice how this $336 million should be applied in the evaluation of Site C versus the Alternative Portfolio.

It appears that the Commission staff model has inconsistent application of inflation factors and discount rates. Inflation is applied to costs assuming they occur at the start of a fiscal year. Discounting is applied to costs assuming they occur at the end of a fiscal year. Inflation and discounting should be applied to the same period. BC Hydro's modelling shows that for the Low Load Case in Table 39, the NPV for Alternative Portfolio should be $51 million higher. Please confirm that $51 million should be added to the Alternative Portfolio for the correct application of inflation factors and discount rates.

BC Hydro has confirmed that loss savings they provided to Commission staff associated with demand-side management (DSM) include adjustments to reflect transmission and distribution loss savings. It appears that the Commission staff model has double-counted the transmission loss savings component. Removal of this double counting would advance the need for new resources and increase the cost of the Alternative Portfolio. BC Hydro's modelling suggests that the impact of this correction would be an increase in the NPV cost of the Alternative Portfolio by $201 million. Please confirm whether the transmission loss savings component has been double-counted and whether $201 million should be added to the cost of the Alternative Portfolio.

Our staff have also discussed with BC Hydro the impact of certain assumptions, and how the costs of those assumptions would be recovered from ratepayers.

BC Hydro has suggested that recovery in rates of sunk costs in a Termination scenario should be over a 10-year period. In the Continue scenario, the sunk costs, as part of the overall project, would be recovered over the 70-year amortization period. The Commission staff model does not include sunk costs in the tTermination scenario, and removed it from the Ceontinue Site C scenario. Effectively this assumes that sunk costs will be recovered in rates over 70 years if the Project is terminated. Recovering costs in rates over a shorter period has a material impact on the Alternative Portfolio. Please provide an estimation of the rate impact using these two time-frames. We are also interested in how the Commission reconciles its 30-year amortization of termination costs, and this modelling result of sunk cost amortization over 70 years, with the rate setting principle of intergenerational equity.

We understand that there was significant discussion during the Commission's process on the cost of capital. The Alternative Portfolio assumes that BC Hydro finances all new resources on its balance sheet. Other than redevelopment of existing sites and Site C, BC Hydro has for almost three decades has been primarily procuring new supply from competitive processes or bilateral agreements benchmarked to competitive processes. How does the Commission assess the impact on ratepayers of the additional debt associated with the assumptions underlying the Alternative Portfolio? Further, we are having difficulty understanding when the Commission used BC Hydro's cost of capital for IPP projects and when the Commission used the cost of capital faced by an IPP (what they actually pay) and the resultant rate impact. For example, we note on page 159-160 that the Commission takes the position that IPP financing is the relevant assumption for the Alternative Portfolio, and the BC Hydro financing assumption should only be used for the UEC analysis. On pages 167, 170 and Appendix C (Assumption 2), it is clear the Commission used BC Hydro financing, e.g., 100% debt financing at a cost of 3.43% for the Alternative Portfolio. Please clarify which cost of capital should be used in analysing rate impacts.

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BC Hydro has informed us that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate DSM in comparison to other resources. The Commission staff model uses the Utility Resource Cost (URC) standard. Using the URC underestimates the actual cost of DSM to ratepayers. BC Hydro estimates that using the TRC consistent with previous Commission decisions would increase the cost of DSM in the

DRAFT

Alternative Portfolio by $444 million on an NPV basis. Please confirm that the TRC test is the appropriate metric.

Finally, in concluding that BC Hydro's Low Load Forecast is most appropriate for the Commission's assessment of Site C, please confirm that the Commission's assessment does not include additional load requirements to meet the energy objectives of reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels, encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia and encourage communities to reduce greenhouse gas emissions and use energy efficiently. Please identify the impact of ~~associated with~~ electrification initiatives to meet these objectives. For example, t~~T~~he government in its September Budget Update noted that increases in the Carbon Tax would be used to fund energy retrofits consistent with the government's PowerBC Plan. This would be aligned with increased levels of DSM spending in the Commission's Alternative Portfolio. The government also is working with the Federal government on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the Greenhouse Gas Reduction (Clean Energy) Regulation under the *Clean Energy Act*.

The government has stated that it plans to make a decision on Site C by the end of the year. The Commission's timely response to the matters identified above will help our Ministries provide the advice necessary to support government's decision-making.

Dave Nikolejsin Deputy Minister Ministry of Energy, Mines and Petroleum Resources	Lori Wanamaker Deputy Minister Ministry of Finance

DRAFT

From:	Wieringa, Paul EMPR:EX
To:	Rowe, Katherine EMPR:EX
Subject:	s.12,s.13
Date:	Thursday, October 26, 2017 12:38:00 PM
Attachments:	s.12,s.13

s.12,s.13

From: Rowe, Katherine EMPR:EX
Sent: Thursday, October 26, 2017 10:42 AM
To: Wieringa, Paul EMPR:EX
Subject: s.12,s.13
Importance: High

Hi Paul – s.12,s.13

Thanks!

Page 583 to/à Page 598

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	Dias, Oswald EMPR:EX
Subject:	RE: Job numbers
Date:	Wednesday, October 18, 2017 10:02:00 AM
Attachments:	image001.png

It looks like the table came from BC Hydro. Perhaps you can track it down.

From: Dias, Oswald EMPR:EX
Sent: Wednesday, October 18, 2017 10:00 AM
To: Wieringa, Paul EMPR:EX
Subject: RE: Job numbers

Thank you.

From: Wieringa, Paul EMPR:EX
Sent: Wednesday, October 18, 2017 10:00 AM
To: Dias, Oswald EMPR:EX
Subject: Job numbers

https://energeticcity.ca/2017/10/site-c-sees-local-hiring-boom-august-total-job-numbers-fall/

Paul Wieringa

Executive Director

Energy Policy and Regulations

Ministry of Energy, Mines and Petroleum Resources

Telephone: 250-952-0651

Facsimile: 250-952-0258

Energizing BC—clean, sustainable and productive

cid:image003.png@01D1E405.FEB4DB90



From:	Wieringa, Paul EMPR:EX
To:	Haslam, David GCPE:EX; MacLaren, Les EMPR:EX; Rowe, Katherine EMPR:EX
Cc:	Beaupre, Darren GCPE:EX; Grewar, Colin GCPE:EX
Subject:	RE: Justine
Date:	Thursday, October 26, 2017 3:53:00 PM

Les: my suggested response below.

From: Haslam, David GCPE:EX
Sent: Thursday, October 26, 2017 3:18 PM
To: MacLaren, Les EMPR:EX; Rowe, Katherine EMPR:EX; Wieringa, Paul EMPR:EX
Cc: Beaupre, Darren GCPE:EX; Grewar, Colin GCPE:EX
Subject: Justine

All – Globe and Mail reporter Justine Hunter call us. She wants to interview MMM on Site C Review. She had a few specific questions on BCH financial modeling and procurement. MMM will likely do the interview – as a first step to engage the gallery on the upcoming release of the report and next steps. But I told Justine MMM will not speak to specific info in the review at this time. That said I told her it's probably best to go to the BCUC but I would scope it out. Below are her questions:

She's been reading comments on the BCUC website and it's her understanding BCH did not provide financial modelling impacts to the BCUC on the Site C options: continue/postpone/cancel. I said that's unlikely. The process is BCH provides information and people/organizations comment on the info. That doesn't mean their comments are accurate. Is this a valid statement.

Yes. BC Hydro made its original submission on the impacts of continuing/postpone/cancel; Deloitte did similar calculations; BC Hydro has commented on Deloitte's report; BC Hydro has submitted additional information in response to Information Requests; other parties have made submissions and BC Hydro has commented on some of those (at the request of the BCUC); and BC Hydro commented and supplied information on an Alternative Portfolio to Site C.

On procurement she asked if the Minister is aware of the upcoming procurement costs if the project comes forward and will they be factored in cabinet's decision. I said I can't speak to the procurement costs specifically because we can't compromise the process (and neither will the minister). But I would check. I think the answer is all information including upcoming contract costs will be factored into the decision. Please confirm.

The BCUC Chair has conveyed his dismay on the sensitivity of redacted information. BC Hydro will continue to ensure that contracts are awarded prudently.

From:	Wieringa, Paul EMPR:EX
To:	Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX
Subject:	RE: Offer of Support
Date:	Thursday, November 9, 2017 11:37:00 AM

Perhaps they can help out on GHG issues.

From: Rowe, Katherine EMPR:EX
Sent: Thursday, November 9, 2017 11:32 AM
To: Sopinka, Amy EMPR:EX
Cc: Wieringa, Paul EMPR:EX
Subject: FW: Offer of Support

Something else we can touch on this afternoon?

From: MacLaren, Les EMPR:EX
Sent: Thursday, November 9, 2017 10:59 AM
To: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: FW: Offer of Support

Any pieces we would want to farm out?

Les

From: Plecas, Bobbi ENV:EX
Sent: Thursday, November 9, 2017 10:56 AM
To: MacLaren, Les EMPR:EX
Cc: Laaksonen-Craig, Susanna ENV:EX; Nikolejsin, Dave MNGD:EX
Subject: Offer of Support

Les

I am aware of the amount of Site C work you have on your plate. If there is any work our CAS folks can do to support you, please don't hesitate to let us know.

Bobbi

From:	Wieringa, Paul EMPR:EX
To:	Dias, Oswald EMPR:EX
Cc:	Rowe, Katherine EMPR:EX
Subject:	RE: Outline of Site C Env/Ag concerns presentation
Date:	Saturday, October 21, 2017 8:58:00 AM

s.13

From: Dias, Oswald EMPR:EX
Sent: Friday, October 20, 2017 4:06 PM
To: Wieringa, Paul EMPR:EX
Subject: Outline of Site C Env/Ag concerns presentation

Hi Paul,

Do you have any suggestions regarding the proposed outline?

Much appreciated!

Os

From:	Wieringa, Paul EMPR:EX
To:	Buchanan, Jack EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	RE: Projected Water Rental Revenue from Site C
Date:	Thursday, October 26, 2017 9:51:00 AM

https://www.sitecproject.com/sites/default/files/Economic%20Benefits%20-%20January%202016.pdf

My source of water rental info. Can you check with the Comptroller of Water Rights?

From: Buchanan, Jack EMPR:EX
Sent: Thursday, October 26, 2017 9:49 AM
To: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: RE: Projected Water Rental Revenue from Site C

Okay. So far I'm at $13 million in 2024 for capacity plus energy and a further $1.3 million for permits over crown land, but I hadn't tracked down Site C's volume for storage costs. Are we satisfied with the BC Hydro estimate?

From: Wieringa, Paul EMPR:EX
Sent: Thursday, October 26, 2017 9:30
To: Rowe, Katherine EMPR:EX
Cc: Buchanan, Jack EMPR:EX
Subject: RE: Projected Water Rental Revenue from Site C

I found on-line that BC Hydro estimates water rentals to be $35 million per year.

From: Rowe, Katherine EMPR:EX
Sent: Thursday, October 26, 2017 9:29 AM
To: Wieringa, Paul EMPR:EX
Subject: FW: Projected Water Rental Revenue from Site C

Jack is on it

From: Buchanan, Jack EMPR:EX
Sent: Thursday, October 26, 2017 9:28 AM
To: Rowe, Katherine EMPR:EX
Subject: Re: Projected Water Rental Revenue from Site C

I don't know that we have it, but I should be able to calculate or talk to WMB this AM. IT's not especially complicated.

From: Rowe, Katherine EMPR:EX
Sent: October-26-17 9:09:46 AM
To: Buchanan, Jack EMPR:EX
Subject: Projected Water Rental Revenue from Site C

Hi Jack – Paul is looking for the projected annual water rentals that Site C would generate, and would like an answer this am. Is this a figure we have somewhere? I looked through the 2014 Cab and TB Subs but didn't see anything there. If we don't already have it, is this something you could calculate quickly, or something we'd need to get from Water Management Branch?

Cheers

Katherine Rowe
Director, Generation and Regulatory Branch | **NEW!** Phone: 778.698.7190| Cell: 250.216.5823 |Ministry of Energy, Mines and Petroleum Resources

Energizing BC—clean, sustainable and productive

From:	Wieringa, Paul EMPR:EX
To:	Buchanan, Jack EMPR:EX
Cc:	Rowe, Katherine EMPR:EX
Subject:	s.12,s.13
Date:	Monday, October 23, 2017 3:56:00 PM
Attachments:	s.12,s.13

s.12,s.13

From: Buchanan, Jack EMPR:EX
Sent: Monday, October 23, 2017 3:31 PM
To: Wieringa, Paul EMPR:EX
Cc: Rowe, Katherine EMPR:EX
Subject: s.12,s.13

Hi Paul,

s.12,s.13

Jack

From: Buchanan, Jack EMPR:EX
Sent: Monday, October 23, 2017 15:06
To: Wieringa, Paul EMPR:EX
Cc: Rowe, Katherine EMPR:EX
Subject: s.12,s.13

Hi Paul,

s.12,s.13

Jack

Page 605 to/à Page 618

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	McNeil, Kevin EMPR:EX
Cc:	EMPR Correspondence EMPR:EX
Subject:	RE: Requesting advice,: Site C - Dan Kruk
Date:	Thursday, November 2, 2017 9:29:00 AM

MCITZ

From: McNeil, Kevin EMPR:EX
Sent: Thursday, November 2, 2017 9:17 AM
To: Wieringa, Paul EMPR:EX
Cc: EMPR Correspondence EMPR:EX
Subject: RE: Requesting advice,: Site C - Dan Kruk

Ok thanks, would you recommend they refer to our Minister, or MCITZ?

From: Wieringa, Paul EMPR:EX
Sent: Thursday, November 2, 2017 8:57 AM
To: McNeil, Kevin EMPR:EX
Cc: EMPR Correspondence EMPR:EX
Subject: RE: Requesting advice,: Site C - Dan Kruk

I think it would be OK to meet with the Minister. With the release of the BCUC report, and the commitment that government will make a decision by the end of the year on whether to cancel or proceed with Site C, this group may have information that they wish to share with the Minister.

From: McNeil, Kevin EMPR:EX
Sent: Thursday, November 2, 2017 8:30 AM
To: Wieringa, Paul EMPR:EX
Cc: EMPR Correspondence EMPR:EX
Subject: FW: Requesting advice,: Site C - Dan Kruk

Hi Paul, please see the attached call log (a bit dated – Oct 3rd).

Looking for advice to pass on to MCITZ.

I assume a mtg with their Minister would not be recommended, as this is a contractual issue that should be referred to BCH. Would you agree?

Thanks,

Kevin

From: EMPR Correspondence EMPR:EX
Sent: Wednesday, November 1, 2017 4:48 PM
To: McNeil, Kevin EMPR:EX
Subject: FW: Requesting advice,: Site C - Dan Kruk

Hi Kevin,

Could you please review the attached phone log & the below request from Citizens' Services.

Please advise what next steps, if any, our Ministry should take &/or what we can suggest to them.

Thanks,

Janet

From: Firth, Janet EMPR:EX **On Behalf Of** EMPR Correspondence EMPR:EX
Sent: Wednesday, November 1, 2017 4:38 PM
To: Wright, Sam MTIC:EX
Cc: Sanders, Trent CITZ:EX
Subject: FW: Requesting advice,: Site C - Dan Kruk

Hi Sam,

The writer requested a mtg with Min. Sims before the BCUC report was released, & the report was released today.

I will forward this to our Site C subject experts, so that they can advise further on what action if any we will take.

I'll get back to you with more once I have it.

Thanks,

Janet

From: Wright, Sam MTIC:EX
Sent: Monday, October 30, 2017 9:22 AM
To: EMPR Correspondence EMPR:EX
Subject: Requesting advice,: Site C

Good Morning,

Please see the below email from the Minister's Office of Citizens' Services in regards to the attached item.

Could you advise if this item belongs better to your Ministry?

Thank you,

Sam

From: Sanders, Trent CITZ:EX
Sent: Monday, October 23, 2017 9:21 AM
To: Wright, Sam MTIC:EX
Cc: Cook, Jeannette MTIC:EX
Subject: Requesting advice, Cliff #107262

Hi Sam,

We are looking for some advice on this phone log from Dan Kruk from Construction Maintenance & Allied Workers, Cliff #107262. Should we proceed with arranging a meeting? If so, could we request advice for the meeting, and should any other staff be in attendance?

Trent Sanders

Administrative Assistant – Minister's Office

Ministry of Citizens' Services

Phone: 1-250-387-9699

Email: Trent.Sanders@gov.bc.ca

Page 621 to/à Page 696

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	MacLaren, Les EMPR:EX; Lloyd, Evan GCPE:EX; Gibbs, Robb GCPE:EX; Zadravec, Don GCPE:EX; "Sauer, Darwin"
Cc:	Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX; Haslam, David GCPE:EX; Sanderson, Melissa EMPR:EX
Subject:	s.12,s.13
Date:	Saturday, October 28, 2017 4:19:00 PM

s.12,s.13

From: MacLaren, Les EMPR:EX
Sent: Saturday, October 28, 2017 4:09 PM
To: Lloyd, Evan GCPE:EX; Gibbs, Robb GCPE:EX; Zadravec, Don GCPE:EX; 'Sauer, Darwin'
Cc: Wieringa, Paul EMPR:EX; Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX; Haslam, David GCPE:EX; Sanderson, Melissa EMPR:EX
Subject: s.12,s.13

Gentlemen:

s.12,s.13

s.22 and will pick this up again tomorrow to make adjustments as required.

Les

From:	Wieringa, Paul EMPR:EX
To:	MacLaren, Les EMPR:EX; Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	RE: s.12,s.13
Date:	Monday, October 30, 2017 8:30:00 AM

s.12,s.13

From: MacLaren, Les EMPR:EX
Sent: Monday, October 30, 2017 6:33 AM
To: Wieringa, Paul EMPR:EX; Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject: FW s.12,s.13

Thanks Paul. s.12,s.13

s.12,s.13

Comments?

Les

From: Wieringa, Paul EMPR:EX
Sent: Saturday, October 28, 2017 4:20 PM
To: MacLaren, Les EMPR:EX; Lloyd, Evan GCPE:EX; Gibbs, Robb GCPE:EX; Zadravec, Don GCPE:EX; 'Sauer, Darwin'
Cc: Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX; Haslam, David GCPE:EX; Sanderson, Melissa EMPR:EX
Subject: RE: s.12,s.13

s.12,s.13

From: MacLaren, Les EMPR:EX
Sent: Saturday, October 28, 2017 4:09 PM
To: Lloyd, Evan GCPE:EX; Gibbs, Robb GCPE:EX; Zadravec, Don GCPE:EX; 'Sauer, Darwin'
Cc: Wieringa, Paul EMPR:EX; Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX; Haslam, David GCPE:EX; Sanderson, Melissa EMPR:EX
Subject: s.12,s.13

Gentlemen:

s.12,s.13

s.22 and will pick this up again tomorrow to make adjustments as required.

Les

From:	Wieringa, Paul EMPR:EX
To:	Sopinka, Amy EMPR:EX; MacLaren, Les EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	RE: s.12,s.13
Date:	Saturday, October 28, 2017 8:22:00 AM

Will do, and yes, I am available at 2 p.m.

From: Sopinka, Amy EMPR:EX
Sent: Saturday, October 28, 2017 8:22 AM
To: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: RE: s.12,s.13

s.12,s.13

s.22 but will be back at it around noon. Can we arrange the call for 2 pm?

A

From: MacLaren, Les EMPR:EX
Sent: Saturday, October 28, 2017 7:02 AM
To: Sopinka, Amy EMPR:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: RE: s.12,s.13

Thanks Amy! I have played with this a little.

s.12,s.13

s.22 Can we do a call at 2 or 3 pm (let me know what works)? We can use my conference line 1-877-353-9184 Participant IDs s.15

Les

From: Sopinka, Amy EMPR:EX
Sent: Friday, October 27, 2017 10:18 PM
To: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: s.12,s.13

Good evening,

s.12,s.13

Amy

From:	Wieringa, Paul EMPR:EX
To:	Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX
Cc:	MacLaren, Les EMPR:EX
Subject:	RE: s.12,s.13
Date:	Saturday, October 28, 2017 9:00:00 AM

s.12,s.13

From: Rowe, Katherine EMPR:EX
Sent: Saturday, October 28, 2017 8:49 AM
To: Sopinka, Amy EMPR:EX
Cc: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Subject: Re: s.12,s.13
Hi Amy - s.12,s.13
s.12,s.13

2 pm works for me
Katherine

Sent from my iPhone

On Oct 28, 2017, at 8:21 AM, Sopinka, Amy EMPR:EX <Amy.Sopinka@gov.bc.ca> wrote:

s.12,s.13

s.22 but will be back at it around noon. Can we arrange the call for 2 pm?

A

From: MacLaren, Les EMPR:EX
Sent: Saturday, October 28, 2017 7:02 AM
To: Sopinka, Amy EMPR:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: RE: s.12,s.13
Thanks Amy! I have played with this a little.
s.12,s.13

s.12,s.13

---

s.22 . Can we do a call at 2 or 3 pm (let me know what works)? We can use my conference line 1-877-353-9184 Participant ID s.15

Les

From: Sopinka, Amy EMPR:EX
Sent: Friday, October 27, 2017 10:18 PM
To: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: s.12,s.13

Good evening,

s.12,s.13

Amy

From:	Wieringa, Paul EMPR:EX
To:	MacLaren, Les EMPR:EX; Rowe, Katherine EMPR:EX; Cutler, Scott EMPR:EX; Haslam, David GCPE:EX
Subject:	RE: Site C Overview - Project Need and Load Forecast
Date:	Thursday, October 26, 2017 1:47:00 PM

Scott is s.22

If needed, I could be there until about 5. (Tonight happens to be the worst day for me.) However, I think you and Katherine have it well in hand.

From: MacLaren, Les EMPR:EX
Sent: Thursday, October 26, 2017 11:22 AM
To: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Cutler, Scott EMPR:EX; Haslam, David GCPE:EX
Subject: RE: Site C Overview - Project Need and Load Forecast

You will note I played with this one a little. Please save this version and bring 5 copies.

What's our roster for 4:30-5:30 this afternoon? Paul, are you available? Scott, do you want to be part of the discussion?

Les

From: MacLaren, Les EMPR:EX
Sent: Thursday, October 26, 2017 11:11 AM
To: Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX
Cc: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Cutler, Scott EMPR:EX; Haslam, David GCPE:EX
Subject: Site C Overview - Project Need and Load Forecast

Melissa and James:

Here is our next installment for this afternoon's briefing at 4:30 – dealing with the need for Site C and critics views on BC Hydro's load forecast.

As discussed, we will also spend some time on residential 2-tier rates in advance of MMM's CBC interview tomorrow.

Les

From: Wieringa, Paul EMPR:EX
To: Rowe, Katherine EMPR:EX
Cc: Sopinka, Amy EMPR:EX
Subject: s.12,s.13
Date: Tuesday, November 7, 2017 9:29:47 AM

Send it as a draft to both Les and Christine K.

Sent from my iPhone

On Nov 7, 2017, at 9:09 AM, Rowe, Katherine EMPR:EX <Katherine.Rowe@gov.bc.ca> wrote:

> Thank you so much, you two! I will make these changes and get it to Les.
>
> **From:** Wieringa, Paul EMPR:EX
> **Sent:** Tuesday, November 7, 2017 7:08 AM
> **To:** Sopinka, Amy EMPR:EX
> **Cc:** Rowe, Katherine EMPR:EX
> **Subject:** s.12,s.13
> s.12,s.13
>
> Sent from my iPhone
>
> On Nov 7, 2017, at 6:44 AM, Sopinka, Amy EMPR:EX <Amy.Sopinka@gov.bc.ca> wrote:
>
> > s.12,s.13
> >
> > Amy
> >
> > **From:** Wieringa, Paul EMPR:EX
> > **Sent:** Monday, November 6, 2017 10:49 PM
> > **To:** Rowe, Katherine EMPR:EX
> > **Cc:** Sopinka, Amy EMPR:EX
> > **Subject:** s.12,s.13
> > s.12,s.13
> >
> > **From:** Rowe, Katherine EMPR:EX
> > **Sent:** Monday, November 6, 2017 9:40 PM
> > **To:** Wieringa, Paul EMPR:EX
> > **Cc:** Sopinka, Amy EMPR:EX
> > **Subject:** s.12,s.13
> > Hi Paul – s.12,s.13

Would you like to take a look over this, please, before we re-send to Les, and provide to Christine Kennedy?
Amy, I know you likely haven't had a chance to look at the last draft yet – any comments you have on this one would be welcome.
Cheers
Katherine

From:	Wieringa, Paul EMPR:EX
To:	Sopinka, Amy EMPR:EX
Cc:	Rowe, Katherine EMPR:EX
Subject:	Re: s.12 s.13
Date:	Tuesday, November 7, 2017 7:07:39 AM

s.12,s.13

Sent from my iPhone

On Nov 7, 2017, at 6:44 AM, Sopinka, Amy EMPR:EX <Amy.Sopinka@gov.bc.ca> wrote:

s.12,s.13

Amy

From: Wieringa, Paul EMPR:EX
Sent: Monday, November 6, 2017 10:49 PM
To: Rowe, Katherine EMPR:EX
Cc: Sopinka, Amy EMPR:EX
Subject: s.12,s.13

s.12,s.13 this is a good start to ensure that we have covered everything.

From: Rowe, Katherine EMPR:EX
Sent: Monday, November 6, 2017 9:40 PM
To: Wieringa, Paul EMPR:EX
Cc: Sopinka, Amy EMPR:EX
Subject: s.12 s.13

Hi Paul – s.12,s.13

s.12,s.13

Would you like to take a look over this, please, before we re-send to Les, and provide to Christine Kennedy?
Amy, I know you likely haven't had a chance to look at the last draft yet – any comments you have on this one would be welcome.
Cheers
Katherine

From:	Wieringa, Paul EMPR:EX
To:	Rowe, Katherine EMPR:EX
Cc:	Sopinka, Amy EMPR:EX
Subject:	RE:s.12,s.13
Date:	Monday, November 6, 2017 10:48:00 PM
Attachments:	s.12,s.13

s.12,s.13

From: Rowe, Katherine EMPR:EX
Sent: Monday, November 6, 2017 9:40 PM
To: Wieringa, Paul EMPR:EX
Cc: Sopinka, Amy EMPR:EX
Subject:s.12,s.13
Hi Paul –s.12,s.13
s.12,s.13

Would you like to take a look over this, please, before we re-send to Les, and provide to Christine Kennedy?
Amy, I know you likely haven't had a chance to look at the last draft yet – any comments you have on this one would be welcome.
Cheers
Katherine

Page 707 to/à Page 714

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	Rowe, Katherine EMPR:EX
Subject:	RE:s.12,s.13
Date:	Tuesday, November 7, 2017 10:58:00 AM

Wait til 2

From: Rowe, Katherine EMPR:EX
Sent: Tuesday, November 7, 2017 9:33 AM
To: Wieringa, Paul EMPR:EX
Subject: Res.12,s.13
Will do
s.12,s.13 or wait until
you, Amy and I get together at 2?

Sent from my iPhone

On Nov 7, 2017, at 9:29 AM, Wieringa, Paul EMPR:EX <Paul.Wieringa@gov.bc.ca> wrote:

> Send it as a draft to both Les and Christine K.
>
> Sent from my iPhone
>
> On Nov 7, 2017, at 9:09 AM, Rowe, Katherine EMPR:EX <Katherine.Rowe@gov.bc.ca> wrote:
>
> > Thank you so much, you two! I will make these changes and get it to Les.
> >
> > **From:** Wieringa, Paul EMPR:EX
> > **Sent:** Tuesday, November 7, 2017 7:08 AM
> > **To:** Sopinka, Amy EMPR:EX
> > **Cc:** Rowe, Katherine EMPR:EX
> > **Subject:** Re:s.12,s.13
> > s.12,s.13
> >
> > Sent from my iPhone
> >
> > On Nov 7, 2017, at 6:44 AM, Sopinka, Amy EMPR:EX <Amy.Sopinka@gov.bc.ca> wrote:
> >
> > > s.12,s.13
> > >
> > > Amy
> > >
> > > **From:** Wieringa, Paul EMPR:EX
> > > **Sent:** Monday, November 6, 2017 10:49 PM
> > > **To:** Rowe, Katherine EMPR:EX
> > > **Cc:** Sopinka, Amy EMPR:EX

Subject: RE: s.12,s.13
s.12,s.13

From: Rowe, Katherine EMPR:EX
Sent: Monday, November 6, 2017 9:40 PM
To: Wieringa, Paul EMPR:EX
Cc: Sopinka, Amy EMPR:EX
Subject: s.12,s.13
Hi Paul - s.12,s.13
s.12,s.13

Would you like to take a look over this, please, before we re-send to Les, and provide to Christine Kennedy?
Amy, I know you likely haven't had a chance to look at the last draft yet – any comments you have on this one would be welcome.
Cheers
Katherine

From:	Wieringa, Paul EMPR:EX
To:	Les.MacLaren@gov.bc.ca; Sopinka, Amy EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	Site C BCUC Report - Initial Comments for Cabinet 1-11-17.docx
Date:	Wednesday, November 1, 2017 8:25:30 AM
Attachments:	s.12,s.13

Comments in the document.

Page 718 to/à Page 721

Withheld pursuant to/removed as

s.12;s.13

From:	Wieringa, Paul EMPR:EX
To:	Rowe, Katherine EMPR:EX; Buchanan, Jack EMPR:EX
Subject:	s.12,s.13
Date:	Wednesday, October 25, 2017 8:46:15 AM
Attachments:	s.12,s.13

s.12,s.13

Page 723 to/à Page 737

Withheld pursuant to/removed as

s.12;s.13

From:	Savidant, Michael
To:	Foster, Doug FIN:EX
Cc:	MacLaren, Les EMPR:EX; O"Riley, Christopher; Layton, Ryan; Reimann, Randy; Fane, Lindsay
Subject:	s.12,s.13
Date:	Tuesday, November 28, 2017 10:57:09 AM

Doug,

s.12,s.13

Michael Savidant
Manager – Commercial Negotiations
Business and Economic Development

BC Hydro
333 Dunsmuir St, 17th Floor
Vancouver, BC V6B 5R3
P 604.623.3694
M 604.250.9603
E michael.savidant@bchydro.com

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From:	MacLaren, Les EMPR:EX
To:	Wright, Don J. PREM:EX; Meggs, Geoff PREM:EX; Kennedy, Christine PREM:EX; Lloyd, Evan GCPE:EX; Zadravec, Don GCPE:EX; Foster, Doug FIN:EX
Cc:	Nikolejsin, Dave MNGD:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX; Wanamaker, Lori FIN:EX
Subject:	BC Hydro Results of Analysis of BCUC Portfolio
Date:	Saturday, November 18, 2017 5:21:00 PM
Attachments:	20171117 - Results of portfolio analysis of Commission Portfolio.docx

Good afternoon:

This is for discussion at our meeting tomorrow.

As noted in BC Hydro's November 16 submission to the BCUC setting out the computational and input errors they identified in the BCUC's models for Site C and the Illustrative Alternative Portfolio, BC Hydro has also now completed its analysis of running the BCUC's assumptions through BC Hydro's modelling tools (attached).

After correcting for the errors, and using the BCUC's assumptions of $10B capital cost, $3.9B sunk plus termination cost amortized over 30 years, low market prices for surplus sales, and BC Hydro financing the alternative portfolio, the analysis shows Site C benefits to ratepayers of $800M NPV under the low load scenario, and $1.5B under the mid-load, compared to the BCUC's Alternative Portfolio.

BC Hydro also notes where it disagrees with the BCUC's assumptions and why. BC Hydro has included sensitivity cases related to IPP financing, demand side management costs, period of recovery of sunk/termination costs, and Site C capital costs. In all cases except Site C at $12B in a low load scenario (NPV -$100M), the impact of more reasonable assumptions improves the benefits of Site C to ratepayers materially.

Particularly useful are the two attachments on pages 6 and 7. Attachment 1 is a table that clearly shows the differences in assumptions between BC Hydro's initial August 30 filing, a more optimistic view of resource costs that was filed in response to a BCUC request, and the BCUC's assumptions about Site C and the Alternative Portfolio. Attachment 2 is a waterfall chart that shows the impact of various assumptions moving from August 30, to the optimistic scenario, to the current analysis using BCUC assumptions. Other than the BCUC's assumptions on higher termination costs, all other assumptions favour the Alternative Portfolio over Site C.

We are currently updating our draft PowerPoint for PAC this week, and will circulate that later today or tomorrow morning.

Les

From: Savidant, Michael [mailto:michael.savidant@bchydro.com]
Sent: Friday, November 17, 2017 5:31 PM
To: MacLaren, Les EMPR:EX; Foster, Doug FIN:EX
Cc: O'Riley, Christopher; McSherry, Diane; Reimann, Randy; Magre, Leela; Layton, Ryan; James, Fred
Subject: Results of portfolio analysis of Commission Portfolio

Les and Doug,

Please find attached a note providing the results of our running the Commission's Illustrative Alternative assumptions through our portfolio modelling tools. As you'll see, the results for the Low Load Forecast scenario are roughly in-line with our high-level calculation of the impact of the errors.

Please let us know if you have any questions.

Thanks,

Mike

Michael Savidant
Manager – Commercial Negotiations
Business and Economic Development

BC Hydro
333 Dunsmuir St, 17th Floor
Vancouver, BC V6B 5R3
P 604.623.3694
M 604.250.9603
E michael.savidant@bchydro.com

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As described in our letter to the Commission of November 16, 2017, BC Hydro has utilized its portfolio modeling to analyse the assumptions made by the Commission in its Illustrative Alternative Portfolio (Exhibit A-24). This document provides a summary of where BC Hydro's portfolio modelling differs from the Commission's methodology, as well as the findings from our portfolio analysis utilizing these assumptions.

BC Hydro continues to disagree with many of the assumptions made by the Commission in its Illustrative Alternative, but has retained the Commission's assumptions in the analysis of the Illustrative Alternative portfolio where they were believed to have been made on purpose. While BC Hydro has calculated the present value costs to ratepayers of the Commission's Illustrative Alternative portfolio, we do not believe the costs and resources utilized in this portfolio are plausible. As such, BC Hydro makes no representation on our ability to deliver this portfolio in the manner assumed by the Commission.

The key findings from this updated portfolio analysis as compared to previous BC Hydro submissions are as follows:

($2018 billions)	August 30th Submission	Optimistic Portfolio Sensitivity	Commission Illustrative Alternative
Low Load Forecast	6.1	Not calculated	0.8
Mid Load Forecast	7.3	6.4	1.5
High Load Forecast	10.6	Not calculated	Not calculated

BC Hydro is also developing an annual incremental rate impact forecast consistent with these present value results and expects the incremental rate impact analysis to be available next week.

The following sections provide summaries of:

- Corrections to errors and methodology made by the Commission in their model
- Key assumptions which BC Hydro continues to believe are incorrect or not supported by the evidence.

Correction for errors and methodological limitations in Commission model:

BC Hydro's portfolio modelling corrects for the following errors in the Commission's model, as outlined to the Commission in our letter of November 16, 2017:

- Applying the correct discount rate to Site C surplus
- Correction of inconsistent inflation factors, financing costs, and discount rates[1]
- Elimination of double-counting of transmission losses on demand-side management
- Recovery of sunk costs in both the scenario where Site C is completed (over 70 years) and the scenario where Site C is terminated (over 30 years, as used by the Commission for termination costs).
- Applying the correct binary technology to geothermal resources rather than flash technology

BC Hydro's portfolio analysis methodology also provides a long-term system-wide assessment of the costs of the options available to BC Hydro to meet customer load. The key benefits of this methodology as compared to a more simplified method include:

[1] Note that subsequent to the preparation of our November 16th letter, BC Hydro discovered that the Commission's model did not take into account higher near-term interest rates. This has also been corrected for in the current analysis.

- Allows for selection of resources in an optimal manner, rather than assuming specific resources come into service. System Optimizer selects from available resources in order to find the lowest present value cost to ratepayers.
    - This functionality is why our portfolios select wind and pumped storage as the preferred non-DSM resource option. If we were to force the inclusion of geothermal resources as in the Commission portfolio, alternative portfolio costs would increase,
    - Note that System Optimizer does not have functionality to select demand-side management options. As a result we have assumed the same DSM timing as in the Commission Illustrative Alternative.
- A long-term evaluation period that provides analysis representative of the impact to ratepayers of the decision to complete or terminate Site C.
    - This includes in the evaluation the impact of the decision on Site C to "what comes next" to meet domestic load.
    - The Commission's analysis with a limitation to a shorter period or a fixed amount of energy and capacity creates a false choice between resources (such as enhanced DSM) that would be pursued in all cases.
- Analysis based upon BC Hydro's planning view of the load resource balance, rather than an operational view.
    - BC Hydro's planning view of the Load Resource Balance reflects the capability of resources based on BC Hydro's planning criteria, including the requirement contained in subsection 6(2) of the Clean Energy Act to achieve electricity self-sufficiency under prescribed water conditions from its hydroelectric Heritage assets.
    - An operating view of the Load Resource Balance reflects the forecasted operation of the same resources (as in the planning view of the load resource balance) given market conditions, expected system conditions in the near term and average conditions in the long term[2]. Use of an operating view incorrectly advances the apparent need for new resources by approximately two years.
- Consideration of transmission impacts of resource options. In integrating a resource option to BC Hydro's system, there needs to be (i) transmission from the generator to a point of interconnection on the BC Hydro system which is typically at a substation at a lower voltage than 500 kV, (ii) upgrades that are required from the lower voltage sub-station to the 500 kV bulk system, and (iii) upgrades on the bulk transmission system.
    - BC Hydro's resource option costs include the cost of transmission from the generator to a point of interconnection on the BC Hydro system. These costs have been estimated based on costs that were identified to accommodate IPP projects from the Clean Power Call.
    - BC Hydro's portfolio modelling also includes the costs of network upgrades that are required to accommodate IPP projects on the transmission lines from the IPP point of interconnection to the 500 kV bulk system.
    - The Commission seems to have interpreted network upgrades to be included in the transmission costs from the project to the point of interconnection and have not considered any other transmission costs.
    - BC Hydro's portfolio modelling includes an assessment of when bulk transmission upgrades will be required to enable incremental resource options to effectively supply domestic demand. These upgrades were explicitly excluded from the Commission's analysis.
- Consideration of the market benefits provided by shaping capability.
    - BC Hydro's portfolio modelling reflects the daily, monthly and seasonal value to resource shaping.

[2] The most obvious difference between the Planning View and the Operational View is the energy from dispatchable thermal resources. The Planning View reflects the firm energy that dispatchable thermal resources are capable of generating and can be relied upon for planning purpose (Island Generation at 2,170 GWh and Prince Rupert Generating Station at 180 GWh). In contrast, the Operational View shows how much dispatchable thermal resources are expected to run (Island Generation at 140 GWh and Prince Rupert at 0 GWh).

Remaining Commission assumptions which are incorrect or not supported by the evidence:

Other than the correction for errors and methodological issues above, BC Hydro's analysis has preserved Commission assumptions that have been made in the Final Report (A-24) and associated modelling (A-24-2). In many cases BC Hydro believes these assumptions are incorrect or are not supported by the evidence. As previously stated, BC Hydro makes no representation that we will be able to deliver on the Commission portfolio's resources or costs should a decision be made to terminate Site C.

Key assumptions that BC Hydro continues to disagree with include:

- The Commission portfolio relies on substantially more savings from capacity-focused DSM than BC Hydro believes is appropriate to plan on.
    - The Commission allows for up to 400MW of Industrial Load Curtailment at $75/kW-yr.
        - The Commission's sole basis for this volume appears to be a submission from AMPC that suggests there is 200-400MW of Industrial Load Curtailment available based on "realistic procurement efforts, using less restrictive contract terms".
        - AMPC provides no analysis for how they arrived at this figure other than a pro-rated number from Hydro Quebec which would yield only 245MW. It is also unlikely the "less restrictive contract terms" would meet BC Hydro's long term planning needs.
        - BC Hydro notes that we tested a shorter term product (4 hours) in our Year 2 Load Curtailment pilot with the concept of aggregating products to meet our long term planning needs. No customer bid in such a product.
    - The Commission allows for 400 MW of optional time of use savings.
        - This is substantially higher than BC Hydro's assessment of 120MW of available optional time of use savings.
        - The Commission appears to rely on jurisdictional evidence as rationale for the higher amount (400 MW) of TOU potential. However, in reviewing their references, we can only find evidence of residential customer TOU uptake. We believe that higher potential would only be possible if there is also participation by the General Service classes but are not aware of any jurisdictional evidence that shows that there is significant TOU potential with the General Service classes.
- The use of BC Hydro financing for all resources. This assumption either means a substantial change in how BC Hydro does business or does not reflect the true costs to ratepayers. BC Hydro financing either means:
    - That BC Hydro builds all new resources on our balance sheet. This would be a change from the decades of policy and precedent that IPPs construct new resources in BC, and has the potentially to have material impacts on BC Hydro's credit rating and the IPP industry.

      OR
    - That the Commission's PVs are not reflective of the true costs to ratepayers, who would pay IPP costs of capital rather than BC Hydro cost of debt. There is no question that an IPPs cost of capital can be expected to be higher than BC Hydro's cost of capital.

  We have included a sensitivity scenario where this issue is addressed and IPP financing is used for IPP resources rather than BC Hydro financing.
- The use of the Utility Cost rather than the Total Resource Cost to evaluate the cost of DSM.
    - This is incorrect. The incremental costs in the TRC are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.

  We have included a sensitivity scenario where this issue is addressed and Total Resource Cost is used rather than Utility Cost.
- The use of extremely low prices for wind resources.

- The Commission has utilized extremely optimistic cost declines for wind projects, and also assumed that these projects could be renewed or refurbished at further aggressive cost savings.
  - The costs assumed by the Commission for new-build wind resources are less than half of the results of BC Hydro's most recent competitive call for power. While we agree that costs declines in wind projects are occurring, the costs of wind assumed by the Commission are not expected to be obtainable.
  - The Commission has assumed a further 30% cost savings for wind renewal terms. The Commission has also assumed that there will be no requirement to rebuild transmission lines and roads at refurbishment. This appears to double-count expected cost savings during refurbishment.
- The table below shows a comparison of the cost of wind used in BC Hydro's original analysis, our "Optimistic Portfolio Sensitivity", and the Commission's assumptions made in their Illustrative Alternative portfolio. Note that the Commission Assumptions column includes both the impact of the financing assumption and the cost decline assumption.

Table 1 – Wind Cost Assumptions (2018 real dollars)

$/MWh	Cost Component	Aug 30th Portfolio	Optimistic Sensitivity	Commission Illustrative Alternative[3]
New-build wind resources (F2040)	at point of interconnection	82	64	43
	Wind integration	5	5	1
Wind refurbishment (F2070)	at point of interconnection	82	58	31
	Wind integration	5	5	1

- The use of an electricity market price forecast below expert consensus.
  - The Commission has prepared their own Mid-C market forecast that is between the mid and low case of the ABB market price forecast.
  - This is well below not only the third party price forecast used by BC Hydro (ABB) but also all other third party price forecasts provided during the Site C Inquiry.
  - We have left in the Commission's assumption of providing a $1/MWh benefit to Site C for the ability to integrate wind but note that we are unclear on the basis for this assumption.

Results

Table 2 below shows the present value benefits to ratepayers of completing Site C. Values are shown using three sets of assumptions:

- The assumptions in our August 30th Submission (F1-1), which remains BC Hydro's best estimate of the impact of terminating Site C.

[3] Note that the unit energy costs we have utilized in our analysis of the Commission's Illustrative Alternative have been calculated based on the Commission's cost decline assumptions stated in their Final Report. These unit energy costs are approximately 2 to 3 $/MWh lower than what the Commission seems to be utilizing in their spreadsheet model. We are unclear if this is an error in the stated assumptions, the spreadsheet calculation, or BC Hydro's interpretation of the Commission's intent. We emphasize that our assumption is more conservative and favors the alternative portfolio.

- The assumptions used in our Optimistic Portfolio Sensitivity provided in the response to BCUC IR 2.46.0 (Exhibit F1-8), which remains BC Hydro's best assessment of a plausible, although low likelihood, set of resource planning assumptions.
- The assumptions used by the Commission in their Illustrative Alternative portfolio (Exhibit A-24-2). As noted above, BC Hydro has retained the Commission's assumptions in their Illustrative Alternative portfolio, but does not believe the assumptions used in this portfolio are plausible.

Table 2 – Present Value Benefits of Completing Site C

($2018 billions)	August 30th Submission	Optimistic Portfolio Sensitivity	Commission Illustrative Alternative
Low Load Forecast	6.1	Not calculated	0.8
Mid Load Forecast	7.3	6.4	1.5
High Load Forecast	10.6	Not calculated	Not calculated

BC Hydro has prepared a table summarizing the differences in portfolio assumptions between the portfolio in BC Hydro's August 30th submission to the BCUC, the Optimistic Portfolio Sensitivity BC Hydro provided as part of our response to BCUC IR 2.46.0, and the Commission's Illustrative Alternative. Please refer to Attachment 1.

BC Hydro has also prepared a figure showing the present value impact of changing assumptions and methodologies between the August 30th portfolio and the Commission's illustrative alternative. Please refer to Attachment 2.

In addition to our base results, we have also developed sensitivity analyses for the following items:
- Use of IPP financing rather that BC Hydro financing for alternative resources
- Use of Total Resource Cost rather than Utility Cost for demand-side management

Table 3 below shows the results of this sensitivity analysis on the Commission's Illustrative Alternative

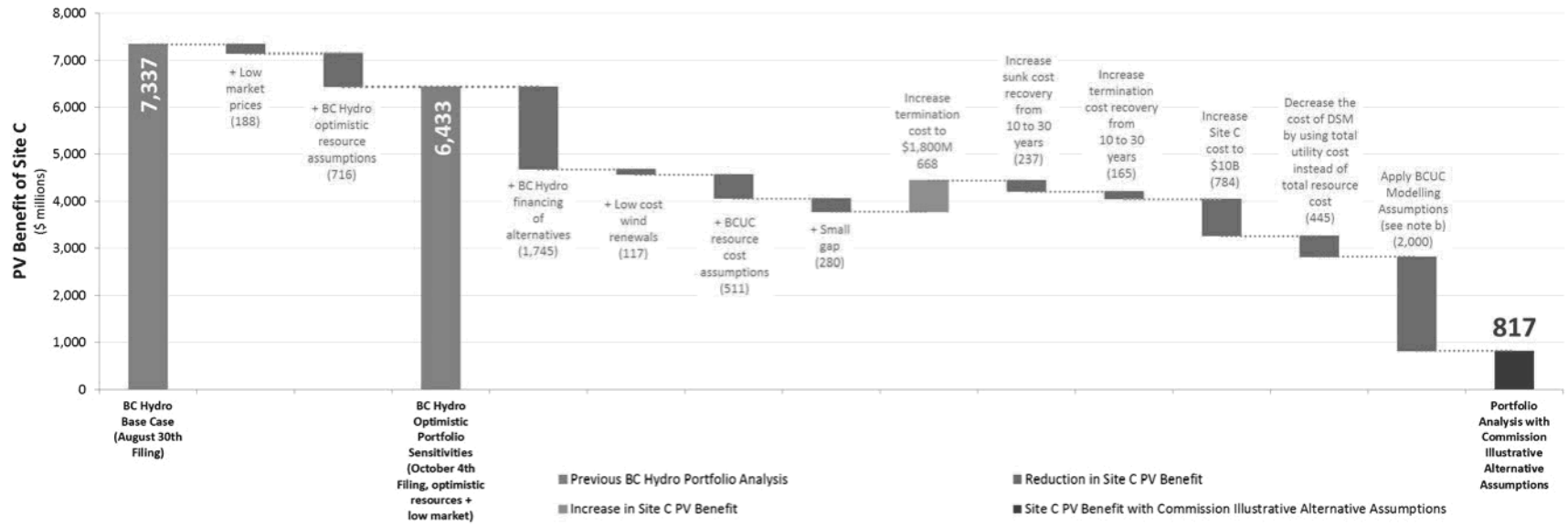
Table 3 – Sensitivity Analysis for Commission Illustrative Alternative Portfolio ($2018 billions)

	Low Load Forecast	**Mid Load Forecast**
Base Commission Assumptions	0.8	1.5
Financing: IPP financing for alternative resources	1.2	2.8
DSM Costs: Total Resource Cost rather than Utility Cost	1.3	1.6
Cost Recovery Period: Sunk / termination costs recovered over 10 years	1.2	1.9
Site C capital cost: $12B rather than $10B	(0.1)	0.6

Attachment 1 – Summary of Portfolio Modelling Assumptions

Assumptions Scenario	August 30 Filing	BC Hydro Optimistic Portfolio Sensitivity	BC Hydro Analysis using Commission Illustrative Alternative Portfolio Assumptions
MODEL ASSUMPTIONS			
Load Forecast Scenarios	- Low / Mid / High	- Low / Mid / High	- Low / Mid (insufficient time to run high load scenario)
Financing Assumption	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances all resources
Market Prices	- ABB Mid Forecast	- ABB Mid Forecast	- BCUC Market Price Forecast
Site C Costs	- $8.335 billion	- $8.335 billion	- $10 billion
Termination and Sunk Costs	- $3.2 billion ($2.1 sunk costs, $1.1 termination costs)	- $3.2 billion ($2 1 sunk costs, $1.1 termination costs)	- $3.9 billion ($2.1 sunk costs, $1.8 termination costs)
Sunk & termination cost recovery period	- 10 years	- 10 years	- 30 years
ALTERNATIVE RESOURCE ASSUMPTIONS			
Capacity Focused DSM	- Industrial Load Curtailment: 85 MW	- Industrial Load Curtailment: 85 MW - Capacity Focused DSM potential: 450MW	- Industrial Load Curtailment: 400 MW - Capacity Focused DSM and optional TOU potential: 640MW
Resource Smart	- Revelstoke Unit 6 when selected by model	- Revelstoke Unit 6 when selected by model - GMS upgrade when selected by model	- Revelstoke Unit 6 assumed in-place in Fiscal 2026
Wind	BC Hydro Resource Options Update w/ IPP financing: - F2040 new build @ $82/MWh ($2018) - F2070 refurbishment @ $82/MWh ($2018) - Wind integration cost of $5/MWh	Lower wind costs w/ BCH financing: - F2040 new build @ $64/MWh ($2018) - F2070 refurbishment @ $58/MWh ($2018) - Wind integration cost of $5/MWh	Much lower wind costs w/ BCH financing, with further reductions for refurbishment/renewal: - F2040 new build @ $43/MWh ($2018) - F2070 refurbishment @ $31/MWh ($2018) - Wind integration cost of $1/MWh
Pumped Storage	BC Hydro Resource Options Update: - F2030 new build @ $125/kW-yr ($2018)	BC Hydro Resource Options Update: - F2030 new build @ $125/kW-yr ($2018)	BC Hydro Resource Options Update: - F2030 new build @ $52/kW-yr ($2018)
Geothermal	- Excluded as not confirmed to be commercially viable	- 200MW of potential @ $120/MWh	- 80MW of potential @ $80/MWh (not selected in portfolio)
Solar	- Excluded as not economic	Modeled using NREL mid cost declines (43% by 2040) - (not selected in portfolio)	Modeled using Commission-suggested cost declines (60% by 2040) - (not selected in portfolio)
Batteries	- Excluded as not economic	- Modeled using Commission-suggested (Lazard) cost declines (50% by 2040) (not selected in portfolio)	- Screened out due to high cost. Aligns with suggestion in the Commission's final report.

Attachment 2 – Impact of Changes to Portfolio Assumptions and Methodologies [a]



Notes:

a. The value differentials are applied left to right in order. This is important, as there are overlap effects between some changes. As a result, if some changes are applied earlier in the "cascade" they will have a larger impact.

b. The BCUC Modeling Assumptions that make up the $2 billion difference in PV include:
   - Use of 630 MW of Capacity focused DSM + Optional Time of Use rates
   - Use of 400 MW of industrial load curtailment with no long-term commitments (i.e. can be "switched on and off" year to year)
   - Optimistic assumptions regarding renewal of wind projects
   - Commission market price assumption instead of ABB market prices
   - Reduction in wind integration adder to $1/MWh

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
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November 10, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

s.13

1 Exhibit A-24.

2 Exhibit A-24-2-1.

s.13

s.13

s.13

s.13

s.13

s.13

Yours sincerely,

Fred James
Chief Regulatory Officer

fj/ma

From:	MacLaren, Les EMPR:EX
To:	Wright, Don J. PREM:EX; Meggs, Geoff PREM:EX; Wanamaker, Lori FIN:EX; Foster, Doug FIN:EX; Zadravec, Don GCPE:EX; Lloyd, Evan GCPE:EX; Kennedy, Christine PREM:EX
Cc:	Rowe, Katherine EMPR:EX; Nikolejsin, Dave MNGD:EX
Subject:	BCUC Site C Report
Date:	Saturday, November 4, 2017 10:05:00 AM
Attachments:	BCUC Report - Initial Findings from BCH Review v3 3-11-17.docx

Good morning.

To support discussions that may be occurring today and our meeting tomorrow to map out work streams leading to Cabinet meetings later this month, attached is analysis to date of the BCUC report that I received last evening from the BC Hydro team that has been intensively analyzing the report and modelling behind the Commission's results. Some of the errors have been quantified and the differences are material in favour of Site C over the Commission's alternative portfolio.

Coming out of an exchange with Chris O'Riley this morning, we propose one way that we could get the results of this analysis out into the public domain. We could have EMPR, under Dave Nik's signature, write to the Chair of the BCUC with something along the lines of the following:

- We are supporting government's decision-making on Site C
- In your report you note that the alternative portfolio developed by Commission staff is not a substitute for BC Hydro's planning processes
- We understand that BC Hydro modelled over 60 scenarios testing various assumptions, including a number alternatives requested by the Commission, but that the Commission's Illustrative Alternative Portfolio in your final report was not analyzed using BC Hydro's modelling tools
- We therefore asked BC Hydro to provide an assessment of the Commission's alternative portfolio and would like to get the Commission's response to the issues identified in BC Hydro's initial analysis (we could include some or all of the issues BC Hydro has identified)
- More issues may be identified as we work through this material, etc.

The Commission would need to make the letter public. This would provide an opportunity for others, especially the intervenor groups used to dealing with BC Hydro's modelling in other BCUC processes, to weigh in. Because a number of the issues are computational or assumption errors, there may be little that critics can say about them.

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy, Mines and Petroleum Resources
NOTE NEW OFFICE PHONE NUMBER: 778-698-7183
Cell: 250-889-3479
Energizing BC—clean, sustainable and productive

Site C Inquiry
Overview of Initial Findings from BC Hydro Review of BCUC Final Report
November 3, 2017

This document provides a summary of items identified through BC Hydro's preliminary analysis that are expected to be most material to the Commission's conclusions regarding a comparison of Site C to the Commission's alternative portfolio (the "Illustrative Alternative portfolio").

Please note:

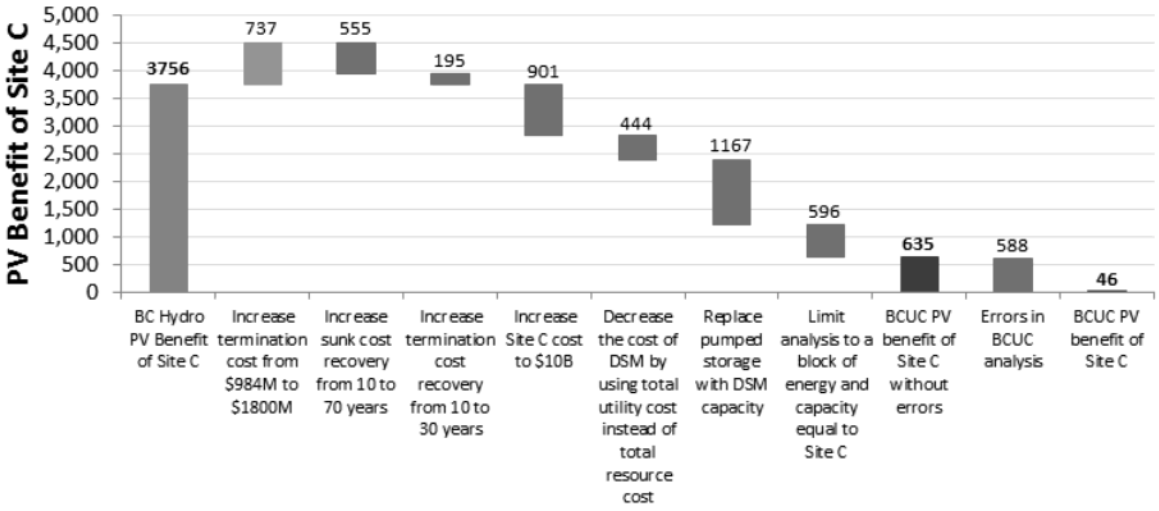
- This list is not exhaustive. Additional issues and errors have been identified that are not in this summary.
- BC Hydro's review is not yet complete. Additional issues may be identified in the future.

The table below provides a summary of these issues with the expected impact on the Commission's calculations of PV costs and benefits. Note that there may be overlap and compounding effects between items, and they should not be considered directly additive.

	Issue	**Impact on Cost of Termination**
1.	**Modelling Errors**	
A	Application of incorrect discount rate to Site C surplus	+$336 million
B	Inconsistent application of inflation factors and discount rates	+$51 million
C	Double-counting of transmission losses on DSM	+$201 million
2.	**Assumptions that do not reflect true costs to ratepayers**	
A	Inaccurate treatment of sunk costs	+$555 million
B	Inaccurate treatment of termination costs	+$195 million
C	Use of BC Hydro financing for all resources	Not calculated (depends on other assumptions)
D	Use of modified block analysis, ignoring value of DSM when proceeding with Site C	+$596 million
E	Use of Total Utility Cost rather than Total Resource Cost for DSM	+$444 million
3.	**Assumptions that are incorrect and not supported by evidence**	
A	Adoption of the Low Load Forecast as the expected case	Not estimated at this time
B	Adoption of 400MW of industrial load curtailment without evidence	
C	Use of an arbitrarily lowered market price forecast	
D	Assumption that the alternative portfolio has the same firming and shaping capability as Site C	
E	Use of incorrect technology assumptions on geothermal resources	
4.	**Assumptions that are inconsistent with legislation and/or policy**	
A	"Remobilization" of Burrard	Not estimated at this time
B	Use of Columbia River Treaty entitlement	
C	Increased reliance on external market purchases to meet demand	

Errors in Sections 1 and 2 are largely due to the Commission's adoption of their own modelling tools and rejection of BC Hydro's modelling tools. The Commission should not have eliminated BC Hydro's portfolio analysis evidence from consideration in this inquiry as it is the most complete assessment of the impacts and has been used successfully for many years in the context of resource planning. BC Hydro was available throughout the process to respond to questions and ran all of the sensitivities requested by the Commission. BC Hydro identified errors and assumption concerns with other portfolios that we were asked to assess. However, we were never asked to comment on the simplified Illustrative Alternative Portfolio, upon which the Commission ended up relying.

The graph below shows the assumptions the Commission has made to go from BC Hydro's "Commission Portfolio" PV estimate of $3.8 billion benefits of completing Site C to their assessment of zero benefits. The graph also shows the PV impact of correcting the errors listed in Section 1.



1. Modelling Errors

This section covers items that we believe are mistakes, rather than unjustified assumptions.

A. The Commission's model has a mathematical error in its treatment of the Site C energy surplus.
- The Illustrative Alternative model uses a **nominal dollar** market price and discounts at a **nominal dollar** discount rate. This is a correct method.
- The Site C model uses a 2018 **real dollar** market price and discounts at a **nominal dollar** discount rate. This is an incorrect method as the discount rate should be consistent with the dollar basis of prices.
- We believe this is a mistake rather than a conscious assumption, as there is no feasible basis for this difference nor has the Commission identified it in their assumptions.
- This mistake undervalues the Site C surplus on a Present Value basis.
- In the Commission Scenario Low Load Case used in Table 40, the impact is a $336 million higher cost of Site C than is correct.

B. The Commission's model has a mathematical error due to inconsistent application of inflation factors and discount rates.
- Inflation is applied to costs assuming they occur at the **start** of a fiscal year.
- Discounting is applied to costs assuming they occur at the **end** of a fiscal year.
- This inconsistent approach is incorrect. Inflation and discounting should be applied to the same period.
- In the Commission Scenario using the Low Load Case in Table 39, this results in a $51M lower cost of the Illustrative Alternatives than is correct.

C. The Commission has double-counted transmission loss savings associated with DSM which has the effect of understating the cost of the Commission's alternative portfolio relative to Site C.
   - In its original October 11th portfolio, the Commission increased the amount of energy provided by DSM by ~11% to reflect the avoidance of transmission losses.
   - In our October 18th response, we flagged that this was incorrect as the energy volumes they were using were already adjusted to reflect loss avoidance.
   - The Commission has stated that they continue to believe their adjustment is appropriate as they believe BC Hydro's adjustment was only for distribution losses, and a further adjustment is required for transmission losses.
   - This is incorrect. The volumes used by the Commission had already been adjusted to reflect transmission losses as well as distribution losses, and thus the Commission scenario double-counts transmission loss savings. Correction of this issue would advance the need for new resources and increase the cost of the Illustrative Alternative portfolio by ~$201 million.

2. Assumptions that do not reflect true costs to ratepayers

This section covers assumptions the Commission has made that are not mathematical errors, but are not representative of how costs would actually be recovered from ratepayers.

A. The Commission's treatment of sunk costs (i.e., the $2.1 billion in costs that will be spent by Dec 31, 2017 but have yet to be recovered from ratepayers) is not representative of the costs to ratepayers.
   - The Commission's model ignores sunk costs in the Terminate scenario and removes them from Site C costs in the Continue scenario.
   - This method would be correct if sunk costs are recovered from rates in the same manner for both the Terminate and Continue scenarios. However, this is not the case.
     - In the Continue scenario, sunk costs are effectively recovered over the 70 year amortization life of Site C.
     - In the Termination scenario, costs will be recovered over a substantially shorter period because it would be contrary to regulatory principle to have ratepayers (who aren't even born yet) paying for a project decades from now that had been cancelled and from which they are deriving no benefit at all. BC Hydro believes an appropriate period that is consistent with regulatory principle is 10 years.
   - Treating sunk costs the way the Commission has assumed in their analysis effectively assumes that they will be recovered over 70 years if the Project is terminated. This substantially underestimates the likely rate impact of these sunk costs in a Termination scenario.
   - Due to this difference in how sunk costs are recovered, the cost to ratepayers of the Illustrative Alternative portfolio is $555 million higher than estimated by the Commission

B. The Commission's treatment of termination costs is not representative of the likely costs to ratepayers.
   - In the Illustrative Alternative portfolio the Commission recovers termination costs over 30 years.
   - BC Hydro believes this period of recovery is too long for similar reasons as described for sunk costs in a termination context. This means a ratepayer who is not even born today would be paying for the project's termination in 2045.
   - Using a more reasonable 10 year recovery period increases the cost of the Illustrative Alternative Portfolio by $195 million.

C. The Commission assumes BC Hydro cost of financing for all resources.
   - The Commission has framed this as being intended to ensure an "apples to apples" comparison. However, this assumption either means a substantial change in how BC Hydro does business or does not reflect the true costs to ratepayers.

- BC Hydro financing either means:
  - That BC Hydro builds all new resources on our balance sheet. This would be a change from the decades of policy and precedent that IPPs construct new resources in BC, and has the potentially to have material impacts on BC Hydro's credit rating and the IPP industry.
    OR
  - That the Commission's PVs are not reflective of the true costs to ratepayers, who would pay IPP costs of capital rather than BC Hydro cost of debt. There is no question that an IPPs cost of capital can be expected to be higher than BC Hydro's cost of capital.
- The impact of this assumption depends on the amount of IPP resources in a portfolio. In the Commission scenario with low load assumed, DSM accounts for the vast majority of resources to meet load, and as such the financing assumption does not have a high impact. If a more reasonable load forecast assumption were used, more IPP resources are required, and the impact of financing will be substantial.
- We also note that the Commission has used a 6.4% "nominal" cost of capital for IPPs in their sensitivity test, supposedly based on BC Hydro's estimate. This is incorrect – our estimate of IPP cost of capital is 6.4% real (not nominal). The nominal cost of capital would be ~8.4%. As a result, the Commission's sensitivity analysis is incorrect.

D. The Commission conducts a modified block analysis, which ignores the benefit of incremental DSM if Site C were to be built.
   - The Commission truncates their analysis of new resource requirements to ~20 years (although they extend the cost of these resources out to 70 years).
   - As a result, the Commission effectively assumes that enhanced DSM would not occur if Site C continues. This is incorrect as BC Hydro would delay enhanced DSM with Site C but would still pursue it before other resources.
   - As a result, this ignores substantial differences in the cost of available future options.
     - If Site C continues, BC Hydro will continue to be able to pursue DSM. There is no change in available future options.
     - If Site C is terminated, there is no credible scenario where BC Hydro pursues Site C 10 years in the future (when new non-DSM resources would be required, even with the Commission's aggressive DSM assumptions). We would have lost our cheapest non-DSM option to serve our customers.
   - Ignoring this difference underestimates the PV cost of termination by $596 million.

E. The Commission utilizes Utility Cost rather than Total Resource Cost for DSM.
   - The Commission rejects BC Hydro's position (and their own previous findings in other Commission proceedings) that the Total Resource Cost is the appropriate way to evaluate DSM in comparison to other resource options. They appear to base this off the requirements of the OIC, and appear to assume that the TRC does not reflect direct costs to ratepayers.
   - This is incorrect. The incremental costs in the TRC are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.
   - Utilizing the TRC in a manner consistent with how the Commission used it in previous decisions increases the cost of the Illustrative Alternative portfolio by $444 million.

3. Assumptions that are incorrect and not supported by the evidence

This section covers assumptions that BC Hydro does not believe are reasonable given the information available to us and the Commission.

A. Adoption of the Low Load Forecast as the expected case

- The panel has found the mid forecast to be overall optimistic and considers appropriate to use the Low Load Forecast to develop its recommendations. It is unclear on what basis the Commissions is making this adjustment. Lower industrial load? Higher elasticity? Removal of LNG?
- BC Hydro has difficulty reconciling the Low Load Forecast with any scenario other than one that includes some or more of:
  - Major industrial load destruction. BC Hydro's low mining and forestry sector assumptions assume 1,800 GWh (250MW) of industrial load closures.
  - Low long-term economic growth (i.e. less than 1%/year)
  - Large amounts of customers going off-grid due to solar rooftops or similar switching.
  - Major declines in residential and/or commercial end-use intensities in addition to those underlying the additional DSM the Commission has relied upon
- While this scenario is possible, it is not expected and hence BC Hydro's used it as a low probability low load scenario

B. The Commission allows for up to 400MW of Industrial Load Curtailment at $75/kW-yr with no meaningful evidence.
   - The Commission's sole basis for this volume appears to be a submission from AMPC that suggests there is 200-400MW of Industrial Load Curtailment available based on "realistic procurement efforts, using less restrictive contract terms".
     - AMPC provides no analysis for how they arrived at this figure other than a pro-rated number from Hydro Quebec which would yield only 245MW.
     - The Commission provides no basis for utilizing the upper end of this range.
     - It is unlikely the "less restrictive contract terms" would meet BC Hydro's long term planning needs.
   - BC Hydro notes that we tested a shorter term product (4 hours) in our Year 2 Load Curtailment pilot. No customer bid in such a product.
   - BC Hydro has undertaken an industrial load curtailment pilot, the results of which determined that 85 MW was available in a form that would allow the deferral of physical assets to meet BC Hydro's customer's needs reliably.
   - The adoption of high levels of Industrial Load Curtailment is also inconsistent with the use of BC Hydro's Low Load Forecast.
     - While the Commission does not say on what basis they adopt the Low Load Forecast, it is unlikely BC Hydro would achieve this level of load without industrial demand destruction.
     - Under such a scenario, industrial load would be permanently "curtailed" (by going out of business) and would not be available for temporary curtailment to meet capacity needs.
     - We estimate that at least 40% of the potential for industrial load curtailment would not be available under the Low Load Forecast scenario.

C. Use of an arbitrarily lower market price forecast than the third party forecast used by BC Hydro
   - The Commission rejects BC Hydro's use of the ABB market forecast and adopts a market forecast between the mid and low case of the ABB market price forecast.
   - The ABB market price forecast used by BC Hydro is an independent forecast developed by ABB and built upon extensive research, analysis, and understanding of the North American electricity markets. ABB is one of the world's largest engineering companies and over 100 customers in the energy industry subscribe to their market forecast.
   - BC Hydro has also provided electricity price forecasts developed by the North West Power Planning Council, IHS Markit, and the PIRA Energy Group. The North West Power Planning Council is the entity that develops the long-term power plan for the states of Idaho, Montana, Oregon, and Washington. IHS Markit is a global business information provider while PIRA is a service provider to companies in over 60 countries, including many of the largest Global Oil and Gas firms.

- Every single one of the mid electricity market forecast developed by the organizations mentioned above is higher than the forecast that the Panel used as their mid case. BC Hydro believes that the Panel forecast relates to a pessimistic scenario and that the ABB mid forecast better represents a consensus mid-point view of several organizations that are experts in this domain.

D. The Commission assumes that the Illustrative Alternative portfolio has approximately the same level of firming and shaping as Site C.
   - The Commission reaches this conclusion by assuming that the existing system has sufficient firming and shaping such that incremental amounts have little to no value.
   - BC Hydro has provided a substantial volume of evidence on the value of Site C capacity, firming and shaping.

E. The Commission includes geothermal in their Illustrative Alternative portfolio, but applies the cost of hydrothermal flash technology to resources that require binary technology.
   - Neither Canoe Reach nor Lake Else has temperatures high enough to support flash technology.
   - Switching to binary technology would result in:
     - Higher costs, as binary is more expensive than flash technology
     - Lower net capacity factors, as binary technology is expected to achieve an 80% net capacity factor rather than the net 90% of flash technology according to NREL. Note that the Commission uses a 95% capacity factor – BC Hydro is unaware of the basis for this assumption.
   - Further, the Commission does not account for reservoir degradation which is expected to result annual generation output by 1% per year over the life of the project and would make the redevelopment of these sites after 30 years at a 30% cost reduction unlikely.

4. Assumptions that are incompatible with legislation and/or policy

This section will cover assumptions that violate existing legislation and/or policy. This section remains under development, but it expected to cover the following items:

A. "Remobilization" of Burrard
B. Use of the Columbia River Treaty entitlement
C. Increased reliance on external markets

From:	David Craig
To:	MacLaren, Les EMPR:EX
Subject:	CEC Comments on Alternative Portfolio - Clean Copy with Errata
Date:	Monday, October 23, 2017 3:09:36 PM
Attachments:	Comments on Alternative Portfolio Errata Clean.docx Site C Inquiry - Technical Sessions - CEC Input Transcript - MX-3140N_20171023_155341.pdf Site C Inquiry - Technical Sessions - F82-3_CEC_SiteC_Submissions.pdf

Les,

Here are the Commercial Energy Consumers comments on the Utility Commission Alternative Portfolio block that might be a replacement for Site C (This points out about $7.2 billion in errors and flawed assumptions in the Commission's preliminary write up on the Alternative) , as well as the CEC presentation to the Commission transcript and slides (which points out an omission of over $2 billion in assessment of ratepayer impacts).

I have pointed out to the Commission Panel that they need to understand the basic errors imbedded in the analytical methodologies clearly, let alone the more complex aspects of system planning.

Also I noted earlier a problem with identifying ratepayer impacts, which I presented to the BCUC Panel October 14th. It is critical that the impact of cancellation be properly understood and for now it is not properly represented in the BCUC Panel preliminary report.

Just wanted to keep you up to date.

Please let me know if you would like discuss this and if so when might be a good time for a call.

Thanks.

Cheers

David

Mr. David Craig
Executive Director
Commercial Energy Consumers (CEC) Association of BC
Suite 720 – 1190 Melville Street
Vancouver, B.C., V6E 3W1
Phone: 604-568-4904
Cell: 604-351-2332

Commercial Energy Consumers Association of BC (CEC)

Comments on the Alternative Portfolio

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COMMERCIAL ENERGY CONSUMERS

PRESENTATION TO

BRITISH COLUMBIA UTILITIES COMMISSION

ON SITE C INQUIRY

Page 071 to/à Page 074

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From: O"Riley, Christopher
To: MacLaren, Les EMPR:EX; Nikolejsin, Dave MNGD:EX
Subject: s.12,s.13
Date: Friday, December 1, 2017 6:38:37 PM
Attachments: s.12,s.13

---

s.12,s.13

Chris O'Riley | President & Chief Operating Officer
BC Hydro
333 Dunsmuir Street, 18th floor
Vancouver, BC V6B 5R3
P 604 623 4577
E chris.oriley@bchydro.com
bchydro.com
Smart about power in all we do.

From: Savidant, Michael
Sent: 2017, December 01 6:11 PM
To: O'Riley, Christopher; Yaremko, Cheryl
Cc: Reimann, Randy; Magre, Leela; Layton, Ryan
Subject:s.12,s.13

Chris/Cheryl,
s.12,s.13

Let me know if you have any questions.
-Mike

Michael Savidant
Manager – Commercial Negotiations
Business and Economic Development

BC Hydro
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P 604.623.3694

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Page 077

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s.12;s.13;s.17

Page 078 to/à Page 079

Withheld pursuant to/removed as

s.12;s.21;s.13;s.17

Page 080 to/à Page 081

Withheld pursuant to/removed as

s.12;s.13;s.17

Withheld pursuant to/removed as

s.12;s.13

From:	Rowe, Katherine EMPR:EX
To:	MacLaren, Les EMPR:EX
Cc:	Sopinka, Amy EMPR:EX; Wieringa, Paul EMPR:EX
Subject:	s.12,s.13
Date:	Friday, November 17, 2017 9:24:38 AM
Attachments:	s.12,s.13

s.12,s.13

Katherine Rowe
Director, Generation and Regulatory Branch | **NEW!** Phone: 778.698.7190| Cell: 250.216.5823 |Ministry of Energy, Mines and Petroleum Resources
Energizing BC—clean, sustainable and productive

From:	Sanderson, Melissa EMPR:EX
To:	Lloyd, Evan GCPE:EX; Gibbs, Robb GCPE:EX; Kristianson, Eric GCPE:EX; Zadravec, Don GCPE:EX; Haslam, David GCPE:EX; Howlett, Tim GCPE:EX
Cc:	MacLaren, Les EMPR:EX; Nikolejsin, Dave MNGD:EX
Subject:	FW: BCUC Site C Inquiry - Errata to Final Report
Date:	Thursday, November 16, 2017 6:09:08 PM
Attachments:	11-16-2017_A-26 Site C Report Errata.pdf A-26-1_Appendix-C_Commission-Illustrative-Alternative-Portfolio.xlsx

Hi everyone,

We received an errata today in our general Minister email box from the BCUC.

Thanks,

Melissa

From: Commission Secretary BCUC:EX
Sent: Thursday, November 16, 2017 4:42 PM
To: Minister, EMPR EMPR:EX
Subject: BCUC Site C Inquiry - Errata to Final Report

Dear Minister,

Please see attached correspondence with respect to the above-noted matter.

Original will not follow. A hard copy of the attached is available upon request.

Please call the BCUC Regulatory Services at 604-660-4700 to request a copy.

Regards,

Katie Berezan

Administrative Assistant, Regulatory Services

British Columbia Utilities Commission

P: 604.660.4700 **BC Toll Free:** 1.800.663.1385 **F:** 604.660.1102

bcuc.com

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bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

November 16, 2017

BCUC INQUIRY RESPECTING SITE C **A-26**

Sent via eFile

The Honourable Michelle Mungall, M.L.A.
Minister of Energy, Mines and Petroleum Resources
Parliament Buildings
PO Box 9060 Stn Gov't
Victoria, BC V8W 9E2
EMPR.Minister@gov.bc.ca

Re: British Columbia Hydro and Power Authority – British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922 – Final Report

Dear Minister:

Further to our letter yesterday attaching the errata to the Site C Inquiry Final Report, please be advised we have also corrected the Commission's Illustrative Alternative Portfolio spreadsheet as described in more detail within the errata.

Please see the complete errata attached to this letter, which will now be inserted into the Commission's Final Report and associated Executive Summary.

Please contact our office if you have any questions.

Sincerely,

for

Patrick Wruck
Commission Secretary

Page 086 to/à Page 118

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From:	Nikolejsin, Dave MNGD:EX
To:	MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Subject:	FW: City of Vancouver report calls for up to 75% increase in electrical load forecast
Date:	Wednesday, November 15, 2017 1:28:06 PM
Attachments:	image003.jpg

fyi

From: Greg D'Avignon [mailto:greg.davignon@bcbc.com]
Sent: November 15, 2017 1:11 PM
To: Nikolejsin, Dave MNGD:EX
Subject: City of Vancouver report calls for up to 75% increase in electrical load forecast

Met with the city today and they referenced the following report issued Oct 2017 (ironically after the close of the BCUC report) on their load forecast coming from the City of Vancouver's Renewable City Strategy as part of the sustainable city plan which has targets to have 100% renewable energy consumption in Vancouver before 2050. Ironically it calls on the opposite assessment of electrical load forecast than that of BCUC citing a substantive fuel switching to electricity as part of their plan in all modes of consumption inclusive of transportation, industrial, commercial, and residential . It look s like population growth of over 400,000 people and electricity largely form Hydro of over 50-75% depending on population growth models.
https://www.sitecproject.com/sites/default/files/CoV-Energy-and-Emissions-Forecast-Final-Report-Oct-10-2017.pdf

Greg D'Avignon
President and CEO
Business Council of British Columbia
810-1050 West Pender Street
Vancouver , B.C. V6E 3S7
Direct: 604-696-6586 | Mobile: 604-377-6740
www.bcbc.com | @bizcouncilbc

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Where Leaders Meet to Unlock BC's Full Potential

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From:	O"Riley, Christopher
To:	MacLaren, Les EMPR:EX
Subject:	s.12,s.13
Date:	Friday, December 1, 2017 7:24:49 AM
Attachments:	s.12,s.13

s.12,s.13

Chris O'Riley | President & Chief Operating Officer
BC Hydro
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Vancouver, BC V6B 5R3
P 604 623 4577
E chris.oriley@bchydro.com
bchydro.com
Smart about power in all we do.

From: Savidant, Michael
Sent: 2017, November 30 12:10 PM
To: O'Riley, Christopher
Cc: Fane, Lindsay
Subject: s.12,s.13

Chris,

s.12,s.13

-M

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Allied Hydro Council of BC

Representing BC Hydro dam construction workers since 1961

MEDIA ADVISORY Tuesday November 14, 2017

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Allied Hydro Council of BC

Representing BC Hydro dam construction workers since 1961

NEWS RELEASE Wednesday November 15, 2017

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From:	Foster, Doug FIN:EX
To:	MacLaren, Les EMPR:EX
Subject:	FW: s.12,s.13
Date:	Tuesday, November 21, 2017 6:09:57 AM

Fyi. D.

From: Dunn, Jonathan FIN:EX
Sent: Monday, November 20, 2017 12:15 PM
To: Foster, Doug FIN:EX
Subject: s.12,s.13

Hi Doug
s.12,s.13

Best
Jon

From: Foster, Doug FIN:EX
Sent: Sunday, November 19, 2017 12:55 PM
To: Gonzalez, Selina FIN:EX; Dunn, Jonathan FIN:EX
Subject: s.12,s.13

s.12,s.13

d.

From:	Haslam, David GCPE:EX
To:	Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX
Cc:	MacLaren, Les EMPR:EX; Grewar, Colin GCPE:EX; Beaupre, Darren GCPE:EX; Marshall, Samantha EMPR:EX
Subject:	FW: New version - Briefing Note on Report
Date:	Wednesday, November 1, 2017 9:24:38 AM
Attachments:	BN - Site C BCUC Panel deeply pessimistic about B.C.'s future FINAL.doc ATT00002.htm

Attached is BCH briefing note on report. Samatha – please print

BRIEFING NOTE – BCUC PANEL DEEPLY PESSIMISTIC ABOUT B.C.'S FUTURE

Confidential – Advice to Cabinet

Background and Summary

On November 1, 2017 the British Columbia Utilities Commission will issue its Final Report to the Government of British Columbia in the Site C Inquiry.

The Commission has provided a report and findings that are deeply pessimistic about B.C.'s economic future and unrealistic about what resources are available and their cost. The Commission has also established an "Illustrative Alternative Portfolio" that would result in a number of adverse outcomes for British Columbia's energy future.

The major issues identified to date are listed below:

1. The Commission has taken "no position on which of the termination or completion scenarios has the greatest cost to ratepayers" and does not calculate rate impacts. However, incremental rate increases would be more than 10% over a 10-year recovery period if Site C were terminated, and electricity would be less affordable for British Columbians.

2. The Commission's Load Growth Scenario assumes that British Columbia's economy will slow, large industry will leave the province and jobs will be lost across a number of sectors.

3. BC Hydro takes risks on unproven alternative capacity resources and appears to rely on demand-side management for over 900MW of capacity. This would result in higher costs and reliability impacts for customers if these capacity resources fail to materialize.

4. BC Hydro finances all new projects, resulting in a diminished role for the clean energy industry and more debt and risk on BC Hydro's balance sheet.

5. The mitigation options proposed would increase greenhouse gas emissions in B.C.

6. The majority of First Nations affected by Site C do not oppose the Project and would lose benefits if Site C were to be terminated..

Initial Assessment of the Final BCUC Report

1. Overall, electricity would be less affordable for British Columbians.

- If Site C were terminated, there are $3.9 billion in costs that must be recovered, from either the taxpayer or the ratepayer: $2.1 billion in costs incurred prior to termination ("sunk costs") and $1.8 billion in termination costs (according to the Commission Panel's estimates) which are expected to be incurred over the next two years.

- This is expected to result in an incremental increase to BC Hydro's rates of more than 10% over a 10 year recovery period.

- The report also assumes that termination costs are amortized (recovered) over 30 years so as to reduce the up-front rate impacts. The longer this period, the more carrying costs BC Hydro has to pay. This would also mean asking a ratepayer in 2045 who is not even born today to pay for a project cancelled in 2017.

- It appears from the Commission's assumptions that sunk costs of $2.1 billion may be included in the completion scenario, but not in the termination scenario. If this correct, this would be a very significant methodological error that understates the cost of the alternative portfolio.

- The Commission has stated that BC Hydro's revised forecast of $8.945 billion results in the use of all of the remaining project contingency. This is incorrect. This forecast preserves the remaining project contingency to manage future risks.

2. The Commission's Load Growth Scenario assumes that British Columbia's economy will slow, large industry will leave the province and jobs will be lost across a number of sectors, not just at BC Hydro or the Site C project.

- The scenario that makes the Commission's alternative portfolio work (a low load scenario or even lower than the low load case) is one that assumes that future provincial electricity demand is unreasonably low. This is a scenario in which the Province has failed to deliver a strong economy, businesses have exited the province, Liquefied Natural Gas has failed to materialize and there has been a failure to deliver on GHG commitments through electrification.

- This low load scenario means a loss of jobs associated with the failed industrial businesses, without new jobs to replace them. This is in addition to the job losses and other negative economic impacts that would result from the termination of Site C.

- The Commission scenarios are premised on the assumption that none of the Liquefied Natural Gas projects (LNG Canada, Woodfibre, FortisBC Tilbury Phase 2) included in BC Hydro's load forecast will proceed.

- The report finds that low-carbon electrification should not be included in the load forecast for the purpose of resource planning. Disregarding the impacts of electrification altogether cannot be reconciled with the Province's commitment to reduce greenhouse gas emissions.

3. BC Hydro takes risks on unproven alternative capacity resources, with higher costs and reliability impacts for customers if these fail to materialize.

- The Illustrative Alternative Portfolio used by the Commission requires BC Hydro takes risks on alternative resources that have not been proven to be viable or cost-effective, including what appears to be over 900MW of capacity from demand-side management.

- Dispatchable storage hydro provides "dependable capacity": these are resources that BC Hydro can depend upon to meet customer needs when they are greatest. Dependable capacity is critical to system reliability.

- Reducing BC Hydro's access to dependable capacity could create an increased risk to reliability and/or require BC Hydro to import power when it is most costly.

- The Illustrative Alternative Portfolio includes almost no new capacity resources – rather it relies on 900MW of capacity from demand-side management. Capacity-focused demand-side management is highly uncertain, and the Commission has relied on substantially more MW than BC Hydro believes is feasible. The report further suggests that BC Hydro could encourage hot water shutoffs during periods of peak demand and could implement time of use rates. This points to the risk that the current reliability of the system that British Columbians depend upon could be compromised.

- The report concludes that because BC Hydro has substantial existing dispatchable resources, a portfolio with resources that are not dispatchable is viable. This is incorrect. New renewable intermittent resources like wind, solar and run-of-river hydro require the support of dependable and flexible resources like storage hydro.

- The Illustrative Alternative Portfolio includes 81MW of geothermal projects starting in Fiscal 2025. However, the report also states that "there may actually be no geothermal potential" in B.C. There is a risk to making this assumption, given that after decades of investigation, there are no successful geothermal projects anywhere in B.C.

4. BC Hydro finances all new projects, resulting in a diminished role for the clean energy industry and more debt and risk on BC Hydro's balance sheet.

- For decades, BC Hydro has partnered with the clean energy industry in purchasing power from independent power producers.

- The report assumes that BC Hydro finances all incremental resources. In effect, this leaves no future role for the independent clean energy sector, and runs counter to the long-standing policy of having the private sector develop, finance and assume the risk for these projects.

5. Mitigation options proposed would increase greenhouse gas emissions in British Columbia.

- The Commission Panel suggests that, with policy changes, gas-fired generation is an option to meet future energy needs and to mitigate the risk of alternatives. This would include remobilizing Burrard Thermal to provide capacity to the electricity system.

- The report suggests that fuel-switching can lower energy demand, which implied fuel switching from electricity to fossil-fuel based sources, increasing greenhouse gas emissions. In fact, the expanded use of electricity in the place of fossil fuels to reduce greenhouse gas emissions (low-carbon electrification), increases demand for electricity.

6. The majority of First Nations affected by Site C do not oppose the Project and would lose benefits if Site C was terminated.

- While the report refers to impacts on First Nations, the majority of the First Nations affected by the Project do not oppose the Project and would lose long-term benefits if it is terminated.

- One of those First Nations, McLeod Lake, stated in the Inquiry process that termination will unravel the process of reconciliation and be economically catastrophic for their community.

From:	Marshall, Samantha EMPR:EX
To:	Nikolejsin, Dave MNGD:EX; MacLaren, Les EMPR:EX
Cc:	Cochrane, Marlene EMPR:EX
Subject:	FW: Site C Dam Impact on BC Manufacturing
Date:	Thursday, November 23, 2017 8:49:12 AM
Attachments:	Site C Impact on BC Manufacturing20171123.pdf image001.png image003.jpg

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Good morning,

Melissa has asked me to forward this to your attention.

Thank you,

Samantha Marshall
Administrative Assistant to the Honourable Michelle Mungall
Minister of Energy, Mines and Petroleum Resources
Phone: 250-953-0900
Email: Samantha.Marshall@gov.bc.ca

Canadian Manufacturers & Exporters
British Columbia

Suite 2163 – 13353 Commerce Parkway
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Tel: (604) 713-7800
bc.cme-mec.ca

Samantha)
Please
Scan + Store
With Dave N +
Marlene + Les

November 14, 2017

The Honourable Michelle Mungall
Minister of Energy, Mines and Petroleum Resources
Room 301, Parliament Buildings
Victoria, BC V8V 1X4

RE: Site C Dam Impact on BC Manufacturing

Dear Minister Mungall,

I am writing on behalf of Canadian Manufacturers & Exporters (CME) to encourage the BC government to move forward on the Site C dam project.

The BC Utilities Commission (BCUC) report made clear that the risks to the ratepayers are roughly equivalent whether the government proceeds with the project or not. Government must base its decision on issues outside of the contents of the report.

As detailed in the attached submission, CME has identified four specific issues that mandate government to proceed with the Site C project:

1. The report does not account for the increased electricity usage demanded by the electrification of things like transportation and home heating. That shift will have a significant impact on load demands.
2. The economic benefits of proceeding go beyond the jobs on site and include the manufacturers around BC that provide material like steel, bolts, and concrete to the project.
3. CME members have indicated that ongoing cancellation of major projects will negatively impact their decisions around investment and job creation in BC.
4. Future investment in industries that feature significant amounts of processing, like hydrogen power development or manufacturing solar power ingots and cells, demands access to firm electrical power.

CME believes that government is faced with a choice between providing a boost to BC's economy by proceeding with the project at the risk of one day having too much clean electrical power generation; or creating short term harm to our economy by cancelling the project, and running the risk of not having enough clean power for our electrical future.

The choice seems clear.

Sincerely,

Andrew Wynn-Williams
Divisional Vice President, British Columbia

MINISTER OF ENERGY, MINES, AND PETROLEUM RESOURCES
REFERRAL NUMBER
DRAFT REPLY ☐ INFO/FILE ☒ REPLY DIRECT ☐
RECEIVED NOV 20 2017
REFER TO: Deputy for files
REMARKS

cc: The Hon. John Horgan, Premier
The Hon. Bruce Ralston, Minister of Jobs, Trade and Technology

encl: CME Analysis of the BC Utilities Commission Inquiry Respecting Site C Dam, November 2017

Canadian Manufacturers & Exporters
British Columbia

Canadian Manufacturers & Exporters

ANALYSIS OF THE BC UTILITIES COMMISSION INQUIRY RESPECTING SITE C DAM

November 2017

Introduction

On November 1, 2017 the BC Utilities Commission (the Commission) released its final report *Inquiry Respecting Site C*. To prepare the report the Commission investigated three separate cases. These were:

1. To proceed with the dam construction as planned.
2. To cancel the project, remediate the site and invest in alternative energy portfolios.
3. To delay the project and proceed or not at a later date.

The Commission investigated the accuracy of the information leading to BC Hydro's initial decisions, made its own estimations of the cost of each decision, and analysed the resulting risk to the ratepayer. CME would like to commend the Commission for its through and responsible approach to the preparation of this report.

Key Findings

As one key finding of the report, the Commission strongly advised against delaying the decision on the project to later date. This option represented the greatest risk to the ratepayer and the greatest long term cost.

With respect to the other two options however, the decision is not as clear. The Commission identified risks with both cases. The risks in each case revolved around the average load and corresponding costs. The Commission recommended scaling back BC Hydro's load projections but was also cautious in its approach to other elements of the future. It has noted that disrupting technologies could undermine the need for the Site C power, but also that such technologies could be more expensive than projected, or in the case of geothermal, have not yet been proven viable in British Columbia.

This analysis of the future cost to ratepayers included potential cost overruns if the project proceeds, and the cost of cancelling the project and remediating the site if the project does not. After including all of these issues and their potential impact on ratepayers, the BCUC very clearly states that it does not take a position on either proceeding with or cancelling the project. In fact, the key finding of the report was that: *"... the cost to the ratepayers of Site C and the Illustrative Alternative Portfolio are virtually equivalent, within the uncertainty inherent in the assumptions."*

In other words, the Commission has placed the decision firmly into the hands of government to proceed or not based on issues outside the impact on the ratepayer. Given this, there are issues outside the scope of the report that warrant proceeding with the project.

Accounting for Paradigm Shift

When estimating the future electrical loads required by British Columbia there are two key issues that were not considered either by BC Hydro or the Commission. One is the ongoing conversion to electricity of energy usage currently served by fossil fuels (transportation, home heating, and etcetera). The second is the disruptive potential of distributed, home-based micro-generation. These issues were not overlooked in error but were deliberately omitted because they represent a paradigm shift, as opposed to normal forecasting.

Although the Commission has not considered these issues it is critical that government take them into account. Given initiatives like the City of Vancouver banning the use of natural gas and the increasing pace of vehicle electrification, the shift to electrification of our transportation and move away from fossil fuels is a far more prevalent, urgent and ongoing change.

Economic Impacts

From the perspective of the manufacturing industry, this decision must be made based not just on the risk to the ratepayer, but on the risk to the economy. The negative impacts on our economy would be both immediate, for those directly related to the project, and long term, for those considering investing in British Columbia.

The economic benefits of proceeding are clear for the industry in terms of jobs and investment. Beyond the 2,000 jobs created on the site, there is also the economic boost caused by the demand for materials created by BC manufacturers. These include companies that make products like steel, bolts and fasteners, concrete, and related equipment. Many have already made business plans based on this project.

There is also a risk to the overall economy should the government decide not to proceed. Consultation with CME members indicates that, should the cancellation of major projects in BC continue, it will lead to job losses within those companies, or potentially, companies leaving BC altogether. The short-term job losses would be compounded by a longer term impact on investment, particularly in the northern regions of our province. This represents a significant risk to BC's economy.

Future Industrial Development

Another issue not considered by the Commission is the potential that long-term, firm, predictable, and relatively inexpensive power provides for future industrial development. The uncertain future of LNG development in BC has led to that no longer being considered a significant driver of usage, however there are other power heavy processing industries that BC could attract with the electricity generated by Site C.

Importantly, some of these are directly related to the development of clean energy solutions. The hydrogen and fuel cell industry is an excellent example. In conjunction with battery electric vehicles, hydrogen fuel cells will be used to power vehicles and used as range extenders in hybrids. The benefit of hydrogen is zero emissions at the tail pipe. When the hydrogen is produced from electrolysis with clean energy such as hydro, truly emission free transportation can be achieved. Further development could also come from the opportunity to export bulk hydrogen to Asia, manufactured in BC from our clean, renewable and relatively low cost hydro power.

Another industry with similar considerations is the development of solar power ingots and cells. The most important consideration for the development of such items is not access to market but instead access to power and silicon. The development of Site C might not secure such investments but cancelling it would most likely remove BC from consideration for such important industrial development.

Conclusion

The Commission report has narrowed down the government's choices. It has concluded that, within the parameters of its mandate, the decision to proceed with the project or to cancel the project would represent roughly equal risk to the province in terms of cost. Given the other issues around the paradigm shift to higher electricity usage, the risk to the economy and the potential economic development that Site C represents, the choice seems clear.

If the government proceeds with the project it provides a boost to the economy at the risk of, one day, having too much clean electrical power generation (and hence a higher cost to the ratepayer). If the government cancels the project it creates economic harm in the short term, precludes certain long term economic development opportunities and still runs the risk of not having enough clean power for our electrical future.

Recommendation:
That the Provincial Government proceed with the construction of the Site C dam.

From:	Savidant, Michael
To:	MacLaren, Les EMPR:EX; Foster, Doug FIN:EX
Cc:	Magre, Leela
Subject:	FW: Site C Inquiry - BC Hydro Results of Analysis of Commission Portfolio
Date:	Tuesday, November 28, 2017 10:05:55 AM
Attachments:	2017_11_27_SiteC_BCH_CRSP.pdf

Not sure if you guys got a copy of this – this is the final letter on PV results we submitted to the BCUC yesterday.

From: BC Hydro, Regulatory Grp
Sent: 2017, November 27 10:00 AM
To: BC Hydro, Regulatory Grp; James, Fred
Cc: Ferreira, Alice
Subject: Site C Inquiry - BC Hydro Results of Analysis of Commission Portfolio

Please find attached:
BC Hydro Results of Analysis of Commission Portfolio submitted to BCUC on November 27, 2017

Please read the attachment for full details.

You are receiving this email for information only. If you no longer wish to receive emails regarding this matter or if you feel there are others who should receive these emails going forward, please notify bchydroregulatorygroup@bchydro.com.

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Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

November 27, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1598922
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Results of Analysis of Commission Portfolio

BC Hydro is writing further to our letter to the Commission of November 16, 2017. As described in our previous letter, BC Hydro has now utilized our portfolio and rate impact models to analyze the assumptions made by the Commission in its Illustrative Alternative Portfolio referenced in the Final Report. This document provides a summary of the findings from our analysis utilizing these assumptions.

Our analysis of the Commission's Illustrative Alternative Portfolio addresses the methodological errors identified to the Commission in our November 16, 2017 letter, but has retained the Commission's assumptions in the analysis of the Illustrative Alternative Portfolio where they appear to be deliberate. Please refer to Attachment 1 for a summary of these corrections. Further details on the analysis methodology and results are provided in Attachments 2, 3 and 4.

BC Hydro continues to have concerns with a number of the assumptions made by the Commission in its Illustrative Alternative Portfolio. We believe the costs and resources utilized in this portfolio have a very low probability of occurring or of being achievable. As such, BC Hydro makes no representation on our ability to deliver this portfolio in the manner assumed by the Commission.

We have provided two scenarios:

1. A scenario which is consistent with the Commission's past decisions on how to assess the cost to ratepayers of demand-side management and current policy regarding financing of alternative resources, specifically:
   - Using Total Resource Cost (**TRC**) for demand-side management resources rather than the Utility Cost.

- Using IPP financing rates for new generation resources, reflective of IPPs constructing alternative resources other than Site C and upgrades to BC Hydro facilities.

2. A scenario which utilizes the Commission's assumptions from the Final Report regarding the cost of demand-side management and financing of alternative resources, specifically:
   - Using Utility Cost rather than Total Resource Cost.
   - Using BC Hydro rather than IPP financing rates.

The key findings from this updated portfolio analysis as compared to previous BC Hydro submissions are shown in Table 1 below. We have performed calculations for the Low and Mid Load forecasts. We have not had sufficient time to calculate impacts for the High Load forecast.

Table 1 provides:

- Present value results representing the difference in present value costs between the Terminate and Continue scenarios.
- Incremental Cumulative Rate Impacts, which represent the difference in rates between the Terminate and Continue scenarios.

Table 1 Ratepayer Impacts of Site C Termination

Portfolio Assumptions	Current Policy and Precedent (TRC & IPP Financing)				Commission Assumptions (Utility Cost & BCH Financing)			
Present Value Cost Analysis ($2018 billions)								
Low Load Forecast	1.7				0.8			
Mid Load Forecast	4.2				2.0			
Estimated Incremental Cumulative Rate Increases (%)								
	F20	**F24**	**F44**	**F94**	**F20**	**F24**	**F44**	**F94**
Low Load Forecast	6.8	7.7	10.5	36.5	6.8	7.7	9.0	32.5
Mid Load Forecast	6.4	7.2	8.3	25.1	6.4	7.2	3.8	13.8

As shown by these results:

- Terminating Site C results in $1.7 billion of higher present value costs to ratepayers than completing Site C, even when utilizing the low load forecast and the assumptions in the Commission's Illustrative Alternative.
- Terminating Site C results in higher cumulative rate impacts in all years relative to completing Site C, even when utilizing the low load forecast and the assumptions in the Commission's Illustrative Alternative.
- Utilizing a 30-year amortization period for termination and sunk costs (as the Commission assumes for termination costs) results in a near-term rate impact of approximately 7 per cent for five years when coupled with the Commission's

Illustrative Alternative Portfolio assumptions. This initial rate impact would be greater than 10 per cent if a ten-year amortization period is utilized.

- BC Hydro believes it is contrary to the regulatory principle of intergenerational equity to have future ratepayers pay for a project decades from now that had been cancelled and from which they are deriving no benefit.

- In all portfolios, cumulative rate impacts of Termination are larger in the low load than the mid load forecast. This is because of the reduction in customer sales resulting from the combination of low load growth and a large amount of incremental demand-side management in the Commission's Illustrative Alternative Portfolio.

Figure 1 and Figure 2 below show the annual cumulative rate impacts, as set out in Table 1, of Termination as compared to Completion of Site C under the Low and Mid Load forecasts (respectively).

Figure 1 Incremental Rate Impacts: Termination, Low Load

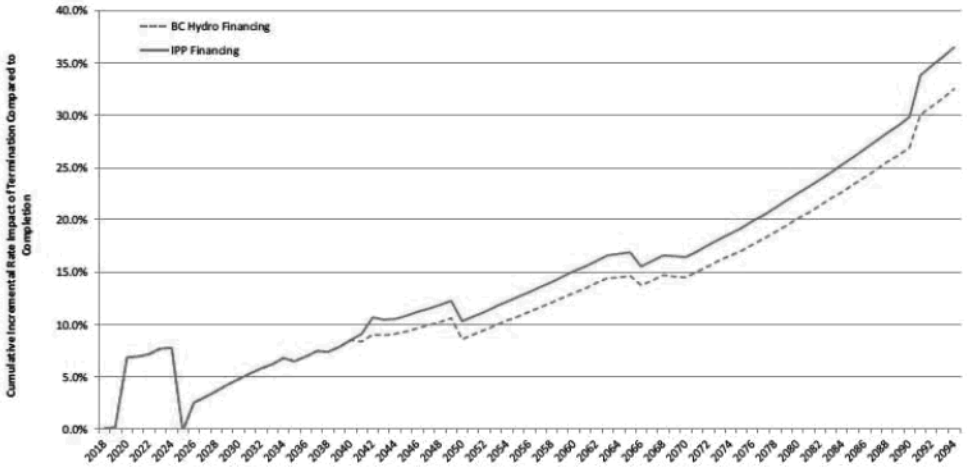
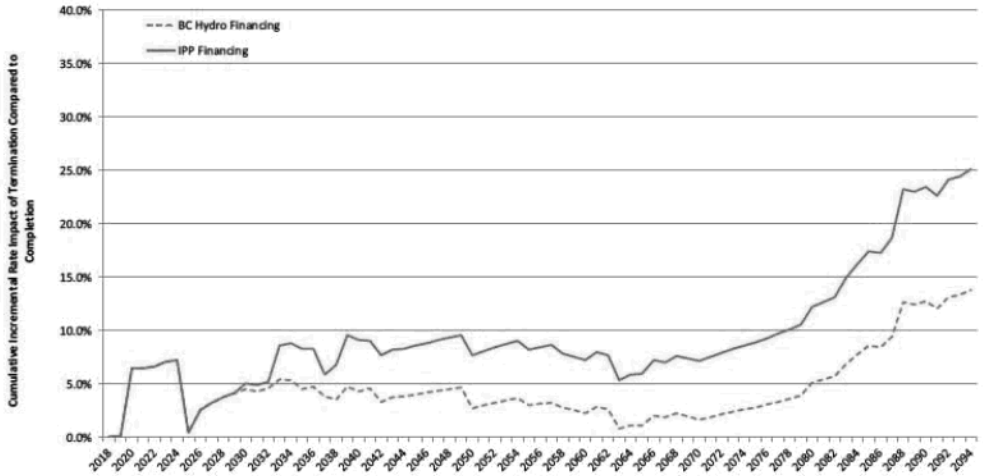


Figure 2 Incremental Rate Impacts: Termination, Mid Load



For further information, please contact Fred James at 604-623-4046 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

fj/ma

Enclosures (4)

Attachment 1	Summary of Methodology and Areas of Correction
Attachment 2	Comparison of Analysis to Previous Filings
Attachment 3	Resources Identified in Analysis using Illustrative Alternative Portfolio
Attachment 4	Incremental Cumulative Rate Impact Analysis

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Site C Inquiry

Results of Analysis of Commission Portfolio

Attachment 1

Summary of Portfolio Modelling Methodology and Assumptions

1 BC Hydro Portfolio Modelling, Corrected For Commission's Methodological and Input Errors

BC Hydro's portfolio modelling corrects for the following errors in the Commission's model, as outlined to the Commission in our letter of November 16, 2017:

- Applying the correct discount rate to Site C surplus.
- Correction of inconsistent inflation factors, financing costs, and discount rates.[1]
- Elimination of double-counting of transmission losses on demand-side management.
- Recovery of sunk costs in both the scenario where Site C is completed (over 70 years) and the scenario where Site C is terminated (over 30 years, as used by the Commission for termination costs).
- Applying the correct binary technology to geothermal resources rather than flash technology.

BC Hydro's portfolio analysis methodology also provides a long-term system-wide assessment of the costs of the options available to BC Hydro to meet customer load. The key benefits of this methodology as compared to a more simplified method include:

- Allows for selection of resources in an optimal manner, rather than assuming specific resources come into service. System Optimizer (a third party tool used by BC Hydro to identify the most cost-effective resource options) selects from available resources in order to find the lowest present value cost to ratepayers. Note that, as shown in Attachment 3, BC Hydro's system optimizer makes different resource selections that the Commission's Illustrative Alternative Portfolio. This is because these resources have lower costs to ratepayers than the ones selected by the Commission. Key differences are:
  - Use of Industrial Load Curtailment (**ILC**) for a larger number of years than the Illustrative Alternative.
  - Selection of wind and pumped storage as the preferred generation-side resource rather than geothermal resources. Table 1 below shows an illustrative comparison of the cost of wind and pumped storage in 2040 using the Commission's cost assumptions (i.e. BC Hydro financing) to the cost of geothermal using the cost assumptions appropriate for binary rather than flash technology. As shown, a combination of wind and pumped storage is less expensive than geothermal when the Commission's cost assumptions are used. If we were to force the inclusion of geothermal resources as in the Commission portfolio, alternative portfolio costs would increase.

[1] Note that subsequent to the preparation of our November 16, 2017 letter, BC Hydro discovered that the Commission's model did not take into account higher near-term interest rates. This has also been corrected for in the current analysis.

Table 1 Comparison of Geothermal and Wind + Pumped Storage Unit Energy Costs ($2018, using BCH financing)

Resource	Units	Commission Illustrative Alternative[2]
Wind (new-build @ POI with wind integration)	$/MWh	44
Pumped Storage (new-build @ POI)	$/kW-year	53
Cost of equivalent wind + pumped storage block	**$/MWh**	**48**
Geothermal	**$/MWh**	**80**

  - Note that System Optimizer does not have functionality to select demand-side management options other than ILC. As a result we have assumed the same timing for energy-focused DSM as in the Commission Illustrative Alternative.

- A long-term evaluation period that provides analysis representative of the impact to ratepayers of the decision to complete or terminate Site C.
  - This includes in the evaluation the impact of the decision on Site C to "what comes next" to meet domestic load.
  - The Commission's analysis used a shorter period for assessing costs and benefits and a fixed amount of energy and capacity. These constraints create a false comparison between resources (such as enhanced DSM) that would be pursued in all cases. Refer to our comments on the Commission's October 11, 2017 portfolio (Exhibit F1-17) for additional discussion.
- Analysis based upon BC Hydro's planning view of the load resource balance, rather than an operational view as used by the Commission.
  - BC Hydro's planning view of the Load Resource Balance reflects the capability of resources based on BC Hydro's planning criteria, including the requirement contained in subsection 6(2) of the *Clean Energy Act* to achieve electricity self-sufficiency under prescribed water conditions from its hydroelectric Heritage assets. The planning view is what determines the timing of future resource acquisitions.
  - An operating view of the Load Resource Balance reflects the forecasted operation of the same resources (as determined by the planning view of the load resource balance) given market conditions, expected system conditions in the near term and average

[2] Note that the unit energy costs we have utilized in our analysis of the Commission's Illustrative Alternative have been calculated based on the Commission's cost decline assumptions stated in their Final Report. These unit energy costs are approximately 2 to 3 $/MWh lower than what the Commission seems to be utilizing in their spreadsheet model. We are unclear if this is an error in the stated assumptions, the spreadsheet calculation, or BC Hydro's interpretation of the Commission's intent. We emphasize that our methodology is more conservative and favors the alternative portfolio.

conditions in the long term.[3] Use of an operating view incorrectly advances the apparent need for new resources by approximately two years.

- Consideration of transmission impacts of resource options.
  - In integrating a resource option to BC Hydro's system, there needs to be (i) transmission from the generator to a point of interconnection on the BC Hydro system which is typically at a substation at a lower voltage than 500 kV, (ii) upgrades that are required from the lower voltage sub-station to the 500 kV bulk system, and (iii) upgrades on the bulk transmission system.
  - BC Hydro's resource option costs include the cost of transmission from the generator to a point of interconnection on the BC Hydro system. BC Hydro's portfolio modelling also includes the costs of network upgrades that are required to accommodate IPP projects on the transmission lines from the IPP point of interconnection to the 500 kV bulk system, which further understates the costs associated with these resources. The costs of network upgrades were estimated based on costs that were identified from the Clean Power Call
  - The Commission appears to have interpreted network upgrades to be included in the transmission costs from the project to the point of interconnection and have not considered any other transmission costs.
  - BC Hydro's portfolio modelling includes an assessment of when bulk transmission upgrades will be required to enable incremental resource options to effectively supply domestic demand. These upgrades were explicitly excluded from the Commission's analysis.
- Consideration of the market benefits provided by shaping capability.
  - BC Hydro's portfolio modelling reflects the daily, monthly and seasonal value to resource shaping, in contrast to the Commission's use of a flat Mid-C export price.
- Consideration of the actual cost of financing resources, through the use of IPP financing for new generation resources other than Site C, upgrades to BC Hydro facilities, and DSM. This is consistent with current practice and policy regarding the development of IPP resources.
  - We have also included a scenario in which BC Hydro financing is used for IPP resources rather than IPP financing.
- Consideration of the actual cost of demand-side management to ratepayers, through the use of the Total Resource Cost rather than solely the Utility Cost. This is consistent with a ratepayer perspective and how the Commission has considered DSM costs in the past.

---

[3] The most obvious difference between the Planning View and the Operational View is the energy from dispatchable thermal resources. The Planning View reflects the firm energy that dispatchable thermal resources are capable of generating and can be relied upon for planning purpose (Island Generation at 2,170 GWh and Prince Rupert Generating Station at 180 GWh). In contrast, the Operational View shows how much dispatchable thermal resources are expected to run (Island Generation at 140 GWh and Prince Rupert at 0 GWh).

- The incremental costs in the Total Resource Cost are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.
- We have also included a scenario where the Commissions assumption of Utility Cost is used over the Total Resource Cost.

2 Rates Modelling of Cumulative Rate Increases Alternative Portfolios as Compared to Site C

For each scenario, BC Hydro estimated the incremental impact on the main components of BC Hydro's total revenue requirement (amortization, finance charges, operating costs and energy costs), compared with their respective base cases (i.e., continuation of Site C).

For both load scenarios, the incremental impact is measured against hypothetical Base Cases which use the same Commission cost and DSM assumptions described above. In both the Base Cases and the Termination Cases, BC Hydro's system optimizer selects the most cost-effective resources to meet customer demand based on either the mid or low load forecast.

The incremental changes to BC Hydro's revenue requirement, as well as changes to revenue from incremental DSM, are used to estimate the incremental cumulative rate increases for each scenario. The estimated incremental cumulative rate increases represents the magnitude (in percentages), in a given future year, that cumulative rate increases (compared with current fiscal 2017 rates) would be higher or lower in the scenario than they would have otherwise been in the base case, in that same year.

BC Hydro considered the following main items in estimating the ratepayer impact under a termination and remediation scenario:

1. Costs spent to-date on advancing the Project and costs directly related to termination and remediation; and
2. Costs for ratepayers of advancing energy and capacity resources in comparison to a portfolio that includes the Project.

These incremental costs are described below:

- Remove:
  - Site C costs of $10 billion (total Site C construction costs as estimated by the Commission including the forecast balance of Site C Regulatory Account) are removed at the end of fiscal 2024;
  - Site C operating costs (comprised of water rental costs, operating costs, and taxes) are removed beginning in fiscal 2025; and
  - Future sustaining capital expenditures totalling $2.1 billion are removed from the fiscal 2024 to fiscal 2094 period.

- Replace with:
  - Site C Regulatory Account costs of $4.0 billion (sunk, termination and remediation costs) are added at the end of fiscal 2019. These are comprised of the costs of $3.8 billion recognized as shown below at December 31, 2017 (which would increase by interest to $4.0 billion by the end of fiscal 2019):
    - Project capital costs to termination date ($1.6 billion);
    - Costs already in the Site C regulatory account ($0.5 billion); and
    - Costs directly related to the Project termination and remediation that would be recovered from ratepayers ($1.7 billion of recognized present value, which will increase to $1.8 billion, to be recovered from ratepayers); and
  - Incremental cost of advancing alternative sources of energy and capacity in order to compensate for the removal of Site C. These include advancing both energy and capacity focused DSM measures and generation resources.

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Results of Analysis of Commission Portfolio

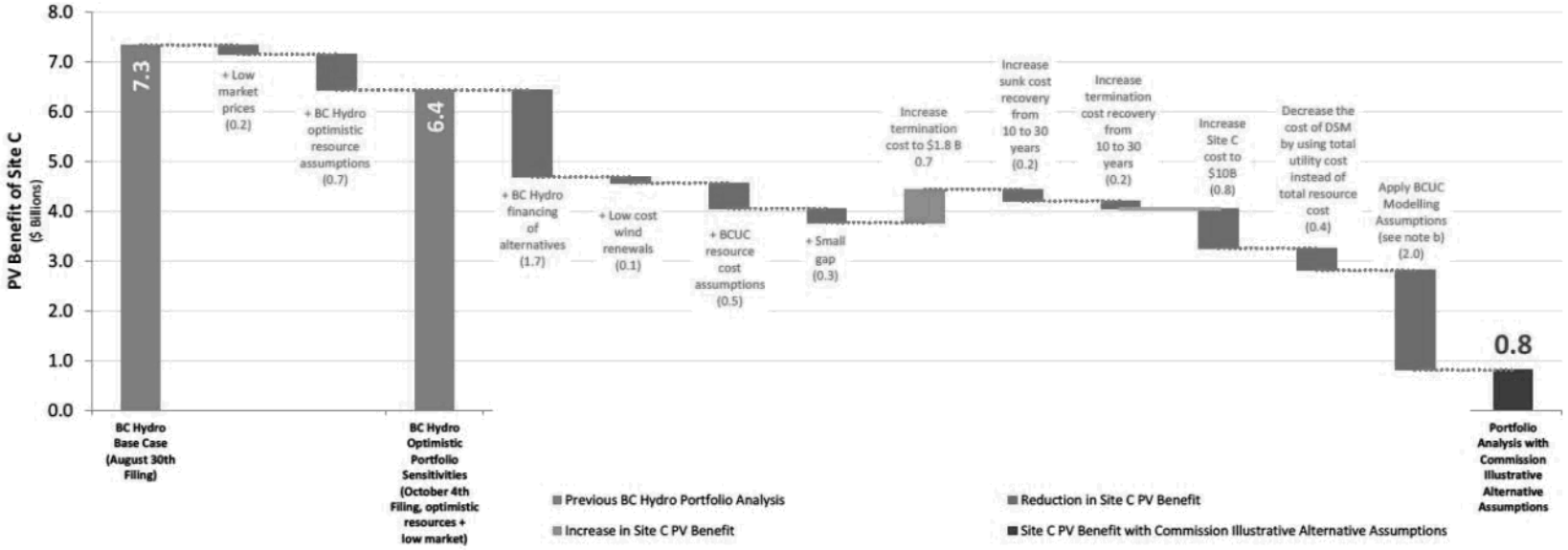
Attachment 2

Comparison of Assumptions and Results to Previous Filings

Assumptions Scenario	August 30 Filing	BC Hydro Optimistic Portfolio Sensitivity	Commission Illustrative Alternative Portfolio Assumptions
MODEL ASSUMPTIONS			
Load Forecast Scenarios	- Low / Mid / High	- Low / Mid / High	- Low / Mid (insufficient time to run high load scenario)
Financing Assumption	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances Site C, DSM, and Resource Smart - IPP financing for alternatives (BCH financing run as sensitivity)
Market Prices	- ABB Mid Forecast	- ABB Mid Forecast	- BCUC Market Price Forecast
Site C Costs	- $8.335 billion	- $8.335 billion	- $10 billion
Termination and Sunk Costs	- $3.2 billion ($2.1 sunk costs, $1.1 termination costs)	- $3.2 billion ($2.1 sunk costs, $1.1 termination costs)	- $3.9 billion ($2.1 sunk costs, $1.8 termination costs)
Sunk & termination cost recovery period	- 10 years	- 10 years	- 30 years
ALTERNATIVE RESOURCE ASSUMPTIONS			
Energy focused demand-side management	- Baseline: RRA DSM plan - Option: 2012 IRP option 2 - Total Resource Cost	- Baseline: RRA DSM plan - Option: 2012 IRP option 2 - Total Resource Cost	- Baseline: 2012 IRP option 2 - Total Resource Cost (Utility Cost run as sensitivity)
Capacity Focused DSM	- Industrial Load Curtailment: 85 MW	- Industrial Load Curtailment: 85 MW - Capacity Focused DSM potential: 450 MW	- Industrial Load Curtailment: 400 MW - Capacity Focused DSM and optional TOU potential: 640 MW

Assumptions Scenario	August 30 Filing	BC Hydro Optimistic Portfolio Sensitivity	Commission Illustrative Alternative Portfolio Assumptions
Resource Smart	- Revelstoke Unit 6 when selected by model	- Revelstoke Unit 6 when selected by model - GMS upgrade when selected by model	- Revelstoke Unit 6 assumed in-place in Fiscal 2026
Wind	BC Hydro Resource Options Update w/ IPP financing.	Lower wind costs w/ IPP financing.	Lower wind costs, with further reductions for refurbishment/renewal.
Pumped Storage	BC Hydro Resource Options Update	BC Hydro Resource Options Update	BC Hydro Resource Options Update
Geothermal	Excluded as not confirmed to be commercially viable	- 200 MW of potential	- 80MW of potential at reduced prices (not selected in portfolio)
Solar	Excluded as not economic	Modeled using NREL mid cost declines (43% by 2040) (not selected in portfolio)	Modeled using Commission-suggested cost declines (60% by 2040) - (not selected in portfolio)
Batteries	Excluded as not economic	Modeled using Commission-suggested cost declines (50% by 2040) (not selected in portfolio)	- Screened out due to high cost. Aligns with suggestion in the Commission's final report.

Impact of Changes to Portfolio Assumptions and Methodologies [a]



Notes:

a. The value differentials are applied left to right in order. This is important, as there are overlap effects between some changes. As a result, if some changes are applied earlier in the "cascade" they will have a larger impact.

b. The BCUC Modeling Assumptions that make up the $2 billion difference in PV include:
   - Use of 630 MW of Capacity focused DSM + Optional Time of Use rates;
   - Use of 400 MW of industrial load curtailment with no long-term commitments (i.e., can be "switched on and off" year to year);
   - Optimistic assumptions regarding renewal of wind projects;
   - Commission market price assumption instead of ABB market prices; and
   - Reduction in wind integration adder to $1/MWh.

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Results of Analysis of Commission Portfolio

Attachment 3

Resources Selected in Analysis using Illustrative Alternative Assumptions

Continue Site C, Mid Load Forecast							
Generation				DSM			
Year	Name	Capacity	Annual Energy	Year	Name	Capacity	Annual Energy
2023	Site C	1145	5286	2024	BCUC_CFDSM_2025start	210	0
2025	Revelstoke Unit 6	500	26	2024	BCUC_oTOU_2025start	430	0
2035	Wind_PC18	138	524	2029	Ind Load Curtailment	100	0
2035	Wind_NC09	333	1074	2032	Ind Load Curtailment	150	0
2036	Pumped_Storage_LM	1000	0	2033	Ind Load Curtailment	250	0
2038	Wind_PC14	144	570	2034	Ind Load Curtailment	400	0
2039	Wind_PC28	153	641	2035	Ind Load Curtailment	400	0
2040	Wind_PC10	297	1119	2038	Ind Load Curtailment	100	0
2040	Wind_PC48	150	538	2039	Ind Load Curtailment	300	0
2041	Wind_PC20	156	594	2040	Ind Load Curtailment	400	0
2041	Pumped_Storage_LM	1000	0				
2042	Wind_VI02	147	446				

Terminate Site C, Mid Load Forecast							
Generation				DSM			
Year	Name	Capacity	Annual Energy	Year	Name	Capacity	Annual Energy
2025	Revelstoke Unit 6	500	26	2018	BCUC_oTOU_2018start	430	0
2029	Wind_NC09	333	1074	2018	BCUC_CFDSM_2018start	210	0
2032	Wind_PC14	144	570	2024	Ind Load Curtailment	250	0
2032	Wind_PC18	138	524	2025	Ind Load Curtailment	50	0
2032	Pumped_Storage_LM	1000	0	2026	Ind Load Curtailment	150	0
2033	Wind_PC20	156	594	2027	Ind Load Curtailment	300	0
2034	Wind_VI02	147	446	2028	Ind Load Curtailment	350	0
2035	Wind_PC28	153	641	2029	Ind Load Curtailment	400	0
2035	Wind_PC48	150	538	2030	Ind Load Curtailment	250	0
2036	Wind_PC13	135	577	2031	Ind Load Curtailment	400	0
2037	Wind_PC10	297	1119	2035	Ind Load Curtailment	150	0
2037	Wind_PC17	102	335	2036	Ind Load Curtailment	400	0
2037	Wind_SI15	303	898	2037	Ind Load Curtailment	400	0
2038	Pumped_Storage_LM	1000	0	2040	Ind Load Curtailment	150	0
2039	Wind_PC19	117	482	2041	Ind Load Curtailment	300	0
2040	Wind_PC09	207	774	2042	Ind Load Curtailment	400	0
2041	Wind_PC21	99	405				
2041	Wind_SI12	186	586				
2042	Wind_SI16	660	1814				

Cell in red indicates final DSM volume. DSM capacity ramps up to this value beginning in the year shown

Continue Site C, Low Load Forecast							
Generation				DSM			
Year	Name	Capacity	Annual Energy	Year	Name	Capacity	Annual Energy
2023	Site C	1145	5286	2029	BCUC_CFDSM_2030start	210	0
2025	Revelstoke Unit 6	500	26	2029	BCUC_oTOU_2030start	430	0
				2040	Ind Load Curtailment	100	0
				2041	Ind Load Curtailment	200	0

Terminate Site C, Low Load Forecast							
Generation				DSM			
Year	Name	Capacity	Annual Energy	Year	Name	Capacity	Annual Energy
2025	Revelstoke Unit 6	500	26	2024	BCUC_CFDSM_2025start	210	0
2040	Wind_PC14	144	570	2024	BCUC_oTOU_2025start	430	0
2040	Wind_PC18	138	524	2037	Ind Load Curtailment	50	0
2040	Wind_PC48	150	538	2038	Ind Load Curtailment	200	0
2041	Pumped_Storage_LM	1000	0	2039	Ind Load Curtailment	350	0
				2040	Ind Load Curtailment	400	0

Cell in red indicates final DSM volume. DSM capacity ramps up to this value beginning in the year shown

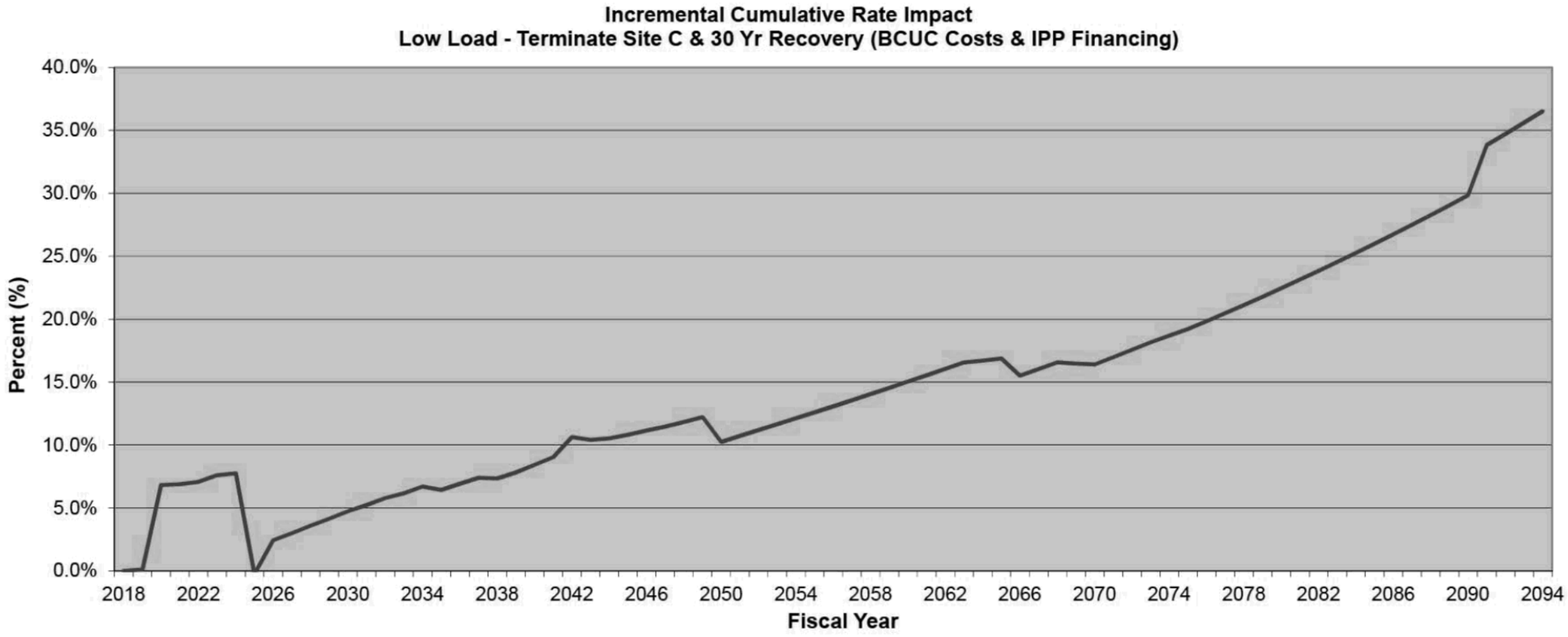
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Results of Analysis of Commission Portfolio

Attachment 4

Incremental Cumulative Rate Impact Analysis


Incremental Cumulative Rate Impact
Low Load - Terminate Site C & 30 Yr Recovery (BCUC Costs & IPP Financing)
Percent (%)
40.0%
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
2018
2022
2026
2030
2034
2038
2042
2046
2050
2054
2058
2062
2066
2070
2074
2078
2082
2086
2090
2094
Fiscal Year

BC Hydro
Rate Impact Analysis

Rate Impact Model - Low Load - Terminate 30 Yrs wi h BCUC Costs & IPP Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		0.0	(6 9)	(12.7)	(23.8)	(38.3)	(51.3)	(78.4)	25.6	122.4	122.6	122.8	120.7	122.5	123.4	124.4	121.9	127 3	119.4	119.3	131.5	139.4	156 9	175.8	201.8	295.1	284.7
2	**Operating Costs**		0.0	6.1	80.1	96.6	112.6	117.0	121.6	121.6	121.8	123.6	93.3	86 8	52.2	40.2	25.8	14.1	(10 8)	3.5	27.0	28.3	35.0	56.3	47.9	39.4	41.8	44.0
3	**Amortization**		0.0	0 0	133.0	133.0	133.0	133.0	133 0	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)
4	**Finance Charges**		0.0	0.1	150.1	143.6	133.3	132.1	130 8	(210.9)	(206.9)	(202.4)	(198.5)	(195.6)	(193.7)	(192.9)	(192.7)	(193.1)	(194 3)	(195.7)	(196.6)	(196.9)	(197.0)	(196.6)	(195.9)	(195.4)	(194.9)	(194.2)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	(6.1)	(80.1)	(96.6)	(112.6)	(117.0)	(121.6)	(137.0)	(161.7)	(179.3)	(150.1)	(144.7)	(111.3)	(100.5)	(87.3)	(76.8)	(53 2)	(68.8)	(93.6)	(96.1)	(104.3)	(126.9)	(119.9)	(112.9)	(116.8)	(120.5)
7	DSM Recoveries		0.0	0 0	0.4	5.7	12.2	19.7	27 5	35.6	44.7	55.5	67.5	77 5	87.1	94.5	101.2	107.1	112 2	115.3	114.6	114.4	113.3	112.4	112.8	111.6	108.4	104.2
8	**Estimated Total Change in Revenue Requirement:**		0.0	(6 8)	270.8	258.5	240.2	233.5	213 0	(175.0)	(89.5)	(89.8)	(74.9)	(65 2)	(53.0)	(45.0)	(38.3)	(36.7)	(28 5)	(36.0)	(39.0)	(28.8)	(23.4)	(7.7)	10.8	34.8	123.8	108.5
9	**Estimated Revenue Requirement - Base Case**		4,638	4,768	4,931	5,156	5,350	5,525	5,718	6,065	6,257	6,435	6,432	6,626	6,800	6,992	7,201	7,414	7,599	7,578	7,782	8,012	8,187	8,414	8,658	8,925	9,068	9,466
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,638	4,761	5,201	5,414	5,590	5,758	5,931	5,890	6,168	6,345	6,358	6,560	6,747	6,947	7,163	7,378	7,571	7,542	7,743	7,983	8,163	8,407	8,669	8,960	9,192	9,574
11	**Domestic Revenues**		(4,638)	(4,756)	(4,907)	(5,116)	(5,282)	(5,425)	(5,589)	(5,901)	(6,059)	(6,210)	(6,195)	(6,370)	(6,527)	(6,702)	(6,889)	(7,083)	(7,248)	(7,230)	(7,402)	(7,615)	(7,793)	(8,008)	(8,234)	(8,488)	(8,630)	(9,015)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	0.0	5 2	294.3	298.1	308.3	333.1	342 0	(10.8)	108.8	134.8	162.9	190 5	219.9	245.4	274.4	294.3	322 8	312.6	340.5	367.9	370.3	399 0	435.4	472.3	562.4	559.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.00%	0.11%	6.00%	5.83%	5.84%	6.14%	6.12%	-0.18%	1.79%	2.17%	2.63%	2.99%	3.37%	3.66%	3.98%	4.15%	4.45%	4.32%	4.60%	4.83%	4.75%	4.98%	5.29%	5.56%	6.52%	6.21%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		107.7	110.4	113.8	118.2	121.3	123.9	126.6	133.0	135.6	137.9	136.3	139 0	140.9	142.9	145.5	148.5	150.7	148.8	150.5	153.2	154.5	156 9	159.4	162.4	163.0	167.7
15	Scenario	Line 14 * (1+Line 13)	107.7	110.5	120.6	125.1	128.3	131.5	134.4	132.7	138.0	140.9	139.9	143 2	145.7	148.2	151.3	154.7	157.4	155.2	157.5	160.6	161.9	164.7	167.9	171.4	173.7	178.1
16	Base Case	(Line 14 - 100) / 100	7.7%	10.4%	13.8%	18.2%	21.3%	23.9%	26.6%	33.0%	35.6%	37.9%	36.3%	39 0%	40.9%	42.9%	45.5%	48.5%	50.7%	48.8%	50.5%	53.2%	54.5%	56 9%	59.4%	62.4%	63.0%	67.7%
17	Scenario	(Line 15 - 100) / 100	7.7%	10.5%	20.6%	25.1%	28.3%	31.5%	34.4%	32.7%	38.0%	40.9%	39.9%	43 2%	45.7%	48.2%	51.3%	54.7%	57.4%	55.2%	57.5%	60.6%	61.9%	64.7%	67.9%	71.4%	73.7%	78.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.0%	0.1%	6.8%	6.9%	7.1%	7.6%	7.7%	-0.2%	2.4%	3.0%	3.6%	4 2%	4.7%	5.2%	5.8%	6.2%	6.7%	6.4%	6.9%	7.4%	7.3%	7 8%	8.4%	9.0%	10.6%	10.4%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Low Load - Terminate 30 Yrs wi h BCUC Costs & IPP Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51	2069 / 52	2070 / 53
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		290.4	296.2	302.1	308.1	314.3	320.6	327.0	333.5	340.2	347.0	354.0	361.0	368.3	375.6	383.1	390.8	398.6	406.6	414.7	423.0	431.5	440.1	343.4	350.3	357.3	364.4	371.7
2	**Operating Costs**		46.6	64.1	61.9	61.4	62.6	62.8	63.0	64.2	65.5	66.8	68.1	69.5	70.9	72.3	73.8	75.2	76.7	78.3	79.8	81.4	83.1	84.7	86.4	88.2	89.9	91.7	93.6
3	**Amortization**		(9.8)	(9.8)	(9.8)	(9.8)	(9.8)	(9.9)	(143.0)	(143 0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(151.6)	(160.2)	(160 2)	(160.2)	(160.2)	(173.9)	(187.6)
4	**Finance Charges**		(193.2)	(191.7)	(189 9)	(188.3)	(186.6)	(185.1)	(181.5)	(175.6)	(169.7)	(163.9)	(158.2)	(152.4)	(146.6)	(140.8)	(135.0)	(129.2)	(123.4)	(117.6)	(111.8)	(106.0)	(111.7)	(117.2)	(110.7)	(104.1)	(97.6)	(112.0)	(125.8)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(124.5)	(143.7)	(143.1)	(144.1)	(147.0)	(148.9)	(150.8)	(153 8)	(156.9)	(160.0)	(163.2)	(166.5)	(169.8)	(173.2)	(176.6)	(180.2)	(183.8)	(187.5)	(191.2)	(195.0)	(198.9)	(202.9)	(207 0)	(211.1)	(215.3)	(219.6)	(224.0)
7	DSM Recoveries		102.2	100.9	103.0	105.9	109.7	114.4	120.7	126.2	130.2	134.3	138.0	140.4	143.5	147.3	151.0	154.8	158.5	161.2	164.1	167.3	170.5	173.8	177.3	180.8	184.5	188.1	191.9
8	**Estimated Total Change in Revenue Requirement:**		111.7	116.0	124.3	133.2	143.1	153.8	35.4	51.6	66.3	81.1	95.7	109.1	123.3	138.2	153.3	168.4	183.6	197.9	212.6	227.7	222.8	218.4	129.3	143.9	158.6	138.8	119.7
9	**Estimated Revenue Requirement - Base Case**		9,762	9,976	10,193	10,414	10,631	10,854	11,075	11,296	11,520	11,755	11,998	12,235	12,477	12,723	12,973	13,226	13,483	13,748	14,018	14,294	14,577	14,866	15,161	15,462	15,769	16,083	16,402
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	9,873	10,092	10,317	10,547	10,774	11,008	11,110	11,348	11,586	11,836	12,094	12,344	12,600	12,861	13,126	13,394	13,667	13,946	14,231	14,522	14,800	15,084	15,290	15,606	15,928	16,221	16,522
11	**Domestic Revenues**		(9,301)	(9,505)	(9,712)	(9,923)	(10,130)	(10,343)	(10,553)	(10,764)	(10,977)	(11,201)	(11,433)	(11,659)	(11,889)	(12,123)	(12,362)	(12,603)	(12,848)	(13,100)	(13,357)	(13,620)	(13,890)	(14,166)	(14,447)	(14,733)	(15,026)	(15,325)	(15,630)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	572.1	587.2	605.5	623.8	644.0	665.2	557.2	583.8	609.1	635.0	661.0	685.6	711.1	737.7	764.5	791.6	818.9	845.7	873.1	901.2	909.6	918.8	843.7	872.4	901.6	896.6	892.5
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.15%	6.18%	6.23%	6.29%	6.36%	6.43%	5.28%	5.42%	5.55%	5.67%	5.78%	5.88%	5.98%	6.08%	6.18%	6.28%	6.37%	6.46%	6.54%	6.62%	6.55%	6.49%	5.84%	5.92%	6.00%	5.85%	5.71%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		171.2	175.1	178.9	182.4	186.2	190.1	193.9	197.8	201.7	205.9	210.1	214.3	218.5	222.8	227.2	231.6	236.1	240.8	245.5	250.3	255.3	260.3	265.5	270.8	276.1	281.6	287.2
15	Scenario	Line 14 * (1+Line 13)	181.7	185.9	190.0	193.8	198.0	202.3	204.2	208.6	212.9	217.5	222.3	226.9	231.6	236.4	241.2	246.2	251.2	256.3	261.5	266.9	272.0	277.2	281.0	286.8	292.7	298.1	303.6
16	Base Case	(Line 14 - 100) / 100	71.2%	75.1%	78 9%	82.4%	86.2%	90.1%	93.9%	97.8%	101.7%	105.9%	110.1%	114.3%	118.5%	122.8%	127.2%	131.6%	136.1%	140.8%	145.5%	150.3%	155.3%	160.3%	165 5%	170.8%	176.1%	181.6%	187.2%
17	Scenario	(Line 15 - 100) / 100	81.7%	85.9%	90 0%	93.8%	98.0%	102.3%	104.2%	108.6%	112.9%	117.5%	122.3%	126.9%	131.6%	136.4%	141.2%	146.2%	151.2%	156.3%	161.5%	166.9%	172.0%	177.2%	181 0%	186.8%	192.7%	198.1%	203.6%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	10.5%	10.8%	11 2%	11.5%	11.8%	12.2%	10.2%	10.7%	11.2%	11.7%	12.1%	12.6%	13.1%	13.6%	14.1%	14.5%	15.0%	15.5%	16.0%	16.6%	16.7%	16.9%	15.5%	16.0%	16.6%	16.5%	16.4%

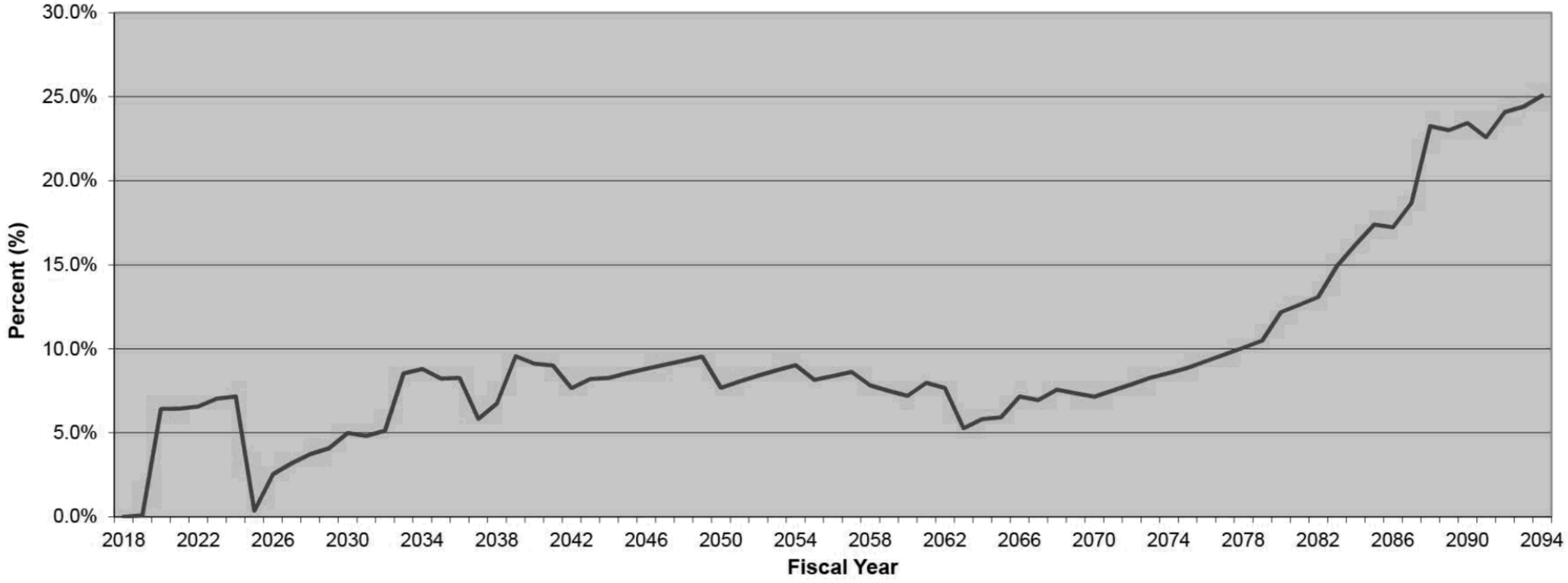
BC Hydro
Rate Impact Analysis

Rate Impact Model - Low Load - Terminate 30 Yrs wi h BCUC Costs & IPP Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																								
1	**Domestic Energy Costs**		379.2	386.8	394.5	402.4	410.4	418.6	427.0	435.5	444.3	453.1	462.2	471.5	480.9	490.5	500.3	510.3	520.5	530.9	541.5	552.4	736.5	751.2	766.2	781.5
2	**Operating Costs**		95.4	97.3	99.3	101.3	103.3	105.4	107.5	109.6	111.8	114.0	116.3	118.6	121.0	123.4	125.9	128.4	131.0	133.6	136.3	139.0	141.8	144.6	147.5	150.5
3	**Amortization**		(187.6)	(187.6)	(187.6)	(189.6)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)	(191.5)
4	**Finance Charges**		(118.3)	(110.7)	(103.1)	(98.8)	(94.5)	(86.7)	(78.8)	(71.0)	(63.1)	(55.2)	(47.3)	(39.3)	(31.4)	(23.4)	(15.3)	(7.3)	0.8	9.0	17.1	25.3	33.5	41.8	50.1	58.4
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		(228.5)	(233.1)	(237.7)	(242.5)	(247.3)	(252.3)	(257.3)	(262 5)	(267.7)	(273.1)	(278.5)	(284.1)	(289.8)	(295.6)	(301.5)	(307.5)	(313.7)	(320.0)	(326.4)	(332.9)	(339.5)	(346.3)	(353 3)	(360.3)
7	DSM Recoveries		195.7	199.7	203.7	207.7	211.9	216.1	220.4	224.8	229.3	233.9	238.6	243.4	248.2	253.2	258.3	263.4	268.7	274.1	279.6	285.2	290.9	296.7	302.6	308.7
8	**Estimated Total Change in Revenue Requirement:**		135.9	152.3	168.9	180.5	192.3	209.7	227.2	245.0	263.1	281.3	299.8	318.5	337.5	356.7	376.2	395.9	415.9	436.1	456.7	477.5	671.6	696.5	721.7	747.3
9	**Estimated Revenue Requirement - Base Case**		16,729	17,062	17,401	17,748	18,101	18,461	18,829	19,204	19,587	19,977	20,375	20,781	21,195	21,617	22,048	22,488	22,936	23,393	23,860	24,336	24,821	25,316	25,821	26,336
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	16,865	17,214	17,570	17,928	18,293	18,671	19,056	19,449	19,850	20,258	20,675	21,099	21,532	21,974	22,424	22,884	23,352	23,829	24,316	24,813	25,493	26,012	26,543	27,083
11	**Domestic Revenues**		(15,941)	(16,258)	(16,581)	(16,911)	(17,248)	(17,592)	(17,942)	(18,299)	(18,664)	(19,036)	(19,415)	(19,802)	(20,196)	(20,599)	(21,009)	(21,428)	(21,855)	(22,291)	(22,736)	(23,189)	(23,651)	(24,123)	(24,604)	(25,095)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	924.1	956.2	988.8	1,016.7	1,045.1	1,079.5	1,114.4	1,149 8	1,185.9	1,222.5	1,259.8	1,297.6	1,336.1	1,375.2	1,415.0	1,455.4	1,496.5	1,538.3	1,580.8	1,624.1	1,841.1	1,889.2	1,938 3	1,988.1
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	5.80%	5.88%	5.96%	6.01%	6.06%	6.14%	6.21%	6.28%	6.35%	6.42%	6.49%	6.55%	6.62%	6.68%	6.74%	6.79%	6.85%	6.90%	6.95%	7.00%	7.78%	7.83%	7 88%	7.92%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		293.0	298.8	304.7	310.8	317.0	323.3	329.7	336.3	343.0	349.8	356.8	363.9	371.2	378.6	386.1	393.8	401.7	409.7	417.8	426.2	434.7	443.3	452.2	461.2
15	Scenario	Line 14 * (1+Line 13)	309.9	316.4	322.9	329.5	336.2	343.1	350.2	357.4	364.8	372.3	380.0	387.8	395.7	403.8	412.1	420.6	429.2	437.9	446.9	456.0	468.5	478.1	487.8	497.7
16	Base Case	(Line 14 - 100) / 100	193.0%	198.8%	204.7%	210.8%	217.0%	223.3%	229.7%	236 3%	243.0%	249.8%	256.8%	263.9%	271.2%	278.6%	286.1%	293.8%	301.7%	309.7%	317.8%	326.2%	334.7%	343.3%	352 2%	361.2%
17	Scenario	(Line 15 - 100) / 100	209.9%	216.4%	222 9%	229.5%	236.2%	243.1%	250.2%	257.4%	264.8%	272.3%	280.0%	287.8%	295.7%	303.8%	312.1%	320.6%	329.2%	337.9%	346.9%	356.0%	368.5%	378.1%	387 8%	397.7%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	17.0%	17.6%	18.2%	18.7%	19.2%	19.8%	20.5%	21.1%	21.8%	22.5%	23.2%	23.8%	24.6%	25.3%	26.0%	26.7%	27.5%	28.3%	29.1%	29.8%	33.8%	34.7%	35.6%	36.5%

Incremental Cumulative Rate Impact
Mid Load - Terminate Site C & 30 Yr Recovery (BCUC Costs & IPP Financing)



BC Hydro
Rate Impact Analysis

Rate Impact Model - Mid Load - Terminate 30 Yrs with BCUC Costs & IPP Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		0.0	(7 3)	(13.7)	(25.6)	(41.0)	(55.0)	(82.9)	50.7	137.6	148.6	170.4	182 0	236.6	249.8	287.9	493.7	531.7	554.0	577.1	467.0	560.4	747 8	743.8	766.5	715.3	765.5
2	**Operating Costs**		0.0	11 5	95.7	126.3	140.9	149.5	133 0	121.7	98.5	68.8	34.7	(69.4)	(60.2)	(80.3)	(79.7)	(98.0)	(140.0)	(168.0)	(165.7)	(132.6)	(116.8)	(93 3)	(78.0)	(81.1)	(63.4)	(36.8)
3	**Amortization**		0.0	0 0	133.0	133.0	133.0	133.0	133 0	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)
4	**Finance Charges**		0.0	0 2	150.6	144.8	135.4	135.1	134 3	(207.5)	(204.1)	(201.2)	(199.4)	(200.3)	(202.7)	(205.4)	(208.3)	(211.4)	(215.4)	(220.5)	(225.6)	(229.6)	(232.2)	(233.6)	(234.0)	(233.7)	(232.8)	(230.7)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	(11.5)	(95.7)	(126.3)	(140.9)	(149.5)	(133.0)	(137.1)	(138.5)	(124.5)	(91.5)	11 5	1.1	20.0	18.3	35.3	76.1	102.8	99.1	64.7	47.5	22.7	5.9	7.6	(11.5)	(39.6)
7	DSM Recoveries		0.0	0 0	0.8	7.1	15.6	25.0	34 9	43.8	52.9	62.2	70.5	76.6	75.8	75.7	74.4	73.2	70 8	65.0	51.7	36.7	23.0	9.9	(0.5)	(10.1)	(19.8)	(27.3)
8	**Estimated Total Change in Revenue Requirement:**		0.0	(7.1)	270.6	259.4	243.0	238.1	219.4	(138.2)	(63.3)	(56.0)	(25.2)	(9.4)	40.8	50.0	82.7	283.0	313 3	323.4	326.8	196.4	272.1	443.6	427.5	439.5	377.9	421.2
9	**Estimated Revenue Requirement - Base Case**		4,638	4,851	5,038	5,293	5,525	5,727	5,946	6,308	6,517	6,719	6,741	6,956	7,178	7,392	7,633	7,885	8,101	8,106	8,382	8,828	9,037	9,325	9,648	9,947	10,223	10,621
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,638	4,843	5,309	5,553	5,768	5,966	6,166	6,170	6,453	6,663	6,716	6,946	7,219	7,442	7,716	8,168	8,414	8,429	8,709	9,025	9,309	9,769	10,075	10,386	10,601	11,042
11	**Domestic Revenues**		(4,638)	(4,839)	(5,016)	(5,255)	(5,460)	(5,632)	(5,823)	(6,152)	(6,329)	(6,505)	(6,528)	(6,740)	(6,962)	(7,191)	(7,446)	(7,713)	(7,941)	(7,979)	(8,251)	(8,698)	(8,927)	(9,220)	(9,545)	(9,856)	(10,145)	(10,546)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	0.0	4.4	293.3	297.4	308.3	333.5	343 0	17.7	124.7	157.6	187.1	206.6	256.3	250.9	270.2	455.2	473 0	449.9	457.8	326.4	382.4	548 2	530.4	530.2	455.8	496.0
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.00%	0.09%	5.85%	5.66%	5.65%	5.92%	5.89%	0.29%	1.97%	2.42%	2.87%	3.06%	3.68%	3.49%	3.63%	5.90%	5.96%	5.64%	5.55%	3.75%	4.28%	5.95%	5.56%	5.38%	4.49%	4.70%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		103.3	106.3	109.9	113.8	116.4	118.9	121 5	126.8	129.1	131.8	130.4	132 9	135.5	138.2	141.4	144.7	147 8	146.0	148.9	155.4	157.3	160 8	164.0	167.5	170.3	174.4
15	Scenario	Line 14 * (1+Line 13)	103.3	106.4	116.3	120.2	123.0	125.9	128.7	127.2	131.6	135.0	134.1	137 0	140.4	143.0	146.5	153.2	156.6	154.3	157.2	161.2	164.0	170.4	173.2	176.5	178.0	182.6
16	Base Case	(Line 14 - 100) / 100	3.3%	6 3%	9.9%	13.8%	16.4%	18.9%	21 5%	26.8%	29.1%	31.8%	30.4%	32 9%	35.5%	38.2%	41.4%	44.7%	47 8%	46.0%	48.9%	55.4%	57.3%	60 8%	64.0%	67.5%	70.3%	74.4%
17	Scenario	(Line 15 - 100) / 100	3.3%	6.4%	16.3%	20.2%	23.0%	25.9%	28.7%	27.2%	31.6%	35.0%	34.1%	37 0%	40.4%	43.0%	46.5%	53.2%	56.6%	54.3%	57.2%	61.2%	64.0%	70.4%	73.2%	76.5%	78.0%	82.6%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.0%	0.1%	6.4%	6.4%	6.6%	7.0%	7 2%	0.4%	2.5%	3.2%	3.7%	4.1%	5.0%	4.8%	5.1%	8.5%	8 8%	8.2%	8.3%	5.8%	6.7%	9.6%	9.1%	9.0%	7.7%	8.2%

BC Hydro
Rate Impact Analysis

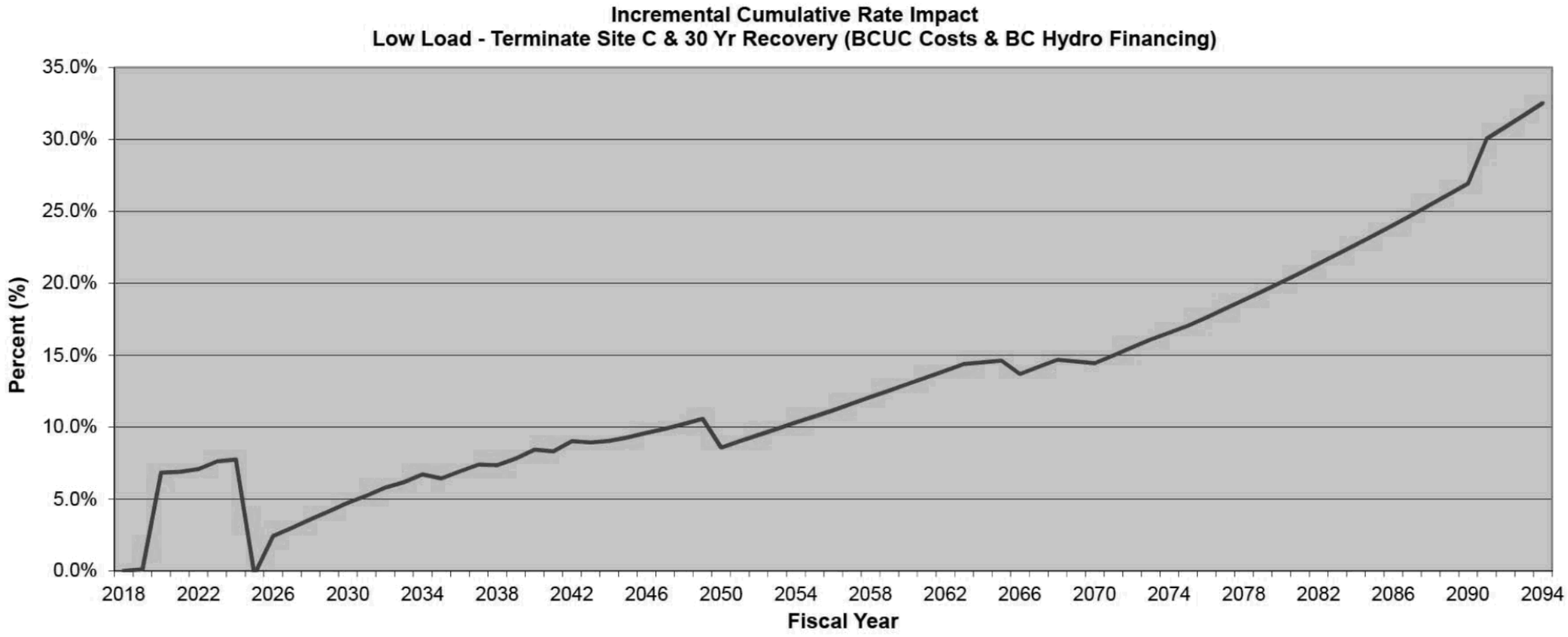
Rate Impact Model - Mid Load - Terminate 30 Yrs with BCUC Costs & IPP Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51	2069 / 52	2070 / 53
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		780.8	796.4	812.4	828.6	845.2	862.1	879.3	896.9	914.9	933.2	951.8	900.3	918.3	936.7	892.2	872.8	855.3	904.0	884.9	736.5	788.0	812.3	885.8	870.0	904.5	922.6	941.0
2	**Operating Costs**		(21.8)	(38.6)	(42.8)	(50.8)	(75.3)	(80.5)	(84.0)	(87.6)	(93.3)	(97.2)	(101.2)	(99.0)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120 5)	(122.9)	(125.4)	(127.9)	(130.5)
3	**Amortization**		(9.8)	(9.8)	(9.8)	(9.8)	(9.8)	(9.9)	(143.0)	(143 0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(151.6)	(160.2)	(160 2)	(160.2)	(160.2)	(173.9)	(187.6)
4	**Finance Charges**		(227.8)	(224.8)	(222 2)	(219.9)	(218.3)	(217.3)	(214.2)	(209 0)	(204.2)	(199.7)	(195.4)	(191.1)	(186.7)	(182.3)	(177.9)	(173.4)	(168.9)	(164.2)	(159.4)	(154.5)	(161.3)	(167.7)	(162 2)	(156.6)	(151.1)	(166.5)	(181.5)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(56.2)	(41.0)	(38.3)	(32.0)	(9.1)	(5.5)	(3.8)	(1.9)	2.0	4.0	6.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(30.8)	(26.3)	(23.5)	(19.6)	(16.2)	(13.3)	(7.8)	(0.7)	6.0	10.2	13.1	14.2	14.5	15.0	14.2	11.6	7.8	5.1	2.5	0.4	(0.2)	(0.6)	(0.8)	(0.9)	(0.8)	(0.5)	(0.1)
8	**Estimated Total Change in Revenue Requirement:**		434.5	456.1	475.7	496.5	516.5	535.6	426.5	454.6	482.3	507.4	531.5	483.4	504.1	525.4	482.6	463.0	444.2	492.7	473.6	325.8	359.1	365.7	442.1	429.3	467.0	453.7	441.3
9	**Estimated Revenue Requirement - Base Case**		10,938	11,167	11,402	11,641	11,870	12,108	12,342	12,575	12,811	13,060	13,319	13,572	13,831	14,094	14,363	14,648	14,938	15,132	15,433	15,739	16,015	16,291	16,503	16,792	17,146	17,486	17,834
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,372	11,623	11,878	12,138	12,387	12,643	12,769	13,030	13,293	13,568	13,851	14,056	14,335	14,620	14,846	15,111	15,383	15,625	15,906	16,065	16,374	16,657	16,945	17,221	17,613	17,940	18,275
11	**Domestic Revenues**		(10,866)	(11,099)	(11,339)	(11,582)	(11,815)	(12,057)	(12,296)	(12,535)	(12,775)	(13,030)	(13,294)	(13,553)	(13,818)	(14,088)	(14,363)	(14,648)	(14,938)	(15,132)	(15,433)	(15,739)	(16,015)	(16,291)	(16,503)	(16,792)	(17,146)	(17,486)	(17,834)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	505.7	523.5	539.3	555.8	571.4	586.0	472.2	495.3	517.9	537.7	556.2	502.3	517.0	532.0	482.6	463.0	444.2	492.7	473.6	325.8	359.1	365.7	442.1	429.3	467.0	453.7	441.3
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	4.65%	4.72%	4.76%	4.80%	4.84%	4.86%	3.84%	3.95%	4.05%	4.13%	4.18%	3.71%	3.74%	3.78%	3.36%	3.16%	2.97%	3.26%	3.07%	2.07%	2.24%	2.24%	2.68%	2.56%	2.72%	2.59%	2.47%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		177.8	181.5	185.2	188.6	192.3	196.1	199.9	203.7	207.5	211.5	215.7	219.8	224.0	228.3	232.6	237.3	242.0	245.1	250.0	254.9	259.4	263.9	267.3	272.0	277.7	283.2	288.9
15	Scenario	Line 14 * (1+Line 13)	186.0	190.1	194.0	197.6	201.6	205.6	207.6	211.7	215.9	220.3	224.8	228.0	232.4	236.9	240.5	244.8	249.2	253.1	257.6	260.2	265.2	269.8	274.5	278.9	285.3	290.6	296.0
16	Base Case	(Line 14 - 100) / 100	77.8%	81.5%	85.2%	88.6%	92.3%	96.1%	99.9%	103.7%	107.5%	111.5%	115.7%	119.8%	124.0%	128.3%	132.6%	137.3%	142.0%	145.1%	150.0%	154.9%	159.4%	163.9%	167 3%	172.0%	177.7%	183.2%	188.9%
17	Scenario	(Line 15 - 100) / 100	86.0%	90.1%	94.0%	97.6%	101.6%	105.6%	107.6%	111.7%	115.9%	120.3%	124.8%	128.0%	132.4%	136.9%	140.5%	144.8%	149.2%	153.1%	157.6%	160.2%	165.2%	169.8%	174 5%	178.9%	185.3%	190.6%	196.0%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	8.3%	8.6%	8.8%	9.0%	9.3%	9.5%	7.7%	8.0%	8.4%	8.7%	9.0%	8.1%	8.4%	8.6%	7.8%	7.5%	7.2%	8.0%	7.7%	5.3%	5.8%	5.9%	7.2%	7.0%	7.6%	7.3%	7.1%

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																								
1	**Domestic Energy Costs**		959.9	979.1	998.6	1,018.6	1,039.0	1,059.8	1,081.0	1,102.6	1,124.6	1,225.1	1,249.6	1,274.6	1,384.9	1,459.8	1,530.9	1,517.8	1,604.3	1,883.5	1,865.8	1,890.0	1,834.6	1,924.5	1,941 2	1,980.1
2	**Operating Costs**		(133.1)	(135.7)	(138 5)	(141.2)	(144.1)	(146.9)	(149.9)	(152 9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(187.6)	(187.6)	(187.6)	(189.6)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)
4	**Finance Charges**		(175.0)	(168.6)	(162 2)	(159.1)	(155.9)	(149.3)	(142.8)	(136 2)	(129.6)	(123.0)	(116.5)	(109.9)	(103.3)	(96.8)	(90.2)	(83.6)	(77.1)	(70.5)	(63.9)	(57.4)	(50.8)	(44.2)	(37.7)	(31.1)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		464.1	487.1	510.4	528.8	547.5	572.0	596.8	622.0	647.6	751.5	779.4	807.7	921.3	999.4	1,073.6	1,063.5	1,153.0	1,435.2	1,420.3	1,447.2	1,394.5	1,487.1	1,506 3	1,547.6
9	**Estimated Revenue Requirement - Base Case**		18,189	18,551	18,920	19,297	19,681	20,074	20,473	20,881	21,297	21,722	22,155	22,596	23,047	23,506	23,975	24,605	25,096	25,596	26,162	26,747	27,462	28,073	28,609	29,180
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	18,653	19,038	19,431	19,826	20,229	20,646	21,070	21,503	21,945	22,473	22,934	23,404	23,968	24,506	25,049	25,669	26,249	27,031	27,582	28,194	28,856	29,560	30,115	30,727
11	**Domestic Revenues**		(18,189)	(18,551)	(18,920)	(19,297)	(19,681)	(20,074)	(20,473)	(20,881)	(21,297)	(21,722)	(22,155)	(22,596)	(23,047)	(23,506)	(23,975)	(24,605)	(25,096)	(25,596)	(26,162)	(26,747)	(27,462)	(28,073)	(28,609)	(29,180)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	464.1	487.1	510.4	528.8	547.5	572.0	596.8	622.0	647.6	751.5	779.4	807.7	921.3	999.4	1,073.6	1,063.5	1,153.0	1,435.2	1,420.3	1,447.2	1,394.5	1,487.1	1,506 3	1,547.6
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	2.55%	2.63%	2.70%	2.74%	2.78%	2.85%	2.92%	2.98%	3.04%	3.46%	3.52%	3.57%	4.00%	4.25%	4.48%	4.32%	4.59%	5.61%	5.43%	5.41%	5.08%	5.30%	5 27%	5.30%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		294.6	300.5	306.5	312.6	318.8	325.1	331.6	338.2	345.0	351.8	358.8	366.0	373.3	380.7	388.3	398.5	406.5	414.6	423.8	433.2	444.8	454.7	463.4	472.6
15	Scenario	Line 14 * (1+Line 13)	302.1	308.4	314.7	321.1	327.7	334.4	341.3	348.3	355.5	364.0	371.5	379.1	388.2	396.9	405.7	415.8	425.2	437.8	446.8	456.7	467.4	478.8	487.8	497.7
16	Base Case	(Line 14 - 100) / 100	194.6%	200.5%	206 5%	212.6%	218.8%	225.1%	231.6%	238.2%	245.0%	251.8%	258.8%	266.0%	273.3%	280.7%	288.3%	298.5%	306.5%	314.6%	323.8%	333.2%	344.8%	354.7%	363.4%	372.6%
17	Scenario	(Line 15 - 100) / 100	202.1%	208.4%	214.7%	221.1%	227.7%	234.4%	241.3%	248.3%	255.5%	264.0%	271.5%	279.1%	288.2%	296.9%	305.7%	315.8%	325.2%	337.8%	346.8%	356.7%	367.4%	378.8%	387 8%	397.7%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	7.5%	7.9%	8.3%	8.6%	8.9%	9.3%	9.7%	10.1%	10.5%	12.2%	12.6%	13.1%	14.9%	16.2%	17.4%	17.2%	18.7%	23.2%	23.0%	23.4%	22.6%	24.1%	24.4%	25.1%


Incremental Cumulative Rate Impact
Low Load - Terminate Site C & 30 Yr Recovery (BCUC Costs & BC Hydro Financing)
Percent (%)
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
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2082
2086
2090
2094
Fiscal Year

BC Hydro
Rate Impact Analysis

Rate Impact Model - Low Load - Terminate 30 Yrs with BCUC Costs & BCH Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		0.0	(6 9)	(12.7)	(23.8)	(38.3)	(51.3)	(78.4)	25.6	122.4	122.6	122.8	120.7	122.5	123.4	124.4	121.9	127 3	119.4	119.3	131.5	139.4	156 9	175.8	164.2	210.1	204.2
2	**Operating Costs**		0.0	6.1	80.1	96.6	112.6	117.0	121.6	121.6	121.8	123.6	93.3	86 8	52.2	40.2	25.8	14.1	(10 8)	3.5	27.0	28.3	35.0	56.3	47.9	39.4	41.8	44.0
3	**Amortization**		0.0	0 0	133.0	133.0	133.0	133.0	133 0	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)
4	**Finance Charges**		0.0	0.1	150.1	143.6	133.3	132.1	130 8	(210.9)	(206.9)	(202.4)	(198.5)	(195.6)	(193.7)	(192.9)	(192.7)	(193.1)	(194 3)	(195.7)	(196.6)	(196.9)	(197.0)	(196.6)	(195.9)	(195.4)	(194.9)	(194.2)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	(6.1)	(80.1)	(96.6)	(112.6)	(117.0)	(121.6)	(137.0)	(161.7)	(179.3)	(150.1)	(144.7)	(111.3)	(100.5)	(87.3)	(76.8)	(53 2)	(68.8)	(93.6)	(96.1)	(104.3)	(126.9)	(119.9)	(112.9)	(116.8)	(120.5)
7	DSM Recoveries		0.0	0 0	0.4	5.7	12.2	19.7	27 5	35.6	44.7	55.5	67.5	77 5	87.1	94.5	101.2	107.1	112 2	115.3	114.6	114.4	113.3	112.4	112.8	111.6	108.4	104.2
8	**Estimated Total Change in Revenue Requirement:**		0.0	(6 8)	270.8	258.5	240.2	233.5	213 0	(175.0)	(89.5)	(89.8)	(74.9)	(65 2)	(53.0)	(45.0)	(38.3)	(36.7)	(28 5)	(36.0)	(39.0)	(28.8)	(23.4)	(7.7)	10.8	(2.9)	38.8	28.0
9	**Estimated Revenue Requirement - Base Case**		4,638	4,768	4,931	5,156	5,350	5,525	5,718	6,065	6,257	6,435	6,432	6,626	6,800	6,992	7,201	7,414	7,599	7,578	7,782	8,012	8,187	8,414	8,658	8,927	9,069	9,484
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,638	4,761	5,201	5,414	5,590	5,758	5,931	5,890	6,168	6,345	6,358	6,560	6,747	6,947	7,163	7,378	7,571	7,542	7,743	7,983	8,163	8,407	8,669	8,924	9,108	9,512
11	**Domestic Revenues**		(4,638)	(4,756)	(4,907)	(5,116)	(5,282)	(5,425)	(5,589)	(5,901)	(6,059)	(6,210)	(6,195)	(6,370)	(6,527)	(6,702)	(6,889)	(7,083)	(7,248)	(7,230)	(7,402)	(7,615)	(7,793)	(8,008)	(8,234)	(8,489)	(8,630)	(9,032)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	0.0	5 2	294.3	298.1	308.3	333.1	342 0	(10.8)	108.8	134.8	162.9	190 5	219.9	245.4	274.4	294.3	322 8	312.6	340.5	367.9	370.3	399 0	435.4	434.7	477.5	480.1
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.00%	0.11%	6.00%	5.83%	5.84%	6.14%	6.12%	-0.18%	1.79%	2.17%	2.63%	2.99%	3.37%	3.66%	3.98%	4.15%	4.45%	4.32%	4.60%	4.83%	4.75%	4.98%	5.29%	5.12%	5.53%	5.32%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		107.7	110.4	113.8	118.2	121.3	123.9	126.6	133.0	135.6	137.9	136.3	139 0	140.9	142.9	145.5	148.5	150.7	148.8	150.5	153.2	154.5	156 9	159.4	162.4	163.0	168.0
15	Scenario	Line 14 * (1+Line 13)	107.7	110.5	120.6	125.1	128.3	131.5	134.4	132.7	138.0	140.9	139.9	143 2	145.7	148.2	151.3	154.7	157.4	155.2	157.5	160.6	161.9	164.7	167.9	170.7	172.1	177.0
16	Base Case	(Line 14 - 100) / 100	7.7%	10.4%	13.8%	18.2%	21.3%	23.9%	26.6%	33.0%	35.6%	37.9%	36.3%	39 0%	40.9%	42.9%	45.5%	48.5%	50.7%	48.8%	50.5%	53.2%	54.5%	56 9%	59.4%	62.4%	63.0%	68.0%
17	Scenario	(Line 15 - 100) / 100	7.7%	10.5%	20.6%	25.1%	28.3%	31.5%	34.4%	32.7%	38.0%	40.9%	39.9%	43 2%	45.7%	48.2%	51.3%	54.7%	57.4%	55.2%	57.5%	60.6%	61.9%	64.7%	67.9%	70.7%	72.1%	77.0%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.0%	0.1%	6.8%	6.9%	7.1%	7.6%	7.7%	-0.2%	2.4%	3.0%	3.6%	4 2%	4.7%	5.2%	5.8%	6.2%	6.7%	6.4%	6.9%	7.4%	7.3%	7 8%	8.4%	8.3%	9.0%	8.9%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Low Load - Terminate 30 Yrs with BCUC Costs & BCH Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2044 27	2045 28	2046 29	2047 30	2048 31	2049 32	2050 33	2051 34	2052 35	2053 36	2054 37	2055 38	2056 39	2057 40	2058 41	2059 42	2060 43	2061 44	2062 45	2063 46	2064 47	2065 48	2066 49	2067 50	2068 51	2069 52	2070 53
	Change in Revenue Requirement (Ratepayer Costs):																												
1	**Domestic Energy Costs**		208.3	212.5	216.7	221.1	225.5	230.0	234.6	239.3	244.1	249.0	253.9	259.0	264.2	269.5	274.9	280.4	286.0	291.7	297.5	303.5	309.6	315.7	243.5	248.4	253.4	258.4	263.6
2	**Operating Costs**		46.6	64.1	61.9	61.4	62.6	62.8	63.0	64.2	65.5	66.8	68.1	69.5	70.9	72.3	73.8	75.2	76.7	78.3	79.8	81.4	83.1	84.7	86.4	88.2	89.9	91.7	93.6
3	**Amortization**		(9.8)	(9.8)	(9.8)	(9.8)	(9.8)	(9.9)	(143.0)	(143 0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(151.6)	(160.2)	(160 2)	(160.2)	(160.2)	(173.9)	(187.6)
4	**Finance Charges**		(193.2)	(191.7)	(189 9)	(188.3)	(186.6)	(185.1)	(181.5)	(175.6)	(169.7)	(163.9)	(158.2)	(152.4)	(146.6)	(140.8)	(135.0)	(129.2)	(123.4)	(117.6)	(111.8)	(106.0)	(111.7)	(117.2)	(110.7)	(104.1)	(97.6)	(112.0)	(125.8)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																												
6	DSM Additions		(124.5)	(143.7)	(143.1)	(144.1)	(147.0)	(148.9)	(150.8)	(153 8)	(156.9)	(160.0)	(163.2)	(166.5)	(169.8)	(173.2)	(176.6)	(180.2)	(183.8)	(187.5)	(191.2)	(195.0)	(198.9)	(202.9)	(207 0)	(211.1)	(215.3)	(219.6)	(224.0)
7	DSM Recoveries		102.2	100.9	103.0	105.9	109.7	114.4	120.7	126.2	130.2	134.3	138.0	140.4	143.5	147.3	151.0	154.8	158.5	161.2	164.1	167.3	170.5	173.8	177.3	180.8	184.5	188.1	191.9
8	**Estimated Total Change in Revenue Requirement:**		29.6	32.3	38.9	46.1	54.3	63.2	(57.0)	(42.7)	(29.8)	(16.9)	(4.3)	7.1	19.2	32.1	45.0	58.0	71.0	83.0	95.5	108.2	100.9	94.1	29.4	42.0	54.6	32.8	11.6
9	**Estimated Revenue Requirement - Base Case**		9,781	9,996	10,213	10,434	10,651	10,875	11,096	11,318	11,542	11,778	12,021	12,259	12,501	12,747	12,998	13,251	13,509	13,774	14,045	14,322	14,605	14,895	15,190	15,492	15,799	16,114	16,434
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	9,810	10,028	10,252	10,480	10,705	10,938	11,039	11,275	11,512	11,761	12,017	12,266	12,520	12,780	13,043	13,309	13,580	13,857	14,140	14,430	14,706	14,989	15,220	15,534	15,854	16,146	16,446
11	**Domestic Revenues**		(9,319)	(9,524)	(9,731)	(9,942)	(10,149)	(10,363)	(10,573)	(10,785)	(10,998)	(11,223)	(11,455)	(11,681)	(11,912)	(12,147)	(12,385)	(12,627)	(12,873)	(13,125)	(13,383)	(13,647)	(13,917)	(14,193)	(14,474)	(14,762)	(15,055)	(15,354)	(15,660)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	491.0	504.4	521.1	537.7	556.2	575.6	465.8	490.6	514.0	538.0	562.1	584.7	608.2	632.7	657.4	682.4	707.5	732.0	757.2	783.0	789.0	795.8	745.1	771.9	799.0	792.0	785.9
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	5.27%	5.30%	5.35%	5.41%	5.48%	5.55%	4.41%	4.55%	4.67%	4.79%	4.91%	5.01%	5.11%	5.21%	5.31%	5.40%	5.50%	5.58%	5.66%	5.74%	5.67%	5.61%	5.15%	5.23%	5.31%	5.16%	5.02%
	Typical Customer Bill (F2017 = 100)																												
14	Base Case		171.5	175.5	179.2	182.7	186.5	190.4	194.3	198.2	202.1	206.3	210.5	214.7	218.9	223.2	227.6	232.1	236.6	241.2	246.0	250.8	255.8	260.8	266.0	271.3	276.7	282.2	287.8
15	Scenario	Line 14 * (1+Line 13)	180.5	184.8	188.8	192.6	196.7	201.0	202.9	207.2	211.6	216.1	220.9	225.4	230.1	234.9	239.7	244.6	249.6	254.7	259.9	265.2	270.3	275.5	279.7	285.5	291.4	296.7	302.2
16	Base Case	(Line 14 - 100) / 100	71.5%	75.5%	79 2%	82.7%	86.5%	90.4%	94.3%	98.2%	102.1%	106.3%	110.5%	114.7%	118.9%	123.2%	127.6%	132.1%	136.6%	141.2%	146.0%	150.8%	155.8%	160.8%	166 0%	171.3%	176.7%	182.2%	187.8%
17	Scenario	(Line 15 - 100) / 100	80.5%	84.8%	88 8%	92.6%	96.7%	101.0%	102.9%	107 2%	111.6%	116.1%	120.9%	125.4%	130.1%	134.9%	139.7%	144.6%	149.6%	154.7%	159.9%	165.2%	170.3%	175.5%	179.7%	185.5%	191.4%	196.7%	202.2%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	9.0%	9.3%	9.6%	9.9%	10.2%	10.6%	8.6%	9.0%	9.4%	9.9%	10.3%	10.7%	11.2%	11.6%	12.1%	12.5%	13.0%	13.5%	13.9%	14.4%	14.5%	14.6%	13.7%	14.2%	14.7%	14.6%	14.4%

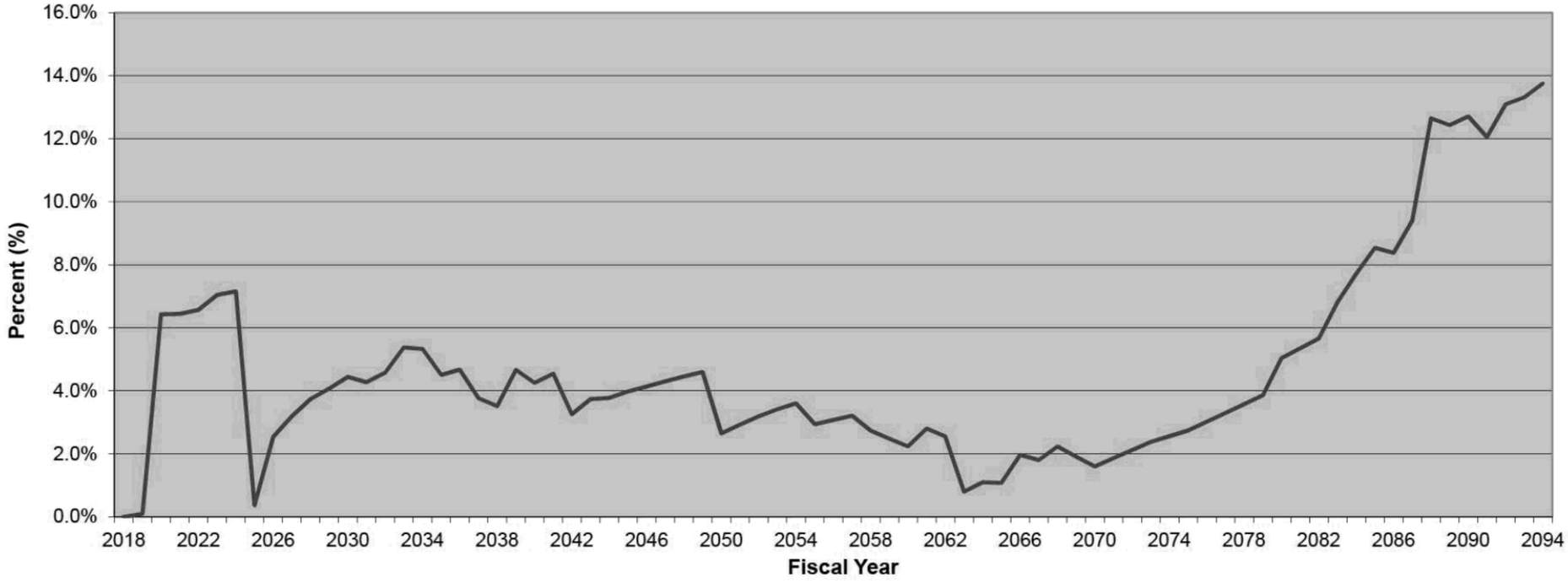
BC Hydro
Rate Impact Analysis

Rate Impact Model - Low Load - Terminate 30 Yrs with BCUC Costs & BCH Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 54	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Change in Revenue Requirement (Ratepayer Costs):																									
1	**Domestic Energy Costs**		268.9	274.2	279.7	285.3	291.0	296.9	302.8	308.8	315.0	321.3	327.8	334.3	341.0	347.8	354.8	361.9	369.1	376.5	384.0	391.7	528.4	538.9	549.7	560.7
2	**Operating Costs**		95.4	97.3	99.3	101.3	103.3	105.4	107.5	109.6	111.8	114.0	116.3	118.6	121.0	123.4	125.9	128.4	131.0	133.6	136.3	139.0	141.8	144.6	147.5	150.5
3	**Amortization**		(187.6)	(187.6)	(187.6)	(189.6)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)	(191.5)
4	**Finance Charges**		(118.3)	(110.7)	(103.1)	(98.8)	(94.5)	(86.7)	(78.8)	(71.0)	(63.1)	(55.2)	(47.3)	(39.3)	(31.4)	(23.4)	(15.3)	(7.3)	0.8	9.0	17.1	25.3	33.5	41.8	50.1	58.4
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		(228.5)	(233.1)	(237.7)	(242.5)	(247.3)	(252.3)	(257.3)	(262 5)	(267.7)	(273.1)	(278.5)	(284.1)	(289.8)	(295.6)	(301.5)	(307.5)	(313.7)	(320.0)	(326.4)	(332.9)	(339.5)	(346.3)	(353 3)	(360.3)
7	DSM Recoveries		195.7	199.7	203.7	207.7	211.9	216.1	220.4	224.8	229.3	233.9	238.6	243.4	248.2	253.2	258.3	263.4	268.7	274.1	279.6	285.2	290.9	296.7	302.6	308.7
8	**Estimated Total Change in Revenue Requirement:**		25.6	39.8	54.2	63.4	72.9	87.9	103.0	118.3	133.8	149.5	165.3	181.4	197.6	214.0	230.6	247.4	264.5	281.7	299.1	316.8	463.5	484.2	505.2	526.4
9	**Estimated Revenue Requirement - Base Case**		16,761	17,095	17,435	17,782	18,136	18,497	18,865	19,241	19,624	20,015	20,414	20,821	21,236	21,659	22,091	22,531	22,980	23,439	23,906	24,383	24,869	25,365	25,871	26,387
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	16,787	17,134	17,489	17,845	18,209	18,585	18,968	19,359	19,758	20,165	20,579	21,002	21,433	21,873	22,321	22,779	23,245	23,720	24,205	24,699	25,332	25,849	26,376	26,913
11	**Domestic Revenues**		(15,971)	(16,289)	(16,613)	(16,944)	(17,281)	(17,626)	(17,977)	(18,335)	(18,700)	(19,072)	(19,452)	(19,840)	(20,235)	(20,639)	(21,050)	(21,470)	(21,898)	(22,334)	(22,780)	(23,234)	(23,697)	(24,170)	(24,652)	(25,144)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	815.3	845.3	875.6	901.2	927.4	959.4	991.9	1,024 9	1,058.4	1,092.5	1,127.2	1,162.4	1,198.1	1,234.5	1,271.5	1,309.0	1,347.2	1,386.0	1,425.5	1,465.6	1,635.3	1,679.3	1,724.1	1,769.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	5.10%	5.19%	5.27%	5.32%	5.37%	5.44%	5.52%	5.59%	5.66%	5.73%	5.79%	5.86%	5.92%	5.98%	6.04%	6.10%	6.15%	6.21%	6.26%	6.31%	6.90%	6.95%	6.99%	7.04%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		293.5	299.4	305.3	311.4	317.6	323.9	330.4	337.0	343.7	350.5	357.5	364.6	371.9	379.3	386.9	394.6	402.4	410.5	418.6	427.0	435.5	444.2	453.1	462.1
15	Scenario	Line 14 * (1+Line 13)	308.5	314.9	321.4	328.0	334.6	341.6	348.6	355.8	363.1	370.6	378.2	386.0	393.9	402.0	410.2	418.6	427.2	435.9	444.8	453.9	465.6	475.1	484.7	494.6
16	Base Case	(Line 14 - 100) / 100	193.5%	199.4%	205 3%	211.4%	217.6%	223.9%	230.4%	237 0%	243.7%	250.5%	257.5%	264.6%	271.9%	279.3%	286.9%	294.6%	302.4%	310.5%	318.6%	327.0%	335.5%	344.2%	353.1%	362.1%
17	Scenario	(Line 15 - 100) / 100	208.5%	214.9%	221.4%	228.0%	234.6%	241.6%	248.6%	255 8%	263.1%	270.6%	278.2%	286.0%	293.9%	302.0%	310.2%	318.6%	327.2%	335.9%	344.8%	353.9%	365.6%	375.1%	384.7%	394.6%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	15.0%	15.5%	16.1%	16.6%	17.0%	17.6%	18.2%	18.8%	19.5%	20.1%	20.7%	21.4%	22.0%	22.7%	23.4%	24.1%	24.8%	25.5%	26.2%	26.9%	30.1%	30.9%	31.7%	32.5%

Incremental Cumulative Rate Impact
Mid Load - Terminate Site C & 30 Yr Recovery (BCUC Costs & BC Hydro Financing)



BC Hydro
Rate Impact Analysis

Rate Impact Model - Mid Load - Terminate 30 Yrs with BCUC Costs & BCH Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		0.0	(7 3)	(13.7)	(25.6)	(41.0)	(55.0)	(82.9)	50.7	137.6	148.6	170.4	182 0	208.8	221.4	258.9	325.3	345 3	350.2	378.7	353.6	379.4	468 9	462.6	505.7	455.4	497.3
2	**Operating Costs**		0.0	11 5	95.7	126.3	140.9	149.5	133 0	121.7	98.5	68.8	34.7	(69.4)	(60.2)	(80.3)	(79.7)	(98.0)	(140.0)	(168.0)	(165.7)	(132.6)	(116.8)	(93 3)	(78.0)	(81.1)	(63.4)	(36.8)
3	**Amortization**		0.0	0 0	133.0	133.0	133.0	133.0	133 0	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)	(9 8)	(9.8)	(9.8)	(9.8)	(9.8)
4	**Finance Charges**		0.0	0 2	150.6	144.8	135.4	135.1	134 3	(207.5)	(204.1)	(201.2)	(199.4)	(200.3)	(202.7)	(205.4)	(208.3)	(211.4)	(215.4)	(220.5)	(225.6)	(229.6)	(232.2)	(233.6)	(234.0)	(233.7)	(232.8)	(230.7)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	(11.5)	(95.7)	(126.3)	(140.9)	(149.5)	(133.0)	(137.1)	(138.5)	(124.5)	(91.5)	11 5	1.1	20.0	18.3	35.3	76.1	102.8	99.1	64.7	47.5	22.7	5.9	7.6	(11.5)	(39.6)
7	DSM Recoveries		0.0	0 0	0.8	7.1	15.6	25.0	34 9	43.8	52.9	62.2	70.5	76.6	75.8	75.7	74.4	73.2	70 8	65.0	51.7	36.7	23.0	9.9	(0.5)	(10.1)	(19.8)	(27.3)
8	**Estimated Total Change in Revenue Requirement:**		0.0	(7.1)	270.6	259.4	243.0	238.1	219.4	(138.2)	(63.3)	(56.0)	(25.2)	(9.4)	12.9	21.7	53.7	114.6	126 9	119.6	128.5	83.0	91.1	164.7	146.3	178.7	118.1	153.0
9	**Estimated Revenue Requirement - Base Case**		4,638	4,851	5,038	5,293	5,525	5,727	5,946	6,308	6,517	6,719	6,741	6,956	7,178	7,392	7,633	7,885	8,101	8,106	8,345	8,687	8,893	9,165	9,468	9,725	9,963	10,373
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,638	4,843	5,309	5,553	5,768	5,966	6,166	6,170	6,453	6,663	6,716	6,946	7,191	7,414	7,687	8,000	8,228	8,225	8,473	8,770	8,984	9,330	9,614	9,904	10,081	10,526
11	**Domestic Revenues**		(4,638)	(4,839)	(5,016)	(5,255)	(5,460)	(5,632)	(5,823)	(6,152)	(6,329)	(6,505)	(6,528)	(6,740)	(6,962)	(7,191)	(7,446)	(7,713)	(7,941)	(7,979)	(8,214)	(8,559)	(8,785)	(9,062)	(9,367)	(9,636)	(9,887)	(10,300)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	0.0	4.4	293.3	297.4	308.3	333.5	343 0	17.7	124.7	157.6	187.1	206.6	228.5	222.5	241.3	286.8	286.6	246.0	258.9	211.0	199.6	267 5	247.3	267.4	194.0	226.1
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.00%	0.09%	5.85%	5.66%	5.65%	5.92%	5.89%	0.29%	1.97%	2.42%	2.87%	3.06%	3.28%	3.09%	3.24%	3.72%	3.61%	3.08%	3.15%	2.47%	2.27%	2.95%	2.64%	2.78%	1.96%	2.20%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		103.3	106.3	109.9	113.8	116.4	118.9	121 5	126.8	129.1	131.8	130.4	132 9	135.5	138.2	141.4	144.7	147 8	146.0	148.3	152.9	154.8	158.1	161.0	163.7	166.0	170.4
15	Scenario	Line 14 * (1+Line 13)	103.3	106.4	116.3	120.2	123.0	125.9	128.7	127.2	131.6	135.0	134.1	137 0	139.9	142.4	146.0	150.1	153.1	150.5	152.9	156.6	158.3	162.7	165.2	168.3	169.3	174.1
16	Base Case	(Line 14 - 100) / 100	3.3%	6 3%	9.9%	13.8%	16.4%	18.9%	21 5%	26.8%	29.1%	31.8%	30.4%	32 9%	35.5%	38.2%	41.4%	44.7%	47 8%	46.0%	48.3%	52.9%	54.8%	58.1%	61.0%	63.7%	66.0%	70.4%
17	Scenario	(Line 15 - 100) / 100	3.3%	6.4%	16.3%	20.2%	23.0%	25.9%	28.7%	27.2%	31.6%	35.0%	34.1%	37 0%	39.9%	42.4%	46.0%	50.1%	53.1%	50.5%	52.9%	56.6%	58.3%	62.7%	65.2%	68.3%	69.3%	74.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.0%	0.1%	6.4%	6.4%	6.6%	7.0%	7 2%	0.4%	2.5%	3.2%	3.7%	4.1%	4.4%	4.3%	4.6%	5.4%	5 3%	4.5%	4.7%	3.8%	3.5%	4.7%	4.3%	4.5%	3.3%	3.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Mid Load - Terminate 30 Yrs with BCUC Costs & BCH Financing.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2044 27	2045 28	2046 29	2047 30	2048 31	2049 32	2050 33	2051 34	2052 35	2053 36	2054 37	2055 38	2056 39	2057 40	2058 41	2059 42	2060 43	2061 44	2062 45	2063 46	2064 47	2065 48	2066 49	2067 50	2068 51	2069 52	2070 53
	Change in Revenue Requirement (Ratepayer Costs):																												
1	**Domestic Energy Costs**		507.3	517.4	527.8	538.3	549.1	560.1	571.3	582.7	594.4	606.3	618.4	579.7	591.3	603.2	578.5	563.1	549.1	584.4	568.9	460.2	496.8	513.0	565.1	551.9	575.4	586.9	598.6
2	**Operating Costs**		(21.8)	(38.6)	(42.8)	(50.8)	(75.3)	(80.5)	(84.0)	(87.6)	(93.3)	(97.2)	(101.2)	(99.0)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120 5)	(122.9)	(125.4)	(127.9)	(130.5)
3	**Amortization**		(9.8)	(9.8)	(9.8)	(9.8)	(9.8)	(9.9)	(143.0)	(143 0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(143.0)	(151.6)	(160.2)	(160 2)	(160.2)	(160.2)	(173.9)	(187.6)
4	**Finance Charges**		(227.8)	(224.8)	(222 2)	(219.9)	(218.3)	(217.3)	(214.2)	(209 0)	(204.2)	(199.7)	(195.4)	(191.1)	(186.7)	(182.3)	(177.9)	(173.4)	(168.9)	(164.2)	(159.4)	(154.5)	(161.3)	(167.7)	(162 2)	(156.6)	(151.1)	(166.5)	(181.5)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																												
6	DSM Additions		(56.2)	(41.0)	(38.3)	(32.0)	(9.1)	(5.5)	(3.8)	(1.9)	2.0	4.0	6.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(30.8)	(26.3)	(23.5)	(19.6)	(16.2)	(13.3)	(7.8)	(0.7)	6.0	10.2	13.1	14.2	14.5	15.0	14.2	11.6	7.8	5.1	2.5	0.4	(0.2)	(0.6)	(0.8)	(0.9)	(0.8)	(0.5)	(0.1)
8	**Estimated Total Change in Revenue Requirement:**		161.0	177.0	191.2	206.3	220.4	233.6	118.4	140.4	161.8	180.6	198.0	162.9	177.2	191.9	168.9	153.3	138.0	173.1	157.7	49.5	67.8	66.4	121.4	111.2	137.9	118.0	98.9
9	**Estimated Revenue Requirement - Base Case**		10,685	10,909	11,139	11,373	11,597	11,829	12,058	12,286	12,515	12,760	13,012	13,260	13,512	13,770	14,032	14,310	14,594	14,808	15,102	15,401	15,680	15,961	16,197	16,490	16,832	17,167	17,508
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	10,846	11,086	11,330	11,579	11,817	12,062	12,177	12,426	12,677	12,940	13,211	13,423	13,690	13,962	14,201	14,464	14,732	14,981	15,259	15,451	15,748	16,027	16,318	16,601	16,970	17,285	17,607
11	**Domestic Revenues**		(10,615)	(10,843)	(11,077)	(11,315)	(11,543)	(11,780)	(12,013)	(12,246)	(12,481)	(12,730)	(12,988)	(13,241)	(13,500)	(13,763)	(14,032)	(14,310)	(14,594)	(14,808)	(15,102)	(15,401)	(15,680)	(15,961)	(16,197)	(16,490)	(16,832)	(17,167)	(17,508)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	230.5	243.0	253.2	264.2	274.1	282.9	163.1	180.2	196.6	210.1	222.1	181.3	189.7	198.3	168.9	153.3	138.0	173.1	157.7	49.5	67.8	66.4	121.4	111.2	137.9	118.0	98.9
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	2.17%	2.24%	2.29%	2.33%	2.37%	2.40%	1.36%	1.47%	1.57%	1.65%	1.71%	1.37%	1.41%	1.44%	1.20%	1.07%	0.95%	1.17%	1.04%	0.32%	0.43%	0.42%	0.75%	0.67%	0.82%	0.69%	0.57%
	Typical Customer Bill (F2017 = 100)																												
14	Base Case		173.7	177.4	180.9	184.2	187.8	191.6	195.3	199.0	202.7	206.7	210.8	214.8	218.9	223.0	227.3	231.8	236.4	239.9	244.6	249.5	254.0	258.5	262.3	267.1	272.6	278.1	283.6
15	Scenario	Line 14 * (1+Line 13)	177.4	181.3	185.0	188.5	192.3	196.2	198.0	201.9	205.9	210.1	214.4	217.7	221.9	226.2	230.0	234.3	238.6	242.7	247.2	250.3	255.1	259.6	264.3	268.9	274.9	280.0	285.2
16	Base Case	(Line 14 - 100) / 100	73.7%	77.4%	80.9%	84.2%	87.8%	91.6%	95.3%	99.0%	102.7%	106.7%	110.8%	114.8%	118.9%	123.0%	127.3%	131.8%	136.4%	139.9%	144.6%	149.5%	154.0%	158.5%	162 3%	167.1%	172.6%	178.1%	183.6%
17	Scenario	(Line 15 - 100) / 100	77.4%	81.3%	85.0%	88.5%	92.3%	96.2%	98.0%	101 9%	105.9%	110.1%	114.4%	117.7%	121.9%	126.2%	130.0%	134.3%	138.6%	142.7%	147.2%	150.3%	155.1%	159.6%	164 3%	168.9%	174.9%	180.0%	185.2%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	3.8%	4.0%	4.1%	4.3%	4.5%	4.6%	2.7%	2.9%	3.2%	3.4%	3.6%	2.9%	3.1%	3.2%	2.7%	2.5%	2.2%	2.8%	2.6%	0.8%	1.1%	1.1%	2.0%	1.8%	2.2%	1.9%	1.6%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Mid Load - Terminate 30 Yrs with BCUC Costs & BCH Financing.xlsx

Summary
Page 4

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 54	2072 55	2073 56	2074 57	2075 58	2076 59	2077 60	2078 61	2079 62	2080 63	2081 64	2082 65	2083 66	2084 67	2085 68	2086 69	2087 70	2088 71	2089 72	2090 73	2091 74	2092 75	2093 76	2094 77
	Change in Revenue Requirement (Ratepayer Costs):																									
1	**Domestic Energy Costs**		610.6	622.8	635.3	648.0	660.9	674.2	687.7	701.4	715.4	784.7	800.4	816.4	884.7	936.2	984.3	971.4	1,031.6	1,229.2	1,212.9	1,227.4	1,184.1	1,246.2	1,256 9	1,282.0
2	**Operating Costs**		(133.1)	(135.7)	(138 5)	(141.2)	(144.1)	(146.9)	(149.9)	(152 9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(187.6)	(187.6)	(187.6)	(189.6)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191.5)	(191 5)	(191.5)
4	**Finance Charges**		(175.0)	(168.6)	(162 2)	(159.1)	(155.9)	(149.3)	(142.8)	(136 2)	(129.6)	(123.0)	(116.5)	(109.9)	(103.3)	(96.8)	(90.2)	(83.6)	(77.1)	(70.5)	(63.9)	(57.4)	(50.8)	(44.2)	(37.7)	(31.1)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		114.9	130.9	147.0	158.1	169.5	186.4	203.5	220.8	238.4	311.1	330.1	349.5	421.1	475.8	527.0	517.1	580.3	780.9	767.4	784.7	744.0	808.7	822.0	849.6
9	**Estimated Revenue Requirement - Base Case**		17,856	18,212	18,574	18,944	19,321	19,706	20,099	20,499	20,907	21,324	21,749	22,183	22,625	23,076	23,536	24,116	24,597	25,088	25,629	26,186	26,840	27,422	27,953	28,511
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	17,971	18,342	18,721	19,102	19,491	19,892	20,302	20,720	21,146	21,635	22,079	22,532	23,046	23,551	24,063	24,633	25,178	25,869	26,396	26,970	27,584	28,231	28,775	29,361
11	**Domestic Revenues**		(17,856)	(18,212)	(18,574)	(18,944)	(19,321)	(19,706)	(20,099)	(20,499)	(20,907)	(21,324)	(21,749)	(22,183)	(22,625)	(23,076)	(23,536)	(24,116)	(24,597)	(25,088)	(25,629)	(26,186)	(26,840)	(27,422)	(27,953)	(28,511)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	114.9	130.9	147.0	158.1	169.5	186.4	203.5	220.8	238.4	311.1	330.1	349.5	421.1	475.8	527.0	517.1	580.3	780.9	767.4	784.7	744.0	808.7	822.0	849.6
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.64%	0.72%	0.79%	0.83%	0.88%	0.95%	1.01%	1.08%	1.14%	1.46%	1.52%	1.58%	1.86%	2.06%	2.24%	2.14%	2.36%	3.11%	2.99%	3.00%	2.77%	2.95%	2 94%	2.98%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		289.2	295.0	300.9	306.8	313.0	319.2	325.5	332.0	338.6	345.4	352.3	359.3	366.5	373.8	381.2	390.6	398.4	406.4	415.1	424.1	434.7	444.2	452.8	461.8
15	Scenario	Line 14 * (1+Line 13)	291.1	297.1	303.2	309.4	315.7	322.2	328.8	335.6	342.5	350.4	357.6	365.0	373.3	381.5	389.8	399.0	407.8	419.0	427.5	436.9	446.8	457.3	466.1	475.6
16	Base Case	(Line 14 - 100) / 100	189.2%	195.0%	200 9%	206.8%	213.0%	219.2%	225.5%	232.0%	238.6%	245.4%	252.3%	259.3%	266.5%	273.8%	281.2%	290.6%	298.4%	306.4%	315.1%	324.1%	334.7%	344.2%	352 8%	361.8%
17	Scenario	(Line 15 - 100) / 100	191.1%	197.1%	203 2%	209.4%	215.7%	222.2%	228.8%	235.6%	242.5%	250.4%	257.6%	265.0%	273.3%	281.5%	289.8%	299.0%	307.8%	319.0%	327.5%	336.9%	346.8%	357.3%	366.1%	375.6%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	1.9%	2.1%	2.4%	2.6%	2.7%	3.0%	3.3%	3.6%	3.9%	5.0%	5.3%	5.7%	6.8%	7.7%	8.5%	8.4%	9.4%	12.6%	12.4%	12.7%	12.1%	13.1%	13.3%	13.8%

From: Foster, Doug FIN:EX
To: MacLaren, Les EMPR:EX
Cc: Gonzalez, Selina FIN:EX; Dunn, Jonathan FIN:EX; Wanamaker, Lori FIN:EX
Subject: s.12,s.13
Date: Tuesday, November 28, 2017 12:04:14 PM
Attachments: s.12,s.13

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s.12,s.13

d

From: Foster, Doug FIN:EX
Sent: Tuesday, November 28, 2017 11:51 AM
To: Wanamaker, Lori FIN:EX
Subject: RE: s.12,s.13

s.12,s.13

d.

From: Wanamaker, Lori FIN:EX
Sent: Tuesday, November 28, 2017 8:51 AM
To: Foster, Doug FIN:EX
Subject: RE: s.12,s.13

s.12,s.13

Let's discuss.
Lori

From: Foster, Doug FIN:EX
Sent: Tuesday, November 28, 2017 8:23 AM
To: Wanamaker, Lori FIN:EX
Subject: FW s.12,s.13

fyi

From: Foster, Doug FIN:EX
Sent: Tuesday, November 28, 2017 8:00 AM
To: MacLaren, Les EMPR:EX
Cc: Wieringa, Paul EMPR:EX; Gonzalez, Selina FIN:EX
Subject: RE: s.12,s.13

s.12,s.13

Let me know if this works.
d.

From: Foster, Doug FIN:EX
Sent: Tuesday, November 28, 2017 6:48 AM
To: MacLaren, Les EMPR:EX
Cc: Wieringa, Paul EMPR:EX
Subject: s.12,s.13

Thanks.
s.12,s.13

d.

From: MacLaren, Les EMPR:EX
Sent: Tuesday, November 28, 2017 6:39 AM
To: Foster, Doug FIN:EX
Cc: Wieringa, Paul EMPR:EX
Subject: s.12,s.13

Hi Doug:
s.12,s.13

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy, Mines and Petroleum Resources
NOTE NEW OFFICE PHONE NUMBER: 778-698-7183
Cell: 250-889-3479
Energizing BC—clean, sustainable and productive

Page 178 to/à Page 183

Withheld pursuant to/removed as

s.12;s.13

From:	Foster, Doug FIN:EX
To:	MacLaren, Les EMPR:EX
Subject:	FW: Site C related documents.
Date:	Friday, November 17, 2017 4:27:48 PM
Attachments:	Hydro Alt Profile_v2.xlsx

s.12,s.13

From: Foster, Doug FIN:EX
Sent: Friday, November 17, 2017 4:27 PM
To: Dunn, Jonathan FIN:EX
Subject: FW: Site C related documents.

thanks jonathan.

d

From: Dunn, Jonathan FIN:EX
Sent: Friday, November 17, 2017 10:37 AM
To: Foster, Doug FIN:EX
Subject: RE: Site C related documents.

Hi Doug

s.12,s.13

thx

Jon

From: Foster, Doug FIN:EX
Sent: Friday, November 17, 2017 6:56 AM
To: Dunn, Jonathan FIN:EX
Subject: FW: Site C related documents.

What would this look like?

d.

From: MacLaren, Les EMPR:EX
Sent: Friday, November 17, 2017 6:54 AM
To: Foster, Doug FIN:EX
Subject: RE: Site C related documents.

s.12,s.13

Les

From: Foster, Doug FIN:EX
Sent: Thursday, November 16, 2017 3:08 PM
To: MacLaren, Les EMPR:EX
Subject: FW: Site C related documents.

s.12,s.13

d.

From: Dunn, Jonathan FIN:EX
Sent: Thursday, November 16, 2017 12:08 PM
To: Foster, Doug FIN:EX
Subject: FW: Site C related documents.

Hi Doug

s.12,s.13

Thx

Jon

Page 185 to/à Page 188

Withheld pursuant to/removed as

s.12;s.13

From:	O"Riley, Christopher
To:	MacLaren, Les EMPR:EX
Subject:	Fwd: Briefing Note on Report
Date:	Wednesday, November 1, 2017 11:33:03 AM
Attachments:	BN - Site C BCUC Panel deeply pessimistic about B.C.'s future FINAL.doc ATT00001.htm

Updated note

Sent from my iPhone

Begin forwarded message:

From: "Magre, Leela" <Leela.Magre@bchydro.com>
Date: November 1, 2017 at 11:25:44 AM PDT
To: "O'Riley, Christopher" <Chris.Oriley@bchydro.com>
Cc: "Sauer, Darwin" <Darwin.Sauer@bchydro.com>
Subject: Briefing Note on Report

Hello Chris,
Attached is the final version of the briefing note on the report.
Thank you,
Leela

_____

Leela Magre | Manager, Policy & Research
BC Hydro
333 Dunsmuir St, 15th floor
Vancouver, BC V6B 5R3
P 604 623 4008
M 236 993 0338
E leela.magre@bchydro.com
bchydro.com
Smart about power in all we do.

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BRIEFING NOTE – BCUC PANEL DEEPLY PESSIMISTIC ABOUT B.C.'S FUTURE

Confidential – Advice to Cabinet

Background and Summary

On November 1, 2017 the British Columbia Utilities Commission will issue its Final Report to the Government of British Columbia in the Site C Inquiry.

The Commission has provided a report and findings that are deeply pessimistic about B.C.'s economic future and unrealistic about what resources are available and their cost. The Commission has also established an "Illustrative Alternative Portfolio" that would result in a number of adverse outcomes for British Columbia's energy future.

The major issues identified to date are listed below:

1. The Commission has taken "no position on which of the termination or completion scenarios has the greatest cost to ratepayers" and does not calculate rate impacts. However, incremental rate increases would be more than 10% over a 10-year recovery period if Site C were terminated, and electricity would be less affordable for British Columbians.

2. The Commission's Load Growth Scenario assumes that British Columbia's economy will slow, large industry will leave the province and jobs will be lost across a number of sectors.

3. BC Hydro takes risks on unproven alternative capacity resources and appears to rely on demand-side management for over 900MW of capacity. This would result in higher costs and reliability impacts for customers if these capacity resources fail to materialize.

4. BC Hydro finances all new projects, resulting in a diminished role for the clean energy industry and more debt and risk on BC Hydro's balance sheet.

5. The mitigation options proposed would increase greenhouse gas emissions in B.C.

6. The majority of First Nations affected by Site C do not oppose the Project and would lose benefits if Site C were to be terminated..

Initial Assessment of the Final BCUC Report

1. Overall, electricity would be less affordable for British Columbians.

- If Site C were terminated, there are $3.9 billion in costs that must be recovered, from either the taxpayer or the ratepayer: $2.1 billion in costs incurred prior to termination ("sunk costs") and $1.8 billion in termination costs (according to the Commission Panel's estimates) which are expected to be incurred over the next two years.

- This is expected to result in an incremental increase to BC Hydro's rates of more than 10% over a 10 year recovery period.

- The report also assumes that termination costs are amortized (recovered) over 30 years so as to reduce the up-front rate impacts. The longer this period, the more carrying costs BC Hydro has to pay. This would also mean asking a ratepayer in 2045 who is not even born today to pay for a project cancelled in 2017.

- It appears from the Commission's assumptions that sunk costs of $2.1 billion may be included in the completion scenario, but not in the termination scenario. If this correct, this would be a very significant methodological error that understates the cost of the alternative portfolio.

- The Commission has stated that BC Hydro's revised forecast of $8.945 billion results in the use of all of the remaining project contingency. This is incorrect. This forecast preserves the remaining project contingency to manage future risks.

2. The Commission's Load Growth Scenario assumes that British Columbia's economy will slow, large industry will leave the province and jobs will be lost across a number of sectors, not just at BC Hydro or the Site C project.

- The scenario that makes the Commission's alternative portfolio work (a low load scenario or even lower than the low load case) is one that assumes that future provincial electricity demand is unreasonably low. This is a scenario in which the Province has failed to deliver a strong economy, businesses have exited the province, Liquefied Natural Gas has failed to materialize and there has been a failure to deliver on GHG commitments through electrification.

- This low load scenario means a loss of jobs associated with the failed industrial businesses, without new jobs to replace them. This is in addition to the job losses and other negative economic impacts that would result from the termination of Site C.

- The Commission scenarios are premised on the assumption that none of the Liquefied Natural Gas projects (LNG Canada, Woodfibre, FortisBC Tilbury Phase 2) included in BC Hydro's load forecast will proceed.

- The report finds that low-carbon electrification should not be included in the load forecast for the purpose of resource planning. Disregarding the impacts of electrification altogether cannot be reconciled with the Province's commitment to reduce greenhouse gas emissions.

3. BC Hydro takes risks on unproven alternative capacity resources, with higher costs and reliability impacts for customers if these fail to materialize.

- The Illustrative Alternative Portfolio used by the Commission requires BC Hydro takes risks on alternative resources that have not been proven to be viable or cost-effective, including what appears to be over 900MW of capacity from demand-side management.

- Dispatchable storage hydro provides "dependable capacity": these are resources that BC Hydro can depend upon to meet customer needs when they are greatest. Dependable capacity is critical to system reliability.

- Reducing BC Hydro's access to dependable capacity could create an increased risk to reliability and/or require BC Hydro to import power when it is most costly.

- The Illustrative Alternative Portfolio includes almost no new capacity resources – rather it relies on 900MW of capacity from demand-side management. Capacity-focused demand-side management is highly uncertain, and the Commission has relied on substantially more MW than BC Hydro believes is feasible. The report further suggests that BC Hydro could encourage hot water shutoffs during periods of peak demand and could implement time of use rates. This points to the risk that the current reliability of the system that British Columbians depend upon could be compromised.

- The report concludes that because BC Hydro has substantial existing dispatchable resources, a portfolio with resources that are not dispatchable is viable. This is incorrect. New renewable intermittent resources like wind, solar and run-of-river hydro require the support of dependable and flexible resources like storage hydro.

- The Illustrative Alternative Portfolio includes 81MW of geothermal projects starting in Fiscal 2025. However, the report also states that "there may actually be no geothermal potential" in B.C. There is a risk to making this assumption, given that after decades of investigation, there are no successful geothermal projects anywhere in B.C.

4. BC Hydro finances all new projects, resulting in a diminished role for the clean energy industry and more debt and risk on BC Hydro's balance sheet.

- For decades, BC Hydro has partnered with the clean energy industry in purchasing power from independent power producers.

- The report assumes that BC Hydro finances all incremental resources. In effect, this leaves no future role for the independent clean energy sector, and runs counter to the long-standing policy of having the private sector develop, finance and assume the risk for these projects.

5. Mitigation options proposed would increase greenhouse gas emissions in British Columbia.

- The Commission Panel suggests that, with policy changes, gas-fired generation is an option to meet future energy needs and to mitigate the risk of alternatives. This would include remobilizing Burrard Thermal to provide capacity to the electricity system.

- The report suggests that fuel-switching can lower energy demand, which implied fuel switching from electricity to fossil-fuel based sources, increasing greenhouse gas emissions. In fact, the expanded use of electricity in the place of fossil fuels to reduce greenhouse gas emissions (low-carbon electrification), increases demand for electricity.

6. The majority of First Nations affected by Site C do not oppose the Project and would lose benefits if Site C was terminated.

- While the report refers to impacts on First Nations, the majority of the First Nations affected by the Project do not oppose the Project and would lose long-term benefits if it is terminated.

- One of those First Nations, McLeod Lake, stated in the Inquiry process that termination will unravel the process of reconciliation and be economically catastrophic for their community.

From:	Nikolejsin, Dave MNGD:EX
To:	MacLaren, Les EMPR:EX
Subject:	Fwd: Deputy Ministers' Inquiries Respecting Site C
Date:	Friday, November 17, 2017 7:01:10 AM
Attachments:	newlogo.gif ATT00001.htm 20171116 Response to Deputy Minister"s Questions 8 RM.pdf ATT00002.htm

---

Dave Nikolejsin
Deputy Minister
Energy, Mines and Petroleum Resources

Begin forwarded message:

From: Robert McCullough <robert@mresearch.com>
Date: November 16, 2017 at 11:16:06 PM PST
To: <dave.nikolejsin@gov.bc.ca>
Subject: Deputy Ministers' Inquiries Respecting Site C

Dear Mr. Horgan, Mr. Meggs, Ms. Wanamaker, and Mr. Nikolejsin:

We are writing you at the request of our clients, the Peace Valley Landowner Association and the Peace Valley Environment Association, regarding the questions raised in the attached letter dated November 15th, 2017.

We have included detailed answers to your questions as well as highlighting the all important Canadian Entitlement and Non-Treaty Storage issues.

Please feel free to contact us if you have any questions.

Yours,

Robert McCullough and Harry Swain

--

McCullough Research

Robert F. McCullough, Jr.
Principal

Date: November 16, 2017

To: Premier John Horgan
Government of British Columbia

From: Robert McCullough and Harry Swain

Subject: Deputy Ministers' Inquiries Respecting Site C

We are writing you at the request of our clients, the Peace Valley Landowner Association and the Peace Valley Environment Association, regarding the questions raised in the attached letter dated November 15th, 2017.

At the outset, it is important to note that the British Columbia Utilities Commission's (BCUC) Site C Inquiry Report is detailed and well documented. The final report represents the careful consideration and weighing of 10,000 pages of testimony, 2 days of expert presentations, 11 public input sessions, and hundreds of pages of consultant, preliminary ad final reports.

Importantly, the BCUC has taken a conservative approach in their calculations – which is good - although industry experts would take a more pessimistic view of load forecasts and cost overruns, a more optimistic view of the savings from terminating Site C, and would factor in the non-treaty storage available from the Mica Dam.

The answers to the questions raised by your Deputy Ministers are set out below.

I. Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?

Answer:

Yes, the existing investment for Site C ($2.1 billion) is included in both the Site C Case and the Alternative Portfolio since these costs have been spent and cannot be recovered. Termination (reclamation) costs have been charged to the Alternative Portfolio as well.

6123 Reed College Place • Portland • Oregon • 97202 • 503-777-4616 • Robert@MResearch.com

The BCUC treatment of these costs is consistent with economic theory and practice and concludes that there is no cost advantage to proceeding with Site C. It should be noted that the treatment of sunk costs is known as the Fallacy of Sunk Costs by the newly appointed Nobel Laureate Richard Thaler. Once costs have been spent, they do not exert a "thumb on the scales" for future investment decisions.

2. In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

Answer:

Not per se, but the difference between IPP and Crown Corporation should be minimal. It is a postulate of finance that the cost of capital depends on the credit support of the buyer. When an IPP approaches the financial markets, it is the quality of the Power Purchase Agreement (PPA) and the counterparty that determines the cost of capital. If the Province of British Columbia is the ultimate guarantor of the project (in this case with a Triple A credit rating), the cost of capital is virtually the same whether the Crown Corporation or an IPP builds the project.

3. Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?

Answer:

Properly designed demand side programs are also advantageous to the consumer and produce more benefits than their costs. For example, time of use rates and curtailment programs allow the consumer to correctly time their use of energy and response to system exigencies. A good example is the operation of a paper mill with thermo-mechanical pulping (TMP). The opportunity to schedule TMP for off-peak hours is a significant advantage to the paper mill. And, appropriate curtailment opportunities can be profitable for both the utility (in this case BC Hydro) and the paper mill. During the California energy crisis of 2000-2001, Northwest Power Pool industries from Trail, British Columbia to Eugene, Oregon shifted their operations to gain the benefits of serving California loads during high price periods.

4. If the Site C project were terminated, the $4.0 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over I 0, 30 or 70 years?

Answer:

The BCUC assumed that sunk costs as well as termination costs would be recovered over thirty years. This is unnecessarily conservative. Economic theory and practice does not require that recovery of a project's costs be accelerated simply because a project was terminated. Logically, the termination of the project should have the same impact on ratepayers as proceeding with the project. Penalizing ratepayers for a bad utility decision is also inequitable. If the goal is to objectively compare the options, then the same seventy-year amortization schedule that is currently in effect should be employed.

The highly accelerated recovery of sunk and reclamation costs is inappropriate – and punitive. It should be noted that forcing the public to pay in advance of already financed costs makes little economic sense. Indeed, various costs could be recovered in one year if the goal is to alarm the public. The reality is that the costs were incurred on a seventy-year amortization schedule and should remain on that schedule. To my knowledge, based on almost 40 years of experience in this area, there is no overwhelming legal or economic purpose to raise rates immediately.

5. We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. Did the Commission assume lower demand for electricity (reflected in the low load forecast used in the report) because it is forecasting a period of lower economic growth? Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?

Answer:

BC Hydro's submissions contradict the experience of lower load growth experienced across the U.S. and Canada. BC Hydro was unable to justify their forecast, or, indeed, accurately explain the components that contributed to their high estimates. The record at the BCUC clearly proves that BC Hydro has over forecasted in virtually every case for many years.

In part, this reflects the decline of traditional industries like pulp and paper, but a more extensive impact is the shift to LED lighting and other energy efficiency measures.

Over more than half a century, for 77% of the time, BC Hydro's forecasts have overstated reality. BCUC might have chosen a lower forecast than the BC Hydro low forecast had their terms of reference allowed. They have a better grasp of industrial evolution, and of price elasticity, than BC Hydro. The fact is that the old one-to-one relation of economic growth to electricity demand has been broken for 20 years all over North America. BC Hydro has just been slow to realize this.

The BCUC clearly weighed all the evidence before it and concluded that in these circumstances the low load forecast is the appropriate forecast. Importantly, the BCUC noted that if it were not outside the terms of reference it would likely/may have found that an even lower load forecast would be appropriate. It is important to remember that Deloitte found that BC Hydro has historically overestimated electricity demand by 30% on average.

BC Hydro has not addressed the issue of increased electrification in its submissions, nor did the mandate in the Order in Council directly address this scenario.

That said, there were expert submissions on this topic that indicated that the most important components of electrification – transportation – occur off-peak. The evidence is based on solid research from California and New York where electrification programs are more advanced.

The BCUC noted that increased DSM, consumer self help such as solar panels on houses, coupled with the decline in electricity demand in heritage industries like pulp and paper will very likely offset any increase in electrification demand.

In the event the actual level of demand exceeds the forecast, the alternative scenario utilizing renewables including wind can be expanded – resources that are largely unlimited in scope, low in cost, and readily deployable in response to increased demand.

Northwest Power Pool utilities (Washington, Oregon, Idaho, and Montana) in the United States currently have ten times the wind resources as British Columbia with more being sited and built every day. Most all forecasts suggest the cost of these resources will continue to decrease making the cost of Site C power even less competitive.

Finally, I was disappointed that the questions missed the most important finding of the BCUC – that the Canadian Entitlement – roughly the same size as Site C – is a dependable source of energy and capacity. Moreover, that the authors appeared to have missed the opportunity that I identified – and was positively received by the BCUC and the press – to use the large underutilized resource of the Non-Treaty Storage Agreement to serve the

citizens of British Columbia rather than being rented to the Bonneville Power Administration.

Conclusion:

I trust this memorandum provides helpful information and analysis that complements the information and analysis you receive from the BCUC. If you have any questions regarding the accuracy or applicability of the above commentary, please do not hesitate to contact me.

Please note that Harry Swain, former Chair of the Federal/Provincial Panel on Site C has reviewed and concurs with the above observations and analysis.

Yours,



Robert McCullough

CC BCUC
BC Government MLAs

BRITISH COLUMBIA

November 15, 2017

Ref.: 102700

Mr. David Morton
Chair
BC Utilities Commission

Email: David.Morton@bcuc.com

Re: Inquiry Respecting Site C

The Ministry of Energy, Mines and Petroleum Resources and Ministry of Finance are supporting the government decision process surrounding the future of the Site C project. On behalf of our respective Ministers, we would like to thank the BC Utilities Commission (Commission) for the report *Inquiry Respecting Site C*. Completing an inquiry of this scope over an abbreviated timeframe and with high levels of public and First Nations input is a considerable achievement.

As our ministries analyze the Commission's report, along with other implications associated with government proceeding with or terminating the Site C project, we want to ensure that we fully understand the assumptions and computations that the Commission made in the analysis of potential alternative sources of energy generation and capacity. Accordingly, we are requesting further explanation or additional information on the points listed below and in the Appendix attached to this letter.

1. Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?

   We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not, could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

2. In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects

Ministry of Energy, Mines and Petroleum Resources
Office of the Deputy Minister
Mailing Address: PO Box 9319, Stn Prov Govt Victoria, BC V8W 9N3
Location: 8th Floor, 1810 Blanshard Street Victoria
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Facsimile: 250 952-0269
Website: www.em.gov.bc.ca/

included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?

3. Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?

4. If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?

    - Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?

    - Recently it has been stated that recovering the project's sunk and remediation costs over a 10-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?

5. We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:

    - Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?

    - Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?

We sincerely appreciate the Commission's timely response to these questions and requests for clarification. Government has committed to making a decision on the Site C project before the end of the year. The Commission's responses to our questions will assist our ministries in better understanding the report and the assumptions that underlie it as we prepare advice to support government in making a decision that will be in the best interests of British Columbians.

Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines
and Petroleum Resources

Lori Wanamaker
Deputy Minister
Ministry of Finance

Attachment

Appendix: Detailed Questions for the Commission

We understand that while BC Hydro modelled over 60 scenarios and tested various assumptions, including a number of alternatives requested by the Commission, the alternative portfolio that the Commission included in the final report was not analyzed using BC Hydro's modelling tools. On this basis, government has asked BC Hydro to provide an assessment of the model used to develop the Commission's final alternative portfolio. BC Hydro will provide the Commission with the results of that assessment separately.

In our initial analysis of the report, our ministries have identified several areas that we would appreciate the Commission's feedback on. Several of our questions relate to the impact of certain assumptions made in the report, and how the costs of those assumptions would be recovered from ratepayers.

We understand that BC Hydro follows standards for rate-regulated utilities in its financial statements and in preparing its applications for review by the Commission. This accounting framework follows a number of principles in relation to the amortization of capital assets and the deferral of other costs for the purpose of matching recoveries from ratepayers to periods over which benefits are provided.

It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.

The Commission's process involved some deliberations on the cost of capital. The alternative portfolio presented in the report assumes that BC Hydro will finance all new resources on its balance sheet. However, other than redevelopment of existing sites and Site C, BC Hydro has, for almost three decades, been primarily procuring new supply from competitive processes or bilateral agreements that are benchmarked to competitive processes. This effectively means that BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.

It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio, and the BC Hydro financing assumption should only be used for the Unit Energy Cost (UEC) analysis. However, on pages 167, 170 and Appendix C (Assumption 2), it appears that the

Commission has used BC Hydro financing (100% debt financing at a cost of 3.43%) for the alternative portfolio. If we are interpreting this correctly, we would appreciate clarification on which cost of capital should be used in analysing rate impacts.

BC Hydro has suggested that recovery in rates of sunk costs in a termination scenario should occur over a 10-year period. If the project were to continue as planned, the sunk costs, as part of the overall project costs, will be recovered over a 70-year period, consistent with the amortization of the Site C asset. The Commission model appears to exclude sunk costs in the termination scenario, and has removed those costs from the completion scenario as well. Effectively this assumes that sunk costs will be recovered through rates over 70 years if the project is terminated. Recovering costs in rates over a shorter period has a material impact on the costs of the alternative portfolio. It would be helpful if the Commission could provide an estimate of the impact on rates of using these two timeframes.

The tables on page 17 of the executive summary and page 170 in the main report include a summary of the Commission's sample scenarios showing the effect of modifying one or more variables to the resulting Net Present Value cost to ratepayers. As noted above, the Commission's alternative portfolio does not appear to include sunk costs, and sunk costs have also been removed on the continue scenario. The tables also include UECs. For the Site C scenario, the UECs reflect costs, including sunk costs, of Site C being either $10 billion or $12 billion depending on assumptions. Our review of the Commission report suggests that the alternative portfolio does not include termination costs. It would be helpful if the Commission could confirm this and provide a version of the UEC portion of the table with termination costs included in the alternative portfolio. This would help provide a consistent basis for comparing costs between the scenarios of completing or terminating the project.

It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis?

We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's *Clean Energy Act* energy objectives of:

- Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;
- Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,
- Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.

It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.
It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the *Greenhouse Gas Reduction (Clean Energy) Regulation* under the *Clean Energy Act*. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures.

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

From:	O"Riley, Christopher
To:	MacLaren, Les EMPR:EX
Subject:	Fwd: Overview of Initial Findings from BC Hydro Review of BCUC Final Report
Date:	Friday, November 3, 2017 8:28:53 PM
Attachments:	20171103 - BCUC Final Report - Overview of Initial Findings from BCH Review v3.docx ATT00001.htm

Sent from my iPhone

Begin forwarded message:

From: "Savidant, Michael" <michael.savidant@bchydro.com>
Date: November 3, 2017 at 4:43:22 PM PDT
To: "O'Riley, Christopher" <Chris.Oriley@bchydro.com>
Cc: "McSherry, Diane" <diane.mcsherry@bchydro.com>, "Layton, Ryan" <ryan.layton@bchydro.com>, "Magre, Leela" <Leela.Magre@bchydro.com>, "Jubb, Anthea" <Anthea.Jubb@bchydro.com>, "mghikas@fasken.com" <mghikas@fasken.com>, "Bridget Gilbride (bgilbride@fasken.com)" <bgilbride@fasken.com>, "James, Fred" <Fred.James@bchydro.com>
Subject: Overview of Initial Findings from BC Hydro Review of BCUC Final Report

Chris,
Here is an overview of our findings from a review of the BCUC final report. As stated in the introduction, this is a preliminary view and may evolve as we look at things in more detail. The team has done exceptional work to identify why the BCUC's findings vary from ours, and I think the results are illuminating.
We are planning to notify the BCUC of the items in Section 1 on Monday given they represent basic mathematical errors. Let me know if you are OK with this approach.
Let me know if you have any questions.
-Mike

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Michael Savidant
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Site C Inquiry
Overview of Initial Findings from BC Hydro Review of BCUC Final Report
November 3, 2017

This document provides a summary of items identified through BC Hydro's preliminary analysis that are expected to be most material to the Commission's conclusions regarding a comparison of Site C to the Commission's alternative portfolio (the "Illustrative Alternative portfolio").

Please note:

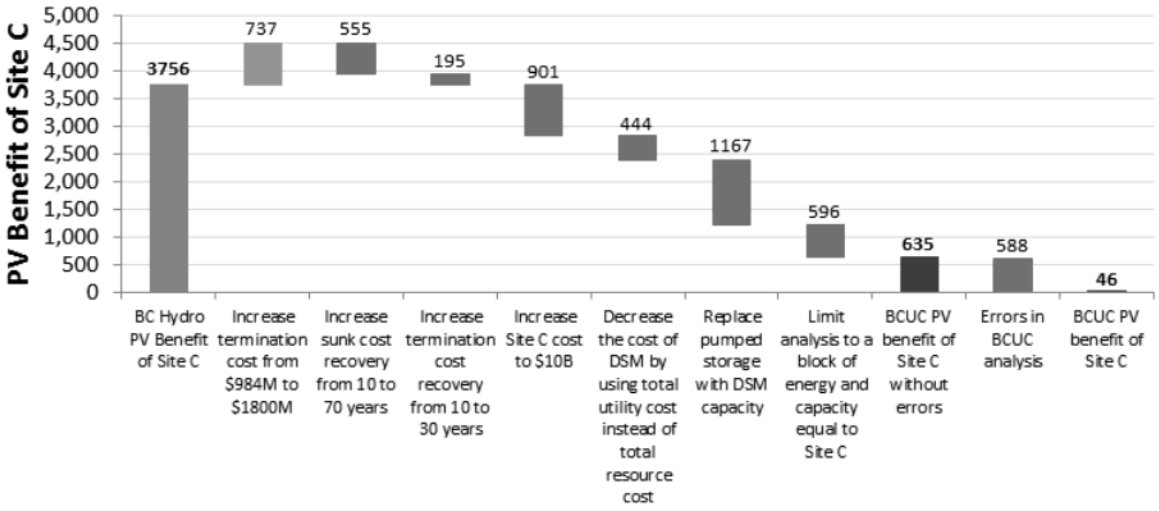
- This list is not exhaustive. Additional issues and errors have been identified that are not in this summary.
- BC Hydro's review is not yet complete. Additional issues may be identified in the future.

The table below provides a summary of these issues with the expected impact on the Commission's calculations of PV costs and benefits. Note that there may be overlap and compounding effects between items, and they should not be considered directly additive.

	Issue	**Impact on Cost of Termination**
1.	**Modelling Errors**	
A	Application of incorrect discount rate to Site C surplus	+$336 million
B	Inconsistent application of inflation factors and discount rates	+$51 million
C	Double-counting of transmission losses on DSM	+$201 million
2.	**Assumptions that do not reflect true costs to ratepayers**	
A	Inaccurate treatment of sunk costs	+$555 million
B	Inaccurate treatment of termination costs	+$195 million
C	Use of BC Hydro financing for all resources	Not calculated (depends on other assumptions)
D	Use of modified block analysis, ignoring value of DSM when proceeding with Site C	+$596 million
E	Use of Total Utility Cost rather than Total Resource Cost for DSM	+$444 million
3.	**Assumptions that are incorrect and not supported by evidence**	
A	Adoption of the Low Load Forecast as the expected case	Not estimated at this time
B	Adoption of 400MW of industrial load curtailment without evidence	
C	Use of an arbitrarily lowered market price forecast	
D	Assumption that the alternative portfolio has the same firming and shaping capability as Site C	
E	Use of incorrect technology assumptions on geothermal resources	
4.	**Assumptions that are inconsistent with legislation and/or policy**	
A	"Remobilization" of Burrard	Not estimated at this time
B	Use of Columbia River Treaty entitlement	
C	Increased reliance on external market purchases to meet demand	

Errors in Sections 1 and 2 are largely due to the Commission's adoption of their own modelling tools and rejection of BC Hydro's modelling tools. The Commission should not have eliminated BC Hydro's portfolio analysis evidence from consideration in this inquiry as it is the most complete assessment of the impacts and has been used successfully for many years in the context of resource planning. BC Hydro was available throughout the process to respond to questions and ran all of the sensitivities requested by the Commission. BC Hydro identified errors and assumption concerns with other portfolios that we were asked to assess. However, we were never asked to comment on the simplified Illustrative Alternative Portfolio, upon which the Commission ended up relying.

The graph below shows the assumptions the Commission has made to go from BC Hydro's "Commission Portfolio" PV estimate of $3.8 billion benefits of completing Site C to their assessment of zero benefits. The graph also shows the PV impact of correcting the errors listed in Section 1.



1. Modelling Errors

This section covers items that we believe are mistakes, rather than unjustified assumptions.

A. The Commission's model has a mathematical error in its treatment of the Site C energy surplus.
   - The Illustrative Alternative model uses a **nominal dollar** market price and discounts at a **nominal dollar** discount rate. This is a correct method.
   - The Site C model uses a 2018 **real dollar** market price and discounts at a **nominal dollar** discount rate. This is an incorrect method as the discount rate should be consistent with the dollar basis of prices.
   - We believe this is a mistake rather than a conscious assumption, as there is no feasible basis for this difference nor has the Commission identified it in their assumptions.
   - This mistake undervalues the Site C surplus on a Present Value basis.
   - In the Commission Scenario Low Load Case used in Table 40, the impact is a $336 million higher cost of Site C than is correct.

B. The Commission's model has a mathematical error due to inconsistent application of inflation factors and discount rates.
   - Inflation is applied to costs assuming they occur at the **start** of a fiscal year.
   - Discounting is applied to costs assuming they occur at the **end** of a fiscal year.
   - This inconsistent approach is incorrect. Inflation and discounting should be applied to the same period.
   - In the Commission Scenario using the Low Load Case in Table 39, this results in a $51M lower cost of the Illustrative Alternatives than is correct.

C. The Commission has double-counted transmission loss savings associated with DSM which has the effect of understating the cost of the Commission's alternative portfolio relative to Site C.
   - In its original October 11th portfolio, the Commission increased the amount of energy provided by DSM by ~11% to reflect the avoidance of transmission losses.
   - In our October 18th response, we flagged that this was incorrect as the energy volumes they were using were already adjusted to reflect loss avoidance.
   - The Commission has stated that they continue to believe their adjustment is appropriate as they believe BC Hydro's adjustment was only for distribution losses, and a further adjustment is required for transmission losses.
   - This is incorrect. The volumes used by the Commission had already been adjusted to reflect transmission losses as well as distribution losses, and thus the Commission scenario double-counts transmission loss savings. Correction of this issue would advance the need for new resources and increase the cost of the Illustrative Alternative portfolio by ~$201 million.

2. Assumptions that do not reflect true costs to ratepayers

This section covers assumptions the Commission has made that are not mathematical errors, but are not representative of how costs would actually be recovered from ratepayers.

A. The Commission's treatment of sunk costs (i.e., the $2.1 billion in costs that will be spent by Dec 31, 2017 but have yet to be recovered from ratepayers) is not representative of the costs to ratepayers.
   - The Commission's model ignores sunk costs in the Terminate scenario and removes them from Site C costs in the Continue scenario.
   - This method would be correct if sunk costs are recovered from rates in the same manner for both the Terminate and Continue scenarios. However, this is not the case.
     - In the Continue scenario, sunk costs are effectively recovered over the 70 year amortization life of Site C.
     - In the Termination scenario, costs will be recovered over a substantially shorter period because it would be contrary to regulatory principle to have ratepayers (who aren't even born yet) paying for a project decades from now that had been cancelled and from which they are deriving no benefit at all. BC Hydro believes an appropriate period that is consistent with regulatory principle is 10 years.
   - Treating sunk costs the way the Commission has assumed in their analysis effectively assumes that they will be recovered over 70 years if the Project is terminated. This substantially underestimates the likely rate impact of these sunk costs in a Termination scenario.
   - Due to this difference in how sunk costs are recovered, the cost to ratepayers of the Illustrative Alternative portfolio is $555 million higher than estimated by the Commission

B. The Commission's treatment of termination costs is not representative of the likely costs to ratepayers.
   - In the Illustrative Alternative portfolio the Commission recovers termination costs over 30 years.
   - BC Hydro believes this period of recovery is too long for similar reasons as described for sunk costs in a termination context. This means a ratepayer who is not even born today would be paying for the project's termination in 2045.
   - Using a more reasonable 10 year recovery period increases the cost of the Illustrative Alternative Portfolio by $195 million.

C. The Commission assumes BC Hydro cost of financing for all resources.
   - The Commission has framed this as being intended to ensure an "apples to apples" comparison. However, this assumption either means a substantial change in how BC Hydro does business or does not reflect the true costs to ratepayers.

- BC Hydro financing either means:
  - That BC Hydro builds all new resources on our balance sheet. This would be a change from the decades of policy and precedent that IPPs construct new resources in BC, and has the potentially to have material impacts on BC Hydro's credit rating and the IPP industry.

    OR
  - That the Commission's PVs are not reflective of the true costs to ratepayers, who would pay IPP costs of capital rather than BC Hydro cost of debt. There is no question that an IPPs cost of capital can be expected to be higher than BC Hydro's cost of capital.
- The impact of this assumption depends on the amount of IPP resources in a portfolio. In the Commission scenario with low load assumed, DSM accounts for the vast majority of resources to meet load, and as such the financing assumption does not have a high impact. If a more reasonable load forecast assumption were used, more IPP resources are required, and the impact of financing will be substantial.
- We also note that the Commission has used a 6.4% "nominal" cost of capital for IPPs in their sensitivity test, supposedly based on BC Hydro's estimate. This is incorrect – our estimate of IPP cost of capital is 6.4% real (not nominal). The nominal cost of capital would be ~8.4%. As a result, the Commission's sensitivity analysis is incorrect.

D. The Commission conducts a modified block analysis, which ignores the benefit of incremental DSM if Site C were to be built.
   - The Commission truncates their analysis of new resource requirements to ~20 years (although they extend the cost of these resources out to 70 years).
   - As a result, the Commission effectively assumes that enhanced DSM would <u>not</u> occur if Site C continues. This is incorrect as BC Hydro would delay enhanced DSM with Site C but would still pursue it before other resources.
   - As a result, this ignores substantial differences in the cost of available future options.
     - If Site C continues, BC Hydro will continue to be able to pursue DSM. There is no change in available future options.
     - If Site C is terminated, there is no credible scenario where BC Hydro pursues Site C 10 years in the future (when new non-DSM resources would be required, even with the Commission's aggressive DSM assumptions). We would have lost our cheapest non-DSM option to serve our customers.
   - Ignoring this difference underestimates the PV cost of termination by $596 million.

E. The Commission utilizes Utility Cost rather than Total Resource Cost for DSM.
   - The Commission rejects BC Hydro's position (and their own previous findings in other Commission proceedings) that the Total Resource Cost is the appropriate way to evaluate DSM in comparison to other resource options. They appear to base this off the requirements of the OIC, and appear to assume that the TRC does not reflect direct costs to ratepayers.
   - This is incorrect. The incremental costs in the TRC are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.
   - Utilizing the TRC in a manner consistent with how the Commission used it in previous decisions increases the cost of the Illustrative Alternative portfolio by $444 million.

3. Assumptions that are incorrect and not supported by the evidence

This section covers assumptions that BC Hydro does not believe are reasonable given the information available to us and the Commission.

A. Adoption of the Low Load Forecast as the expected case

- The panel has found the mid forecast to be overall optimistic and considers appropriate to use the Low Load Forecast to develop its recommendations. It is unclear on what basis the Commissions is making this adjustment. Lower industrial load? Higher elasticity? Removal of LNG?
- BC Hydro has difficulty reconciling the Low Load Forecast with any scenario other than one that includes some or more of:
  - Major industrial load destruction. BC Hydro's low mining and forestry sector assumptions assume 1,800 GWh (250MW) of industrial load closures.
  - Low long-term economic growth (i.e. less than 1%/year)
  - Large amounts of customers going off-grid due to solar rooftops or similar switching.
  - Major declines in residential and/or commercial end-use intensities in addition to those underlying the additional DSM the Commission has relied upon
- While this scenario is possible, it is not expected and hence BC Hydro's used it as a low probability low load scenario

B. The Commission allows for up to 400MW of Industrial Load Curtailment at $75/kW-yr with no meaningful evidence.
   - The Commission's sole basis for this volume appears to be a submission from AMPC that suggests there is 200-400MW of Industrial Load Curtailment available based on "realistic procurement efforts, using less restrictive contract terms".
     - AMPC provides no analysis for how they arrived at this figure other than a pro-rated number from Hydro Quebec which would yield only 245MW.
     - The Commission provides no basis for utilizing the upper end of this range.
     - It is unlikely the "less restrictive contract terms" would meet BC Hydro's long term planning needs.
   - BC Hydro notes that we tested a shorter term product (4 hours) in our Year 2 Load Curtailment pilot. No customer bid in such a product.
   - BC Hydro has undertaken an industrial load curtailment pilot, the results of which determined that 85 MW was available in a form that would allow the deferral of physical assets to meet BC Hydro's customer's needs reliably.
   - The adoption of high levels of Industrial Load Curtailment is also inconsistent with the use of BC Hydro's Low Load Forecast.
     - While the Commission does not say on what basis they adopt the Low Load Forecast, it is unlikely BC Hydro would achieve this level of load without industrial demand destruction.
     - Under such a scenario, industrial load would be permanently "curtailed" (by going out of business) and would not be available for temporary curtailment to meet capacity needs.
     - We estimate that at least 40% of the potential for industrial load curtailment would not be available under the Low Load Forecast scenario.

C. Use of an arbitrarily lower market price forecast than the third party forecast used by BC Hydro
   - The Commission rejects BC Hydro's use of the ABB market forecast and adopts a market forecast between the mid and low case of the ABB market price forecast.
   - The ABB market price forecast used by BC Hydro is an independent forecast developed by ABB and built upon extensive research, analysis, and understanding of the North American electricity markets. ABB is one of the world's largest engineering companies and over 100 customers in the energy industry subscribe to their market forecast.
   - BC Hydro has also provided electricity price forecasts developed by the North West Power Planning Council, IHS Markit, and the PIRA Energy Group. The North West Power Planning Council is the entity that develops the long-term power plan for the states of Idaho, Montana, Oregon, and Washington. IHS Markit is a global business information provider while PIRA is a service provider to companies in over 60 countries, including many of the largest Global Oil and Gas firms.

- Every single one of the mid electricity market forecast developed by the organizations mentioned above is higher than the forecast that the Panel used as their mid case. BC Hydro believes that the Panel forecast relates to a pessimistic scenario and that the ABB mid forecast better represents a consensus mid-point view of several organizations that are experts in this domain.

D. The Commission assumes that the Illustrative Alternative portfolio has approximately the same level of firming and shaping as Site C.
   - The Commission reaches this conclusion by assuming that the existing system has sufficient firming and shaping such that incremental amounts have little to no value.
   - BC Hydro has provided a substantial volume of evidence on the value of Site C capacity, firming and shaping.

E. The Commission includes geothermal in their Illustrative Alternative portfolio, but applies the cost of hydrothermal flash technology to resources that require binary technology.
   - Neither Canoe Reach nor Lake Else has temperatures high enough to support flash technology.
   - Switching to binary technology would result in:
     - Higher costs, as binary is more expensive than flash technology
     - Lower net capacity factors, as binary technology is expected to achieve an 80% net capacity factor rather than the net 90% of flash technology according to NREL. Note that the Commission uses a 95% capacity factor – BC Hydro is unaware of the basis for this assumption.
   - Further, the Commission does not account for reservoir degradation which is expected to result annual generation output by 1% per year over the life of the project and would make the redevelopment of these sites after 30 years at a 30% cost reduction unlikely.

4. Assumptions that are incompatible with legislation and/or policy

This section will cover assumptions that violate existing legislation and/or policy. This section remains under development, but it expected to cover the following items:

A. "Remobilization" of Burrard
B. Use of the Columbia River Treaty entitlement
C. Increased reliance on external markets

From:	Haslam, David GCPE:EX
To:	McNish, James EMPR:EX; Sanderson, Melissa MEM:EX
Cc:	Grewar, Colin GCPE:EX; Beaupre, Darren GCPE:EX; Sovka, David GCPE:EX; Nikolejsin, Dave MNGD:EX; MacLaren, Les MEM:EX; Zadravec, Don GCPE:EX; Howlett, Tim GCPE:EX
Subject:	IN - BC Hydro Reply to Prelim. Report
Date:	Thursday, October 12, 2017 1:54:32 PM
Attachments:	IN_Site C Review_BC Hydro Reply to Preliminary Report_Oct12_146pm_LM.docx

All – attached (and in text below) is the EMPR IN on BC Hydro's latest submission to BCUC Site C review posted web-posted this am. No media coverage or calls so far.

- We initiated the BCUC review of Site C to ensure we make the right decision for B.C. families and keep BC Hydro rates affordable.
- The review is working – giving the BCUC, Government, and all British Columbians the information, analysis and answers we need to make the right decision on the project.
- I want to respect the independence of the review process and will not make any further comment at this time.
- Once we have the final report, government will consider the advice from the BCUC, along with other environmental and First Nations considerations, and make a final decision on the future of Site C in a timely manner.

If asked about BC Hydro's reply to the preliminary report:

- BC Hydro has filed its final written reply submission to the preliminary report of the Site C review that was released by the BCUC on September 20th.
- In its reply BC Hydro has reiterated its position that:
    - British Columbia will need more power to meet demand.
    - Completing the remaining work on Site C remains the most cost- effective and lowest risk option to provide the reliable power B.C. needs.
    - Site C best supports the fight against climate change with lower GHG emissions of any alternative, and enabling the integration of other intermittent renewable sources of energy like wind and solar.
- The BCUC will consider BC Hydro's and other parties' submissions as it continues through the review process and in completing its final report, due November 1st.

- BC Hydro and 16 other invited individuals and organizations will appear before the BCUC on October 13th and 14th to make oral presentations and answer questions from the BCUC Panel.
- The BCUC is also wrapping up its public consultations – over 240 individuals and organizations have made written submissions to the BCUC review, and more than 300 people made presentations at a series of community and First Nations public input sessions around the province.

Key Facts Regarding the Issue:

On October 11, 2017, BC Hydro filed its final written reply submission to the BCUC's preliminary report for the Site C review that was released on September 20th.

The reply submission runs 45 pages plus appendices and highlights a number of factors that speak to why BC Hydro believes completing Site C as planned remains in the best interest of ratepayers, even with the recently-announced 7% ($610M) increase in the Site C budget. These factors tie back to the relative cost and cost risk among the three options in the terms of reference for the review (costs to complete, terminate or suspend the project), and Site C's role in the fight against climate change.

Key findings:

1) BC Hydro will need new resources to serve its customers. Based on a mid-load forecast BC Hydro will require new capacity by fiscal 2023 and energy by fiscal 2028. Supporting electrification initiatives to combat climate change would result in BC Hydro's requirements for energy and capacity to be moved forward. Site C is still cost effective in a low load growth scenario.
2) Site C will provide a long-term, cost-effective and flexible supply of clean energy and capacity with the lowest greenhouse gas emissions of any resource alternative. The submission quotes the report of the Joint Review Panel which found that Site C "would produce a vastly smaller burden of greenhouse gases than any alternative save nuclear power, which B.C. has prohibited" and that the project "would improve the foundation for the integration of other renewable, low-carbon energy sources as the need arises."
3) While there are residual risks to be managed on Site C, the significant progress made to date has reduced delivery and cost risks relative to other resource options. The submission notes that planning for Site C began 13 years ago, consultation with Aboriginal groups has been ongoing for a decade and agreements have been reached with the majority of impacted First Nations, the environmental assessment is complete and have been upheld in various Courts, BC Hydro has obtained the majority of required permits, and major contracts are in place and construction has been ongoing for two years.
4) Upon termination, ratepayers would pay 36% of the updated cost ($8.945 billion) of the project without anything to show for it. The cost to terminate construction and remediate the site, and recover sunk costs (as agreed by Deloitte and BC Hydro) would be $3.2 billion.
5) Suspension results in either a more expensive and riskier project (if the project subsequently proceeds) or a more expensive and riskier termination (if the project is subsequently cancelled).
    - The direct costs arising from suspension and maintenance ($1.1 billion) are approximately the same as the costs of termination.
    - Suspension could compromise BC Hydro's ability to deliver Site C if the project was re-started at a later date. At a minimum, the project would be estimated to cost $13.6 billion if suspended for seven years, and could be higher.

6) Accounting for all costs, Site C is by far the most cost-effective option for ratepayers, in each of, and all combinations of, scenarios with: (i) cost overruns on Site C; (ii) low load growth; and (iii) highly optimistic cost assumptions regarding alternatives.
    - Even with a 10% increase in the cost of Site C, a portfolio of alternatives is still $7.0 billion more costly on a present value basis than completing Site C.
    - In the worst scenario combining (i) +50% cost overrun scenario, (ii) low load growth, and (iii) highly optimistic assumptions of the future cost of alternative resource options, a portfolio of alternatives is still $1.9 billion more costly on a present value basis than completing Site C.
7) The fight against climate change means load growth from electrification is only going to increase and Site C is the best option in support of that fight. Switching to low-carbon electricity would mean that B.C. would need much more clean energy and capacity than could be provided by Site C alone. Site C has the lowest GHG emissions of any other source of energy other than nuclear and facilitates the integration of other renewable resources, such as wind and solar.
8) The adverse effects of the project have been meaningfully and reasonably balanced, including with respect to Aboriginal groups.
    - The Courts have validated the Site C environmental assessment process.
    - The majority of First Nations in closest proximity to and most impacted by the project do not oppose the project and have entered into agreements with BC Hydro that provide significant and ongoing benefits that 5 would be lost if the project were terminated.
    - McLeod Lake Indian Band, who has signed a series of benefit agreements for the project, has characterized the prospect of termination or suspension as an “economic catastrophe for the community” that would “unravel [the] process of reconciliation” and the “renewed relationship” between McLeod Lake and BC Hydro, and by extension, the provincial Crown.
    - Two First Nations (West Moberly and Prophet River First Nations) unsuccessfully challenged the project approvals in court. The BC Court of Appeal and Federal Court of Appeal, in affirming decisions of courts below, concluded that the project impact on those First Nations has been meaningfully and reasonably balanced.

Background:

<u>BCUC Preliminary Report:</u>

The preliminary report was based on data and analysis submitted to the BCUC by BC Hydro and over 150 interested individuals and organizations, and by Deloitte LLP, an independent contractor hired by the BCUC to help with its analysis. The preliminary report raised more questions than answers – the BCUC requested a large amount of additional information from BC Hydro.

Among the key findings in the preliminary report the BCUC found that as of June 30, 2017 the project was on time for an in-service date of 2024, that the BCUC had insufficient information to determine if the project was on-budget, that the cost to terminate and remediate the project would be $1.05 billion on top of sunk costs of $2.1 billion, but that it was premature to determine the cost of suspending the project and restarting it after a period of suspension.

The BCUC preliminary report also identified a number of issues and potential concerns with BC Hydro’s load forecast, with BC Hydro’s calculations of unit energy costs for Site C compared to a portfolio of alternative sources of generation, and with BC Hydro’s decision to include just wind and pumped storage in its model portfolio of alternatives while excluding biomass, geothermal, solar and battery storage.

<u>BC Hydro Response to Information Requests:</u>

The BC Hydro response to the preliminary report is consistent with BC Hydro filings provided to the BCUC between September 29th and October 6th which responded to 73

information requests contained in the preliminary report.
As part of that package of responses, BC Hydro indicated while it was preparing its responses, the Main Civil Works contractor had confirmed that they would not be able to meet the fall 2019 target for river diversion due to tension cracks on the left bank and other construction challenges. The result is river diversion will be delayed to September 2020. There is a one-year contingency or float built into the project schedule, and BC Hydro remains confident it can complete the project by 2024. However BC Hydro has calculated that the one year delay will add 7.3% or $610 million to the $8.335 billion budget for the project, taking the total budget to $8.945 billion, not including the $440 million reserve fund held by the Treasury Board.
In its responses to the information requests BC Hydro also indicated that due to the project's complexity, BC Hydro expects to continue to face risks in other areas, including its second largest procurement (i.e. the generating station and spillways contract) that remains open, and the Highway 29 realignment, and is working to mitigate those challenges.
Next Steps in BCUC Review Process:
Oct. 13-14: Technical Presentation Sessions in Vancouver to provide the BCUC with the opportunity to hear from and ask questions of invited interested parties. BCUC decided which parties to invite to the Technical Presentations:

- Clean Energy Association of BC (CEABC)
- BC Old Age Pensioners Organization (BCOAPO
- Robert McCullough
- Allied Hydro Council of BC
- Marc Eliesen
- Guy Dauncey
- Canadian Wind Energy Association (CanWEA)
- Association of Major Power Consumers (AMPC)
- Canadian Centre for Policy Alternatives
- Harry Swain
- David Vardy
- Rick Hendriks and Philip Raphals
- BC Pulp and Paper Coalition
- BC Sustainable Energy Assn (BCSEA)
- Commercial Energy Consumers (CEC)
- Canadian Geothermal Energy Assn (CanGEA)
- BC Hydro

The public is welcome to attend however presentation spots are available and pre-arranged only for the invited speakers. Sessions will also be live streamed on BCUC website.
The panel’s final report will be submitted to Government on November 1, 2017.

ADVICE TO MINISTER

CONFIDENTIAL GCPE-MEM ISSUE NOTE Ministry of Energy and Mines Date: Oct. 12, 2017 Minister Responsible: Hon. Michelle Mungall	**SITE C REVIEW – BC HYDRO REPLY TO PRELIMINARY REPORT**

ADVICE AND RECOMMENDED RESPONSE:

- We initiated the BCUC review of Site C to ensure we make the right decision for B.C. families and keep BC Hydro rates affordable.

- The review is working – giving the BCUC, Government, and all British Columbians the information, analysis and answers we need to make the right decision on the project.

- I want to respect the independence of the review process and will not make any further comment at this time.

- Once we have the final report, government will consider the advice from the BCUC, along with other environmental and First Nations considerations, and make a final decision on the future of Site C in a timely manner.

If asked about BC Hydro's reply to the preliminary report:

- BC Hydro has filed its final written reply submission to the preliminary report of the Site C review that was released by the BCUC on September 20th.

- In its reply BC Hydro has reiterated its position that:

    - British Columbia will need more power to meet demand.
    - Completing the remaining work on Site C remains the most cost-effective and lowest risk option to provide the reliable power B.C. needs.
    - Site C best supports the fight against climate change with lower GHG emissions of any alternative, and enabling the integration of other intermittent renewable sources of energy like wind and solar.

- The BCUC will consider BC Hydro's and other parties' submissions as it continues through the review process and in completing its final report, due November 1st.

- BC Hydro and 16 other invited individuals and organizations will appear before the BCUC on October 13th and 14th to make oral presentations and answer questions from the BCUC Panel.

- The BCUC is also wrapping up its public consultations – over 240 individuals and organizations have made written submissions to the BCUC review, and more than 300 people made presentations at a series of community and First Nations public input sessions around the province.

KEY FACTS REGARDING THE ISSUE:

On October 11, 2017, BC Hydro filed its final written reply submission to the BCUC's preliminary report for the Site C review that was released on September 20th.

The reply submission runs 45 pages plus appendices and highlights a number of factors that speak to why BC Hydro believes completing Site C as planned remains in the best interest of ratepayers, even with the recently-announced 7% ($610M) increase in the Site C budget. These factors tie back to the relative cost and cost risk among the three options in the terms of reference for the review (costs to complete, terminate or suspend the project), and Site C's role in the fight against climate change.

Key findings:

1) BC Hydro will need new resources to serve its customers. Based on a mid-load forecast BC Hydro will require new capacity by fiscal 2023 and energy by fiscal 2028. Supporting electrification initiatives to combat climate change would result in BC Hydro's requirements for energy and capacity to be moved forward. Site C is still cost effective in a low load growth scenario.

2) Site C will provide a long-term, cost-effective and flexible supply of clean energy and capacity with the lowest greenhouse gas emissions of any resource alternative. The submission quotes the report of the Joint Review Panel which found that Site C "would produce a vastly smaller burden of greenhouse gases than any alternative save nuclear power, which B.C. has prohibited" and that the project "would improve the foundation for the integration of other renewable, low-carbon energy sources as the need arises."

3) While there are residual risks to be managed on Site C, the significant progress made to date has reduced delivery and cost risks relative to other resource options. The submission notes that planning for Site C began 13 years ago, consultation with Aboriginal groups has been ongoing for a decade and agreements have been reached with the majority of impacted First Nations, the environmental assessment is complete and have been upheld in various Courts, BC Hydro has obtained the majority of required permits, and major contracts are in place and construction has been ongoing for two years.

4) Upon termination, ratepayers would pay 36% of the updated cost ($8.945 billion) of the project without anything to show for it. The cost to terminate construction and remediate the site, and recover sunk costs (as agreed by Deloitte and BC Hydro) would be $3.2 billion.

5) Suspension results in either a more expensive and riskier project (if the project subsequently proceeds) or a more expensive and riskier termination (if the project is subsequently cancelled).
    - The direct costs arising from suspension and maintenance ($1.1 billion) are approximately the same as the costs of termination.
    - Suspension could compromise BC Hydro's ability to deliver Site C if the project was re-started at a later date. At a minimum, the project would be estimated to cost $13.6 billion if suspended for seven years, and could be higher.

6) Accounting for all costs, Site C is by far the most cost-effective option for ratepayers, in each of, and all combinations of, scenarios with: (i) cost overruns on Site C; (ii) low load growth; and (iii) highly optimistic cost assumptions regarding alternatives.
    - Even with a 10% increase in the cost of Site C, a portfolio of alternatives is still $7.0 billion more costly on a present value basis than completing Site C.
    - In the worst scenario combining (i) +50% cost overrun scenario, (ii) low load growth, and (iii) highly optimistic assumptions of the future cost of alternative resource options, a portfolio of alternatives is still $1.9 billion more costly on a present value basis than completing Site C.

7) The fight against climate change means load growth from electrification is only going to increase and Site C is the best option in support of that fight. Switching to low-carbon electricity would mean that B.C. would need much more clean energy and capacity than could be provided by Site C alone. Site C has the lowest GHG emissions of any other source of energy other than nuclear and facilitates the integration of other renewable resources, such as wind and solar.

8) The adverse effects of the project have been meaningfully and reasonably balanced, including with respect to Aboriginal groups.
    - The Courts have validated the Site C environmental assessment process.
    - The majority of First Nations in closest proximity to and most impacted by the project do not oppose the project and have entered into agreements with BC Hydro that provide significant and ongoing benefits that 5 would be lost if the project were terminated.
    - McLeod Lake Indian Band, who has signed a series of benefit agreements for the project, has characterized the prospect of termination or suspension as an "economic catastrophe for the community" that would "unravel [the] process of reconciliation" and the "renewed relationship" between McLeod Lake and BC Hydro, and by extension, the provincial Crown.
    - Two First Nations (West Moberly and Prophet River First Nations) unsuccessfully challenged the project approvals in court. The BC Court of Appeal and Federal Court of Appeal, in affirming decisions of courts below, concluded that the project impact on those First Nations has been meaningfully and reasonably balanced.

Background:

<u>BCUC Preliminary Report:</u>

The preliminary report was based on data and analysis submitted to the BCUC by BC Hydro and over 150 interested individuals and organizations, and by Deloitte LLP, an independent contractor hired by the BCUC to help with its analysis. The preliminary report raised more questions than answers – the BCUC requested a large amount of additional information from BC Hydro.

Among the key findings in the preliminary report the BCUC found that as of June 30, 2017 the project was on time for an in-service date of 2024, that the BCUC had insufficient information to determine if the project was on-budget, that the cost to terminate and remediate the project would be $1.05 billion on top

of sunk costs of $2.1 billion, but that it was premature to determine the cost of suspending the project and restarting it after a period of suspension.

The BCUC preliminary report also identified a number of issues and potential concerns with BC Hydro's load forecast, with BC Hydro's calculations of unit energy costs for Site C compared to a portfolio of alternative sources of generation, and with BC Hydro's decision to include just wind and pumped storage in its model portfolio of alternatives while excluding biomass, geothermal, solar and battery storage.

BC Hydro Response to Information Requests:

The BC Hydro response to the preliminary report is consistent with BC Hydro filings provided to the BCUC between September 29th and October 6th which responded to 73 information requests contained in the preliminary report.

As part of that package of responses, BC Hydro indicated while it was preparing its responses, the Main Civil Works contractor had confirmed that they would not be able to meet the fall 2019 target for river diversion due to tension cracks on the left bank and other construction challenges. The result is river diversion will be delayed to September 2020.

There is a one-year contingency or float built into the project schedule, and BC Hydro remains confident it can complete the project by 2024. However BC Hydro has calculated that the one year delay will add 7.3% or $610 million to the $8.335 billion budget for the project, taking the total budget to $8.945 billion, not including the $440 million reserve fund held by the Treasury Board.

In its responses to the information requests BC Hydro also indicated that due to the project's complexity, BC Hydro expects to continue to face risks in other areas, including its second largest procurement (i.e. the generating station and spillways contract) that remains open, and the Highway 29 realignment, and is working to mitigate those challenges.

Next Steps in BCUC Review Process:

Oct. 13-14: Technical Presentation Sessions in Vancouver to provide the BCUC with the opportunity to hear from and ask questions of invited interested parties. BCUC decided which parties to invite to the Technical Presentations:

- Clean Energy Association of BC (CEABC)
- BC Old Age Pensioners Organization (BCOAPO
- Robert McCullough
- Allied Hydro Council of BC
- Marc Eliesen
- Guy Dauncey
- Canadian Wind Energy Association (CanWEA)
- Association of Major Power Consumers (AMPC)
- Canadian Centre for Policy Alternatives
- Harry Swain
- David Vardy
- Rick Hendriks and Philip Raphals
- BC Pulp and Paper Coalition
- BC Sustainable Energy Assn (BCSEA)
- Commercial Energy Consumers (CEC)
- Canadian Geothermal Energy Assn (CanGEA)
- BC Hydro

ADVICE TO MINISTER

The public is welcome to attend however presentation spots are available and pre-arranged only for the invited speakers. Sessions will also be live streamed on BCUC website.

The panel's final report will be submitted to Government on November 1, 2017.

Communications Contact:	Colin Grewar	250-952-0650
Program Area Contact:	Les MacLaren	250-952-0204
File Created:	Oct. 12, 2017	
File Updated:		

From:	Cochrane, Marlene EMPR:EX
To:	Nikolejsin, Dave MNGD:EX
Cc:	MacLaren, Les EMPR:EX; Haslam, David GCPE:EX
Subject:	Letter from D Nikolejsin and L Wanamaker
Date:	Wednesday, November 15, 2017 10:24:03 AM
Attachments:	102700 BCUC Final_Signed.pdf

Dave, the final letter has been sent to Mr. Morton. (Lori's office is also aware.) Thanks.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 10:22 AM
To: Morton, David BCUC:EX
Subject: Letter from D Nikolejsin and L Wanamaker

Good Morning Mr. Morton,

Please see the attached letter from Mr. Dave Nikolejsin, Deputy Minister, Ministry of Energy, Mines and Petroleum Resources, and Ms. Lori Wanamaker, Deputy Minister, Ministry of Finance, regarding the Inquiry Respecting Site C.

Regards,

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

BRITISH COLUMBIA

November 15, 2017

Ref.: 102700

Mr. David Morton
Chair
BC Utilities Commission

Email: David.Morton@bcuc.com

Re: Inquiry Respecting Site C

The Ministry of Energy, Mines and Petroleum Resources and Ministry of Finance are supporting the government decision process surrounding the future of the Site C project. On behalf of our respective Ministers, we would like to thank the BC Utilities Commission (Commission) for the report *Inquiry Respecting Site C*. Completing an inquiry of this scope over an abbreviated timeframe and with high levels of public and First Nations input is a considerable achievement.

As our ministries analyze the Commission's report, along with other implications associated with government proceeding with or terminating the Site C project, we want to ensure that we fully understand the assumptions and computations that the Commission made in the analysis of potential alternative sources of energy generation and capacity. Accordingly, we are requesting further explanation or additional information on the points listed below and in the Appendix attached to this letter.

1. Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?

   We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not, could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

2. In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects

Ministry of Energy, Mines and Petroleum Resources

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included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?

3. Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?

4. If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?

   - Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?

   - Recently it has been stated that recovering the project's sunk and remediation costs over a 10-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?

5. We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:

   - Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?

   - Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?

We sincerely appreciate the Commission's timely response to these questions and requests for clarification. Government has committed to making a decision on the Site C project before the end of the year. The Commission's responses to our questions will assist our ministries in better understanding the report and the assumptions that underlie it as we prepare advice to support government in making a decision that will be in the best interests of British Columbians.

Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines
and Petroleum Resources

Lori Wanamaker
Deputy Minister
Ministry of Finance

Attachment

Appendix: Detailed Questions for the Commission

We understand that while BC Hydro modelled over 60 scenarios and tested various assumptions, including a number of alternatives requested by the Commission, the alternative portfolio that the Commission included in the final report was not analyzed using BC Hydro's modelling tools. On this basis, government has asked BC Hydro to provide an assessment of the model used to develop the Commission's final alternative portfolio. BC Hydro will provide the Commission with the results of that assessment separately.

In our initial analysis of the report, our ministries have identified several areas that we would appreciate the Commission's feedback on. Several of our questions relate to the impact of certain assumptions made in the report, and how the costs of those assumptions would be recovered from ratepayers.

We understand that BC Hydro follows standards for rate-regulated utilities in its financial statements and in preparing its applications for review by the Commission. This accounting framework follows a number of principles in relation to the amortization of capital assets and the deferral of other costs for the purpose of matching recoveries from ratepayers to periods over which benefits are provided.

It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.

The Commission's process involved some deliberations on the cost of capital. The alternative portfolio presented in the report assumes that BC Hydro will finance all new resources on its balance sheet. However, other than redevelopment of existing sites and Site C, BC Hydro has, for almost three decades, been primarily procuring new supply from competitive processes or bilateral agreements that are benchmarked to competitive processes. This effectively means that BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.

It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio, and the BC Hydro financing assumption should only be used for the Unit Energy Cost (UEC) analysis. However, on pages 167, 170 and Appendix C (Assumption 2), it appears that the

Commission has used BC Hydro financing (100% debt financing at a cost of 3.43%) for the alternative portfolio. If we are interpreting this correctly, we would appreciate clarification on which cost of capital should be used in analysing rate impacts.

BC Hydro has suggested that recovery in rates of sunk costs in a termination scenario should occur over a 10-year period. If the project were to continue as planned, the sunk costs, as part of the overall project costs, will be recovered over a 70-year period, consistent with the amortization of the Site C asset. The Commission model appears to exclude sunk costs in the termination scenario, and has removed those costs from the completion scenario as well. Effectively this assumes that sunk costs will be recovered through rates over 70 years if the project is terminated. Recovering costs in rates over a shorter period has a material impact on the costs of the alternative portfolio. It would be helpful if the Commission could provide an estimate of the impact on rates of using these two timeframes.

The tables on page 17 of the executive summary and page 170 in the main report include a summary of the Commission's sample scenarios showing the effect of modifying one or more variables to the resulting Net Present Value cost to ratepayers. As noted above, the Commission's alternative portfolio does not appear to include sunk costs, and sunk costs have also been removed on the continue scenario. The tables also include UECs. For the Site C scenario, the UECs reflect costs, including sunk costs, of Site C being either $10 billion or $12 billion depending on assumptions. Our review of the Commission report suggests that the alternative portfolio does not include termination costs. It would be helpful if the Commission could confirm this and provide a version of the UEC portion of the table with termination costs included in the alternative portfolio. This would help provide a consistent basis for comparing costs between the scenarios of completing or terminating the project.

It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis?

We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's *Clean Energy Act* energy objectives of:

- Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;
- Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,
- Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.

It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.
It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the *Greenhouse Gas Reduction (Clean Energy) Regulation* under the *Clean Energy Act*. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures.

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

Page 229 to/à Page 231

Withheld pursuant to/removed as

s.13

From:	Savidant, Michael
To:	Foster, Doug FIN:EX
Cc:	MacLaren, Les EMPR:EX; O"Riley, Christopher; Reimann, Randy; Rich, John
Subject:	Load Forecast History & Low/High Bands
Date:	Thursday, November 23, 2017 8:25:40 PM
Attachments:	image001.png Load forecast assumptions - High-Mid-Low.docx

Doug,

Please find here the materials you requested with respect to the load forecast.

1. An updated graph (below) showing actual load as compared to our most recent load forecasts.
    a. Note that we've included several versions of the May 2016 load forecast, including the low, as well as with and without LNG, and with and without electrification.
2. A document (attached) discussing representative load drivers in the low and high load bands.
    a. As noted before, the low and the high are the results of Monte Carlo modelling rather than specific assumptions, but these are representative bands for key forecast sectors.

Let us know if this meets your needs.

Thanks,

Mike

cid:image004.png@01D36488.9778E9D0



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From:	Lorne Sivertson
To:	MacLaren, Les EMPR:EX
Subject:	Marvin Schaffer"s Site C Report
Date:	Thursday, November 23, 2017 5:03:44 PM
Attachments:	m-jq-11-15.docx

This may be of interest.

--
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MEMORANDUM

To: **Jim Quail**
From: **Marvin Shaffer**
Date: **November 15, 2017**
Re: **BCUC Site C Report**

The terms of reference for the review of the Site C project called on the BC Utilities Commission (BCUC) to advise on whether the project is on time and on budget, what would be the costs to ratepayers of suspending or terminating the project, and whether there are alternative portfolios of projects and measures that could provide similar benefits at similar or lower cost.

Project Schedule

The BCUC agreed that Site C is currently on schedule to be completed by November 2024 but found that there are tension crack, river diversion and other risks that could result in delay. It concluded the November 2024 in-service date will most likely not be achieved.

A delay in the in-service date will pose no operational problem for BC Hydro. Even under BC Hydro's medium requirements forecast (which the BCUC concluded is too high), BC Hydro will not need any of the 5100 Gwh of energy Site C will produce until 2028. It is forecasting a shortfall of peak generating capacity by 2023, but BC Hydro has access to the downstream benefits under the Columbia River Treaty and other contingency resources that it could use to meet peak capacity requirements until Site C comes on stream.

The main issue with delay is that it adds to the installed cost of completing the project and delays the recovery of any of those costs through surplus sales.

Project Cost

Deloitte Management (technical consultants to the BCUC) estimated that a one year delay in the schedule would increase the cost of Site C to between $9.1 and $10 billion. Based on its expectation of some delay plus consideration of other uncertainties in the work remaining to be done, the BCUC concluded that the total cost of Site C will increase from the current estimate of $8.9 billion to $10 billion or more.

The BCUC used $10 billion in its analysis comparing the present value costs of Site C with its illustrative alternative portfolio of projects. This presumably reflects a P90 value, which

the BCUC said is an appropriate basis to estimate costs. A P90 value is the estimate which there is a 90% probability of achieving.

It is important to note that the arguably very appropriate use of a conservative P90 value for Site C cost was not followed even in an approximate way for the alternative portfolio of projects BCUC used to compare to Site C.

- ***DSM:- Demand side management measures are a major component of BCUC's alternative portfolio. However, BCUC did not undertake any assessment of the uncertainty and risks this resource entails and range of costs that could result. It certainly did not provide any P90 estimates comparable to what BCUC recommended for Site C.***

This is not just a general methodological concern. In its assessment of BC Hydro's load forecast, the BCUC commented on the confounding of the impact of rising prices on electricity requirements versus the impact of DSM programs. Given that BCUC concluded that a low load forecast should be assumed in part because of the effect of rising prices, it is not clear to what extent the price-induced reductions in demand will diminish what can further be achieved with DSM programs. Moreover, there are well documented econometric and other studies that suggest the costs of DSM programs per MWh of demand actually reduced are much higher than the estimates utilities typically calculate based on program participation rates. A key issue is distinguishing program impacts from what would otherwise be done at some point even without the program.

With respect to peak requirements, the Commission noted in its report that a major difference between its illustrative portfolio analysis and the portfolio modelling done by BC Hydro and its own technical consultants was the reliance to a very large degree on capacity-targeted DSM to meet shortfalls. Despite the concerns BC Hydro raised about the effectiveness of those programs, and in some cases the absence of a policy framework at this time that would be needed to implement the measures, the BCUC again provided no assessment of the uncertainty and risks, the range of costs these measures could entail and what P90-comparable estimates should be used.

The DSM estimates are not comparable to what the BCUC estimated for Site C in another very important respect. The BCUC only included the costs it estimated BC Hydro would incur to encourage customers to conserve energy or shift demand to off-peak periods. It did not include the often much larger costs that customers themselves would incur. Its analysis would include, for example, the cost of incentives BC Hydro might offer to encourage customers to purchase more efficient lighting or other electric appliances, but not the amount customers would still have to pay themselves to purchase the more efficient lights or appliances.

The BCUC justified this saying it only included costs that would impact revenue requirements and be recovered in rates. But that is clearly incorrect when trying to

assess and compare the full consequences for customers of demand versus supply side measures. It is not only impacts on revenue requirements but also on other expenditures customers incur that must be taken into account.

- ***Wind:- Wind is the main supply side alternative in the BCUC's alternative portfolio. The estimates BCUC used are very rough, extrapolating from experience in other jurisdictions and making a number of at best uncertain and in some cases very optimistic assumptions. As with DSM, no risk analysis and range or P90-comparable estimate was provided.***

In its modelling, the BCUC effectively assumed all of the wind projects would be developed by BC Hydro. The costs are developed from capital and operating cost estimates under the assumption the required capital would be financed 100% at BC Hydro's borrowing rate. It did not make any effort to estimate what bid prices would be if, as is quite likely, the wind projects were developed by independent power producers (IPPs).[1]

IPP bid prices would incorporate the higher cost of capital private developers face. As well one could not assume, as the BCUC did, that wind projects could be refurbished and available to BC Hydro in the future at 30% less than the cost of a new project. The price BC Hydro would pay for contract renewals at refurbished sites would depend on competitive market conditions at that time.

The BCUC also took a very rough and optimistic approach in its estimate of wind integration costs, the cost of the back-up BC Hydro must provide because of the intermittent nature of wind supply. The BCUC assumed an integration cost of $1/MWh seemingly based on one outlier estimate in a range of costs provided for other jurisdictions. This cost estimate was one-fifth of what BC Hydro submitted and 60% less than the Commission staff itself had put forward for comment.

- ***Geothermal:- When analyzing medium and high load growth cases, BCUC includes 81 MW of geothermal capacity. It explicitly recognized that geothermal may not be commercially viable in British Columbia, but justified its inclusion of geothermal supply saying; "on the balance of probabilities there is a likelihood that some commercially viability may be obtained".***[2] ***That may be true, but it is important to recognize the speculative nature of this alternative and its cost as compared to what is known and what the BCUC has conservatively assumed about Site C.***

---

[1] The BCUC effectively assumed all wind would be developed by BC Hydro to provide what it considered to be an 'apples to apples' comparison to Site C. Aside from the fact it made no effort to provide comparable ('apples to apples') quality of estimates, the point is that assuming BC Hydro development and financing of all wind projects does not indicate what BCUC was asked to advise on – the likely impacts on ratepayers.

[2] BCUC Final Report, Appendix A, p.19.

Load Forecast and Value of Surplus Sales

The BCUC analyzed BC Hydro's load forecast and resource balance to assess the timing of the need for more resources in the province. Whereas BC Hydro submitted that it would need additional peak capacity by 2023 and additional energy by 2028 based on its mid-range load forecast, the Commission concluded that additional capacity and energy would not be needed for many years after that. It concluded that BC Hydro's mid range forecast was too optimistic and that its low forecast should be used in comparing Site C to alternative portfolios. It also decided that Revelstoke 6 should be assumed to be developed in the mid 2020's so as not to exaggerate the shortfall of capacity BC Hydro would have without Site C.

As for electrification policies and trends in response to aggressive GHG reduction targets, the BCUC took a conservative stance: "Given the uncertainty, the Panel finds additional load required for potential electrification initiatives should not be included in BC Hydro's load forecast for the purpose of resource planning".[3]

The BCUC's load forecast and resource balance assumptions result in Site C being surplus to requirements for many years after its 2024 or even delayed in-service date. A critically important issue for ratepayer impact is consequently what revenues BC Hydro can realize from surplus sales. Consistent with its other assumptions about Site C, BCUC took a very conservative approach.

The panel rejected the spot market price forecast trading experts from BC Hydro provided and the even higher forecast of its own technical consultants (Deloitte). Based on low current prices it adopted a lower price forecast over the entire period there would be surplus from Site C available for sale. It also decided not to assign any premium to the market value in light of the dispatchability of Site C power, the storage-related trading potential it offers in conjunction with the upstream Williston reservoir and the surplus dependable peak capacity it would have. The only premium the BCUC included for Site C surplus over its conservative spot market price was a $1/MWh charge for wind integration services it assumed BC Hydro could sell if not needed in British Columbia, a premium that would yield some $3 million per year.

Taken together, the BCUC's findings on load growth and the value of surplus sales serve to minimize the value of proceeding with Site C and therefore to maximize the rate impact it will have. While there is undoubtedly considerable uncertainty about future load growth, the assumptions BCUC made about the value of surplus sales are contrary to the advice of trading experts and its own consultants, and completely ignore the strategic value of a dispatchable hydro resource like Site C, something most experts forecast will be increasingly important the more intermittent resources are added in neighbouring jurisdictions.

It is also important to note that the BCUC did not consider the market potential in Alberta, which in the short term will need energy to replace coal-fired generation and in the

[3] BCUC Final Report, p.81

medium term will need dependable peak generating capacity to complement its planned expansion of wind and other intermittent renewable sources of supply.

Finally and very importantly, the BCUC completely ignored the impact that Site C surplus would have in reducing GHG emissions from thermal power production in Alberta or elsewhere – the most likely source of supply it would displace. Depending on emerging carbon tax or equivalent policies, that could directly increase the value of surplus sales exports. A $50/tonne tax could add $20-$45/Mwh to surplus sales prices – almost equal to or more than the total price BCUC assumed for surplus sales. At a minimum, the impact of Site C surplus on thermal power production and GHG emissions is a critically important social value the BCUC's report did not take into account.

Rate Impact Analysis

In order to assess whether there is an alternative portfolio of projects that could meet BC Hydro requirements at similar or lower cost for ratepayers, BCUC calculated the present value costs (the revenue requirements that must be recovered from customers) associated with the development of Site C as compared to the present value costs of its illustrative alternative portfolio of DSM, wind and geothermal resources (the latter in the mid and high load growth cases only). The present value costs are the discounted sum of BCUC's assumed capital plus operating expenses less surplus sales revenues in both development scenarios.

The results, based on a 'Commission set of assumptions' are shown in Tables 39 and 40 of the report (p.167). These assumptions include: BC Hydro's low load forecast; the Panel's low surplus sales price forecast; Site C costs rising to $10 billion; termination costs of $1.8 billion; and BC Hydro financing for all wind or and other resources in the alternative portfolio. With these assumptions the present value costs shown in the Final Report, excluding sunk costs in both cases, are roughly the same: $3.188 billion for completion of Site C and $46 million more -- $$3.234 billion -- for the illustrative scenario. After correcting for errors in the surplus sales calculations, the BCUC reported a somewhat larger difference ($295 million) favouring Site C.[4]

A number of sensitivity test results are shown in Table 43 (p.170). All but one of the results (correcting for the errors in the numbers shown for the alternative portfolio in the high load growth case) show a greater cost advantage for Site C (most notably assuming anything higher than BC Hydro's low load growth). The only case where the alternative portfolio exhibits lower costs is if Site C costs rise to $12.5 billion and the load growth remains at the low forecast.

Based on its assumptions and calculations the Commission concluded that the costs of completing Site C or pursuing its alternative portfolio are roughly the same. There would be a cost advantage to completion of Site C if load grows more rapidly than the Commission assumed and a cost advantage to the alternative portfolio if Site C costs escalate higher than $10 billion.

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[4] BCUC, Report Errata, November 16, 2017, p.2.

It is important to note, however, that BCUC reached this conclusion based on a manifestly unbalanced set of assumption and an incomplete assessment of costs for its alternative portfolio. It also failed to address the markedly different timing and more immediate challenge of the rate impacts in its alternative portfolio as compared to the completion of Site C.

- ***<u>Lack of balance in assumptions</u>: BCUC concluded that conservative assumptions should be made in respect of the Site C completion scenario. As discussed above, it concluded that a P90 estimate of the remaining costs to complete Site C -- $10 billion – should be used, adding over $1 billion to BC Hydro's latest cost estimate. It concluded it should adopt a low load growth forecast and ignored electricification policies and trends due to the uncertainty surrounding them at this time. It then assigned a lower value to Site C surplus sales than trading experts and its own technical consultants forecast. Further, it ignored the value that Site C can realize from storage and the dispatchability of its production, and it ignored the important social and potential market value surplus sales from Site C will realize by displacing thermal power production and reducing GHG emissions in other jurisdictions.***

  At the same time, while BCUC utilized a P90 estimate in respect of termination costs, it made a number of very questionable and arguably optimistic assumptions about the costs of the measures in its alternative portfolio. It did not address or make any adjustment for the uncertainty in impacts and per unit costs of DSM measures; it did not attempt to estimate the bid prices that BC Hydro would face if it acquired wind energy from IPPs; it used a very low estimate of wind integration costs; and it incorporated geothermal resources in the mid and high load growth cases even though it acknowledged that it is not certain this resource will in fact be commercially viable in BC.

  All of this served to maximize the BCUC's cost estimate for Site C and minimize its cost estimate for the alternative portfolio.

- ***<u>Incomplete assessment of costs:</u> The BCUC did not include all of the costs customers and BC Hydro would incur with its alternative portfolio. As noted earlier in this memo, it improperly excluded what in many cases can be the largest component of DSM costs – the costs that customers themselves incur to reduce requirements or to shift demand to off-peak periods.***

  Also, in determining the shortfalls in peak generation capacity BC Hydro would face without Site C, the BCUC assumed that Revelstoke 6 would be developed in the mid 2020's. However, nowhere in its spreadsheets does it report the costs of developing Revelstoke 6 – a project that would cost some $500 million – more in 2018$. The availability of Revelstoke reduces the need for other capacity oriented measures in alternative portfolio. The BCUC analysis captures the benefit of

Revelstoke 6 for this portfolio but not the costs.

- ***<u>Timing of rate impacts:</u> The BCUC relied on its calculation of present value costs over a 70 year period to assess the consequences for customers of completing Site C versus pursuing its alternative portfolio. While this is an appropriate criterion to compare long term consequences, it says nothing about the different timing of the costs (BC Hydro revenue requirements) and rate impacts.***

  There are in fact major differences in the timing of the costs and rate impacts in the Site C completion versus alternative portfolio scenarios, but the BCUC did not address them. Most importantly, it did not address the timeframe over which the some $4 billion of sunk and termination costs would be recovered.

  If Site C is completed there would be no termination costs and the sunk costs would properly be recovered over the expected economic life of the asset. Distant future as well as current customers would share in this cost because they share in the benefits it offers. If Site C is abandoned, however, there would be no justification for recovering the termination and sunk costs over anything other than a short period. Deferring cost recovery would simply add to (almost double) the rate smoothing and other regulatory accounts that most analysts believe are already far too high. It would impose an unfair burden on future customers.

  An analysis of the annual cost and rate impacts in both scenarios, assuming cost recovery in accordance with standard utility regulation principles, is missing from the BCUC report. If done it would point to a very significant and immediate adverse consequence of terminating the project at this time.[5]

  The BCUC noted one could argue that perhaps government should absorb these costs. But even if that were done it would not change the magnitude of the impact, just the manner in which BC residents would be affected. It would shift the burden of the recovery of the termination and sunk costs to taxpayers as opposed to ratepayers. There would be differences in the extent to which individual families and businesses would be affected but the impact overall would be the same.

<u>Concluding Comments</u>

The main issue with Site C has never been whether it is an attractive electricity supply resource. Operating in conjunction with the upstream Williston reservoir, it is a cost-effective and strategically valuable resource. As the Joint Review Panel concluded:

> *Despite high initial costs and some uncertainty about when the power would be needed, the Project would provide a large and long-term increment of firm*

[5] It would also increase the present value advantage of completing Site C as compared to the alternative portfolio. As shown in Figure 26, p.164, the present value cost of the recovery of sunk (and termination) costs is higher the shorter the amortization period.

> *energy and capacity at a price that would benefit future generations ... and provide a foundation for the integration of other renewable low carbon sources as the need arises.*[6]

From an electricity resource planning perspective, the issue with Site C hasn't been whether, but when.

It is widely recognized that Site C should not have been started when it was. With considerable uncertainty over the load growth forecast, and DSM opportunities that could further delay the need for Site C energy and capacity, the start of construction on Site C could and likely should have been delayed a number of years. But circumstances are different now that over $2 billion has been spent and another near $2 billion would have to be spent to terminate the project at this time.

There is no case in the BCUC report that ratepayers would be better off to abandon the Site C project at this time. One needs an unbalanced and incomplete costing of the alternatives just to conclude an alternative portfolio would be close in cost. And as for suspending and restarting at a time that would have been more attractive before construction had commenced, the BCUC is very clear. It is the worst of the options available to the government.

Unless the government takes the position that Site C should be abandoned now and forever for environmental, First Nations or other such reasons, the best course of action at this time is to continue to complete the project, taking whatever steps are necessary to minimize remaining costs, maximize the value of the surplus Site C will inevitably produce and address as best as possible the issues that First Nations and local residents have in respect of the unavoidable impacts the project will have.

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[6] Report of the Joint Review Panel, Site C Clean Energy Project, May 1, p.(iv).

From:	Rowe, Katherine EMPR:EX
To:	Foster, Doug FIN:EX
Cc:	MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Subject:	s.12 s.13
Date:	Tuesday, November 7, 2017 11:59:38 AM
Attachments:	s.12,s.13

Apologies – I don't have a clean copy of the s.12,s.13 You can ignore my scribbles

Katherine Rowe
Director, Generation and Regulatory Branch | **NEW!** Phone: 778.698.7190| Cell: 250.216.5823 |Ministry of Energy, Mines and Petroleum Resources

Energizing BC—clean, sustainable and productive

Page 244 to/à Page 249

Withheld pursuant to/removed as

s.12;s.13

Nov 5

Site C Inquiry
Overview of Initial Findings from BC Hydro Review of BCUC Final Report
November 3, 2017

This document provides a summary of items identified through BC Hydro's preliminary analysis that are expected to be most material to the Commission's conclusions regarding a comparison of Site C to the Commission's alternative portfolio (the "Illustrative Alternative portfolio").

Please note:

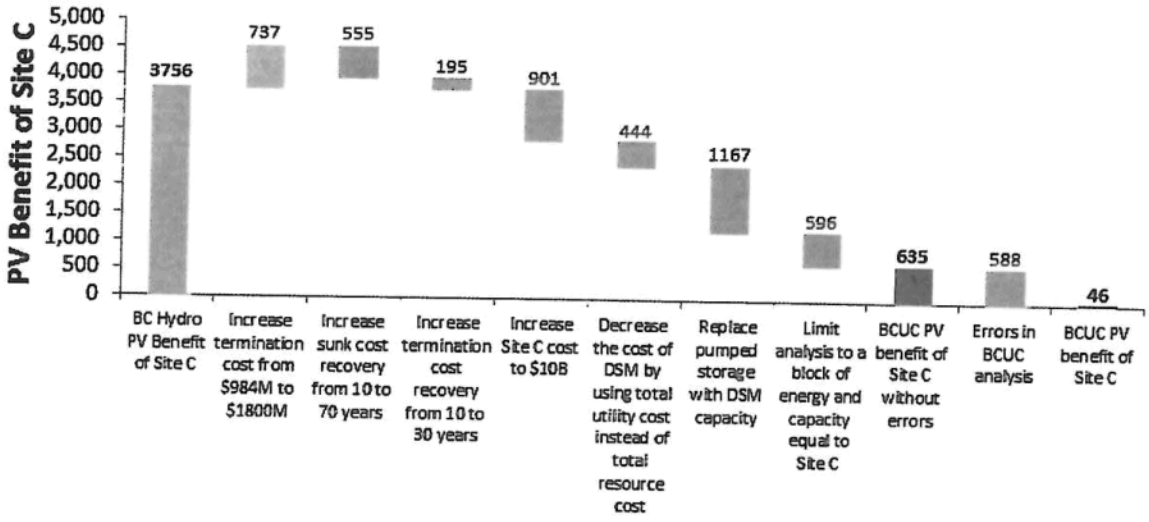
- This list is not exhaustive. Additional issues and errors have been identified that are not in this summary.
- BC Hydro's review is not yet complete. Additional issues may be identified in the future.

The table below provides a summary of these issues with the expected impact on the Commission's calculations of PV costs and benefits. Note that there may be overlap and compounding effects between items, and they should not be considered directly additive.

	Issue	Impact on Cost of Termination
1.	**Modelling Errors**	
A	Application of incorrect discount rate to Site C surplus	+$336 million
B	Inconsistent application of inflation factors and discount rates	+$51 million
C	Double-counting of transmission losses on DSM	+$201 million
2.	**Assumptions that do not reflect true costs to ratepayers**	
A	Inaccurate treatment of sunk costs	+$555 million
B	Inaccurate treatment of termination costs	+$195 million
C	Use of BC Hydro financing for all resources	Not calculated (depends on other assumptions)
D	Use of modified block analysis, ignoring value of DSM when proceeding with Site C	+$596 million
E	Use of Total Utility Cost rather than Total Resource Cost for DSM	+$444 million
3.	**Assumptions that are incorrect and not supported by evidence**	
A	Adoption of the Low Load Forecast as the expected case	Not estimated at this time
B	Adoption of 400MW of industrial load curtailment without evidence	
C	Use of an arbitrarily lowered market price forecast	
D	Assumption that the alternative portfolio has the same firming and shaping capability as Site C	
E	Use of incorrect technology assumptions on geothermal resources	
4.	**Assumptions that are inconsistent with legislation and/or policy**	
A	"Remobilization" of Burrard	Not estimated at this time
B	Use of Columbia River Treaty entitlement	
C	Increased reliance on external market purchases to meet demand	

Errors in Sections 1 and 2 are largely due to the Commission's adoption of their own modelling tools and rejection of BC Hydro's modelling tools. The Commission should not have eliminated BC Hydro's portfolio analysis evidence from consideration in this inquiry as it is the most complete assessment of the impacts and has been used successfully for many years in the context of resource planning. BC Hydro was available throughout the process to respond to questions and ran all of the sensitivities requested by the Commission. BC Hydro identified errors and assumption concerns with other portfolios that we were asked to assess. However, we were never asked to comment on the simplified Illustrative Alternative Portfolio, upon which the Commission ended up relying.

The graph below shows the assumptions the Commission has made to go from BC Hydro's "Commission Portfolio" PV estimate of $3.8 billion benefits of completing Site C to their assessment of zero benefits. The graph also shows the PV impact of correcting the errors listed in Section 1.



1. Modelling Errors

This section covers items that we believe are mistakes, rather than unjustified assumptions.

A. The Commission's model has a mathematical error in its treatment of the Site C energy surplus.
- The Illustrative Alternative model uses a **nominal dollar** market price and discounts at a **nominal dollar** discount rate. This is a correct method.
- The Site C model uses a 2018 **real dollar** market price and discounts at a **nominal dollar** discount rate. This is an incorrect method as the discount rate should be consistent with the dollar basis of prices.
- We believe this is a mistake rather than a conscious assumption, as there is no feasible basis for this difference nor has the Commission identified it in their assumptions.
- This mistake undervalues the Site C surplus on a Present Value basis.
- In the Commission Scenario Low Load Case used in Table 40, the impact is a $336 million higher cost of Site C than is correct.

B. The Commission's model has a mathematical error due to inconsistent application of inflation factors and discount rates.
- Inflation is applied to costs assuming they occur at the **start** of a fiscal year.
- Discounting is applied to costs assuming they occur at the **end** of a fiscal year.
- This inconsistent approach is incorrect. Inflation and discounting should be applied to the same period.
- In the Commission Scenario using the Low Load Case in Table 39, this results in a $51M lower cost of the Illustrative Alternatives than is correct.

C. The Commission has double-counted transmission loss savings associated with DSM which has the effect of understating the cost of the Commission's alternative portfolio relative to Site C.
   - In its original October 11th portfolio, the Commission increased the amount of energy provided by DSM by ~11% to reflect the avoidance of transmission losses.
   - In our October 18th response, we flagged that this was incorrect as the energy volumes they were using were already adjusted to reflect loss avoidance.
   - The Commission has stated that they continue to believe their adjustment is appropriate as they believe BC Hydro's adjustment was only for distribution losses, and a further adjustment is required for transmission losses.
   - This is incorrect. The volumes used by the Commission had already been adjusted to reflect transmission losses as well as distribution losses, and thus the Commission scenario double-counts transmission loss savings. Correction of this issue would advance the need for new resources and increase the cost of the Illustrative Alternative portfolio by ~$201 million.

2. Assumptions that do not reflect true costs to ratepayers

This section covers assumptions the Commission has made that are not mathematical errors, but are not representative of how costs would actually be recovered from ratepayers.

A. The Commission's treatment of sunk costs (i.e., the $2.1 billion in costs that will be spent by Dec 31, 2017 but have yet to be recovered from ratepayers) is not representative of the costs to ratepayers.
   - The Commission's model ignores sunk costs in the Terminate scenario and removes them from Site C costs in the Continue scenario.
   - This method would be correct if sunk costs are recovered from rates in the same manner for both the Terminate and Continue scenarios. However, this is not the case.
     - In the Continue scenario, sunk costs are effectively recovered over the 70 year amortization life of Site C.
     - In the Termination scenario, costs will be recovered over a substantially shorter period because it would be contrary to regulatory principle to have ratepayers (who aren't even born yet) paying for a project decades from now that had been cancelled and from which they are deriving no benefit at all. BC Hydro believes an appropriate period that is consistent with regulatory principle is 10 years.
   - Treating sunk costs the way the Commission has assumed in their analysis effectively assumes that they will be recovered over 70 years if the Project is terminated. This substantially underestimates the likely rate impact of these sunk costs in a Termination scenario.
   - Due to this difference in how sunk costs are recovered, the cost to ratepayers of the Illustrative Alternative portfolio is $555 million higher than estimated by the Commission

B. The Commission's treatment of termination costs is not representative of the likely costs to ratepayers.
   - In the Illustrative Alternative portfolio the Commission recovers termination costs over 30 years.
   - BC Hydro believes this period of recovery is too long for similar reasons as described for sunk costs in a termination context. This means a ratepayer who is not even born today would be paying for the project's termination in 2045.
   - Using a more reasonable 10 year recovery period increases the cost of the Illustrative Alternative Portfolio by $195 million.

C. The Commission assumes BC Hydro cost of financing for all resources.
   - The Commission has framed this as being intended to ensure an "apples to apples" comparison. However, this assumption either means a substantial change in how BC Hydro does business or does not reflect the true costs to ratepayers.

- BC Hydro financing either means:
  - That BC Hydro builds all new resources on our balance sheet. This would be a change from the decades of policy and precedent that IPPs construct new resources in BC, and has the potentially to have material impacts on BC Hydro's credit rating and the IPP industry.

    OR
  - That the Commission's PVs are not reflective of the true costs to ratepayers, who would pay IPP costs of capital rather than BC Hydro cost of debt. There is no question that an IPPs cost of capital can be expected to be higher than BC Hydro's cost of capital.
- The impact of this assumption depends on the amount of IPP resources in a portfolio. In the Commission scenario with low load assumed, DSM accounts for the vast majority of resources to meet load, and as such the financing assumption does not have a high impact. If a more reasonable load forecast assumption were used, more IPP resources are required, and the impact of financing will be substantial.
- We also note that the Commission has used a 6.4% "nominal" cost of capital for IPPs in their sensitivity test, supposedly based on BC Hydro's estimate. This is incorrect – our estimate of IPP cost of capital is 6.4% real (not nominal). The nominal cost of capital would be ~8.4%. As a result, the Commission's sensitivity analysis is incorrect.

D. The Commission conducts a modified block analysis, which ignores the benefit of incremental DSM if Site C were to be built.
   - The Commission truncates their analysis of new resource requirements to ~20 years (although they extend the cost of these resources out to 70 years).
   - As a result, the Commission effectively assumes that enhanced DSM would <u>not</u> occur if Site C continues. This is incorrect as BC Hydro would delay enhanced DSM with Site C but would still pursue it before other resources.
   - As a result, this ignores substantial differences in the cost of available future options.
     - If Site C continues, BC Hydro will continue to be able to pursue DSM. There is no change in available future options.
     - If Site C is terminated, there is no credible scenario where BC Hydro pursues Site C 10 years in the future (when new non-DSM resources would be required, even with the Commission's aggressive DSM assumptions). We would have lost our cheapest non-DSM option to serve our customers.
   - Ignoring this difference underestimates the PV cost of termination by $596 million.

E. The Commission utilizes Utility Cost rather than Total Resource Cost for DSM.
   - The Commission rejects BC Hydro's position (and their own previous findings in other Commission proceedings) that the Total Resource Cost is the appropriate way to evaluate DSM in comparison to other resource options. They appear to base this off the requirements of the OIC, and appear to assume that the TRC does not reflect direct costs to ratepayers.
   - This is incorrect. The incremental costs in the TRC are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.
   - Utilizing the TRC in a manner consistent with how the Commission used it in previous decisions increases the cost of the Illustrative Alternative portfolio by $444 million.

3. Assumptions that are incorrect and not supported by the evidence

This section covers assumptions that BC Hydro does not believe are reasonable given the information available to us and the Commission.

A. Adoption of the Low Load Forecast as the expected case

- The panel has found the mid forecast to be overall optimistic and considers appropriate to use the Low Load Forecast to develop its recommendations. It is unclear on what basis the Commissions is making this adjustment. Lower industrial load? Higher elasticity? Removal of LNG?
- BC Hydro has difficulty reconciling the Low Load Forecast with any scenario other than one that includes some or more of:
  - Major industrial load destruction. BC Hydro's low mining and forestry sector assumptions assume 1,800 GWh (250MW) of industrial load closures.
  - Low long-term economic growth (i.e. less than 1%/year)
  - Large amounts of customers going off-grid due to solar rooftops or similar switching.
  - Major declines in residential and/or commercial end-use intensities in addition to those underlying the additional DSM the Commission has relied upon
- While this scenario is possible, it is not expected and hence BC Hydro's used it as a low probability low load scenario

B. The Commission allows for up to 400MW of Industrial Load Curtailment at $75/kW-yr with no meaningful evidence.
   - The Commission's sole basis for this volume appears to be a submission from AMPC that suggests there is 200-400MW of Industrial Load Curtailment available based on "realistic procurement efforts, using less restrictive contract terms".
     - AMPC provides no analysis for how they arrived at this figure other than a pro-rated number from Hydro Quebec which would yield only 245MW.
     - The Commission provides no basis for utilizing the upper end of this range.
     - It is unlikely the "less restrictive contract terms" would meet BC Hydro's long term planning needs.
   - BC Hydro notes that we tested a shorter term product (4 hours) in our Year 2 Load Curtailment pilot. No customer bid in such a product.
   - BC Hydro has undertaken an industrial load curtailment pilot, the results of which determined that 85 MW was available in a form that would allow the deferral of physical assets to meet BC Hydro's customer's needs reliably.
   - The adoption of high levels of Industrial Load Curtailment is also inconsistent with the use of BC Hydro's Low Load Forecast.
     - While the Commission does not say on what basis they adopt the Low Load Forecast, it is unlikely BC Hydro would achieve this level of load without industrial demand destruction.
     - Under such a scenario, industrial load would be permanently "curtailed" (by going out of business) and would not be available for temporary curtailment to meet capacity needs.
     - We estimate that at least 40% of the potential for industrial load curtailment would not be available under the Low Load Forecast scenario.

C. Use of an arbitrarily lower market price forecast than the third party forecast used by BC Hydro
   - The Commission rejects BC Hydro's use of the ABB market forecast and adopts a market forecast between the mid and low case of the ABB market price forecast.
   - The ABB market price forecast used by BC Hydro is an independent forecast developed by ABB and built upon extensive research, analysis, and understanding of the North American electricity markets. ABB is one of the world's largest engineering companies and over 100 customers in the energy industry subscribe to their market forecast.
   - BC Hydro has also provided electricity price forecasts developed by the North West Power Planning Council, IHS Markit, and the PIRA Energy Group. The North West Power Planning Council is the entity that develops the long-term power plan for the states of Idaho, Montana, Oregon, and Washington. IHS Markit is a global business information provider while PIRA is a service provider to companies in over 60 countries, including many of the largest Global Oil and Gas firms.

- Every single one of the mid electricity market forecast developed by the organizations mentioned above is higher than the forecast that the Panel used as their mid case. BC Hydro believes that the Panel forecast relates to a pessimistic scenario and that the ABB mid forecast better represents a consensus mid-point view of several organizations that are experts in this domain.

D. The Commission assumes that the Illustrative Alternative portfolio has approximately the same level of firming and shaping as Site C.
   - The Commission reaches this conclusion by assuming that the existing system has sufficient firming and shaping such that incremental amounts have little to no value.
   - BC Hydro has provided a substantial volume of evidence on the value of Site C capacity, firming and shaping.

E. The Commission includes geothermal in their Illustrative Alternative portfolio, but applies the cost of hydrothermal flash technology to resources that require binary technology.
   - Neither Canoe Reach nor Lake Else has temperatures high enough to support flash technology.
   - Switching to binary technology would result in:
     - Higher costs, as binary is more expensive than flash technology
     - Lower net capacity factors, as binary technology is expected to achieve an 80% net capacity factor rather than the net 90% of flash technology according to NREL. Note that the Commission uses a 95% capacity factor – BC Hydro is unaware of the basis for this assumption.
   - Further, the Commission does not account for reservoir degradation which is expected to result annual generation output by 1% per year over the life of the project and would make the redevelopment of these sites after 30 years at a 30% cost reduction unlikely.

4. Assumptions that are incompatible with legislation and/or policy

This section will cover assumptions that violate existing legislation and/or policy. This section remains under development, but it expected to cover the following items:

A. "Remobilization" of Burrard
B. Use of the Columbia River Treaty entitlement
C. Increased reliance on external markets

From:	Nikolejsin, Dave MNGD:EX
To:	Wright, Don J. PREM:EX
Cc:	MacLaren, Les EMPR:EX
Subject:	P&A and Site C decision process
Date:	Tuesday, November 14, 2017 3:44:28 PM
Attachments:	s.12,s.13 Site C Final Report - Expert Advisors 14-11-17 dn edits.docx

Don, please find attached 2 related pieces. I sent you the first one earlier but it is now updated.
s.12,s.13

Thanks.

Dave Nikolejsin
Deputy Minister
Energy, Mines and Petroleum Resources

Page 257 to/à Page 261

Withheld pursuant to/removed as

s.12;s.13

Independent Expert Advice on the BC Utilities Commission's Site C Inquiry Final Report

Purpose:

Government is seeking expert advice with respect to the BC Utilities Commission's (BCUC's) Final Report to Government on Site C. Advisors will review, assess and advise Government on the reasonableness and appropriateness of the assumptions developed and used by the BCUC in their Final Report. Advisors will also review the due diligence undertaken by the Ministries of Energy, Mines and Petroleum Resources and Finance. The findings of each advisor will be presented to Cabinet.

Terms of Reference:

Background

The BCUC completed its inquiry into BC Hydro's Site C project, as directed by the Provincial Government through an Order-in- Council (OIC). On November 1, 2017, the British Columbia Utilities Commission Inquiry Respecting Site C Final Report was submitted to the Government of British Columbia (BCUC Final Report).

The BCUC Final Report included the BCUC's estimated costs of completing, suspending or terminating Site C based on assumptions and analysis it developed during the course of the inquiry. The Final Report included an Illustrative Alternative Portfolio, which the BCUC estimated could provide the same level of benefits, GHG emissions and at an equivalent cost when compared to the Site C project.

The BCUC qualified its recommendations on whether to continue or terminate the project, as the most appropriate path forward depended on which assumptions on future conditions are most reasonable. These key assumptions included: the load forecast; the costs of terminating the project; the cost of completing the project; and the cost of the alternative portfolio.

Scope of Work

To aid in informing Cabinet's decision, Government is seeking expert advice on the reasonableness and accuracy of the assumptions used by the BCUC, and the government's analysis of those assumptions, in determining whether the:

- electricity demand in the future will be at the lower band of BC Hydro's load forecast;
- costs of completing or terminating Site C are appropriate and allow for fair and equal estimates for comparison; and
- costs and performance attributes of the Illustrative Alternative portfolio are reasonable and accurate.

In addition, government would like to hear advice on potential mitigation strategies for both terminating and proceeding with the Site C project, and any other advice that will inform government's decision.

The advisors will operate under terms of confidentiality agreements, and will not publicly disclose information related to materials they review, or the advice they provide to Cabinet.

Comment [NDM1]: Just thinking about this term. I know we discussed this but is it reasonable to expect confidentiality? I expect the media and public will want to know what was said.

Deliverable and Proposed Schedule

Advisors will provide a presentation to Cabinet on [November 29, 2017].

Secretariat Support

The Ministry of Energy, Mines and Petroleum Resources will provide secretariat support to advisors.

Advisors:

1. **David Craig** – **presenting advice through lens of major inductrial and commercial rate payers**

   David is President of Consolidated Management Consultants Ltd. He has over 40 years of experience as an executive, officer, and member of Boards of Directors of public institutions, private companies and non-profit organizations. David is consultant for the Commercial Energy Consumers Association of BC and Policy Chair for the BC Chamber of Commerce. The CEC participated in the Site C Inquiry and submitted data and analysis informed by David Craig's experience.

2. **Collen Giroux-Schmidt** – **presenting advice through lens of alternative portfolio industry players**

   Colleen Giroux-Schmidt brings over a decade and a half of experience in BC and Canadian resource development with an extensive knowledge of the renewable energy sector. As Senior Director – Government Relations and Regulatory Affairs for Innergex Renewable Energy Inc., her focus is on working with various stakeholders including all levels of government, First Nations and communities to increase renewable energy opportunities to help the jurisdictions Innergex works in meeting their climate change goals. As the former Chair and a current member of the Board of Directors for Clean Energy BC (CEBC), she helps promote and support the growth of British Columbia's Clean Energy industry. CEBC participated in the BCUC's Site C Inquiry.

3. **Jim Quail** – **presenting advice through lens of consumers and disadvantaged rate payers**

DRAFT

Jim has had a varied career in progressive legal work. He was called to the BC Bar in 1980 and then worked as general counsel, director of planning, and acting executive director at the Legal Services Society of BC, providing free legal services to low-income people. He has also held roles as the Executive Director of the BC Public Interest Advocacy Centre, the Business Manager at Vancouver Municipal and Regional Employees' Union (now CUPE local 15), the Legal Director at the Hospital Employees' Union, and the Legal and Regulatory Director at COPE Local 378.

Jim has special expertise in regulatory law, and has a wealth of experience representing communities, low-income consumers, and BC Hydro workers at the BC Utilities Commission. He comments regularly in the media on issues related to utility rates and energy policy. Jim is an Honourary Member of CUPE Local 15 and an Honourary Life Member of the BC Freedom of Information and Privacy Association.

4. **Karen Tam Wu** – **presenting through lens of environmental/climate advocates**

Karen Tam Wu is the acting B.C. director at the Pembina Institute, Canada's leading clean energy think-tank. She is also the director of the institute's Buildings and Urban Solutions Program, and a member of the B.C. Government's Climate Solutions and Clean Growth Advisory Council.

Through cross-sectoral consultation and engagement, Karen leads initiatives to advance clean energy solutions and improve energy efficiency in B.C. and across Canada. Previously, Karen worked with First Nations, communities, government, and industry on important conservation initiatives in B.C. A registered professional forester, Karen worked with forest companies worldwide for over a decade developing and implementing sustainable forest management systems.

DRAFT

From:	Gibbs, Robb GCPE:EX
To:	MacLaren, Les EMPR:EX; Zadravec, Don GCPE:EX; "Sauer, Darwin"; Lloyd, Evan GCPE:EX
Subject:	s.12,s.13
Date:	Tuesday, October 31, 2017 3:22:09 PM
Attachments:	s.12,s.13

Hi there,

s.12,s.13

Robb

Robb Gibbs
ADM – Strategic Communications
Government Communications & Public Engagement
P: 1-778-698-7469
C: 1-778-584-1242

Page 266 to/à Page 286

Withheld pursuant to/removed as

s.12;s.13

From:	Savidant, Michael
To:	MacLaren, Les EMPR:EX
Cc:	O"Riley, Christopher; Reimann, Randy; Fane, Lindsay
Subject:	s.12,s.13,s.17
Date:	Thursday, November 23, 2017 1:56:28 PM
Attachments:	s.12,s.13,s.17

Les,

s.12,s.13,s.17

-Mike

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Page 288 to/à Page 289

Withheld pursuant to/removed as

s.12;s.13;s.17

From:	Grewar, Colin GCPE:EX
To:	Haslam, David GCPE:EX; "Magre, Leela"
Cc:	Pillon, Lawrence; Scott, Mora; Beaupre, Darren GCPE:EX; Sovka, David GCPE:EX; MacLaren, Les MEM:EX
Subject:	RE: BCUC + Site C
Date:	Tuesday, October 17, 2017 9:01:14 AM
Attachments:	BC Hydro Response to BCUC IR on Rate Impact of Site C_Oct16_2017.docx

Here you go.

Colin Grewar
Public Affairs Officer
Government Communications and Public Engagement
Ministry of Energy, Mines and Petroleum Resources
Phone: 250-952-0650
Colin.Grewar@gov.bc.ca

-----Original Message-----
From: Haslam, David GCPE:EX
Sent: Tuesday, October 17, 2017 8:51 AM
To: 'Magre, Leela'
Cc: Pillon, Lawrence; Scott, Mora; Grewar, Colin GCPE:EX; Beaupre, Darren GCPE:EX; Sovka, David GCPE:EX; MacLaren, Les MEM:EX
Subject: RE: BCUC + Site C

Thx. Colin/David - please put the rates IR into a word doc so I can circulate. Much appreciated. D

-----Original Message-----
From: Magre, Leela [mailto:Leela.Magre@bchydro.com]
Sent: Tuesday, October 17, 2017 8:00 AM
To: Haslam, David GCPE:EX
Cc: Pillon, Lawrence; Scott, Mora; Grewar, Colin GCPE:EX; Beaupre, Darren GCPE:EX; Sovka, David GCPE:EX; MacLaren, Les MEM:EX
Subject: Re: BCUC + Site C

Good morning,

Attached are the IR responses that were filed with the BCUC yesterday. The response on rate impact is IR 3.16.0.

Thanks!
Leela

This email and its attachments are intended solely for the personal use of the individual or entity named above. Any use of this communication by an unintended recipient is strictly prohibited. If you have received this email in error, any publication, use, reproduction, disclosure or dissemination of its contents is strictly prohibited. Please immediately delete this message and its attachments from your computer and servers. We would also appreciate if you would contact us by a collect call or return email to notify us of this error. Thank you for your cooperation.
-BCHydroDisclaimerID5.2.8.1541

BC Hydro Oct. 16th Response to BCUC Information Request on Rate Impact of Site C:

3.16.0 Please explain the expected rate impact of Site C, for the expected life of the dam, if it is completed on time and on budget.

RESPONSE:

As noted in BC Hydro's Fiscal 2017 – Fiscal 2019 Revenue Requirements Application, and in our response to BCUC IR 2.51.0 in this proceeding, BC Hydro's current rate forecasts extend through Fiscal 2024, which is the end of the 10 Year Rates Plan period. We do not have rate forecasts beyond Fiscal 2024. Additionally, the new Government has indicated that a comprehensive review of BC Hydro will be undertaken, and that Government and BC Hydro will be developing a "refreshed plan to keep electricity rates low and predictable over the long-term while making significant investments to expand the system and maintain aging infrastructure."

In order to respond to the question, we considered an indicative, standalone rate impact estimate similar to that prepared for the Joint Review Panel in 2015. In that analysis, we provided estimated rate impacts on a smoothed (over ten years) and unsmoothed basis. The analysis assumes the energy from Site C will initially be sold as surplus. Over time, the Site C energy is assumed to serve domestic load. Using this methodology, if Site C is completed on time and on its updated budget, then:

- **On a smoothed basis, the rate impact is estimated to be approximately 0.5 per cent in F2025, followed by an incremental 0.5 per cent in F2026, with no further incremental rate increases required over the 10 year period beyond F2026. This is shown on Line 22 of the Summary tab in Attachment 1 to this information request.**

- **On an unsmoothed basis, the rate impact is estimated to be approximately 5 per cent in Fiscal 2025, followed by rate decreases in subsequent years. This is shown on Line 21 of the Summary tab in Attachment 2 to this information request.**

- **In either case, the estimated cumulative impact on rates decreases to 0 per cent by F2030, and then to negative 2 per cent in F2036. In other words, by F2036, customer rates will be 2 per cent lower than they otherwise would be without Site C and the customer load which it will be serving. This is shown on Line 14 of the Summary tab in Attachment 1, and on Line 13 of the Summary tab in Attachment 2 to this information request. This is because the costs of Site C are lower than the associated forecast customer revenue.**

- **In either case, after F2036, the cumulative rate decrease will be the same and will continue to decrease over time. By F2094, it is estimated that customer rates will be 5 per cent lower than they otherwise would be without Site C. This is shown on Line 14 of the Summary tab in Attachment 1, and on Line 13 of the Summary tab in Attachment 2 to this information request.**

The analysis considered the Site C costs including amortization, finance charges, water rentals, operating costs, and grants and taxes. Refer to the attached spreadsheets for the details of this calculation.

As part of the current Site C inquiry, the revenue requirement and rate impact analyses which BC Hydro provided in our August 30 Filing, and subsequently in response to BCUC requests provided estimate ratepayer impacts of alternative portfolios (in other words, impacts if alternative portfolios are pursued instead of Site C). The explanation above describes the rate impact only of Site C. As such, the results of this standalone estimated analysis cannot be directly compared to our other analyses. As noted, this standalone rate impact of Site C is similar to the analysis provided during the Joint Review Panel work in 2015.

From:	MacLaren, Les EMPR:EX
To:	Nikolejsin, Dave MNGD:EX
Subject:	RE: BCUC Site C Report
Date:	Sunday, November 5, 2017 11:20:00 AM
Attachments:	RE Site C BCUC.msg

BCUC staff made their own model, starting with a spreadsheet BCH submitted to NPVs of revenue requirements. It is described in Appendix C of the final report.
On October 11 the BCUC released some alternative portfolios using the model that BCH had issues with. They filed the attached response. Table 1 on pages 2 and 3 summarizes BCH's areas of concern. The final report says BCUC made further adjustments based on feedback from BCH and others. The document I circulated yesterday sets out BCH's ongoing concerns with the revised BCUC model.
Les

From: Nikolejsin, Dave MNGD:EX
Sent: Sunday, November 5, 2017 11:03 AM
To: MacLaren, Les EMPR:EX
Subject: RE: BCUC Site C Report
Can you explain the following to me:
2D
2E
What "model" did the BCUC use? Did they make up their own, or use someone else's (e.g. Deloitte?)

From: MacLaren, Les EMPR:EX
Sent: November 4, 2017 10:06 AM
To: Wright, Don J. PREM:EX <Don.J.Wright@gov.bc.ca>; Meggs, Geoff PREM:EX <Geoff.Meggs@gov.bc.ca>; Wanamaker, Lori FIN:EX <Lori.Wanamaker@gov.bc.ca>; Foster, Doug FIN:EX <Doug.Foster@gov.bc.ca>; Zadravec, Don GCPE:EX <Don.Zadravec@gov.bc.ca>; Lloyd, Evan GCPE:EX <Evan.Lloyd@gov.bc.ca>; Kennedy, Christine PREM:EX <Christine.Kennedy@gov.bc.ca>
Cc: Rowe, Katherine EMPR:EX <Katherine.Rowe@gov.bc.ca>; Nikolejsin, Dave MNGD:EX <Dave.Nikolejsin@gov.bc.ca>
Subject: BCUC Site C Report
Good morning.
To support discussions that may be occurring today and our meeting tomorrow to map out work streams leading to Cabinet meetings later this month, attached is analysis to date of the BCUC report that I received last evening from the BC Hydro team that has been intensively analyzing the report and modelling behind the Commission's results. Some of the errors have been quantified and the differences are material in favour of Site C over the Commission's alternative portfolio. Coming out of an exchange with Chris O'Riley this morning, we propose one way that we could get the results of this analysis out into the public domain. We could have EMPR, under Dave Nik's signature, write to the Chair of the BCUC with something along the lines of the following:

- We are supporting government's decision-making on Site C
- In your report you note that the alternative portfolio developed by Commission staff is not a substitute for BC Hydro's planning processes
- We understand that BC Hydro modelled over 60 scenarios testing various assumptions, including a number alternatives requested by the Commission, but that the Commission's Illustrative Alternative Portfolio in your final report was not analyzed using BC Hydro's modelling tools

- We therefore asked BC Hydro to provide an assessment of the Commission's alternative portfolio and would like to get the Commission's response to the issues identified in BC Hydro's initial analysis (we could include some or all of the issues BC Hydro has identified)
- More issues may be identified as we work through this material, etc.

The Commission would need to make the letter public. This would provide an opportunity for others, especially the intervenor groups used to dealing with BC Hydro's modelling in other BCUC processes, to weigh in. Because a number of the issues are computational or assumption errors, there may be little that critics can say about them.

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy, Mines and Petroleum Resources
NOTE NEW OFFICE PHONE NUMBER: 778-698-7183
Cell: 250-889-3479
Energizing BC—clean, sustainable and productive

From:	Magre, Leela
To:	Haslam, David GCPE:EX
Cc:	Pillon, Lawrence; Zadravec, Don GCPE:EX; Grewar, Colin GCPE:EX; Scott, Mora; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX; MacLaren, Les EMPR:EX
Subject:	RE: Site C / BCUC
Date:	Thursday, October 19, 2017 8:06:18 AM
Attachments:	2017_10_18_SiteC_BCH_ALT_PRTF.PDF

Good morning,

Here is the filing attached. There is a good summary from page 1 to the top of page 4. In short --

We identified a number of issues with the October 11th alternative portfolio sent around by the Commission for comment, which we discussed at a high level in our Saturday technical presentation. Altogether, these issues would increase the cost of the October 11th portfolio by approximately $4 billion. The main issues are as follows:

- The portfolio assumes BC Hydro is stopping DSM if we build Site C, which is not correct
- It assumes BC Hydro builds and finances all alternative resources, also not correct
- The battery costs in the portfolio incorrectly exclude capital costs other than balance of system, operating costs of approximately $10 million per year (for a 100MW installation) and operating energy losses of approx.7%, effectively understating the costs of batteries

I'm out of the office today, but you can reach me on my cell or email at any time if you have any questions.

Thanks,
Leela

Leela Magre | Manager, Policy & Research

BC Hydro
333 Dunsmuir St, 15th floor
Vancouver, BC V6B 5R3

P 604 623 4008
M 236 993 0338
E leela magre@bchydro.com

bchydro.com

Smart about power in all we do.

-----Original Message-----
From: Haslam, David GCPE:EX [mailto:David.Haslam@gov.bc.ca]
Sent: 2017, October 19 6:48 AM
To: Magre, Leela
Cc: Pillon, Lawrence; Zadravec, Don GCPE:EX; Grewar, Colin GCPE:EX; Scott, Mora; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX; MacLaren, Les EMPR:EX
Subject: Re: Site C / BCUC

Thx. Including mo staff and Les.

Sent from my iPhone

> On Oct 18, 2017, at 9:10 PM, Magre, Leela <Leela.Magre@bchydro.com> wrote:

>
> Good evening,
>
> Attached is today's filing regarding the October 11th alternative portfolio. It will be posted by the BCUC sometime tomorrow.
>
> Thanks,
> Leela
>
> _____
>
> Leela Magre | Manager, Policy & Research
>
> BC Hydro
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
>
> P 604 623 4008
> M 236 993 0338
> E leela magre@bchydro.com<mailto:leela.magre@bchydro.com>
>
> bchydro.com<http://www.bchydro.com/>
> Smart about power in all we do.
>
> From: Magre, Leela
> Sent: 2017, October 18 10:32 AM
> To: Pillon, Lawrence; David Haslam (David.Haslam@gov.bc.ca); Zadravec,
> Don GCPE:EX (Don.Zadravec@gov.bc.ca); Grewar, Colin GCPE:EX
> (Colin.Grewar@gov.bc.ca)
> Cc: Scott, Mora
> Subject: RE: Site C / BCUC
>
> Good morning,
>
> As a follow-up to Lawrence's email, we are filing today our comments on the October 11th alternative portfolio that the Commission requested feedback on (you will recall we discussed this in our meeting on Friday). We already addressed this topic with the Commission in our presentation on Saturday, and are providing more detail in writing as requested by the Commission. They have requested feedback from other parties as well.
>
> We've identified a number of issues with the October 11th portfolio, which we highlighted in the Saturday presentation. The main ones are as follows. All would increase the cost of the October 11th portfolio:
>
> * The portfolio assumes BC Hydro is stopping DSM if we build Site C, which is not correct
>
> * It assumes BC Hydro builds and finances all alternative resources, also not correct
>
> * The battery costs in the portfolio incorrectly exclude capital costs of balancing the system, operating costs of approximately $10 million per year and operating energy losses of approx.7%, effectively understating the costs of batteries
>
> We will send along the full filing once it has been submitted to the Commission (likely after close of business today).
>
> Thank you and let me know if you have any questions.
>
> Best,
> Leela

>
> _____
>
> Leela Magre | Manager, Policy & Research
>
> BC Hydro
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
>
> P 604 623 4008
> M 236 993 0338
> E leela magre@bchydro.com<mailto:leela.magre@bchydro.com>
>
> bchydro.com<http://www.bchydro.com/>
>
> Smart about power in all we do.
>
> From: Pillon, Lawrence
> Sent: 2017, October 18 9:57 AM
> To: David Haslam
> (David.Haslam@gov.bc.ca<mailto:David.Haslam@gov.bc.ca>); Zadravec, Don
> GCPE:EX (Don.Zadravec@gov.bc.ca<mailto:Don.Zadravec@gov.bc.ca>);
> Grewar, Colin GCPE:EX
> (Colin.Grewar@gov.bc.ca<mailto:Colin.Grewar@gov.bc.ca>)
> Cc: Magre, Leela; Scott, Mora
> Subject: Site C / BCUC
>
> Hi
> Just a heads up that we will be filing another short submission to the
> BCUC later today, a follow-up from Saturday's proceedings. We were asked to provide comments on alternative scenarios. Leela will provide more.
>
> Lawrence
> _____
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> -BCHydroDisclaimerID5.2.8.1541
> <2017_10_18_SiteC_BCH_ALT_PRTF.PDF>

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

October 18, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1598922
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Alternative Portfolios

BC Hydro writes to provide its comments on, and analysis of the BCUC's Alternative Site C Portfolios as requested by the Commission Panel in its letter of October 11, 2017 (**A-22**).

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

fj/ma

Enclosure

Page 299 to/à Page 338

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Page 339 to/à Page 341

Withheld pursuant to/removed as

s.12;s.13

From:	MacLaren, Les EMPR:EX
To:	Foster, Doug FIN:EX; Wright, Don J. PREM:EX; Nikolejsin, Dave MNGD:EX
Subject:	RE: Demand Issue
Date:	Sunday, November 12, 2017 2:04:00 PM
Attachments:	Re; Site C Inquiry and Climate Change Commitments .msg

The attached letter from three nationally recognized experts was sent to the PM, Premier, energy and environment Ministers, and their Deputies this morning. It highlights recent studies where low carbon electrification is required to meet national and provincial GHG emission reductions targets (i.e., the low load forecast is inappropriate). We identify similar concerns in both the cover letter and appendix. I don't think we need additional information on this point. I will send a copy of Sigvaldason's letter to the BCUC Chair.

Les

From: Foster, Doug FIN:EX
Sent: Saturday, November 11, 2017 8:09 AM
To: Wright, Don J. PREM:EX; Nikolejsin, Dave MNGD:EX; MacLaren, Les EMPR:EX
Subject: RE: Demand Issue

Thanks.

Yes I had seen the earlier post too.

Also reviewed Jaccard's work (who was a previous BCUC chair).

One area I was looking to see more discussion in the BCUC process was on the outlook for Alta and how BC (perhaps with Canada) may be part of it climate action agenda with our battery storage capacity.

d

From: Wright, Don J. PREM:EX
Sent: Saturday, November 11, 2017 6:58 AM
To: Nikolejsin, Dave MNGD:EX; MacLaren, Les EMPR:EX; Foster, Doug FIN:EX
Subject: Re: Demand Issue

To clarify, there are two posts worth reading. The one on Nov 10 and the one on Nov 2.

From: Don Wright <don.j.wright@gov.bc.ca>

Date: Saturday, November 11, 2017 at 6:56 AM

To: Dave Nikolejsin <Dave.Nikolejsin@gov.bc.ca>, "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>, "Foster, Doug FIN:EX" <Doug.Foster@gov.bc.ca>

Subject: Re: Demand Issue

And he posted another one later on that is pretty good as well.

https://achemistinlangley.net

From: Don Wright <don.j.wright@gov.bc.ca>

Date: Saturday, November 11, 2017 at 6:47 AM

To: Dave Nikolejsin <Dave.Nikolejsin@gov.bc.ca>, "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>, "Foster, Doug FIN:EX" <Doug.Foster@gov.bc.ca>

Subject: Demand Issue

This guy is a bit of a partisan, but I think he captures the demand-side of the argument well.

https://achemistinlangley.net

From:	Oskar T. Sigvaldason
To:	OfficeofthePremier, Office PREM:EX
Cc:	Weaver.MLA, Andrew LASS:EX; "Justin Trudeau"; Minister, EMPR EMPR:EX; Minister, ENV ENV:EX; "James Carr"; "Catherine McKenna"; OfficeofthePremier, Office PREM:EX; Nikolejsin, Dave MNGD:EX; Plecas, Bobbi ENV:EX; Zacharias, Mark ENV:EX; "Christyne Tremblay"; "Stephen Lucas"; MacLaren, Les EMPR:EX; "Kenneth Peterson"; "James Burpee"; "Kenneth Ogilvie"; "Oskar Sigvaldason"
Subject:	Re; Site C Inquiry and Climate Change Commitments
Date:	Sunday, November 12, 2017 11:20:12 AM
Attachments:	Site C Inquiry - Letter of Concern to Premier John Horgan.pdf

Dear Honorable Premier Mr. John Horgan

Please find enclosed a letter, with supporting documentation, defining stated concerns about BCUC's Final Report, submitted on November1, 2017, on the Site C Inquiry. Our concerns are a direct consequence of the lack of consideration given for low carbon electrification for meeting ambitious and urgent greenhouse gas emissions reductions commitments made by Governments in Canada, including the Governments of British Columbia and Canada.

We have taken the liberty of forwarding copies of this communication to the Leader of the Green Party of British Columbia, to the Prime Minister of Canada, and to Ministers and Deputy Minsters, responsible for Energy and Environment/ Climate Change in your Government and in the Government of Canada. We have also copied the Assistant Deputy Minister responsible for electricity and alternative energy in your Government, and the Executive Chairman of the Board of BC Hydro and Power Authority.

I will be forwarding the "original" of this communication to you by regular mail.

Respectfully submitted by; Oskar Sigvaldason

On behalf of Oskar Sigvaldason, Jim Burpee and Ken Ogilvie

November 13, 2017

Honorable Mr. John Horgan
Premier; Government of British Columbia
P.O. Box 9041, Stn. Prov. Govt.
Victoria, BC; V8W 9E1

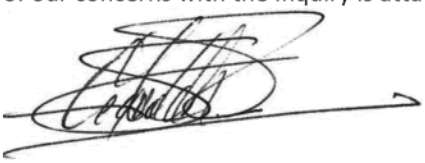
Dear Premier John Horgan

Re; Site C Inquiry and Climate Change Commitments

The undersigned are concerned that the Site C Inquiry by British Columbia Utilities Commission (BCUC) did not properly include global, national and provincial climate change commitments in its deliberations, as reported in their Final Report of November 1, 2017. This omission is at obvious variance with commitments made by Canada in the Paris Accord of December 12, 2015, First Ministers in their Vancouver Declaration of March 3, 2016, and federal and provincial governments, including British Columbia, in the Pan-Canadian Framework on Clean Growth and Climate Change of December 9, 2016.

Comprehensive studies on strategies for achieving major greenhouse gas (GHG) emissions reductions in Canada all show that fossil fuel consumption will have to decrease dramatically over the coming decades, with corresponding increases in the use of low-carbon electricity to meet the safe and reliable energy needs of a growing population and economy. The Site C Inquiry did not adequately consider low-carbon electrification as a critical element in B.C. and Canada for meeting climate change commitments.

Our conclusion is that the Site C Inquiry is flawed and its report does not provide a suitable basis for informing the important decisions that British Columbia and Canada need to make on climate change. A more detailed statement of our concerns with the Inquiry is attached to this letter.



Respectfully submitted by Oskar Sigvaldason
On behalf of Oskar Sigvaldason, Jim Burpee and Ken Ogilvie (summary bios enclosed)

Copies to:
Honorable Dr. Andrew Weaver; Leader, Green Party of British Columbia
Right Honorable Justin Trudeau; Prime Minister of Canada
Honorable Michelle Mungall; Minister, Energy, Mines and Petroleum Resources
Honorable George Heyman; Minister, Environment & Climate Change Strategy
Honorable James Carr; Minister, Natural Resources Canada
Honorable Catherine McKenna; Minister, Environment and Climate Change Canada
Dr. Don Wright; Deputy Minister to the Premier
Mr. Dave Nikolejsin; Deputy Minister; Ministry of Energy, Mines and Petroleum Resources
Ms. Bobbi Plecas; Deputy Minister, Climate Change, Ministry of Environment & Climate Change Strategy
Dr. Mark Zacharias, Deputy Minister, Environment, Ministry of Environment & Climate Change Strategy
Ms. Christyne Tremblay; Deputy Minister, Natural Resources Canada
Dr. Stephen Lucas; Deputy Minister, Environment & Climate Change Canada
Mr. Les MacLaren; Assistant Deputy Minister, Electricity and Alternative Energy Division, Ministry of Energy, Mines and Petroleum Resources
Mr. Ken Peterson; Executive Chairman of the Board, B.C. Hydro and Power Authority

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Withheld pursuant to/removed as

s.22

The following is a copy of the first of two submissions to the BCUC. It was posted on the BCUC web-site on September 27, as Submission F197-1. A second more comprehensive submission was posted on October 10, as Submission F197-2.

Climate Change Considerations with respect to Site C Hydro-electric Project

Submitted by Oskar Sigvaldason, Jim Burpee and Ken Ogilvie

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Page 347 to/à Page 349

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Page 350 to/à Page 355

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s.12;s.13

From:	MacLaren, Les EMPR:EX
To:	Nikolejsin, Dave MNGD:EX
Cc:	Wright, Don J. PREM:EX; Kennedy, Christine PREM:EX
Subject:	RE: Letter to BCUC
Date:	Friday, November 17, 2017 6:54:00 AM

Here is a suggested response:
Thanks Marvin
The Ministry checked with the BC Hydro modellers reviewing all of the BCUC's assumptions and models. The BCUC model fixes Revelstoke Unit 6 timing for both Site C and the proposed Alternative Illustrative Portfolio. Compared to the BCUC model, BC Hydro's portfolio modelling allows Rev 6 to be added when needed. The difference is advancing Rev 6 a couple of years, with an impact that is not expected to be material compared to the other errors identified.
Les

From: Nikolejsin, Dave MNGD:EX
Sent: Thursday, November 16, 2017 5:30 PM
To: MacLaren, Les EMPR:EX
Cc: Wright, Don J. PREM:EX; Kennedy, Christine PREM:EX
Subject: Re: Letter to BCUC
Draft something suitable for Don to send back to Marvin. Thanks

Dave Nikolejsin
Deputy Minister
Energy, Mines and Petroleum Resources

On Nov 16, 2017, at 5:18 PM, MacLaren, Les EMPR:EX <Les.MacLaren@gov.bc.ca> wrote:

> BCUC model fixes Revelstoke Unit 6 timing for both Site C and the Alternative Portfolio. BC Hydro's subsequent portfolio modelling allows Rev 6 to be added when needed. Change is just advancing a couple of years and impact is not expected to be material.
> Les
>
> **From:** Nikolejsin, Dave MNGD:EX
> **Sent:** Thursday, November 16, 2017 3:42 PM
> **To:** MacLaren, Les EMPR:EX
> **Cc:** Wright, Don J. PREM:EX; Kennedy, Christine PREM:EX
> **Subject:** Re: Letter to BCUC
> To me the question to hydro is "is this question in their letter". Find that out first. Then we can discuss next steps
>
> Dave Nikolejsin
> Deputy Minister
> Energy, Mines and Petroleum Resources
>
> On Nov 16, 2017, at 2:59 PM, MacLaren, Les EMPR:EX <Les.MacLaren@gov.bc.ca> wrote:
>
> > Suggest we check with BC Hydro which has been through the models and assumptions with a fine tooth comb. We may already have enough to move the dial but I would like to know.
> > Les

On Nov 16, 2017, at 2:45 PM, Wright, Don J. PREM:EX <Don.J.Wright@gov.bc.ca> wrote:

Thoughts?

From: Marvin Shaffer <marvshaffer@gmail.com>
Date: Thursday, November 16, 2017 at 1:46 PM
To: Don Wright <don.j.wright@gov.bc.ca>
Subject: Letter to BCUC

Hi Don,
The letter the government sent to the BCUC today raised a number of very important questions concerning the BCUC's comparison of the cost and rate implications of completing Site C versus terminating the project and pursuing an alternative portfolio as required.
One question that did not get raised, however, concerns the BCUC's assumptions regarding Revelstoke 6.
In section 4.2.4 of its Final Report, the BCUC explicitly states that it is including Revelstoke 6 in the available supply so as not to overstate the capacity shortfalls without Site C. It would appear, however, that BCUC did not include the costs of developing Revelstoke 6 in its cost analysis. The questions that need to be answered are:
1) Did the BCUC assume that there would be a difference in the timing of the development of Revelstoke 6 in its low load growth scenario with and without the completion of Site C?
2) If not, why not? Why wouldn't the development of 1100 MW of capacity at Site C afffect the need for and therefore timing of Revelstoke 6, particularly given that the BCUC has assumed zero value to surplus capacity?
3) If yes, did the BCUC consider the cost implications of advancing Revelstoke 6 development expenditures in its without Site C case. What was the calculated effect and is it included in the report's present value cost results?
Marvin

From:	Savidant, Michael
To:	Foster, Doug FIN:EX
Cc:	MacLaren, Les EMPR:EX; O"Riley, Christopher; Reimann, Randy; Fane, Lindsay; Lee, Kathy
Subject:	RE: Load Forecast Graphs
Date:	Wednesday, November 22, 2017 12:18:24 PM
Attachments:	s.12,s.13

s.12,s.13

From: Foster, Doug FIN:EX [mailto:Doug.Foster@gov.bc.ca]
Sent: 2017, November 22 7:38 AM
To: Savidant, Michael
Cc: MacLaren, Les EMPR:EX; O'Riley, Christopher; Reimann, Randy; Fane, Lindsay
Subject: s.12,s.13

Thanks.

s.12,s.13

d.

From: Savidant, Michael [mailto:michael.savidant@bchydro.com]
Sent: Tuesday, November 21, 2017 1:42 PM
To: Foster, Doug FIN:EX
Cc: MacLaren, Les EMPR:EX; O'Riley, Christopher; Reimann, Randy; Fane, Lindsay
Subject: s.12,s.13

Doug,

s.12,s.13

Let us know if this meets your needs.
Thanks,
Mike

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Page 359 to/à Page 360

Withheld pursuant to/removed as

s.12;s.13

From:	Rowe, Katherine EMPR:EX
To:	Foster, Doug FIN:EX
Cc:	MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Subject:	s.12,s.13
Date:	Tuesday, November 7, 2017 1:05:32 PM
Attachments:	s.12,s.13

s.12,s.13

Katherine

From: Foster, Doug FIN:EX
Sent: Tuesday, November 7, 2017 12:55 PM
To: Rowe, Katherine EMPR:EX
Cc: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Subject: RE: s.12,s.13

s.12,s.13

From: Rowe, Katherine EMPR:EX
Sent: Tuesday, November 7, 2017 12:00 PM
To: Foster, Doug FIN:EX
Cc: MacLaren, Les EMPR:EX; Wieringa, Paul EMPR:EX
Subject: s.12,s.13

Apologies – I don't have a clean copy of the s.12,s.13 You can ignore my scribbles

Katherine Rowe
Director, Generation and Regulatory Branch | **NEW!** Phone: 778.698.7190| Cell: 250.216.5823 |Ministry of Energy, Mines and Petroleum Resources
Energizing BC—clean, sustainable and productive

Page 362 to/à Page 378

Withheld pursuant to/removed as

s.12;s.13

Page 379 to/à Page 389

Withheld pursuant to/removed as

s.14;s.13

Page 390 to/à Page 419

Withheld pursuant to/removed as

s.12;s.13

From:	Savidant, Michael
To:	MacLaren, Les EMPR:EX; O"Riley, Christopher
Cc:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	RE: Review
Date:	Wednesday, November 8, 2017 9:01:04 PM

Les,

On a Tuesday call with the BCUC we mentioned the issues in Section 1 of the Review note you have previously seen. The specific items discussed were:

A. Use of nominal discount rate on real dollar surplus value in Site C portfolio (Item 1A from Review note)
B. Inconsistent application of inflation and discounting to cashflow timing (Item 1B from Review note)
C. Double-counting of transmission losses on DSM (Item 1C from Review note)
D. Identification of a typo in Table 43 (Item 1D from updated Review note)
E. Use of 6.4% IPP cost of capital as nominal when it is real (should be using 8.4% nominal in sensitivity analysis) (this is covered as a sub-bullet to Item 2C from the review note)

We framed these as potential issues with their model we had noticed, but that appeared inadvertent. We gave them an idea of which ones we believed were most material to the PV results (items A and C). We did not raise any of the issues in Sections 2, 3 or 4 of our review note.

They've asked us for an email with the details of items A and B above over the next few days. We have not sent this yet as we've been busy with estimates and other work.

Geoff Higgins (acting for Fred James) and I were on the call for BCH. On the BCUC side it was Yolanda Domingo and Chris Garand.

There have been no other discussions on the computational issues with the BCUC that I am aware of.

-Mike

From: MacLaren, Les EMPR:EX [mailto:Les.MacLaren@gov.bc.ca]
Sent: 2017, November 08 7:17 PM
To: O'Riley, Christopher; Savidant, Michael
Cc: Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject: Review

Chris and Mike:

Thanks for your voice mail Chris. I was in the legislature on more estimates debate on the rate freeze when you called. The questions you are getting from Foster are for the Fiscal Impacts section of our submission. We have a much broader outline for the submission that canvasses a full range of issues. We can share our latest version tomorrow.

I am planning to raise the computational errors with the BCUC tomorrow and give them an opportunity to make corrections. I heard today that BCH and BCUC staff might have been meeting on these matters and wanted to understand the nature of any interaction before contacting the BCUC. We are also interested in any further computational errors or assumptions that change the relative value of the alternative portfolio and Site C. Obviously the BCUC's move to increase termination costs (if they were included in the UECs) is an increased cost for the Alternative Portfolio relative to Site C. I would be interested if you had others.

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division

BC Ministry of Energy, Mines and Petroleum Resources

NOTE NEW OFFICE PHONE NUMBER: 778-698-7183

Cell: 250-889-3479

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From:	Magre, Leela
To:	Haslam, David GCPE:EX
Cc:	Pillon, Lawrence; Zadravec, Don GCPE:EX; Grewar, Colin GCPE:EX; Scott, Mora; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX; MacLaren, Les EMPR:EX
Subject:	RE: Site C / BCUC
Date:	Thursday, October 19, 2017 8:06:18 AM
Attachments:	2017_10_18_SiteC_BCH_ALT_PRTF.PDF

Good morning,

Here is the filing attached. There is a good summary from page 1 to the top of page 4. In short --

We identified a number of issues with the October 11th alternative portfolio sent around by the Commission for comment, which we discussed at a high level in our Saturday technical presentation. Altogether, these issues would increase the cost of the October 11th portfolio by approximately $4 billion. The main issues are as follows:

- The portfolio assumes BC Hydro is stopping DSM if we build Site C, which is not correct
- It assumes BC Hydro builds and finances all alternative resources, also not correct
- The battery costs in the portfolio incorrectly exclude capital costs other than balance of system, operating costs of approximately $10 million per year (for a 100MW installation) and operating energy losses of approx.7%, effectively understating the costs of batteries

I'm out of the office today, but you can reach me on my cell or email at any time if you have any questions.

Thanks,
Leela

Leela Magre | Manager, Policy & Research

BC Hydro
333 Dunsmuir St, 15th floor
Vancouver, BC V6B 5R3

P 604 623 4008
M 236 993 0338
E leela magre@bchydro.com

bchydro.com

Smart about power in all we do.

-----Original Message-----
From: Haslam, David GCPE:EX [mailto:David.Haslam@gov.bc.ca]
Sent: 2017, October 19 6:48 AM
To: Magre, Leela
Cc: Pillon, Lawrence; Zadravec, Don GCPE:EX; Grewar, Colin GCPE:EX; Scott, Mora; Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX; MacLaren, Les EMPR:EX
Subject: Re: Site C / BCUC

Thx. Including mo staff and Les.

Sent from my iPhone

> On Oct 18, 2017, at 9:10 PM, Magre, Leela <Leela.Magre@bchydro.com> wrote:

>
> Good evening,
>
> Attached is today's filing regarding the October 11th alternative portfolio. It will be posted by the BCUC sometime tomorrow.
>
> Thanks,
> Leela
>
> _____
>
> Leela Magre | Manager, Policy & Research
>
> BC Hydro
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
>
> P 604 623 4008
> M 236 993 0338
> E leela magre@bchydro.com<mailto:leela.magre@bchydro.com>
>
> bchydro.com<http://www.bchydro.com/>
> Smart about power in all we do.
>
> From: Magre, Leela
> Sent: 2017, October 18 10:32 AM
> To: Pillon, Lawrence; David Haslam (David.Haslam@gov.bc.ca); Zadravec,
> Don GCPE:EX (Don.Zadravec@gov.bc.ca); Grewar, Colin GCPE:EX
> (Colin.Grewar@gov.bc.ca)
> Cc: Scott, Mora
> Subject: RE: Site C / BCUC
>
> Good morning,
>
> As a follow-up to Lawrence's email, we are filing today our comments on the October 11th alternative portfolio that the Commission requested feedback on (you will recall we discussed this in our meeting on Friday). We already addressed this topic with the Commission in our presentation on Saturday, and are providing more detail in writing as requested by the Commission. They have requested feedback from other parties as well.
>
> We've identified a number of issues with the October 11th portfolio, which we highlighted in the Saturday presentation. The main ones are as follows. All would increase the cost of the October 11th portfolio:
>
> * The portfolio assumes BC Hydro is stopping DSM if we build Site C, which is not correct
>
> * It assumes BC Hydro builds and finances all alternative resources, also not correct
>
> * The battery costs in the portfolio incorrectly exclude capital costs of balancing the system, operating costs of approximately $10 million per year and operating energy losses of approx.7%, effectively understating the costs of batteries
>
> We will send along the full filing once it has been submitted to the Commission (likely after close of business today).
>
> Thank you and let me know if you have any questions.
>
> Best,
> Leela

>
> _____
>
> Leela Magre | Manager, Policy & Research
>
> BC Hydro
> 333 Dunsmuir St, 15th floor
> Vancouver, BC V6B 5R3
>
> P 604 623 4008
> M 236 993 0338
> E leela magre@bchydro.com<mailto:leela.magre@bchydro.com>
>
> bchydro.com<http://www.bchydro.com/>
>
> Smart about power in all we do.
>
> From: Pillon, Lawrence
> Sent: 2017, October 18 9:57 AM
> To: David Haslam
> (David.Haslam@gov.bc.ca<mailto:David.Haslam@gov.bc.ca>); Zadravec, Don
> GCPE:EX (Don.Zadravec@gov.bc.ca<mailto:Don.Zadravec@gov.bc.ca>);
> Grewar, Colin GCPE:EX
> (Colin.Grewar@gov.bc.ca<mailto:Colin.Grewar@gov.bc.ca>)
> Cc: Magre, Leela; Scott, Mora
> Subject: Site C / BCUC
>
> Hi
> Just a heads up that we will be filing another short submission to the
> BCUC later today, a follow-up from Saturday's proceedings. We were asked to provide comments on alternative scenarios. Leela will provide more.
>
> Lawrence
> _____
> This email and its attachments are intended solely for the personal use of the individual or entity named above. Any use of this communication by an unintended recipient is strictly prohibited. If you have received this email in error, any publication, use, reproduction, disclosure or dissemination of its contents is strictly prohibited. Please immediately delete this message and its attachments from your computer and servers. We would also appreciate if you would contact us by a collect call or return email to notify us of this error. Thank you for your cooperation.
> -BCHydroDisclaimerID5.2.8.1541
> <2017_10_18_SiteC_BCH_ALT_PRTF.PDF>

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

October 18, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1598922
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Alternative Portfolios

BC Hydro writes to provide its comments on, and analysis of the BCUC's Alternative Site C Portfolios as requested by the Commission Panel in its letter of October 11, 2017 (**A-22**).

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

fj/ma

Enclosure

Page 426 to/à Page 465

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From:	Oskar T. Sigvaldason
To:	OfficeofthePremier, Office PREM:EX
Cc:	Weaver.MLA, Andrew LASS:EX; "Justin Trudeau"; Minister, EMPR EMPR:EX; Minister, ENV ENV:EX; "James Carr"; "Catherine McKenna"; OfficeofthePremier, Office PREM:EX; Nikolejsin, Dave MNGD:EX; Plecas, Bobbi ENV:EX; Zacharias, Mark ENV:EX; "Christyne Tremblay"; "Stephen Lucas"; MacLaren, Les EMPR:EX; "Kenneth Peterson"; "James Burpee"; "Kenneth Ogilvie"; "Oskar Sigvaldason"
Subject:	Re; Site C Inquiry and Climate Change Commitments
Date:	Sunday, November 12, 2017 11:20:12 AM
Attachments:	Site C Inquiry - Letter of Concern to Premier John Horgan.pdf

Dear Honorable Premier Mr. John Horgan

Please find enclosed a letter, with supporting documentation, defining stated concerns about BCUC's Final Report, submitted on November1, 2017, on the Site C Inquiry. Our concerns are a direct consequence of the lack of consideration given for low carbon electrification for meeting ambitious and urgent greenhouse gas emissions reductions commitments made by Governments in Canada, including the Governments of British Columbia and Canada.

We have taken the liberty of forwarding copies of this communication to the Leader of the Green Party of British Columbia, to the Prime Minister of Canada, and to Ministers and Deputy Minsters, responsible for Energy and Environment/ Climate Change in your Government and in the Government of Canada. We have also copied the Assistant Deputy Minister responsible for electricity and alternative energy in your Government, and the Executive Chairman of the Board of BC Hydro and Power Authority.

I will be forwarding the "original" of this communication to you by regular mail.

Respectfully submitted by; Oskar Sigvaldason

On behalf of Oskar Sigvaldason, Jim Burpee and Ken Ogilvie

November 13, 2017

Honorable Mr. John Horgan
Premier; Government of British Columbia
P.O. Box 9041, Stn. Prov. Govt.
Victoria, BC; V8W 9E1

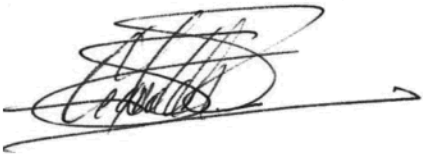
Dear Premier John Horgan

Re; Site C Inquiry and Climate Change Commitments

The undersigned are concerned that the Site C Inquiry by British Columbia Utilities Commission (BCUC) did not properly include global, national and provincial climate change commitments in its deliberations, as reported in their Final Report of November 1, 2017. This omission is at obvious variance with commitments made by Canada in the Paris Accord of December 12, 2015, First Ministers in their Vancouver Declaration of March 3, 2016, and federal and provincial governments, including British Columbia, in the Pan-Canadian Framework on Clean Growth and Climate Change of December 9, 2016.

Comprehensive studies on strategies for achieving major greenhouse gas (GHG) emissions reductions in Canada all show that fossil fuel consumption will have to decrease dramatically over the coming decades, with corresponding increases in the use of low-carbon electricity to meet the safe and reliable energy needs of a growing population and economy. The Site C Inquiry did not adequately consider low-carbon electrification as a critical element in B.C. and Canada for meeting climate change commitments.

Our conclusion is that the Site C Inquiry is flawed and its report does not provide a suitable basis for informing the important decisions that British Columbia and Canada need to make on climate change. A more detailed statement of our concerns with the Inquiry is attached to this letter.



Respectfully submitted by Oskar Sigvaldason
On behalf of Oskar Sigvaldason, Jim Burpee and Ken Ogilvie (summary bios enclosed)

Copies to:
Honorable Dr. Andrew Weaver; Leader, Green Party of British Columbia
Right Honorable Justin Trudeau; Prime Minister of Canada
Honorable Michelle Mungall; Minister, Energy, Mines and Petroleum Resources
Honorable George Heyman; Minister, Environment & Climate Change Strategy
Honorable James Carr; Minister, Natural Resources Canada
Honorable Catherine McKenna; Minister, Environment and Climate Change Canada
Dr. Don Wright; Deputy Minister to the Premier
Mr. Dave Nikolejsin; Deputy Minister; Ministry of Energy, Mines and Petroleum Resources
Ms. Bobbi Plecas; Deputy Minister, Climate Change, Ministry of Environment & Climate Change Strategy
Dr. Mark Zacharias, Deputy Minister, Environment, Ministry of Environment & Climate Change Strategy
Ms. Christyne Tremblay; Deputy Minister, Natural Resources Canada
Dr. Stephen Lucas; Deputy Minister, Environment & Climate Change Canada
Mr. Les MacLaren; Assistant Deputy Minister, Electricity and Alternative Energy Division, Ministry of Energy, Mines and Petroleum Resources
Mr. Ken Peterson; Executive Chairman of the Board, B.C. Hydro and Power Authority

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s.22

The following is a copy of the first of two submissions to the BCUC. It was posted on the BCUC web-site on September 27, as Submission F197-1. A second more comprehensive submission was posted on October 10, as Submission F197-2.

Climate Change Considerations with respect to Site C Hydro-electric Project

Submitted by Oskar Sigvaldason, Jim Burpee and Ken Ogilvie

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Page 470 to/à Page 472

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From:	Dunn, Jonathan FIN:EX
To:	MacLaren, Les EMPR:EX
Cc:	Foster, Doug FIN:EX; "Savidant, Michael"
Subject:	s.12,s.13
Date:	Wednesday, November 22, 2017 3:24:10 PM
Attachments:	s.12,s.13

Hi Les

Thx for the introduction. I spoke to Michael s.12,s.13

s.12,s.13

Kind regards

Jon

From: MacLaren, Les EMPR:EX
Sent: Wednesday, November 22, 2017 1:19 PM
To: 'Savidant, Michael'
Cc: Foster, Doug FIN:EX; Dunn, Jonathan FIN:EX
Subject: s.12,s.13

Hi Mike:

Doug's colleague over at Finance Johnathan Dunn s.12,s.13

s.12,s.13

Johnathan's e-mail is above, and office is 778-698-5894 and cell is 250-216-4437. Johnathan, Mike's coordinates are 604.623.3694 office, and mobile 604.250.9603.

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy, Mines and Petroleum Resources
NOTE NEW OFFICE PHONE NUMBER: 778-698-7183
Cell: 250-889-3479
Energizing BC—clean, sustainable and productive

Page 474

Withheld pursuant to/removed as

s.12;s.13

From:	Layton, Ryan
To:	MacLaren, Les EMPR:EX
Cc:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX; Yaremko, Cheryl
Subject:	RE: Site C rate info
Date:	Monday, October 30, 2017 1:55:31 PM
Attachments:	October 30 graph for Les.xlsx

Hi Les:

Please see attached for the file underlying the termination scenario, further to our discussion earlier today and your note below indicating the suspension scenario is not required.

We've included a new tab - Rate Impact Chart 2060 - which ends the chart at 2060 as you requested.

Lastly, we're looking into your question to me a little while ago about the 'spikes' in 2033/34 and 2040. It will likely be an assumption about new resources coming online - we're working with Randy and team to provide info on that.

Please let us know if you have any questions on the attached.

Thanks

Ryan

-----Original Message-----
From: MacLaren, Les EMPR:EX [mailto:Les.MacLaren@gov.bc.ca]
Sent: 2017, October 30 12:04 PM
To: Yaremko, Cheryl
Cc: Layton, Ryan; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX
Subject: RE: Site C rate info

We were just directed to remove references to the suspend scenario - just go or stop.

I think we have the incremental suspend rate impacts from Appendix R and we can take a crack at a chart as well.

Les

-----Original Message-----
From: MacLaren, Les EMPR:EX
Sent: Monday, October 30, 2017 7:51 AM
To: 'Yaremko, Cheryl'
Cc: Layton, Ryan; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Sopinka, Amy EMPR:EX
Subject: RE: Site C rate info

I will be in transit from the Minister's office. Can we do 10:15? Note my new office # is 778-698-7183.

Les

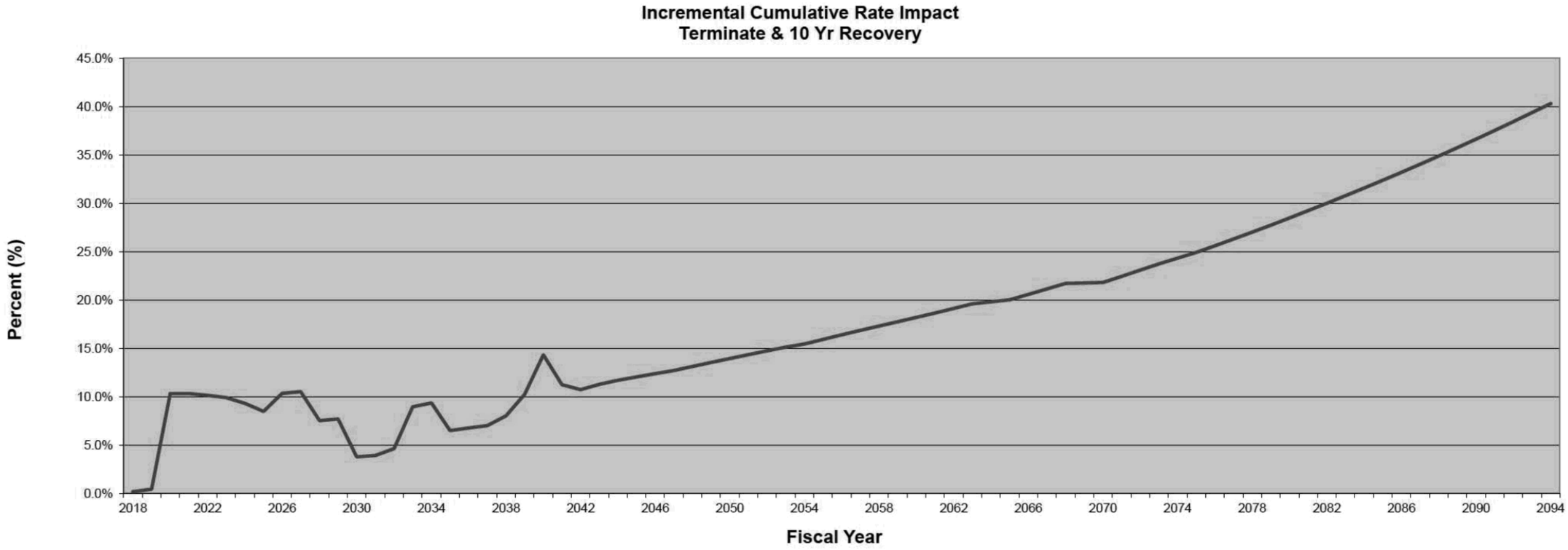
-----Original Message-----
From: Yaremko, Cheryl [mailto:Cheryl.Yaremko@bchydro.com]
Sent: Monday, October 30, 2017 7:29 AM
To: MacLaren, Les EMPR:EX
Cc: Layton, Ryan
Subject: Site C rate info

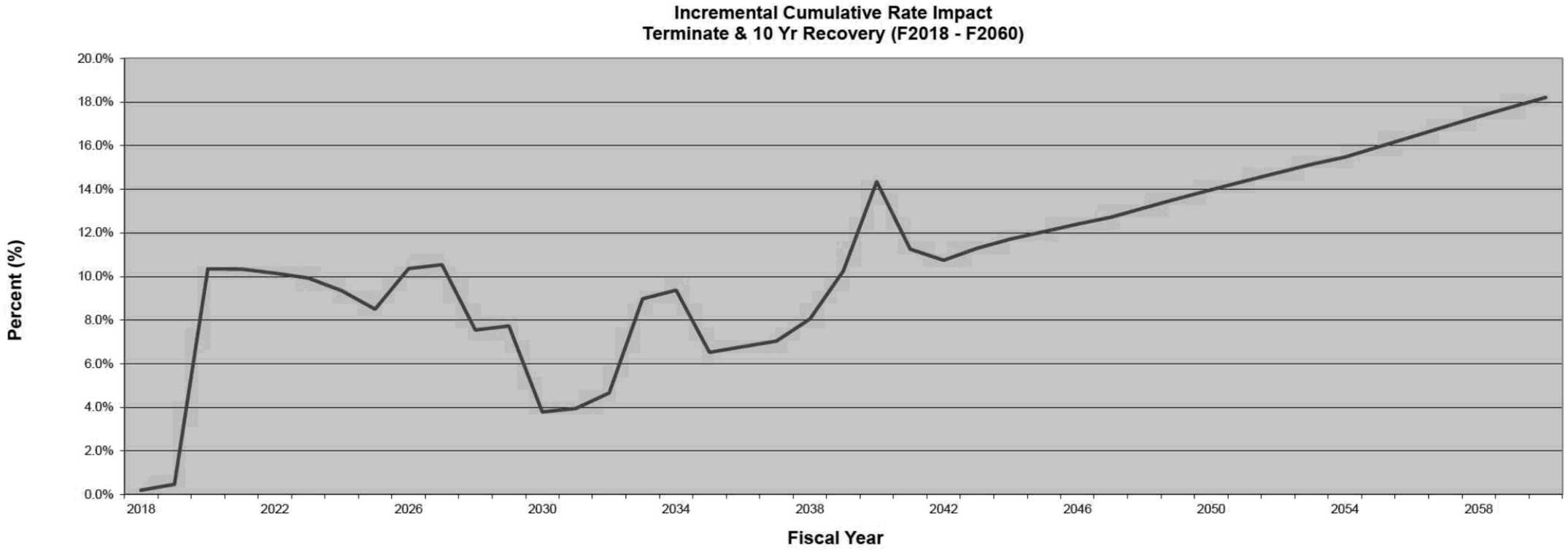
Hi Les,

I understand you were looking for a graph with rate impacts related to Site C scenarios over the weekend. Can Ryan and I call you at 10 to discuss? We do not have the analysis that we believe you requested, so we'd like to make sure we understand what you are looking for and then can let you know how long that will take and/or whether we can use something else.

Cheryl

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-BCHydroDisclaimerID5.2.8.1541


Incremental Cumulative Rate Impact
Terminate & 10 Yr Recovery
Percent (%)
45.0%
40.0%
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
2018
2022
2026
2030
2034
2038
2042
2046
2050
2054
2058
2062
2066
2070
2074
2078
2082
2086
2090
2094
Fiscal Year


Incremental Cumulative Rate Impact
Terminate & 10 Yr Recovery (F2018 - F2060)
Percent (%)
20.0%
18.0%
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2018
2022
2026
2030
2034
2038
2042
2046
2050
2054
2058
Fiscal Year

Revenue Requirement (Ratepayer Costs) Summary
($ millions)

| | | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 | 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 | 2066 | 2067 | 2068 | 2069 | 2070 | 2071 | 2072 | 2073 | 2074 | 2075 | 2076 | 2077 | 2078 | 2079 | 2080 | 2081 | 2082 | 2083 | 2084 | 2085 | 2086 | 2087 | 2088 | 2089 | 2090 | 2091 | 2092 | 2093 | 2094 |
|---|---|---

Finance Charges
($ mi llion)

| | | | 2018 | 2019 | 2030 | 2021 | 2022 | 2023 | 2034 | 2025 | 2036 | 2027 | 2038 | 2039 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 | 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 | 2066 | 2067 | 2068 | 2069 | 2070 | 2071 | 2072 | 2073 | 2074 | 2075 | 2076 | 2077 | 2078 | 2079 | 2080 | 2081 | 2082 | 2083 | 2084 | 2085 | 2086 | 2087 | 2088 | 2089 | 2090 | 2091 | 2092 | 2093 | 2094 |
|---|---|---

Energy Sales and Revenues

| | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 | 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 | 2066 | 2067 | 2068 | 2069 | 2070 | 2071 | 2072 | 2073 | 2074 | 2075 | 2076 | 2077 | 2078 | 2079 | 2080 | 2081 | 2082 | 2083 | 2084 | 2085 | 2086 | 2087 | 2088 | 2089 | 2090 | 2091 | 2092 | 2093 | 2094 |
|---|---|---

nput Data
($ million)

| | | | | | otal | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 | 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 | 2066 | 2067 | 2068 | 2069 | 2070 | 2071 | 2072 | 2073 | 2074 | 2075 | 2076 | 2077 | 2078 | 2079 | 2080 | 2081 | 2082 | 2083 | 2084 | 2085 | 2086 | 2087 | 2088 | 2089 | 2090 | 2091 | 2092 | 2093 | 2094 |
|---|---|---

From:	MacLaren, Les EMPR:EX
To:	Foster, Doug FIN:EX
Subject:	RE: Site C related documents.
Date:	Friday, November 17, 2017 6:54:00 AM

s.12,s.13

Les

From: Foster, Doug FIN:EX
Sent: Thursday, November 16, 2017 3:08 PM
To: MacLaren, Les EMPR:EX
Subject: FW: Site C related documents.

s.12,s.13

d.

From: Dunn, Jonathan FIN:EX
Sent: Thursday, November 16, 2017 12:08 PM
To: Foster, Doug FIN:EX
Subject: FW: Site C related documents.

Hi Doug

s.12,s.13

Thx

Jon

From:	Wright, Don J. PREM:EX
To:	Nikolejsin, Dave MNGD:EX
Cc:	MacLaren, Les EMPR:EX; Foster, Doug FIN:EX; Lloyd, Evan GCPE:EX; Zadravec, Don GCPE:EX; Haslam, David GCPE:EX; Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	Re: Site C Update
Date:	Thursday, November 9, 2017 8:19:09 AM

Yep

Sent from my iPhone

On Nov 9, 2017, at 8:16 AM, Nikolejsin, Dave MNGD:EX <Dave.Nikolejsin@gov.bc.ca> wrote:

> agreed
>
> **From:** MacLaren, Les EMPR:EX
> **Sent:** November 9, 2017 8:07 AM
> **To:** Nikolejsin, Dave MNGD:EX <Dave.Nikolejsin@gov.bc.ca>; Wright, Don J. PREM:EX <Don.J.Wright@gov.bc.ca>; Foster, Doug FIN:EX <Doug.Foster@gov.bc.ca>
> **Cc:** Lloyd, Evan GCPE:EX <Evan.Lloyd@gov.bc.ca>; Zadravec, Don GCPE:EX <Don.Zadravec@gov.bc.ca>; Haslam, David GCPE:EX <David.Haslam@gov.bc.ca>; Wieringa, Paul EMPR:EX <Paul.Wieringa@gov.bc.ca>; Rowe, Katherine EMPR:EX <Katherine.Rowe@gov.bc.ca>
> **Subject:** Site C Update
> Further to our discussion yesterday afternoon, I spoke with BC Hydro last evening and the BCUC Chair this morning.
> On Tuesday BC Hydro staff called BCUC staff to flag the computational errors they had identified related to discount rates and transmission losses (Items 1A, B, C and 2C from the BC Hydro Overview of Initial Findings) plus a typo in table 43. Commission staff asked for further details to be e-mailed, which has not yet occurred.
> The Chair says that the BCUC will issue a public amendment with respect to any errors. His initial thoughts, pending review of the detailed material from BC Hydro, is that changes in the single digits hundreds of millions are unlikely to change the Commission's conclusions, given the ranges in costs associated with some of the assumptions (he cited termination costs which range from $700M to over $2B).
> I noted we were preparing a letter pulling together comments from EMPR, Finance and BCH seeking clarification on a number of the Commission's assumptions. The Commission would make that letter public along with their response.
> Given the above, I recommend that we give BC Hydro the go-ahead to send their detailed information on the modelling errors, and that our letter just focus on the assumption issues. I can work with David to get the next draft circulated later today.
>
> **Les MacLaren**
> Assistant Deputy Minister
> Electricity and Alternative Energy Division
> BC Ministry of Energy, Mines and Petroleum Resources
> **NOTE NEW OFFICE PHONE NUMBER: 778-698-7183**
> Cell: 250-889-3479

From:	Savidant, Michael
To:	Foster, Doug FIN:EX
Cc:	MacLaren, Les EMPR:EX; O"Riley, Christopher; Reimann, Randy; Rich, John; Layton, Ryan
Subject:	Response regarding inputs to low and high load forecast
Date:	Thursday, November 23, 2017 8:45:49 AM
Attachments:	51 Site C Review - Deloitte Questions - August 2017.pdf Load forecast assumptions_20171122_draft .docx

Doug,

We provide here the following:

- Our response to Deloitte during the Inquiry regarding our Monte Carlo inputs that create the low and high load forecast.
- A note describing how these inputs are used to develop the low or high load forecast. The key point here is that the low load forecast is not merely a trace using all the "low" inputs, but rather a probabilistic assessment.

As a result of the use of a Monte Carlo model for the low and high scenarios, there is no single set of assumptions that result in the Low Load Forecast. However, to illustrate a potential scenario that could lead to the Low Load Forecast BC Hydro has prepared a table showing potential changes to load drivers that could result in the required change in load relative to the current mid load forecast.

Driver	**GWH Change**
No load from LNG beyond Woodfibre LNG and Fortis Tilbury phase 1&2	(3,000)
No upstream natural gas load associated with LNG development	(1,000)
Higher conservation and/or industrial load decreases due to price elasticity response	(1,400)
Lower GDP and disposable income than forecast	(275)
Higher industrial load (primarily oil and gas) due to actual project developments that have occurred relative to the current (May 2016) mid Load Forecast).	965
A combination of some of the following: - Lower than expected mining growth - Higher than expected forestry mill closures - Higher than mid (expected) DSM uptake - Large expansion of distributed generation (e.g. rooftop solar)	(3,000)

Please let us know if you have any questions.

-M

_____

Michael Savidant
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Site C Review - Responses to questions raised by Deloitte

August 15th, 2017

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No.	
51	**Date/Source of Question: Request from Mike Savidant on August 15, 2017 at 4:10pm**
	Response provided by: John Rich
	Functional Approver: Randy Reimann
	Question: Commodity price and forecast assumptions by large industrial sector for mid, low and high forecasts.
	Response: **The response below includes:** **Part 1: The mid, low and high commodity prices and explanation of how the prices were developed** **Note: High and low commodity price Information with respect to the Forestry, Oil and Gas and LNG sectors will be provided as soon as possible.** **Part 2: Large industrial Sales mid, low and high forecast inputs and assumptions.** **The high and low large industrial load forecasts are an input into the Monte Carlo simulation as explained in the December 2012 Load Forecast document, Appendix 2, page 80.**

Part 1

1.1 The Mid, Low and High Commodity Prices as PROVIDED IN CONFIDENCE TO THE BCUC IN THE RESPONSE TO AMPC IR 1.19.1. EXHIBIT B-10.

9.0 E. LARGE INDUSTRIAL SECTOR FORECAST

Reference: Exhibit B-1-1, Application, p. 3-9 to p. 3-11.

BC Hydro states:

"BC Hydro prepares the electricity sales forecast for the large industrial sector on an account-by-account basis. The forecast drivers include production forecasts, electric intensity (i.e., kWh/unit of production), and probability weightings. The probability weightings represent the risk assessment of future expansion or contraction or the likelihood of previous trends in sales continuing. Given the uncertain and binary nature of large industrial loads, a range of forecasts were developed for each industrial sub-sector considering:

- An assessment of current state of the global economy;
- A range of projected outcomes for BC's major global trading partners who purchase BC's exports; and
- Supply and demand balance outlooks of major commodities for each sub-sector, including a projected range of future commodity prices.

A mid projection of commodity prices, which is assessed to be the most likely, informs the mid forecast and its probability weightings. These probability weightings also consider factors that pertain to the individual circumstances of customers. For example, a customer's project that does not have environmental approval and is in initial discussions with BC Hydro would have a different probability than a customer's project that is in the final stages of taking electrical service.

BC Hydro's high and low band and mid-level large industrial forecast is also informed by industrial consultants' reports to BC Hydro, various government reports and publications from various sources such as the B.C. Oil and Gas Commission, information on websites for various companies and information on customer operations obtained from BC Hydro key account managers."

AMPC seeks to better understand BC Hydro's forecasting generally, as well as understand the potential effect of recent developments on BC Hydro's forecast.

1.9.1 Please provide the high, base and low commodity price forecasts used in the Large Industrial sector load forecasts, including but not limited to natural gas, gold, copper, molybdenum and crude oil. Please provide references to the sources of these forecasts.

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RESPONSE:

Provided below are tables for the mid, high and low ranges of commodity price forecasts used in the industrial sector load forecast. BC Hydro is filing components of these tables in confidence with the British Columbia Utilities Commission, as BC Hydro has requested but not yet received consent from the vendors to disclose the information. The public version of the response to this information request has been redacted to maintain in confidence commercially sensitive and contractor specific information.

Molybdenum ($US/lb)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	5.0	5.0	5.0	6.6	7.0	7.0	7.0	7.0	7.0	7.0
Mid - Consensus [1]	6.1	6.6	7.2	8.2	9.0	9.5	11.0	11.5	12.0	12.0
High [2]	8.0	10.0	12.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Copper ($US/lb)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	1.8	1.8	1.8	2.0	2.1	2.2	2.3	2.4	2.5	2.5
Mid - Consensus [1]	2.3	2.5	2.6	2.8	3.0	3.0	3.0	3.0	3.0	3.0
High [2]	2.8	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Coal ($US/tonne)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	70	80	80	80	90	100	100	100	100	100

Mid - Consensus [1]	84	91	98	106	120	125	130	130	130	130
High [2]	100	115	125	140	160	160	160	160	160	160
Gold ($US/oz)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	800	800	800	800	900	900	900	900	900	900
Mid - Consensus [1]	1,185	1,221	1,240	1,245	1,250	1,250	1,250	1,250	1,250	1,250
High [2]	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500

Notes:

1. Mid projection from Consensus Economics forecast dated March 2016 up to 2020. From 2021 on, the mid projection is developed by BC Hydro.
2. High and Low are developed by BC Hydro.

Oil and Gas Prices – in real 2015 dollars

Natural Gas - Henry Hub ($US/MMBTU)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2036
Low [2]	1.72	1.80	1.94	2.10	2.30	2.50	2.67	2.77	2.87	3.06
Mid [2]	2.27	2.69	2.88	3.06	3.27	3.34	3.42	3.58	3.73	4.39
High [2]	2.77	3.19	3.47	3.73	4.03	4.14	4.30	4.53	4.73	5.89
Natural Gas - AECO($US/MMBTU)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2036
Low [2]	1.32	1.40	1.54	1.70	1.90	2.10	2.27	2.37	2.47	2.66
Mid [2]	1.62	2.04	2.23	2.41	2.62	2.69	2.77	2.93	3.08	3.74
High [2]	1.92	2.34	2.62	2.88	3.18	3.29	3.45	3.68	3.88	5.04
Crude - WTI ($US/Barrel)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2036
Low [1]	s.17,s.21									
Mid [1]										
High [1]										
Condensate ($US/Barrel)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	44	46	46	46	46	46	46	46	46	46
Mid [1]	s.17,s.21									
High [2]	81	91	98	100	102	104	106	108	109	109
LNG ($US/MMBTU)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2036
Low [1]	s.17,s.21									
Mid [1]										
High [1]										

Notes:

1. Projection from Oil and Gas Subscription Services. The "Long term" is projected by BC Hydro.
2. High and Low are developed by BC Hydro.

Forestry Prices – in nominal dollars

Kraft Pulp ($US/tonne)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term

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Kraft Pulp ($US/tonne)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	544	506	518	525	531	538	544	550	557	557
Mid [1]	600	540	580	650	720	780	835	900	925	925
High [2]	678	704	710	749	813	864	915	966	1,018	1,018
BCTMP ($US/tonne)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	373	342	347	369	391	413	435	457	479	479
Mid [1]	446	368	420	503	570	623	660	670	680	680
High [2]	474	505	518	575	641	694	707	720	720	720
Newsprint ($US/tonne)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	480	485	490	491	491	492	492	493	493	493
Mid [1]	500	515	523	540	528	542	530	535	537	537
High [2]	562	578	593	594	594	595	595	596	596	596
Lumber ($US/Mbfm)	2017	2018	2019	2020	2021	2022	2023	2024	2025	Long term
Low [2]	266	260	256	259	261	264	267	270	273	273
Mid [1]	312	315	318	324	330	336	342	348	354	354
High [2]	366	374	377	384	392	396	404	412	419	419

Notes:

1. Projection from forestry consultants. The "Long term" is projected by BC Hydro.
2. High and Low are developed by BC Hydro.

1.2 Explanation on price forecast following IR response

Mining Sector Commodity Price Assumptions

Copper

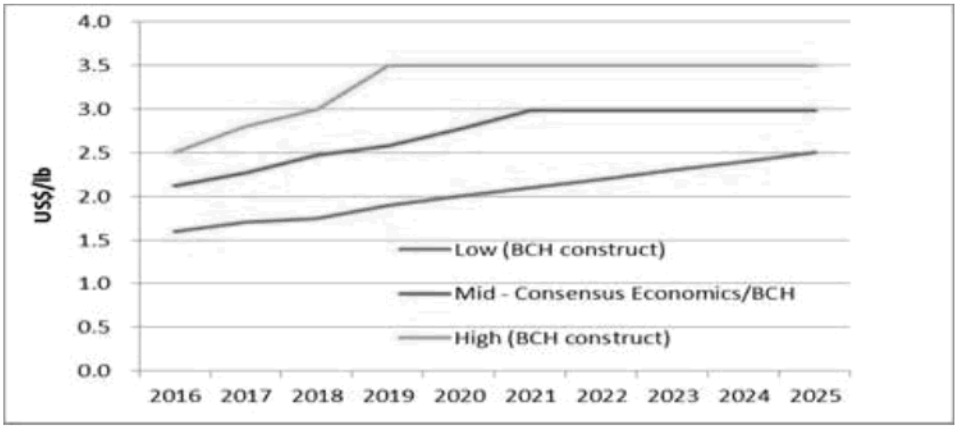
- **Mid Price Forecast: Uses Consensus Economics mean forecast (March 2016) for the first 5 years. The trend and direction can be summarized as:**
  - **As both supply and demand adjust to the new level of growth, current surplus is gradually eroding and prices increase to the marginal total cost (~$2.7/lb).**
  - **Market returns to a balanced position by 2020. Long-term average cost of new supply ($3/lb) dictates the price. This value is relatively close to the March 2016 Consensus Economics assumption of long-term (2021-2025) copper prices at $2.8/lb in real terms.**

- **Low Price Forecast was constructed internally by BCH under the following assumptions**
  - **Current surplus position continues for a longer period of time due to further slowdown in the world economy:**
  - **Weak construction activity in China and the rest of the world, delay of large infrastructure projects, no pick up in India's economy in the next decade.**
  - **The announced copper mines under construction enter the market on schedule offsetting supply curtailments in short term.**
  - **The world economy slows down below the anticipated 3% average level**

s.17,s.21

- As mines don't recoup total costs (including cost for sustaining production), higher cost supply exit the market and we reach a balanced position around $2.5/lb by end of the next decade.

- **High Price Forecast was constructed internally by BCH under the following assumptions**
  - **Markets reach a deficit position by 2018, due to higher than anticipated growth in the world economy.**
  - **Construction activity rebounds and grows strongly led by growth in China, India and the rest of the world.**
  - **Demand for electronics and electrical products increases**
  - **Industrial development increases demand for machinery and equipment. The expansion of the power sector in China and India increases demand for wires and cables.**
  - **World economy grows at a higher pace than the anticipated 3%/year.**
  - **As demand continues to grow at high pace, higher cost supply is brought into production, increasing the long-term marginal cost to $3.5/lb.**



Molybdenum

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Low (BCH construct)	4.8	5.0	5.0	5.0	6.6	7.0	7.0	7.0	7.0	7.0
Mid - Consensus Economics/BCH	**5.5**	**6.1**	**6.6**	**7.2**	**8.2**	**9.0**	**9.5**	**11.0**	**11.5**	**12.0**
High (BCH construct)	6.2	8.0	10.0	12.0	15.0	15.0	15.0	15.0	15.0	15.0

s.17,s.21

- **General expectations are the molybdenum prices have reached the bottom but will stay depressed in short term due to low demand conditions and copper mine supply pressures.**

- **Mid Price Forecast was constructed internally by BC Hydro using the March 2016 Consensus Economics forecast (2016-2020) followed by a gradual increase to $12/lb by 2024. The long-term increase is driven by moderate growth in construction sectors in China, oil and gas industry and automotive industry.**

- **Low Price Forecast case was constructed internally by BC Hydro assuming steady growth in moly by product production from copper mining as well as tepid demand growth. This would keep short and long-term prices below $8/lb range,** s.17,s.21

- **High Price Forecast was constructed internally by BC Hydro reflecting some of Roskill optimistic expectation of high growth in the oil and gas industry driving up the demand for molybdenum. Coupled with supply curtailments from copper producers, the price of molybdenum will recover to $12-14 in the next 4-5 years.**

Metallurgical Coal

$/tonne	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Low (BCH construct)	70	70	80	80	80	90	100	100	100	100
Mid - Consensus Economics/BCH	**82**	**84**	**91**	**98**	**106**	**120**	**125**	**130**	**130**	**130**
High (BCH construct)	90	100	115	125	140	160	160	160	160	160

- **Mid Price Forecast. Uses Consensus Economics mean forecast (March 2016) for the first 5 years. BC Hydro's assumption of long-term marginal price for coal ($130/t) from 2021 on.**

- **Low Price Forecast was developed to a level ($100/t) below the estimated long term operating cost of 75% of the seaborne metallurgical coal production, indicated an outlook of shrinking demand conditions for seaborne metallurgical coal. Seaborne metallurgical coal is comprised of overseas shipments of coal to Asia (mainly China) used in steelmaking process. Over 90 percent of the total seaborne trade of metallurgical coal are accounted for by shipments from Australia, Canada, and the US.**

- **High Price Forecast was set to a long-term level ($160/t) that would be conducive of new supply additions, including potential mine restarts in north east BC.**

Gold

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Low (BCH construct)	900	800	800	800	800	900	900	900	900	900
Mid - Consensus Economics	**1,154**	**1,185**	**1,221**	**1,240**	**1,245**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**
High (BCH construct)	1,300	1,400	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500

- **Gold is a special commodity/investment vehicle, in the sense that demand and price are driven by various factors such as demand for jewelry, investment trends or US interest rates. Global economic and political risk play an important role in the price/demand for gold in short and medium term.**
- **Surplus/deficits for gold is less relevant due to available level of above the ground gold stocks.**
- **Mid Price Forecast. Uses Consensus Economics mean forecast (March 2016) for the first 5 years, flat lined after 2020.**
- **The low and the high price forecasts were constructed at levels below or above the highest and lowest individual gold price forecast captured in the Consensus Economics Mid-price mean forecast.**

<u>Forestry Sector Commodity Price Assumptions</u>

Northern Bleached Softwood Kraft (NBSK)
With roughly 70 percent of BC Kraft exported to China, prices are for delivery to China.

- **Mid Price Forecast was projected by Brian McClay and Associates. The price forecast can be summarized as a downward trend in the short term with a progressive rise thereafter. The assumptions behind the forecast:**
  - **Excess supply, due to global Kraft capacity expanding at a rate far exceeding demand; this will take a couple of years for the markets to clear.**
  - **Substitution effect from NBSK to Bleached Eucalyptus Kraft (BEK) arising from BEK's low price and massive capacity (from Brazilian producers).**
  - **Weakening demand arising from progressively declining GDP expectations for China, the world, USA and Europe.**

- **Low Price Forecast was projected by BC Hydro using professional judgement. The forecast can be summarized as following a pattern like the Mid Price, but much lower. The degree of the spread was projected to capture a P10 scenario and following along a downward trend in Kraft prices. The assumptions behind the forecast arise from greater competition amongst NBSK suppliers due to the following conditions:**
  - **Global Kraft suppliers bring planned new production despite oversupply in the market.**
  - **The market more aggressively substitutes BEK for NBSK in their production lines.**
  - **The global GDP slows to a lower rate than projected in the Mid case.**

- **High Price Forecast was projected BC Hydro using professional judgement. The forecast can be summarized as following a pattern like the Mid Price, but, higher. The degree of the spread was projected to capture a P90 scenario. The assumptions behind the forecast are markets more receptive to price increases due to one or more of the following conditions:**
  - **Global Kraft suppliers curtail production plans, underestimate demand and undersupply the market.**
  - **Product substitution from NBSK to BEK withers as market demand favours NBSK's unique qualities.**
  - **Global GDP growth exceeds the Mid case, with Chinese GDP remaining in the 6 to 7 percent range.**

BCTMP

- **Mid Price Forecast was projected by Brian McClay and Associates. The forecast can be summarized as immediate rise and subsequent decline in the short term followed by a progressive rise thereafter. BC's BCTMP is primarily sold in the Chinese market where it is mainly used in the production of folding boxes. The assumptions behind the forecast:**
  - **Excess supply, due to two new plant start-ups around 2015 caused prices to rapidly decline to Q1 2016; however, with no new BCTMP plants planed over the next few years, the oversupply will clear and prices will recover. However, in the short to medium term, planned new BEK and NBSK plant line start-ups will cause prices to decline, but shortly thereafter, markets will clear and prices recover.**
  - **Substitution effect to BEK arising from its low price and massive supply (from Brazilian producers).**
  - **Weakening demand arising from progressively declining GDP expectations in China.**

- **Low (High) Price Forecasts were projected by BC Hydro using professional judgement. The forecasts can be summarized as following a pattern like the Mid Price, but lower (higher). The degree of the spread was projected to capture a P10 (and P90) scenario. The assumptions behind the forecast arise from more (less) price competition amongst BCTMP suppliers due to one or more of the following conditions:**
  - **Global BCTMP suppliers run (curtail) in the market; planned new BEK and NBSK lines start (are shelved) and markets become oversupplied (undersupplied).**
  - **The market more (less) aggressively substitutes BEK for BCTMP in their production lines.**
  - **The global GDP slows to a lower (higher) rate than projected in the Mid case.**

Newsprint

- **Mid Price Forecast was projected by Brian McClay and Associates. The forecast can be summarized as a modest rise over the forecast period. BC's newsprint is primarily sold in the U.S. market where demand is driven by advertising demand. The assumptions behind the forecast:**
  - **Substitution effect from print to electronic has been and will continue to erode newsprint demand as readers and advertisers decrease their preference for newsprint.**
  - **Supply curtailments of North America producers will continue. Closure of unprofitable mills will gradually occur and serve to lift prices.**

- **Low (High) Price Forecasts were projected by BC Hydro using professional judgement. The forecasts can be summarized as following a pattern like the Mid Price, but flattens (gradually rises). The degree of the spread was projected to capture a P10 (and P90) scenario. The assumptions behind the forecast arise from more (less) price competition amongst newsprint suppliers due to one or more of the following conditions:**
  - **Substitution effect from print to electronic mediums continues (abates); market demand declines (increases).**
  - **Supply curtailments are resisted (undertaken) by producers; market excess (under) supply occurs.**

Lumber – Spruce Pine Fir (SPF)

- **Mid Price Forecast was projected by International Forest Services (IFS). The forecast can be summarized as gradually rising over the forecast period. BC's lumber is primarily sold in the U.S. market with a small share sold to China. The assumptions behind the forecast:**
  - **U.S. housing starts – continue to gradually rise.**
  - **U.S. foreign exchange rate – slight decline then flattens out.**
  - **U.S. supply – moderate level of competitiveness from U.S. producers of SPF.**
  - **U.S. substitution – moderate substitution effect from Southern Yellow Pine.**

  - Softwood Lumber Agreement – 20 to 30 percent countervailing and anti-dumping duties applied or a quota system having a similar impact and
  - Imports outside of Canada – moderate level of imports into the U.S. from Europe, Russia and New Zealand.

- Low (High) Price Forecasts were projected by BC Hydro using professional judgement. The forecasts can be summarized as following a pattern like the Mid Price, but lower (higher). The degree of the spread was projected to capture a P10 (and P90) scenario. The assumptions behind the forecast arise from more (less) price competition amongst lumber suppliers in the U.S. due to one or more of the following conditions:
  - U.S. housing starts – slower (rapid) rise relative to the mid case.
  - U.S. foreign exchange rate – greater appreciation (depreciation) of the U.S. dollar relative to the mid case.
  - U.S. supply – higher (lower) level of competitiveness from U.S. producers of SPF.
  - U.S. substitution – greater (lower) substitution effect from Southern Yellow Pine.
  - Softwood Lumber Agreement – 30 to 40 (10 to 20) percent countervailing and anti-dumping duties applied or a quota system having a similar impact and
  - Imports outside of Canada – greater (lower) level of imports into the U.S. from Europe, Russia and New Zealand.

<u>Oil and Gas Sector Commodity Price Assumptions</u>

Natural Gas – Henry Hub
- Mid Price Forecast was projected by using a combination of Henry Hub forecasts from our paid for subscription services and BC Hydro professional judgement.
- Low (High) Price Forecasts were projected by BC Hydro using professional judgement in combination with low (high) forecasts from Ventyx.

Natural Gas – AECO
- Mid Price Forecast was projected by using a combination of Henry Hub forecasts from our paid for subscription services and BC Hydro professional judgement.
- Low (High) Price Forecasts were projected by BC Hydro using professional judgement in combination with low (high) forecasts from our paid for subscription services.

Crude – WTI
- Mid Price Forecast was projected by using IHS.
  - Short term – Very modest slowdown in production combined with inventory of drilled and completed wells.
  - Longer term – Markets expected to rebalance above breakeven tight oil cost of $80/bbl.
- Low and High Price Forecasts were projected using a combination of IHS and Wood Mackenzie subscription services.

Condensate
- Mid Price Forecast was projected by Sproule.
- Low and High Price Forecasts were projected by BC Hydro using professional judgement.

LNG

- **Mid Price Forecast was projected by using LNG contract prices from Wood Mackenzie. The 50th percentile was selected as the forecast.**
- **Low (High) Price Forecasts were projected by using by using LNG contract prices from Wood Mackenzie. The 10th (90th)) percentile was selected as the forecast.**

Part 2:
Large industrial Sales mid, low and high forecast inputs and assumptions (before DSM and rate impacts)

Mining Sector

	Lower Threshold Mining	Base Mining	Upper Threshold Mining
F2017	3,050	3,817	3,882
F2018	2,357	3,743	3,993
F2019	2,251	3,852	4,060
F2020	2,414	3,886	4,227
F2021	2,545	3,941	4,331
F2022	2,606	4,077	4,464
F2023	2,888	4,097	4,716
F2024	2,884	4,013	4,895
F2025	2,884	4,178	5,048
F2026	2,727	4,196	5,159
F2027	2,586	4,088	5,264
F2028	2,581	4,001	5,523
F2029	2,575	4,019	5,544
F2030	2,567	4,037	5,616
F2031	2,558	4,045	5,620
F2032	2,545	4,072	5,633
F2033	2,532	4,081	5,653
F2034	2,519	4,099	5,656
F2035	2,506	4,117	5,666
F2036	2,493	4,125	5,687

- The low and high mining forecasts assume the price and general market conditions described earlier in the price section. The result of these conditions are:
    - For the Low Case:
        - no new mining projects enter the forecast with the exception of a discounted new project under construction at the time of May 2016 Forecast (Brucejack mine),
        - existing shutdowns extend indefinitely,
        - further shutdown may occur at existing customer resulting in a loss of load compared to the mid case.

- Note that most of the load loss occurs in the first years as prices are expected to slowly increase over time even in the low scenario.

- For the High Case:
  - probability of new projects increase, as well some additional new projects (in comparison to the mid case) may join the forecast in the later years,
  - Higher probability of restart for currently idled projects.

Forestry Sector

	Lower Thresho	Base	Upper Threshold
	Forestry	Forestry	Forestry
F2017	6,975	7,072	7,150
F2018	6,548	6,829	7,152
F2019	6,092	6,624	7,466
F2020	5,614	6,409	7,396
F2021	5,193	6,264	7,266
F2022	4,833	6,171	7,132
F2023	4,773	6,118	7,077
F2024	4,721	6,014	6,929
F2025	4,642	5,927	6,846
F2026	4,641	5,929	6,848
F2027	4,640	5,928	6,850
F2028	4,595	5,856	6,801
F2029	4,530	5,791	6,798
F2030	4,532	5,760	6,799
F2031	4,534	5,763	6,804
F2032	4,536	5,766	6,809
F2033	4,539	5,768	6,814
F2034	4,541	5,771	6,818
F2035	4,543	5,773	6,823
F2036	4,546	5,775	6,827

The Forestry Sector consists of Pulp and Paper, Wood Products and Chemical subsectors.

For the Lower Threshold, the supply, demand and price expectations described in the Forestry Sector Commodity Price Assumptions decrease load by roughly 1,000 GWh by impacting the subsectors as follows:

Pulp and Paper Subsector

- **Lower mill operating rates occur across the subsector.**
- **Two publication paper mill closures occur.**
- **Two Kraft mill closures occur.**
- **A BCTMP mill closes and closure probabilities increase for the others.**

Wood Products Subsector

- **Mill closures and lower operating rates occur as the Mountain Pine Beetle impact, the Softwood Lumber Dispute and U.S. housing starts prove worse than assumed in the Mid Case.**

Chemical Sector

- **A plant closures occurs and significant closure risk rises at another plant due to closures at the pulp and paper mills they supply.**

For the Upper Threshold, the supply, demand and price expectations described in the Forestry Sector Commodity Price Assumptions increase load by roughly 1,000 GWh by impacting the subsectors as follows:

Pulp and Paper Subsector

- **Higher mill operating rates occur across the subsector.**
- **The publication paper mill closure risk is reduced.**
- **Kraft mill closure risk is eliminated.**
- **BCTMP mill closure probabilities are significantly reduced.**

Wood Products Subsector

- **Mill closures are averted and higher operating rates occur as the Mountain Pine Beetle impact, the Softwood Lumber Dispute and U.S. housing starts prove more favourable than assumed in the Mid Case.**

Chemical Sector

- **Plant closures not only do not occur but production levels increase as the pulp and paper mills they supply expand operations.**

Oil and Gas Sector

For the Oil and Gas sector, the upper threshold is proportionally larger than the lower threshold.

	Lower Threshold	Base	Upper Threshold
		O&G	O&G
F2017	1,591	1,645	1,754
F2018	1,806	2,001	2,300
F2019	2,202	2,665	3,458
F2020	2,315	2,925	4,288
F2021	2,315	3,075	5,080
F2022	2,315	3,241	5,859
F2023	2,315	3,368	6,937
F2024	2,315	3,503	7,166
F2025	2,315	3,614	7,228
F2026	2,330	3,756	7,253
F2027	2,387	3,851	7,255
F2028	2,462	3,928	7,334
F2029	2,496	3,970	7,428
F2030	2,524	4,007	7,513
F2031	2,545	4,036	7,606
F2032	2,546	4,068	7,613
F2033	2,546	4,097	7,613
F2034	2,546	4,128	7,614
F2035	2,546	4,130	7,614
F2036	2,541	4,126	7,609

Economically, the reason for this asymmetric spread is due primarily to the shale gas development and electrification potential. This potential is reflected in the forecast assumptions in which the oil and gas sector is categorized below.

The oil and gas sector can be categorized as:

- Shale gas (roughly 60% of total oil and gas load) and
- Pipelines and Other (roughly 40% or total oil and gas load)

Shale Gas Sub-sector

The mid forecast is based entirely on load requests by shale gas producers. Customers can be categorized as LNG Dependent or Non-LNG Dependent. The LNG Dependent forecast is of producers targeting the BC LNG market. The Non-LNG Dependent forecast is of producers targeting the North American market.

- **The table below summarizes the key assumptions for LNG Dependent producers:**

Probabalistic Forecast - Upstream gas

	LNG Dependent							
	Upstream Gas Prod'n Assumptions	Plant Start Date	Plant Load	Probability x	Startup	x	Electrification	Load = Forecast
Base Case	s.17,s.21							= LF

  - **The key assumptions:**
    - **Upstream gas production: 2 major BC LNG terminals. Each needing 1.6 Bcf/day by F2026**
      - **Upstream gas producers** s.17,s.21
      - **Upstream gas producer** s.17,s.21
    - **Plant start date: As requested by the customer**
    - **Plant Load: is phased in by applying a multi-year startup probability.**
    - **Startup: Multi-year probability. This addresses start date uncertainty by phasing in the load over a period of time. For instance, start-up probabilities for** s.17,s.21 **were phased-in over 10 years; for** s.17,s.21 **over 7 years. The probabilities are assigned to produce a load forecast that effectively yields sufficient gas production to meet LNG terminal requirements. These LNG terminal gas requirements and requirement start dates are aligned to expert LNG terminal projections. As a result, BC Hydro's upstream gas forecast for the LNG dependent sites** s.17,s.21 **, are aligned with expert, third party LNG terminal start date and volume projections for BC** s.17,s.21

- **The table below summarizes the key assumptions for Non-LNG Dependent producers:**

Probabalistic Forecast - Upstream gas

	Non-LNG Dependent							
	Upstream Gas Prod'n Assumptions	Plant Start Date	Plant Load	Probability x	Startup	x	Electrification	Load = Forecast
Base Case	s.17,s.21							= LF

- **The key assumptions:**
    - **Upstream gas production assumptions: Gas production forecasts are categorized into two area: Dawson-Groundbirch and GMS; production by fiscal 2026 is 1.9 Bcf/day and 0.5 Bcf/day respectively.**
    - **Plant start date: are as requested by the customer.**
    - **Plant load: is not realized entirely on that date but is phased in by applying multi-year probabilities.**
    - **Startup: Multi-year probabilities are applied to probabilistically phase-in the requested load (to reflect the start date uncertainty).**
    - **Probabilities for startup and electrification are assigned. Start-up probabilities are phased in over 7 years. The probabilities are assigned to produce a load forecast that effectively yields gas production generally aligned to expert projections of gas production. As a result, BC Hydro's upstream gas forecast for Non-LNG Dependent sites is generally aligned to expert, third party North American projections for BC.**

The low forecast is based entirely on load requests by shale gas producers. Like the mid forecast, customers can be categorized as LNG Dependent or Non-LNG Dependent.

- **The table below summaries the assumptions for LNG Dependent producers in context to the mid forecast:**

	LNG Dependent								
	Upstream Gas Prod'n Assumptions	Plant Start Date	Plant Load	X	Probability Startup	X	Probability Electrification		Load = Forecast
Base Case	s.17,s.21								LF
Low Scenari									LF

- **This low forecast is not significantly different to the mid forecast because:**
    - **Upstream gas production: assumes 2 major LNG terminals (like the mid forecast)**
    - **Electrification probabilities: are assumed to only be 20 percent less than the mid case.**

- **The table below summaries the key assumptions for Non-LNG Dependent producers in context to the mid forecast:**

	Non-LNG Dependent							
	Upstream Gas Prod'n Assumptions	Plant Start Date	Plant Load	x	Probability: Startup	x	Probability: Electrification	Load = Forecast
Base Case	s.17,s.21							= LF
Low Scenario								= LF

- **This low forecast is not significantly different to the mid forecast because:**
    - **Upstream gas production: is not materially different than the mid case**

The high forecast is based entirely on load requests by shale gas producers. Like the mid forecast, customers can be categorized as LNG Dependent or Non-LNG Dependent.

- **The table below summaries the assumptions for LNG Dependent producers in context to the mid forecast:**

	LNG Dependent							
	Upstream Gas Prod'n Assumptions	Plant Start Date	Plant Load	x	Probability: Startup	x	Probability: Electrification	Load = Forecast
Base Case	s.17,s.21							= LF
High Scenario								= LF

- **This high forecast is significantly different to the mid forecast because:**
    - **Plant Start Dates: Are sooner (advanced by 3 years). They are timed to coincide with the optimistic official LNG terminal start dates.**
    - **Startup probabilities: Are set to 100 percent.**
    - **Electrification probabilities: Are raised by 50 percent.**

- **The table below summaries the key assumptions for Non-LNG Dependent producers in context with the mid forecast:**

	Non-LNG Dependent								
	Upstream Gas Prod'n Assumptions	Plant Start Date	Plant Load	x	Probability: Startup	x	Probability: Electrification		Load = Forecast
Base Case	s.17,s.21								= LF
High Scenario									= LF

- **This high forecast is significantly different to the mid forecast because:**
    - **Plant Start Dates: Are sooner (advanced by 3 years). They are accelerated to meet assumed North American gas demand in a high scenario.**
    - **Startup probabilities: Are set to 100 percent.**
    - **Electrification probabilities: Are raised by 50 percent.**

<u>Pipelines and Other Subsector</u>

For the Lower Threshold:

- **The sales forecast for Pipelines is lower relative to the mid forecast as no new pipeline projects occur.**
- **The sales forecast for Other is lower relative to the mid forecast as projects are deferred and/or given a lower probability.**

For the Upper Threshold:

- **The sales forecast for Pipelines increases due to higher assumed start-up probabilities for crude oil and condensate pipeline projects, a propane terminal and a natural gas pipeline.**
- **The sales forecast for Other is higher relative to the mid forecast as projects are assigned a higher probability.**

Other Sector

The Other Sector comprises all large industrial customers that do not fall under the following main categories: mining, oil and gas, forestry or LNG. This is a heterogeneous sector including diverse customers such as cement companies, airports, wire manufacturers, universities, ports and terminals etc.

	Lower Threshold	Base	Upper Threshold
	Other	Other	Other
F2017	1,142	1,208	1,214
F2018	1,147	1,281	1,376
F2019	1,149	1,343	1,522
F2020	1,157	1,377	1,561
F2021	1,158	1,398	1,584
F2022	1,160	1,416	1,604
F2023	1,162	1,427	1,617
F2024	1,168	1,473	1,710
F2025	1,168	1,486	1,726
F2026	1,178	1,507	1,753
F2027	1,182	1,523	1,774
F2028	1,185	1,538	1,794
F2029	1,188	1,554	1,815
F2030	1,191	1,567	1,835
F2031	1,193	1,581	1,856
F2032	1,196	1,595	1,876
F2033	1,199	1,609	1,897
F2034	1,202	1,621	1,916
F2035	1,204	1,632	1,935
F2036	1,206	1,644	1,955

The Low forecast case assumes:

- **very little incremental load growth (flat trajectory) from existing major customers (universities, YVR, ports, etc.)**
- **cement production lowered to 2012 levels in long-term.**
- **no new industrial projects into the forecast (Canpotex, T2, HITest, Graymont)**

The High forecast case assumes:

- **higher than anticipated development from existing major customers.**
- **increased probability for new industrial projects.**

Current (May 2016) Mid, Low and High Load Forecast Assumptions

BC Hydro addresses load forecast uncertainty by developing high and low forecast bands around the mid (expected) forecast. The intention of this analysis is to create high and low forecast bands for the entire system load (i.e., sales with losses) with approximately 10 per cent and 90 per cent exceedance probabilities, respectively. The high and low forecast bands are used to provide an indication of the magnitude of load uncertainty.

BC Hydro uses Monte Carlo simulation to develop the high and low total system forecast on a before-DSM basis. Mid (expected) DSM is subsequently applied to the high and mid load forecasts, respectively; and low DSM is applied to the low load forecast to develop an after-DSM forecast band.

The Monte Carlo analysis involves the sampling of probability distributions for key load uncertainty variables such as economic activity (i.e., GDP), electric vehicles, heating degree days, and four probability distributions for the Large Industrial sub-sectors (mining, oil and gas, forestry and other industrial). As a result, the Low/High Load Forecast is not simply the combination of all the “low”/”high” inputs into the Monte Carlo model. Rather it is a probabilistic assessment of the potential impacts of the low, expected, and high inputs. As such, there is no single set of assumptions that result in the Low Load Forecast.

The Large Industrial sector is the most volatile and contributes the largest amount of uncertainty in the total system high and low projections from the Monte Carlo. A high and low sales forecast for each Large Industrial sub-sector is used to bound the uncertainty distribution for each sub-sector. The high and low sector forecasts are developed by altering the mid forecast’s probability weightings (i.e., risk of closure or expansion) and considering other drivers such as high and low commodity prices and project advancements or deferrals. For example, the high and low upstream gas sector sales forecast considers the advancement and deferral of two large LNG project in-service dates.[1]

Key assumptions regarding market conditions, commodity prices and project assumptions for each of the main large industrial sectors in developing the low, mid and high forecast scenarios are summarized in the attached document. This information was provided to Deloitte as part of the Site C Inquiry.

For the Residential and Light Industrial/Commercial sectors, the key uncertainty variables are primarily economic growth and, to a lesser degree, temperature and electric vehicles. The real B.C. GDP influences population trends, employment and income and electricity sales. As such, variations to the mid forecast of real B.C. GDP growth primarily affects the high and low load outcomes from the Monte Carlo analysis for the Residential and Light Industrial/Commercial sectors. A temperature distribution captures the mean and standard deviation of heating degree

[1] The current load forecast assumed that mid LNG plant loads are the same for the high and low total system forecast outcomes from the Monte Carlo. In the development of upstream high and low gas sector sales for there is variation on the development of the LNG industry and its impact on the upstream gas sector sales.

days over the past ten years. For these sectors the following Monte Carlo input assumptions were applied:

1. GDP for economy. A GDP distribution is applied to residential and light commercial and industrial. The mid GDP forecast which comes from the Ministry of Finance for five years and then our third party consultant forecast for the long term is pertibated +/- about 2 percent each year.

2. Temperature distribution of heating degree days for the past 10 years is applied to residential and light industrial and commercial.

3. Electric Vehicle distribution which is bounded by high and low EV forecast. The EV forecast is included in the residential, light industrial and commercial sector forecasts. The high and low EV forecasts are developed from BC Hydro's EV model by allowing for variation as much as five percent in electricity prices, gasoline prices and capital costs.

4. A correlation matrix between GDP and uncertainty distributions for large industrial.

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Withheld pursuant to/removed as

s.12;s.13

From:	Savidant, Michael
To:	MacLaren, Les EMPR:EX
Cc:	O"Riley, Christopher; James, Fred; Layton, Ryan; Reimann, Randy; Magre, Leela
Subject:	Response to request for clarifications on BC Hydro review findings
Date:	Tuesday, November 7, 2017 5:11:10 PM
Attachments:	ATT 1 - Explanation of Item 2D from BC Hydro Review of BCUC Final Report.docx ATT 2 - Development of Portfolio UECs reflecting costs to ratepayers.docx 20171107 - BCUC Final Report - Overview of Initial Findings from BCH Review - Update 1.docx

Les,

Please find attached the following documents in response to your questions regarding our review of the BCUC report:

- A document providing a better explanation of Item 2D in our original note (the opportunity cost of DSM in the Continue scenario).
- A document providing updated UECs correcting the exclusion of surplus value and termination costs.
- An updated review note which references the above documents as attachments as well as adding and expanding on some items (highlighted in blue).

Please let me know if you have any questions.

-Mike

_____

Michael Savidant
Manager – Commercial Negotiations
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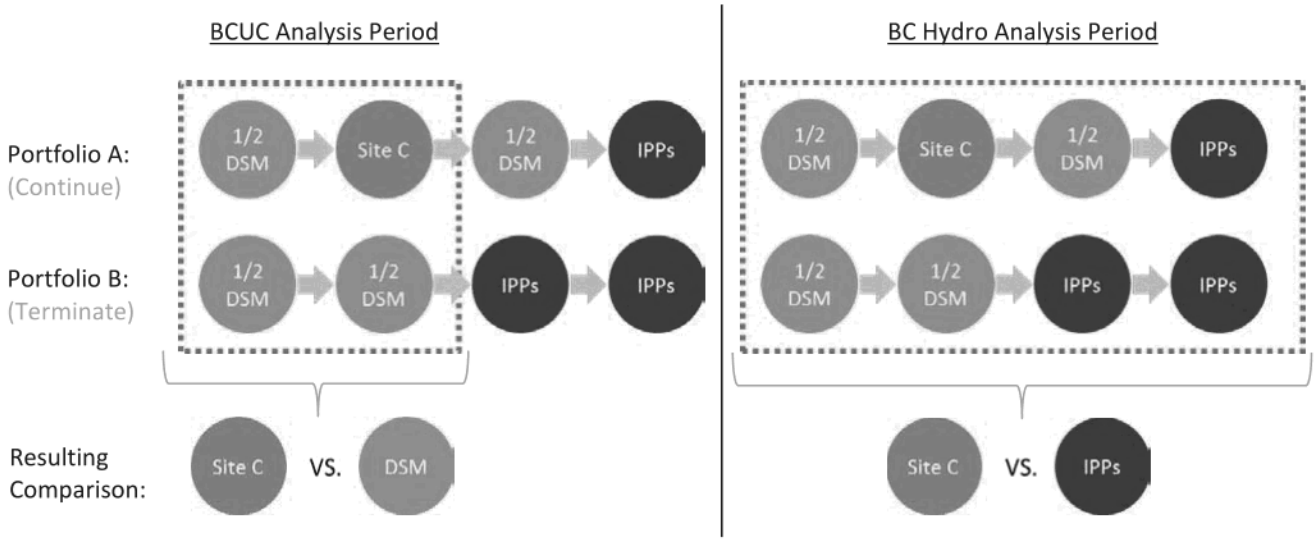
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Attachment 1
Explanation of Item 2D from BC Hydro Review of BCUC Final Report

The simple way to consider the alternative resources to Site C is to look at how a portfolio that includes Site C compares to a portfolio without Site C. The Commission has identified DSM as being the key alternative. That would be true for the first several years of Site C's 70+ years of service. After the first several years, a Site C portfolio would include the same DSM resources as a non-Site C portfolio. In the longer term, the alternative resources would be different would be wind and pumped storage. As a result, the analysis of Site C benefits over a 70 year period will be mostly impacted by the relative costs of wind and pumped storage versus the cost of Site C.

The following simplified illustration demonstrates that by truncating the portfolio analysis to a smaller size, the BCUC approach assumes that additional demand side management (DSM) is the alternative to Site C rather than the incremental (and higher cost) Independent Power Producer (IPP) energy.



As shown here, the long-term difference between Portfolio A and Portfolio B is a trade-off between IPPs and Site C. Given that Demand Side Management is significantly lower cost than IPP energy, BC Hydro is likely to pursue all cost effective DSM savings in advance of IPP energy, with or without Site C. With these common amounts of DSM in both portfolios (with slightly delayed timing in Portfolio A), the important comparison captured by the BC Hydro approach is the additional cost of meeting later need with more expensive IPP energy.

The BCUC approach does not consider "what happens next", and as such significantly underestimates the cost of Terminating Site C at this time. The cost of "what happens next" in the Terminate scenario (more IPPs) is substantially higher than the cost of "what happens next" in the Continue scenario (more DSM plus more IPPs). As a result, the Commission substantially underestimates the cost of termination.

In addition to the above issue with the truncated analysis period, the BCUC method also does not consider the value of having cheaper DSM resources available as a low-cost contingency option if load grows faster than expected, for example:

- In the Continue scenario, the next best option to meet increased need is to advance planned DSM.
- In the Terminate scenario, the next best option to meet increased need is to advance more expensive IPP resources.

As a result, the Terminate scenario has a higher cost risk.

Attachment 2
Development of Portfolio UECs Reflecting Costs to Ratepayers

This document provides corrected portfolio Unit Energy Cost (UEC) values for Site C and the Illustrative Alternative. The Commission's UECs only included the cost to build/develop the resources included in the portfolios, and did not reflect other factors that are included in the overall costs to ratepayers.

The key issues corrected for are:

- The Commission's UEC used present value costs reflecting when alternative resources were brought into service. This recognizes the potential value from bringing projects into service more aligned with load growth. However, the Commission's UEC does not reflect the value of surplus created by bringing projects into service prior to load growth. This penalizes Site C for the large size of project without providing value for the surplus created by this large size.
- The Commission's UEC does not reflect the costs of terminating Site C.
- Note that this analysis only corrects for the exclusion of surplus value and termination costs from the analysis. This does not correct for other errors discovered during the review of the BCUC Final Report.

Without correcting for these issues the Commission's UEC is inconsistent with the portfolio present value amounts presented in the report. The uncorrected UEC does not reflect the actual costs to ratepayers and is misleading regarding the actual costs of the portfolios. The corrected UEC is more meaningful, but still does not reflect the true cost to ratepayers unless it is further corrected for the other errors identified by BC Hydro in our review.

BC Hydro has reviewed the Commission's model for both the Site C portfolio and the Illustrative Alternative. Tables 1 and 2 show the calculation of the corrected UEC for the Low, Mid and High load scenarios. The Low Load scenario in both tables are provided in the Commission's report as Tables 39 and 40 respectively.

Table 1 – UEC Calculation for Site C

	Load Forecast	Low	Mid	High	
A	Sunk Costs (F$18)	2,100	2,100	2,100	Million
B	Site C Cost to Complete (F$18)	4,391	4,391	4,391	Million
C	Flexibility Credit (F$18)	(66)	(66)	(66)	Million
D	Surplus Energy Sales (F$18)	(1,137)	(355)	-	Million
E	**Total Rate Impact (B+C+D)**	**3,188**	**3,969**	**4,325**	**Million**
F	Volume (F18)	98,993	98,993	98,993	GWh
G	UEC (F$18) (B/F)	44.35	44.35	44.35	per MWh
	Corrected UEC (F$18) (E/F) incl. flex credit + surplus value	**32.20**	**40.10**	**43.69**	**per MWh**

Table 2 – UEC Calculation for Illustrative Alternative Portfolio

	Load Forecast	Low	Mid	High	
A	Site C Termination Cost (F$18)	1,395	1,395	1,395	Million
B	Alternative Portfolio Cost (F$18)	2,627	3,466	3,734	Million
C	Surplus Energy Sales (F$18)	(788)	(243)	(9)	Million
D	**Total Rate Impact (A+B+C)**	**3,234**	**4,618**	**5,121**	**Million**
E	Alt. Portfolio Volume (F18)	83,017	102,293	119,557	GWh
F	UEC (F$18) (B/E)	31.64	33.88	31.23	per MWh
	Corrected UEC (F$18) (D/E) incl. termination costs	**38.96**	**45.14**	**42.83**	**per MWh**

(Red text indicates amounts improperly excluded from the original calculation but included in the Corrected UEC)

A comparison of the original and corrected UECs is shown in Table 3 below. As shown, exclusion of the items in red above resulted in showing UECs for the Illustrative Alternative portfolio that were lower than the UECs for completing Site C. When these items are included (as they are in the portfolio present value amounts) this results in UECs for Site C being lower than the Illustrative Alternative (with the exception of the high load scenario).

	BCUC Report Methodology		**Methodology Reflecting Costs to Ratepayers**	
($/MWh, F2018 dollars)	**Continue Site C (w/o surplus value)**	**Illustrative Alternative (w/o termination)**	**Continue Site C**	**Illustrative Alternative**
Low Load Forecast	44.35	31.64	32.20	38.96
Med. Load Forecast	44.35	33.88	40.10	45.14
High Load Forecast	44.35	31.23	43.69	42.83

Site C Inquiry
Overview of Initial Findings from BC Hydro Review of BCUC Final Report
Updated November 7, 2017

This document provides a summary of items identified through BC Hydro's preliminary analysis that are expected to be most material to the Commission's conclusions regarding a comparison of Site C to the Commission's alternative portfolio (the "Illustrative Alternative portfolio").

Please note:

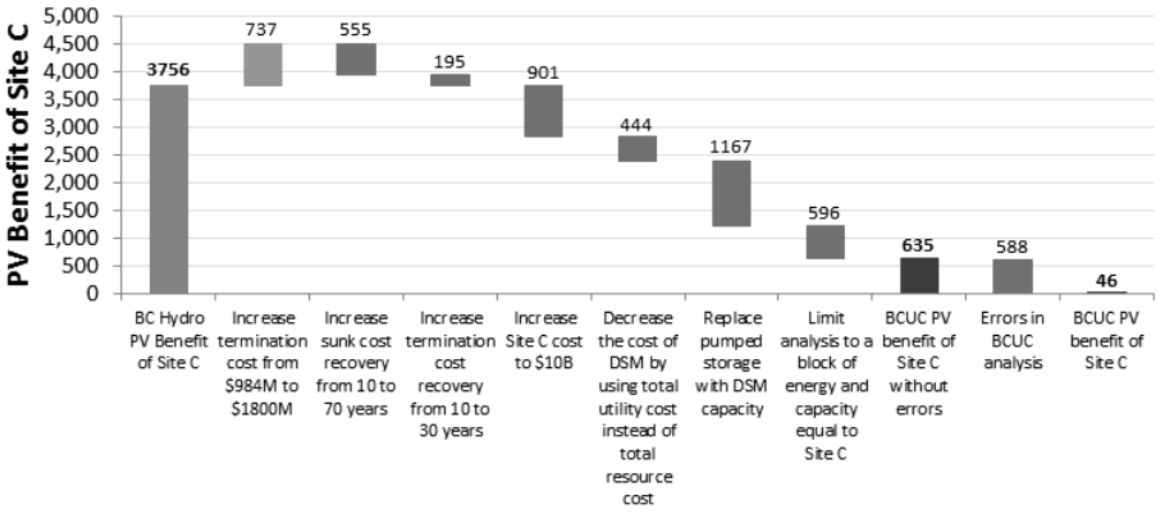
- This list is not exhaustive. Additional issues and errors have been identified that are not in this summary.
- BC Hydro's review is not yet complete. Additional issues may be identified in the future.

The table below provides a summary of these issues with the expected impact on the Commission Scenario calculation of PV costs and benefits. Note that there may be overlap and compounding effects between items, and they should not be considered directly additive.

	Issue	**Impact on PV Cost of Termination**
1.	**Modelling Errors**	
A	Application of incorrect discount rate to Site C surplus	+$336 million
B	Inconsistent application of inflation factors and discount rates	+$51 million
C	Double-counting of transmission losses on DSM	+$201 million
D	Error in Table 43	No impact to Commission Scenario
2.	**Assumptions that do not reflect true costs to ratepayers**	
A	Inaccurate treatment of sunk costs	+$555 million
B	Inaccurate treatment of termination costs	+$195 million
C	Use of BC Hydro financing for all resources	Not isolated (depends on other assumptions)
D	Use of modified block analysis, ignoring opportunity value of DSM	+$596 million
E	Use of Total Utility Cost rather than Total Resource Cost for DSM	+$444 million
F	UEC that includes penalty for Site C timing but no benefit for surplus	Not used in PV analysis
3.	**Assumptions that are incorrect and not supported by evidence**	
A	Adoption of the Low Load Forecast as the expected case	Not estimated at this time
B	Adoption of 400MW of industrial load curtailment without evidence	
C	Use of an arbitrarily lowered market price forecast	
D	Assumption that the alternative portfolio has the same firming and shaping capability as Site C	
E	Use of incorrect technology assumptions on geothermal resources	
F	Proposed use of Non-Treaty Storage Agreement despite it already being included in BC Hydro's planning	
4.	**Assumptions that are inconsistent with legislation and/or policy**	
A	"Remobilization" of Burrard	Not estimated at this time
B	Use of Columbia River Treaty entitlement	
C	Increased reliance on external market purchases to meet demand	

Blue highlight indicates items that are new or materially updated compared to previous notes.

Errors in Sections 1 and 2 are largely due to the Commission's adoption of their own modelling tools and rejection of BC Hydro's modelling tools. The Commission should not have eliminated BC Hydro's portfolio analysis evidence from consideration in this inquiry as it is the most complete assessment of the impacts and has been used successfully for many years in the context of resource planning. BC Hydro was available throughout the process to respond to questions and ran all of the sensitivities requested by the Commission. BC Hydro identified errors and assumption concerns with other portfolios that we were asked to assess. However, we were never asked to comment on the simplified Illustrative Alternative Portfolio, upon which the Commission ended up relying.
The graph below shows the assumptions the Commission has made to go from BC Hydro's "Commission Portfolio" PV estimate of $3.8 billion benefits of completing Site C to their assessment of zero benefits. The graph also shows the PV impact of correcting the errors listed in Section 1.



1. Modelling Errors

This section covers items that we believe are mistakes, rather than unjustified assumptions.

A. The Commission's model has a mathematical error in its treatment of the Site C energy surplus.
- The Illustrative Alternative model uses a **nominal dollar** market price and discounts at a **nominal dollar** discount rate. This is a correct method.
- The Site C model uses a 2018 **real dollar** market price and discounts at a **nominal dollar** discount rate. This is an incorrect method as the discount rate should be consistent with the dollar basis of prices.
- We believe this is a mistake rather than a conscious assumption, as there is no feasible basis for this difference nor has the Commission identified it in their assumptions.
- This mistake undervalues the Site C surplus on a Present Value basis.
- In the Commission Scenario Low Load Case used in Table 40, the impact is a $336 million higher cost of Site C than is correct.

B. The Commission's model has a mathematical error due to inconsistent application of inflation factors and discount rates in the Illustrative Alternative model.
- Inflation is applied to costs assuming they occur at the **start** of a fiscal year.
- Discounting is applied to costs assuming they occur at the **end** of a fiscal year.
- This inconsistent approach is incorrect. Inflation and discounting should be applied to the same period.
- In the Commission Scenario using the Low Load Case in Table 39, this results in a $51M lower cost of the Illustrative Alternatives than is correct. This error does not apply to the Site C model.

C. The Commission has double-counted transmission loss savings associated with DSM which has the effect of understating the cost of the Commission's alternative portfolio relative to Site C.
   - In its original October 11th portfolio, the Commission increased the amount of energy provided by DSM by ~11% to reflect the avoidance of transmission losses.
   - In our October 18th response, we flagged that this was incorrect as the energy volumes they were using were already adjusted to reflect loss avoidance.
   - The Commission has stated that they continue to believe their adjustment is appropriate as they believe BC Hydro's adjustment was only for distribution losses, and a further adjustment is required for transmission losses.
   - This is incorrect. The volumes used by the Commission had already been adjusted to reflect transmission losses as well as distribution losses, and thus the Commission scenario double-counts transmission loss savings. Correction of this issue would advance the need for new resources and increase the cost of the Illustrative Alternative portfolio by ~$201 million.

D. The Commission has made an error in Table 43 with respect to the "Medium Load Forecast + $12 billion Site C cost" scenario.
   - It appears this is a typo or a model update error.
   - The table entry is shown below with the numbers highlighted updated solely for the typo. This does not correct the other modelling errors above.

Scenarios	**A. Illustrative Alternative Portfolio**[598]	**B. Site C**[599]	**Difference (A - B)**
Medium load forecast + $12 billion Site C cost	$4,618	$4,911	($293)

2. Assumptions that do not reflect true costs to ratepayers

This section covers assumptions the Commission has made that are not mathematical errors, but are not representative of how costs would actually be recovered from ratepayers.

A. The Commission's treatment of sunk costs (i.e., the $2.1 billion in costs that will be spent by Dec 31, 2017 but have yet to be recovered from ratepayers) is not representative of the costs to ratepayers.
   - The Commission's model ignores sunk costs in the Terminate scenario and removes them from Site C costs in the Continue scenario.
   - This method would be correct if sunk costs are recovered from rates in the same manner for both the Terminate and Continue scenarios. However, this is not the case.
     - In the Continue scenario, sunk costs are effectively recovered over the 70 year amortization life of Site C.
     - In the Termination scenario, costs will be recovered over a substantially shorter period because it would be contrary to regulatory principle to have ratepayers (who aren't even born yet) paying for a project decades from now that had been cancelled and from which they are deriving no benefit at all. BC Hydro believes an appropriate period that is consistent with regulatory principle is 10 years.
   - Treating sunk costs the way the Commission has assumed in their analysis effectively assumes that they will be recovered over 70 years if the Project is terminated. This substantially underestimates the likely rate impact of these sunk costs in a Termination scenario.
   - Due to this difference in how sunk costs are recovered, the cost to ratepayers of the Illustrative Alternative portfolio is $555 million higher than estimated by the Commission.

B. The Commission's treatment of termination costs is not representative of the likely costs to ratepayers.
   - In the Illustrative Alternative portfolio the Commission recovers termination costs over 30 years.
   - BC Hydro believes this period of recovery is too long for similar reasons as described for sunk costs in a termination context. This means a ratepayer who is not even born today would be paying for the project's termination in 2045.
   - Using a more reasonable 10 year recovery period increases the cost of the Illustrative Alternative Portfolio by $195 million.

C. The Commission assumes BC Hydro cost of financing for all resources.
   - The Commission has framed this as being intended to ensure an "apples to apples" comparison. However, this assumption either means a substantial change in how BC Hydro does business or does not reflect the true costs to ratepayers.
   - BC Hydro financing either means:
     - That BC Hydro builds all new resources on our balance sheet. This would be a change from the decades of policy and precedent that IPPs construct new resources in BC, and has the potentially to have material impacts on BC Hydro's credit rating and the IPP industry.

       OR
     - That the Commission's PVs are not reflective of the true costs to ratepayers, who would pay IPP costs of capital rather than BC Hydro cost of debt. There is no question that an IPPs cost of capital can be expected to be higher than BC Hydro's cost of capital.
   - The impact of this assumption depends on the amount of IPP resources in a portfolio. In the Commission scenario with low load assumed, DSM accounts for the vast majority of resources to meet load, and as such the financing assumption does not have a high impact. If a more reasonable load forecast assumption were used, more IPP resources are required, and the impact of financing will be substantial.
   - We also note that the Commission has used a 6.4% "nominal" cost of capital for IPPs in their sensitivity test, supposedly based on BC Hydro's estimate. This is incorrect – our estimate of IPP cost of capital is 6.4% real (not nominal). The nominal cost of capital would be ~8.4%. As a result, the Commission's sensitivity analysis is incorrect.

D. The Commission conducts a modified block analysis, which ignores the benefit of incremental DSM if Site C were to be built.
   - The Commission truncates their analysis of new resource requirements to ~20 years (although they extend the cost of these resources out to 70 years).
   - As a result, the Commission effectively assumes that enhanced DSM would <u>not</u> occur if Site C continues. This is incorrect as BC Hydro would delay enhanced DSM with Site C but would still pursue it before other resources.
   - As a result, this ignores substantial differences in the cost of available future options.
     - If Site C continues, BC Hydro will continue to be able to pursue DSM. There is no change in available future options.
     - If Site C is terminated, there is no credible scenario where BC Hydro pursues Site C 10 years in the future (when new non-DSM resources would be required, even with the Commission's aggressive DSM assumptions). We would have lost our cheapest non-DSM option to serve our customers.
   - Attachment 1 to this document provides an illustrative example of the impacts of this assumption.
   - Ignoring this difference underestimates the PV cost of termination by $596 million.

E. The Commission utilizes Utility Cost rather than Total Resource Cost for DSM.
   - The Commission rejects BC Hydro's position (and their own previous findings in other Commission proceedings) that the Total Resource Cost is the appropriate way to evaluate DSM in comparison to

other resource options. They appear to base this off the requirements of the OIC, and appear to assume that the TRC does not reflect direct costs to ratepayers.
- This is incorrect. The incremental costs in the TRC are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.
- Utilizing the TRC in a manner consistent with how the Commission used it in previous decisions increases the cost of the Illustrative Alternative portfolio by $444 million.

F. The Commission's UEC calculation includes adjustments for Site C coming into service in advance of being completely required by demand, but does not include the benefit of surplus for this period.
- While the Commission does not use its UEC calculation for evaluating present value costs and benefits, it still positions it as representative of the costs of the various portfolios.
- The Commission calculates its UEC as the present value of project costs when they are brought into service divided by the present value of the energy.
  - It does not include revenue from surplus exports
  - It does not include termination costs
- This means that the Site C portfolio UEC is **penalized** for coming into service before its entire output is required, but **receives no benefit** for the project surplus for this period.
- This also means that the Illustrative Alternative portfolio does not include termination costs that would have to be incurred if this option is chosen.
- These two assumptions lead to a portfolio UEC that is not representative of the costs to ratepayers of Continuing or Terminating Site C.
- The table below shows the UECs that would be calculated when including these other items. See Attachment 2 for derivation of these UECs.
  - Note that these UECs only correct for the exclusion of surplus value and termination costs. They do not correct for any of the other errors or incorrect assumptions outlined in this document.

($/MWh, F2018 dollars)	BCUC Report Methodology		Methodology Reflecting Costs to Ratepayers	
	Continue Site C (w/o surplus value)	Illustrative Alternative (w/o termination)	Continue Site C	Illustrative Alternative
Low Load Forecast	44.35	31.64	32.20	38.96
Medium Load Forecast	44.35	33.88	40.10	45.14
High Load Forecast	44.35	31.23	43.69	42.83

3. Assumptions that are incorrect and not supported by the evidence

This section covers assumptions that BC Hydro does not believe are reasonable given the information available to us and the Commission.

A. Adoption of the Low Load Forecast as the expected case
- The panel has found the mid forecast to be overall optimistic and considers appropriate to use the Low Load Forecast to develop its recommendations. It is unclear on what basis the Commissions is making this adjustment. Lower industrial load? Higher elasticity? Removal of LNG?
- BC Hydro has difficulty reconciling the Low Load Forecast with any scenario other than one that includes some or more of:

- Major industrial load destruction. BC Hydro's low mining and forestry sector assumptions assume 1,800 GWh (250MW) of industrial load closures.
- Low long-term economic growth (i.e. less than 1%/year)
- Large amounts of customers going off-grid due to solar rooftops or similar switching.
- Major declines in residential and/or commercial end-use intensities in addition to those underlying the additional DSM the Commission has relied upon

- While this scenario is possible, it is not expected and hence BC Hydro's used it as a low probability low load scenario

B. The Commission allows for up to 400MW of Industrial Load Curtailment at $75/kW-yr with no meaningful evidence.
   - The Commission's sole basis for this volume appears to be a submission from AMPC that suggests there is 200-400MW of Industrial Load Curtailment available based on "realistic procurement efforts, using less restrictive contract terms".
     - AMPC provides no analysis for how they arrived at this figure other than a pro-rated number from Hydro Quebec which would yield only 245MW.
     - The Commission provides no basis for utilizing the upper end of this range.
     - It is unlikely the "less restrictive contract terms" would meet BC Hydro's long term planning needs.
   - BC Hydro notes that we tested a shorter term product (4 hours) in our Year 2 Load Curtailment pilot. No customer bid in such a product.
   - BC Hydro has undertaken an industrial load curtailment pilot, the results of which determined that 85 MW was available in a form that would allow the deferral of physical assets to meet BC Hydro's customer's needs reliably.
   - The adoption of high levels of Industrial Load Curtailment is also inconsistent with the use of BC Hydro's Low Load Forecast.
     - While the Commission does not say on what basis they adopt the Low Load Forecast, it is unlikely BC Hydro would achieve this level of load without industrial demand destruction.
     - Under such a scenario, industrial load would be permanently "curtailed" (by going out of business) and would not be available for temporary curtailment to meet capacity needs.
     - We estimate that at least 40% of the potential for industrial load curtailment would not be available under the Low Load Forecast scenario.

C. Use of an arbitrarily lower market price forecast than the third party forecast used by BC Hydro
   - The Commission rejects BC Hydro's use of the ABB market forecast and adopts a market forecast between the mid and low case of the ABB market price forecast.
   - The ABB market price forecast used by BC Hydro is an independent forecast developed by ABB and built upon extensive research, analysis, and understanding of the North American electricity markets. ABB is one of the world's largest engineering companies and over 100 customers in the energy industry subscribe to their market forecast.
   - BC Hydro has also provided electricity price forecasts developed by the North West Power Planning Council, IHS Markit, and the PIRA Energy Group. The North West Power Planning Council is the entity that develops the long-term power plan for the states of Idaho, Montana, Oregon, and Washington. IHS Markit is a global business information provider while PIRA is a service provider to companies in over 60 countries, including many of the largest Global Oil and Gas firms.
   - Every single one of the mid electricity market forecast developed by the organizations mentioned above is higher than the forecast that the Panel used as their mid case. BC Hydro believes that the Panel forecast relates to a pessimistic scenario and that the ABB mid forecast better represents a consensus mid-point view of several organizations that are experts in this domain.

D. The Commission assumes that the Illustrative Alternative portfolio has approximately the same level of firming and shaping as Site C.
   - The Commission reaches this conclusion by assuming that the existing system has sufficient firming and shaping such that incremental amounts have little to no value.
   - This is incorrect. The dispatchability of the project allows us to access higher priced periods within the month and within the year.
   - BC Hydro's portfolio analysis includes modelling of export revenues to reflect both the seasonal shaping and dispatchability of resources such as Site C.

E. The Commission includes geothermal in their Illustrative Alternative portfolio, but applies the cost of hydrothermal flash technology to resources that require binary technology.
   - Neither Canoe Reach nor Lake Else has temperatures high enough to support flash technology.
   - Switching to binary technology would result in:
     - Higher costs, as binary is more expensive than flash technology
     - Lower net capacity factors, as binary technology is expected to achieve an 80% net capacity factor rather than the net 90% of flash technology according to NREL. Note that the Commission uses a 95% capacity factor – BC Hydro is unaware of the basis for this assumption.
   - Further, the Commission does not account for reservoir degradation which is expected to result annual generation output by 1% per year over the life of the project and would make the redevelopment of these sites after 30 years at a 30% cost reduction unlikely.

F. The Commission has suggested that BC Hydro may be able to use the Non-Treaty Storage Agreement for additional energy and capacity, although they acknowledge a lack of clear evidence on this topic.
   - The firm energy and dependable capacity due to the NTSA are already accounted for in our planning, and there is **no new incremental energy (or capacity)** associated with this agreement for BC Hydro.
   - The NTSA is not a sale of storage to BPA. It is an agreement between BC Hydro and BPA to coordinate the storage in Canadian reservoirs that is not utilized under the CRT.
     - The NTSA provides for discharge flexibility incremental to the Treaty to meet a variety of objectives including social, environmental, and economics.
     - Both parties benefit from the energy value of generation changes at US federal projects due to the use of BC storage to shape releases.
     - The power benefits under this agreement are already fully utilized by BC Hydro to reduce the cost of energy to our ratepayers.
     - There are also provisions for firm energy delivery and rights under this agreement that could be utilized under the most adverse water conditions.

4. Assumptions that are incompatible with legislation and/or policy

This section covers assumptions that violate existing legislation and/or policy.

A. "Remobilization" of Burrard
   - This contradicts the *Clean Energy Act* and would require a legislative amendment.
   - Beyond the requirement to change the *Act*, "remobilizing" Burrard is not a feasible option.
     - The Burrard units are not capable of generating power. Resuming generation at Burrard would involve rebuilding a new generation facility at the site and comes with substantial costs.
     - Obtaining air permits for new gas fired facility is unlikely for a federally monitored air shed.

B. Use of the Columbia River Treaty entitlement
   - Use of the Columbia River Treaty entitlement ("entitlement") does not meet the definition of self-sufficiency under the *Clean Energy Act*. Use of the entitlement would require either a regulatory change to the definition of self-sufficiency or a legislative amendment.

C. Increased reliance on external markets
   - This contradicts the *Clean Energy Act* and would require either a regulatory change to the definition of self-sufficiency or a legislative amendment.

From:	Savidant, Michael
To:	MacLaren, Les EMPR:EX; Foster, Doug FIN:EX
Cc:	O"Riley, Christopher; McSherry, Diane; Reimann, Randy; Magre, Leela; Layton, Ryan; James, Fred
Subject:	Results of portfolio analysis of Commission Portfolio
Date:	Friday, November 17, 2017 5:30:58 PM
Attachments:	20171117 - Results of portfolio analysis of Commission Portfolio.docx

Les and Doug,

Please find attached a note providing the results of our running the Commission's Illustrative Alternative assumptions through our portfolio modelling tools. As you'll see, the results for the Low Load Forecast scenario are roughly in-line with our high-level calculation of the impact of the errors.

Please let us know if you have any questions.

Thanks,

Mike

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Site C Inquiry
Portfolio Modelling Results using Commission Assumptions

As described in our letter to the Commission of November 16, 2017, BC Hydro has utilized its portfolio modeling to analyse the assumptions made by the Commission in its Illustrative Alternative Portfolio (Exhibit A-24). This document provides a summary of where BC Hydro's portfolio modelling differs from the Commission's methodology, as well as the findings from our portfolio analysis utilizing these assumptions.

BC Hydro continues to disagree with many of the assumptions made by the Commission in its Illustrative Alternative, but has retained the Commission's assumptions in the analysis of the Illustrative Alternative portfolio where they were believed to have been made on purpose. While BC Hydro has calculated the present value costs to ratepayers of the Commission's Illustrative Alternative portfolio, we do not believe the costs and resources utilized in this portfolio are plausible. As such, BC Hydro makes no representation on our ability to deliver this portfolio in the manner assumed by the Commission.

The key findings from this updated portfolio analysis as compared to previous BC Hydro submissions are as follows:

($2018 billions)	August 30th Submission	Optimistic Portfolio Sensitivity	Commission Illustrative Alternative
Low Load Forecast	6.1	Not calculated	0.8
Mid Load Forecast	7.3	6.4	1.5
High Load Forecast	10.6	Not calculated	Not calculated

BC Hydro is also developing an annual incremental rate impact forecast consistent with these present value results and expects the incremental rate impact analysis to be available next week.

The following sections provide summaries of:

- Corrections to errors and methodology made by the Commission in their model
- Key assumptions which BC Hydro continues to believe are incorrect or not supported by the evidence.

Correction for errors and methodological limitations in Commission model:

BC Hydro's portfolio modelling corrects for the following errors in the Commission's model, as outlined to the Commission in our letter of November 16, 2017:

- Applying the correct discount rate to Site C surplus
- Correction of inconsistent inflation factors, financing costs, and discount rates[1]
- Elimination of double-counting of transmission losses on demand-side management
- Recovery of sunk costs in both the scenario where Site C is completed (over 70 years) and the scenario where Site C is terminated (over 30 years, as used by the Commission for termination costs).
- Applying the correct binary technology to geothermal resources rather than flash technology

BC Hydro's portfolio analysis methodology also provides a long-term system-wide assessment of the costs of the options available to BC Hydro to meet customer load. The key benefits of this methodology as compared to a more simplified method include:

[1] Note that subsequent to the preparation of our November 16th letter, BC Hydro discovered that the Commission's model did not take into account higher near-term interest rates. This has also been corrected for in the current analysis.

- Allows for selection of resources in an optimal manner, rather than assuming specific resources come into service. System Optimizer selects from available resources in order to find the lowest present value cost to ratepayers.
    - This functionality is why our portfolios select wind and pumped storage as the preferred non-DSM resource option. If we were to force the inclusion of geothermal resources as in the Commission portfolio, alternative portfolio costs would increase,
    - Note that System Optimizer does not have functionality to select demand-side management options. As a result we have assumed the same DSM timing as in the Commission Illustrative Alternative.
- A long-term evaluation period that provides analysis representative of the impact to ratepayers of the decision to complete or terminate Site C.
    - This includes in the evaluation the impact of the decision on Site C to "what comes next" to meet domestic load.
    - The Commission's analysis with a limitation to a shorter period or a fixed amount of energy and capacity creates a false choice between resources (such as enhanced DSM) that would be pursued in all cases.
- Analysis based upon BC Hydro's planning view of the load resource balance, rather than an operational view.
    - BC Hydro's planning view of the Load Resource Balance reflects the capability of resources based on BC Hydro's planning criteria, including the requirement contained in subsection 6(2) of the Clean Energy Act to achieve electricity self-sufficiency under prescribed water conditions from its hydroelectric Heritage assets.
    - An operating view of the Load Resource Balance reflects the forecasted operation of the same resources (as in the planning view of the load resource balance) given market conditions, expected system conditions in the near term and average conditions in the long term[2]. Use of an operating view incorrectly advances the apparent need for new resources by approximately two years.
- Consideration of transmission impacts of resource options. In integrating a resource option to BC Hydro's system, there needs to be (i) transmission from the generator to a point of interconnection on the BC Hydro system which is typically at a substation at a lower voltage than 500 kV, (ii) upgrades that are required from the lower voltage sub-station to the 500 kV bulk system, and (iii) upgrades on the bulk transmission system.
    - BC Hydro's resource option costs include the cost of transmission from the generator to a point of interconnection on the BC Hydro system. These costs have been estimated based on costs that were identified to accommodate IPP projects from the Clean Power Call.
    - BC Hydro's portfolio modelling also includes the costs of network upgrades that are required to accommodate IPP projects on the transmission lines from the IPP point of interconnection to the 500 kV bulk system.
    - The Commission seems to have interpreted network upgrades to be included in the transmission costs from the project to the point of interconnection and have not considered any other transmission costs.
    - BC Hydro's portfolio modelling includes an assessment of when bulk transmission upgrades will be required to enable incremental resource options to effectively supply domestic demand. These upgrades were explicitly excluded from the Commission's analysis.
- Consideration of the market benefits provided by shaping capability.
    - BC Hydro's portfolio modelling reflects the daily, monthly and seasonal value to resource shaping.

[2] The most obvious difference between the Planning View and the Operational View is the energy from dispatchable thermal resources. The Planning View reflects the firm energy that dispatchable thermal resources are capable of generating and can be relied upon for planning purpose (Island Generation at 2,170 GWh and Prince Rupert Generating Station at 180 GWh). In contrast, the Operational View shows how much dispatchable thermal resources are expected to run (Island Generation at 140 GWh and Prince Rupert at 0 GWh).

Remaining Commission assumptions which are incorrect or not supported by the evidence:

Other than the correction for errors and methodological issues above, BC Hydro's analysis has preserved Commission assumptions that have been made in the Final Report (A-24) and associated modelling (A-24-2). In many cases BC Hydro believes these assumptions are incorrect or are not supported by the evidence. As previously stated, BC Hydro makes no representation that we will be able to deliver on the Commission portfolio's resources or costs should a decision be made to terminate Site C.

Key assumptions that BC Hydro continues to disagree with include:

- The Commission portfolio relies on substantially more savings from capacity-focused DSM than BC Hydro believes is appropriate to plan on.
    - The Commission allows for up to 400MW of Industrial Load Curtailment at $75/kW-yr.
        - The Commission's sole basis for this volume appears to be a submission from AMPC that suggests there is 200-400MW of Industrial Load Curtailment available based on "realistic procurement efforts, using less restrictive contract terms".
        - AMPC provides no analysis for how they arrived at this figure other than a pro-rated number from Hydro Quebec which would yield only 245MW. It is also unlikely the "less restrictive contract terms" would meet BC Hydro's long term planning needs.
        - BC Hydro notes that we tested a shorter term product (4 hours) in our Year 2 Load Curtailment pilot with the concept of aggregating products to meet our long term planning needs. No customer bid in such a product.
    - The Commission allows for 400 MW of optional time of use savings.
        - This is substantially higher than BC Hydro's assessment of 120MW of available optional time of use savings.
        - The Commission appears to rely on jurisdictional evidence as rationale for the higher amount (400 MW) of TOU potential. However, in reviewing their references, we can only find evidence of residential customer TOU uptake. We believe that higher potential would only be possible if there is also participation by the General Service classes but are not aware of any jurisdictional evidence that shows that there is significant TOU potential with the General Service classes.
- The use of BC Hydro financing for all resources. This assumption either means a substantial change in how BC Hydro does business or does not reflect the true costs to ratepayers. BC Hydro financing either means:
    - That BC Hydro builds all new resources on our balance sheet. This would be a change from the decades of policy and precedent that IPPs construct new resources in BC, and has the potentially to have material impacts on BC Hydro's credit rating and the IPP industry.

      OR
    - That the Commission's PVs are not reflective of the true costs to ratepayers, who would pay IPP costs of capital rather than BC Hydro cost of debt. There is no question that an IPPs cost of capital can be expected to be higher than BC Hydro's cost of capital.

  We have included a sensitivity scenario where this issue is addressed and IPP financing is used for IPP resources rather than BC Hydro financing.
- The use of the Utility Cost rather than the Total Resource Cost to evaluate the cost of DSM.
    - This is incorrect. The incremental costs in the TRC are those paid directly by ratepayers – they are not "societal" costs. As a result, use of the Utility Cost underestimates the cost of DSM to ratepayers.

  We have included a sensitivity scenario where this issue is addressed and Total Resource Cost is used rather than Utility Cost.
- The use of extremely low prices for wind resources.

- The Commission has utilized extremely optimistic cost declines for wind projects, and also assumed that these projects could be renewed or refurbished at further aggressive cost savings.
  - The costs assumed by the Commission for new-build wind resources are less than half of the results of BC Hydro's most recent competitive call for power. While we agree that costs declines in wind projects are occurring, the costs of wind assumed by the Commission are not expected to be obtainable.
  - The Commission has assumed a further 30% cost savings for wind renewal terms. The Commission has also assumed that there will be no requirement to rebuild transmission lines and roads at refurbishment. This appears to double-count expected cost savings during refurbishment.
- The table below shows a comparison of the cost of wind used in BC Hydro's original analysis, our "Optimistic Portfolio Sensitivity", and the Commission's assumptions made in their Illustrative Alternative portfolio. Note that the Commission Assumptions column includes both the impact of the financing assumption and the cost decline assumption.

Table 1 – Wind Cost Assumptions (2018 real dollars)

$/MWh	Cost Component	Aug 30th Portfolio	Optimistic Sensitivity	Commission Illustrative Alternative[3]
New-build wind resources (F2040)	at point of interconnection	82	64	43
	Wind integration	5	5	1
Wind refurbishment (F2070)	at point of interconnection	82	58	31
	Wind integration	5	5	1

- The use of an electricity market price forecast below expert consensus.
  - The Commission has prepared their own Mid-C market forecast that is between the mid and low case of the ABB market price forecast.
  - This is well below not only the third party price forecast used by BC Hydro (ABB) but also all other third party price forecasts provided during the Site C Inquiry.
  - We have left in the Commission's assumption of providing a $1/MWh benefit to Site C for the ability to integrate wind but note that we are unclear on the basis for this assumption.

Results

Table 2 below shows the present value benefits to ratepayers of completing Site C. Values are shown using three sets of assumptions:

- The assumptions in our August 30th Submission (F1-1), which remains BC Hydro's best estimate of the impact of terminating Site C.

[3] Note that the unit energy costs we have utilized in our analysis of the Commission's Illustrative Alternative have been calculated based on the Commission's cost decline assumptions stated in their Final Report. These unit energy costs are approximately 2 to 3 $/MWh lower than what the Commission seems to be utilizing in their spreadsheet model. We are unclear if this is an error in the stated assumptions, the spreadsheet calculation, or BC Hydro's interpretation of the Commission's intent. We emphasize that our assumption is more conservative and favors the alternative portfolio.

- The assumptions used in our Optimistic Portfolio Sensitivity provided in the response to BCUC IR 2.46.0 (Exhibit F1-8), which remains BC Hydro's best assessment of a plausible, although low likelihood, set of resource planning assumptions.
- The assumptions used by the Commission in their Illustrative Alternative portfolio (Exhibit A-24-2). As noted above, BC Hydro has retained the Commission's assumptions in their Illustrative Alternative portfolio, but does not believe the assumptions used in this portfolio are plausible.

Table 2 – Present Value Benefits of Completing Site C

($2018 billions)	August 30th Submission	Optimistic Portfolio Sensitivity	Commission Illustrative Alternative
Low Load Forecast	6.1	Not calculated	0.8
Mid Load Forecast	7.3	6.4	1.5
High Load Forecast	10.6	Not calculated	Not calculated

BC Hydro has prepared a table summarizing the differences in portfolio assumptions between the portfolio in BC Hydro's August 30th submission to the BCUC, the Optimistic Portfolio Sensitivity BC Hydro provided as part of our response to BCUC IR 2.46.0, and the Commission's Illustrative Alternative. Please refer to Attachment 1.

BC Hydro has also prepared a figure showing the present value impact of changing assumptions and methodologies between the August 30th portfolio and the Commission's illustrative alternative. Please refer to Attachment 2.

In addition to our base results, we have also developed sensitivity analyses for the following items:
- Use of IPP financing rather that BC Hydro financing for alternative resources
- Use of Total Resource Cost rather than Utility Cost for demand-side management

Table 3 below shows the results of this sensitivity analysis on the Commission's Illustrative Alternative

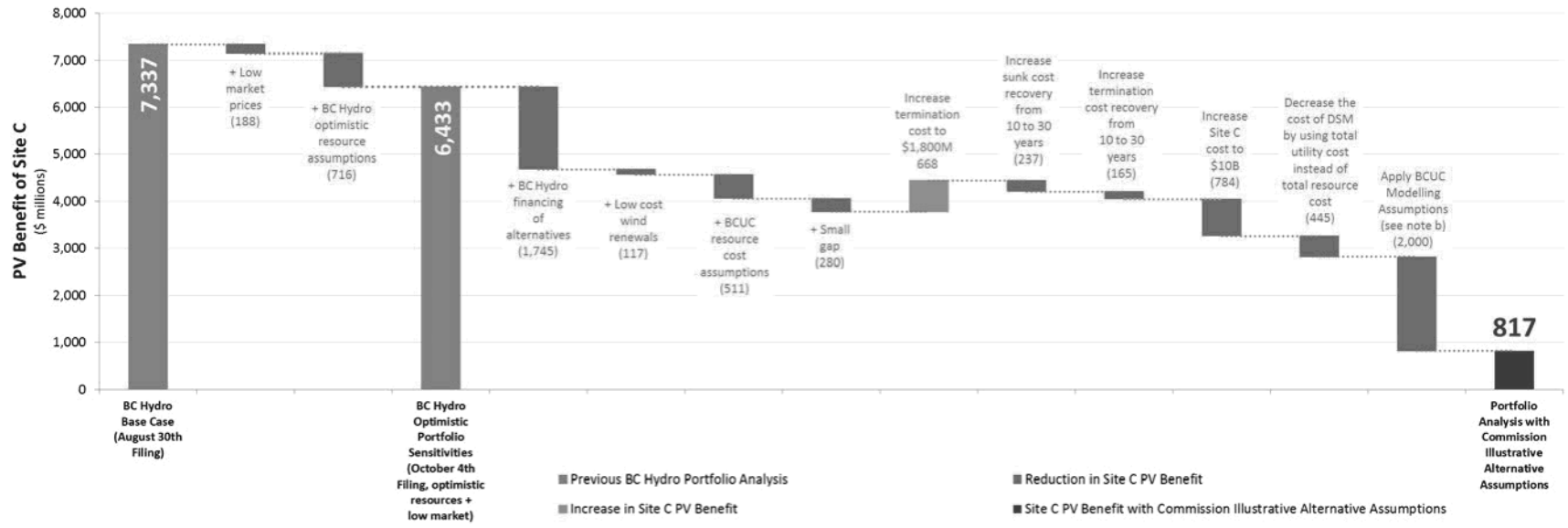
Table 3 – Sensitivity Analysis for Commission Illustrative Alternative Portfolio ($2018 billions)

	Low Load Forecast	**Mid Load Forecast**
Base Commission Assumptions	0.8	1.5
Financing: IPP financing for alternative resources	1.2	2.8
DSM Costs: Total Resource Cost rather than Utility Cost	1.3	1.6
Cost Recovery Period: Sunk / termination costs recovered over 10 years	1.2	1.9
Site C capital cost: $12B rather than $10B	(0.1)	0.6

Attachment 1 – Summary of Portfolio Modelling Assumptions

Assumptions Scenario	August 30 Filing	BC Hydro Optimistic Portfolio Sensitivity	BC Hydro Analysis using Commission Illustrative Alternative Portfolio Assumptions
MODEL ASSUMPTIONS			
Load Forecast Scenarios	- Low / Mid / High	- Low / Mid / High	- Low / Mid (insufficient time to run high load scenario)
Financing Assumption	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances all resources
Market Prices	- ABB Mid Forecast	- ABB Mid Forecast	- BCUC Market Price Forecast
Site C Costs	- $8.335 billion	- $8.335 billion	- $10 billion
Termination and Sunk Costs	- $3.2 billion ($2.1 sunk costs, $1.1 termination costs)	- $3.2 billion ($2 1 sunk costs, $1.1 termination costs)	- $3.9 billion ($2.1 sunk costs, $1.8 termination costs)
Sunk & termination cost recovery period	- 10 years	- 10 years	- 30 years
ALTERNATIVE RESOURCE ASSUMPTIONS			
Capacity Focused DSM	- Industrial Load Curtailment: 85 MW	- Industrial Load Curtailment: 85 MW - Capacity Focused DSM potential: 450MW	- Industrial Load Curtailment: 400 MW - Capacity Focused DSM and optional TOU potential: 640MW
Resource Smart	- Revelstoke Unit 6 when selected by model	- Revelstoke Unit 6 when selected by model - GMS upgrade when selected by model	- Revelstoke Unit 6 assumed in-place in Fiscal 2026
Wind	BC Hydro Resource Options Update w/ IPP financing: - F2040 new build @ $82/MWh ($2018) - F2070 refurbishment @ $82/MWh ($2018) - Wind integration cost of $5/MWh	Lower wind costs w/ BCH financing: - F2040 new build @ $64/MWh ($2018) - F2070 refurbishment @ $58/MWh ($2018) - Wind integration cost of $5/MWh	Much lower wind costs w/ BCH financing, with further reductions for refurbishment/renewal: - F2040 new build @ $43/MWh ($2018) - F2070 refurbishment @ $31/MWh ($2018) - Wind integration cost of $1/MWh
Pumped Storage	BC Hydro Resource Options Update: - F2030 new build @ $125/kW-yr ($2018)	BC Hydro Resource Options Update: - F2030 new build @ $125/kW-yr ($2018)	BC Hydro Resource Options Update: - F2030 new build @ $52/kW-yr ($2018)
Geothermal	- Excluded as not confirmed to be commercially viable	- 200MW of potential @ $120/MWh	- 80MW of potential @ $80/MWh (not selected in portfolio)
Solar	- Excluded as not economic	Modeled using NREL mid cost declines (43% by 2040) - (not selected in portfolio)	Modeled using Commission-suggested cost declines (60% by 2040) - (not selected in portfolio)
Batteries	- Excluded as not economic	- Modeled using Commission-suggested (Lazard) cost declines (50% by 2040) (not selected in portfolio)	- Screened out due to high cost. Aligns with suggestion in the Commission's final report.

Attachment 2 – Impact of Changes to Portfolio Assumptions and Methodologies [a]



Notes:

a. The value differentials are applied left to right in order. This is important, as there are overlap effects between some changes. As a result, if some changes are applied earlier in the "cascade" they will have a larger impact.

b. The BCUC Modeling Assumptions that make up the $2 billion difference in PV include:
   - Use of 630 MW of Capacity focused DSM + Optional Time of Use rates
   - Use of 400 MW of industrial load curtailment with no long-term commitments (i.e. can be "switched on and off" year to year)
   - Optimistic assumptions regarding renewal of wind projects
   - Commission market price assumption instead of ABB market prices
   - Reduction in wind integration adder to $1/MWh

From:	Savidant, Michael
To:	Foster, Doug FIN:EX; MacLaren, Les EMPR:EX
Cc:	Layton, Ryan; O"Riley, Christopher; Yaremko, Cheryl; Magre, Leela
Subject:	Results of Rate Analysis of Commission Portfolio
Date:	Wednesday, November 22, 2017 10:36:36 AM
Attachments:	20171122 - Results of rate analysis of Commission Portfolio.docx Rates ATT 1 - Comparison of Portfolio Assumptions.docx Rates ATT 2 - Aug 30 Rates Analysis.pdf Rates ATT 3 - Optimistic Portfolio Rates Analysis.pdf

Doug and Les,

Please find attached the results of BC Hydro's rate modelling of the Commissions Illustrative Alternative.

As with the PV work we provided last week, we have also included the rates analysis of our previous scenarios.

Let me know if you have any questions.

Thanks,

Mike

_____

Michael Savidant

Manager – Commercial Negotiations

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Site C Inquiry
Rate Analysis Results using Commission Assumptions

BC Hydro has estimated the incremental rate impact of Terminating Site C, and recovering the termination costs over a 30 year period.

The analysis is based upon assumptions that the Commission utilized in their alternative portfolio assessment. These include Commission assumptions regarding:

- BC Hydro finances all future resource developments
- Availability of capacity focused DSM, optional time of use rates, and industrial load curtailment
- Capital cost declines on generation resources and cost of wind integration
- Lower costs of refurbishment of wind turbines
- The Commission's market electricity price forecast

The portfolio assumptions are summarized in Attachment 1 to this note.

As noted in our previous submissions on the PV of the Commission portfolios, while BC Hydro has calculated the ratepayer impacts of the Commission's Illustrative Alternative portfolio, we do not believe the costs and resources utilized in this portfolio are plausible. As such, BC Hydro makes no representation on our ability to deliver this portfolio in the manner assumed by the Commission.

The key findings from this updated portfolio analysis is provided below, combined with BC Hydro's previous present value cost analysis. Figures showing the rate analysis based on the Commission Illustrative Alternative are provided at the end of this note. We have included the rate analysis from the August 30th Submission and the Optimistic Portfolio Sensitivity as Attachments 2 and 3 to this note.

Portfolio Assumptions	**August 30th Submission**				**Optimistic Portfolio Sensitivity**				**Commission Illustrative Alternative**			
Present Value Cost Analysis ($2018 billions)												
Low Load Forecast	6.1				Not calculated				0.8			
Mid Load Forecast	7.3				6.4				2.0[1]			
High Load Forecast	10.6				Not calculated				Not calculated			
Estimated Incremental Cumulative Rate Increases (%)												
	F20	**F24**	**F44**	**F94**	**F20**	**F24**	**F44**	**F94**	**F20**	**F24**	**F44**	**F94**
Low Load Forecast	Not calculated				10.7	10.9	16.1	57.0	6.8	7.7	9.0	32.5
Mid Load Forecast	10.3	9.3	11.7	40.3	10.6	9.8	9.3	37.6	6.4	7.2	3.8	15.3
High Load Forecast	Not calculated				8.7	9.3	9.0	33.1	Not calculated			

We note the following:

- Terminating Site C results in higher cumulative rate impacts in all years, even when using the Commission's Illustrative Alternative portfolio
- The BCUC's assumption of a 30-year amortization period for termination and sunk costs reduces the near-term rate impact of termination to approximately 7% for five years when coupled with the BCUC's Illustrative Alternative portfolio assumptions. BC Hydro believes it is contrary to the

[1] Note that BC Hydro has updated this value compared to our previous submission on PVs. The previous $1.5 billion benefit of continuing Site C in the mid load case is $2.0 billion when correcting for an issue in the original analysis.

regulatory principle of intergenerational equity to have future ratepayers pay for a project decades from now that had been cancelled and from which they are deriving no benefit.

- Cumulative rate impacts are higher in the low load forecast. This is because of the reduction in volume resulting from the large amount of incremental DSM in the Illustrative Alternative.
- Under the mid load forecast, the last 10 years see substantial rate increases as we assume wind can only be refurbished once. New build resources are required in this timeframe with substantial rate impacts.

Methodology

For each scenario (Terminate – Mid Load; Terminate – Low Load), BC Hydro estimated the incremental impact on the main components of BC Hydro's total revenue requirement (amortization, finance charges, operating costs and energy costs), compared with their respective base cases (i.e. continuation of Site C).

For the both load scenarios, the incremental impact is measured against hypothetical Base Cases which use the same BCUC cost and DSM assumptions described above. In both the Base Cases and the Termination Cases, BC Hydro's system optimizer selects the most cost-effective resources to meet customer demand based on either the mid or low load forecast.

The incremental changes to BC Hydro's revenue requirement, as well as changes to revenue from incremental DSM, are used to estimate the incremental cumulative rate increases for each scenario. The estimated incremental cumulative rate increases represents the magnitude (in percentages), in a given future year, that cumulative rate increases (compared with current fiscal 2017 rates) would be higher or lower in the scenario than they would have otherwise been in the base case, in that same year.

BC Hydro considered the following main items in estimating the ratepayer impact under a termination and remediation scenario:

1. Costs spent to-date on advancing the Project and costs directly related to termination and remediation; and
2. Costs for ratepayers of advancing energy and capacity resources in comparison to a portfolio that includes the Project

These incremental costs are described below.

Remove:

- Site C costs of $10 billion (total Site C construction costs as estimated by the BCUC including the forecast balance of Site C Regulatory Account) are removed at the end of fiscal 2024;
- Site C operating costs (comprised of water rental costs, operating costs, and taxes) are removed beginning in fiscal 2025; and
- Future sustaining capital expenditures totalling $2.1 billion are removed from the fiscal 2024 to fiscal 2094 period.

Replace with:

- Site C Regulatory Account costs of $4.0 billion (sunk, termination and remediation costs) are added at the end of fiscal 2019. These are comprised of the costs of $3.8 billion shown below at December 31, 2017 (which would increase by interest to $4.0 billion by the end of fiscal 2019):
    - Project capital costs to termination date ($1.6 billion);
    - Costs already in the Site C regulatory account ($0.5 billion); and
    - Costs directly related to the Project termination and remediation that would be recovered from ratepayers ($1.7 billion); and
- Incremental cost of advancing alternative sources of energy and capacity in order to compensate for the removal of Site C. These include advancing both energy and capacity focused DSM measures and generation resources.

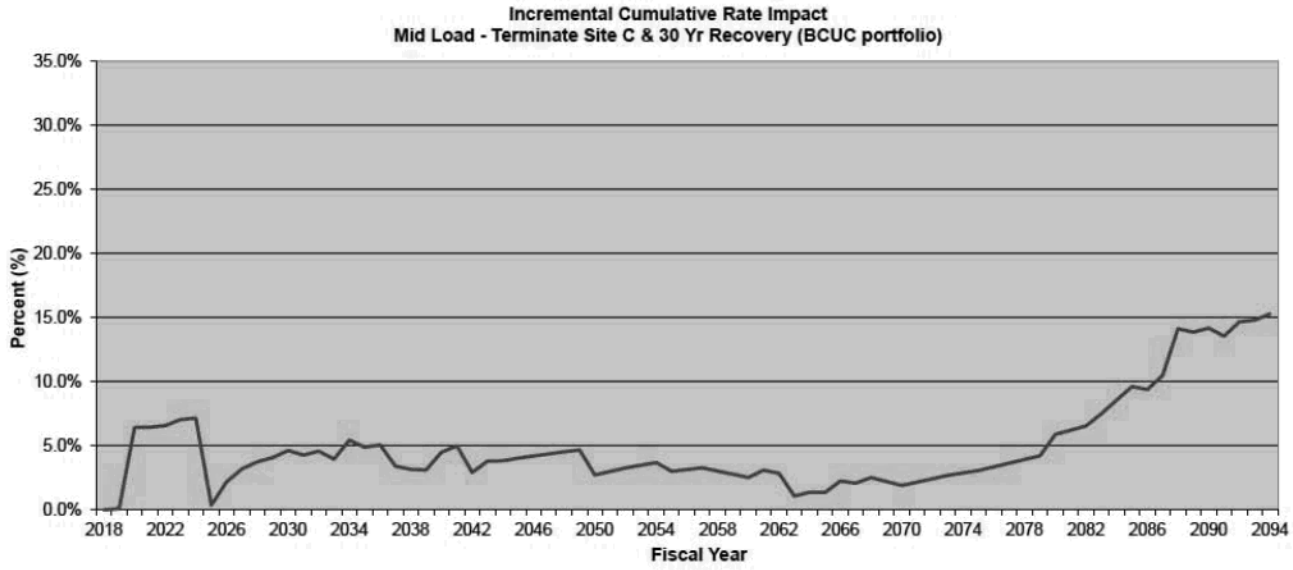
The table below shows the estimated incremental impact on cumulative rate increases under the two Termination scenarios. The incremental cumulative rate increase in fiscal 2020 is shown because it is the first year in which the recovery of the Site C Regulatory Account, as a result of termination, will impact customer rates.

	Estimated Incremental Cumulative Rate Increases (%)			
	in F2020	**in F2024**	**in F2044**	**in F2094**
Mid Load – Terminate Site C and 30 Year Recovery	6.4	7.2	3.8	15.3
Low Load – Terminate Site C and 30 Year Recovery	6.8	7.7	9.0	32.5

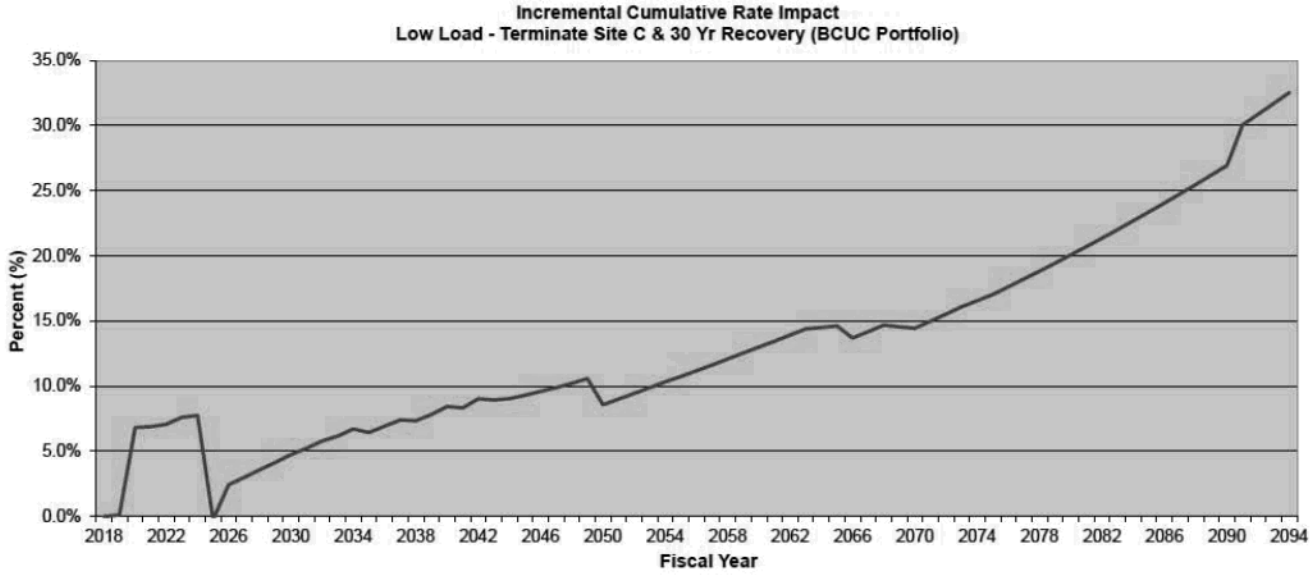
Rate Charts

Charts showing the estimated incremental cumulative rate impacts are shown below for each scenario.

Terminate – Mid Load:



Terminate – Low Load:



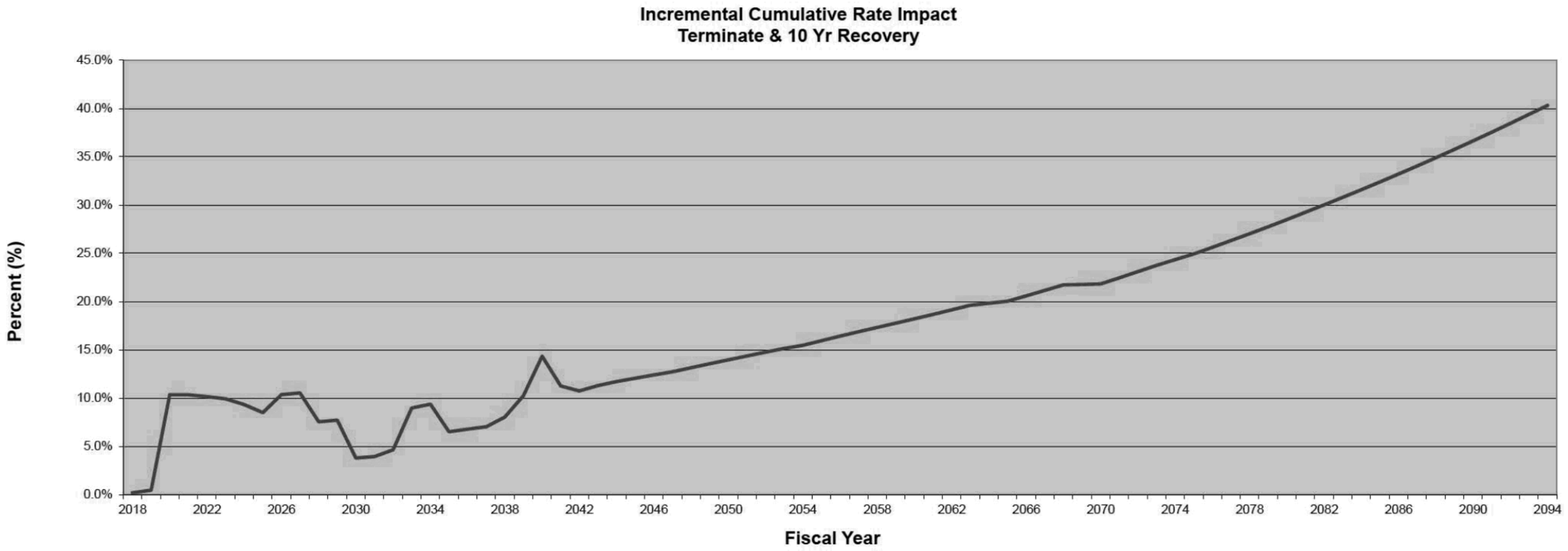
Attachment 1 – Summary of Portfolio Modelling Assumptions

Assumptions Scenario	August 30 Filing	BC Hydro Optimistic Portfolio Sensitivity	BC Hydro Analysis using Commission Illustrative Alternative Portfolio Assumptions
MODEL ASSUMPTIONS			
Load Forecast Scenarios	- Low / Mid / High	- Low / Mid / High	- Low / Mid (insufficient time to run high load scenario)
Financing Assumption	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances Site C, DSM, and Resource Smart - IPPs finance alternative resources	- BC Hydro finances all resources
Market Prices	- ABB Mid Forecast	- ABB Mid Forecast	- BCUC Market Price Forecast
Site C Costs	- $8.335 billion	- $8.335 billion	- $10 billion
Termination and Sunk Costs	- $3.2 billion ($2.1 sunk costs, $1.1 termination costs)	- $3.2 billion ($2 1 sunk costs, $1.1 termination costs)	- $3.9 billion ($2.1 sunk costs, $1.8 termination costs)
Sunk & termination cost recovery period	- 10 years	- 10 years	- 30 years
ALTERNATIVE RESOURCE ASSUMPTIONS			
Capacity Focused DSM	- Industrial Load Curtailment: 85 MW	- Industrial Load Curtailment: 85 MW - Capacity Focused DSM potential: 450MW	- Industrial Load Curtailment: 400 MW - Capacity Focused DSM and optional TOU potential: 640MW
Resource Smart	- Revelstoke Unit 6 when selected by model	- Revelstoke Unit 6 when selected by model - GMS upgrade when selected by model	- Revelstoke Unit 6 assumed in-place in Fiscal 2026
Wind	BC Hydro Resource Options Update w/ IPP financing: - F2040 new build @ $82/MWh ($2018) - F2070 refurbishment @ $82/MWh ($2018) - Wind integration cost of $5/MWh	Lower wind costs w/ BCH financing: - F2040 new build @ $64/MWh ($2018) - F2070 refurbishment @ $58/MWh ($2018) - Wind integration cost of $5/MWh	Much lower wind costs w/ BCH financing, with further reductions for refurbishment/renewal: - F2040 new build @ $43/MWh ($2018) - F2070 refurbishment @ $31/MWh ($2018) - Wind integration cost of $1/MWh
Pumped Storage	BC Hydro Resource Options Update: - F2030 new build @ $125/kW-yr ($2018)	BC Hydro Resource Options Update: - F2030 new build @ $125/kW-yr ($2018)	BC Hydro Resource Options Update: - F2030 new build @ $52/kW-yr ($2018)
Geothermal	- Excluded as not confirmed to be commercially viable	- 200MW of potential @ $120/MWh	- 80MW of potential @ $80/MWh (not selected in portfolio)
Solar	- Excluded as not economic	Modeled using NREL mid cost declines (43% by 2040) - (not selected in portfolio)	Modeled using Commission-suggested cost declines (60% by 2040) - (not selected in portfolio)
Batteries	- Excluded as not economic	- Modeled using Commission-suggested (Lazard) cost declines (50% by 2040) (not selected in portfolio)	- Screened out due to high cost. Aligns with suggestion in the Commission's final report.

BC Hydro
Rate Impact Analysis

Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Rate Impact Chart
Page1



BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Summary
Page 2

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216 9	343.5	363.2	417.4	662.6	717.6	575.5	610.5	654.0	727.1	864.8	1,121.1	965.3	958.9
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128.0	125.5	93.1	(13.3)	42.2	(49 8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81.0)	(77.7)	(80.5)	(62.7)
3	**Amortization**		0.0	0.0	318.6	318.6	318.6	318.6	318.6	199.5	199.5	199.5	199.5	199 5	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	121.4	109.2	94.6	86.7	78.8	(212.8)	(216.8)	(222.7)	(229.4)	(236 9)	(241.0)	(240.1)	(239.8)	(240.0)	(240.9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																										
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8 2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75 3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)
8	**Estimated Total Change in Revenue Requirement:**		(4.0)	(1.3)	433.7	416.7	391.5	364.1	318.2	257.4	342.9	342.0	187.4	196 9	0.3	18.8	70.5	311.3	355.1	199.7	220.5	249.9	312.9	443.4	692.9	530.1	517.8
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,706	8,961	9,243	9,540	9,871	10,182	10,522
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,634	4,843	5,438	5,635	5,856	6,059	6,262	6,410	6,700	6,901	6,969	7,192	7,220	7,463	7,761	8,244	8,534	8,635	8,926	9,211	9,556	9,984	10,564	10,712	11,039
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,192)	(6,378)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,549)	(8,815)	(9,098)	(9,393)	(9,725)	(10,046)	(10,395)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	8.8	21.2	469.9	475.4	474.4	470.0	448.2	412.4	508.6	522.8	378.9	392 5	194.9	205.7	246.2	480.8	508.8	357.9	377.0	395.7	457.8	590.3	838.6	665.9	644.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.19%	0.44%	9.46%	9.21%	8.82%	8.41%	7.71%	6.88%	8.21%	8.20%	5.75%	5.77%	2.77%	2.83%	3.28%	6.19%	6.34%	4.32%	4.41%	4.49%	5 03%	6.28%	8.62%	6.63%	6.20%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121.2	123.6	126.1	128.6	131.2	133 8	136.5	139.2	142.0	144.8	147.7	150.7	153.7	156.8	159.9	163.1	166.4	169.7	173.1
15	Scenario	Line 14 * (1+Line 13)	103.7	107.1	119.7	122.6	125.3	128.1	130.5	132.1	136.5	139.2	138.7	141 5	140.3	143.2	146.7	153.8	157.1	157.2	160.5	163.8	168.0	173.4	180.7	181.0	183.8
16	Base Case	(Line 14 - 100) / 100	3 5%	6.6%	9.4%	12.2%	15.1%	18.1%	21.2%	23.6%	26.1%	28.6%	31.2%	33.8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.7%	56.8%	59.9%	63.1%	66.4%	69.7%	73.1%
17	Scenario	(Line 15 - 100) / 100	3.7%	7.1%	19.7%	22.6%	25.3%	28.1%	30.5%	32.1%	36.5%	39.2%	38.7%	41.5%	40.3%	43.2%	46.7%	53.8%	57.1%	57.2%	60.5%	63.8%	68.0%	73.4%	80.7%	81.0%	83.8%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0 2%	0.5%	10.3%	10.3%	10.2%	9.9%	9.3%	8.5%	10.4%	10.5%	7.5%	7.7%	3.8%	3.9%	4.7%	9.0%	9.4%	6.5%	6.8%	7.0%	8.0%	10.3%	14.3%	11.2%	10.7%

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Summary
Page 3

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2043 26	2044 27	2045 28	2046 29	2047 30	2048 31	2049 32	2050 33	2051 34	2052 35	2053 36	2054 37	2055 38	2056 39	2057 40	2058 41	2059 42	2060 43	2061 44	2062 45	2063 46	2064 47	2065 48	2066 49	2067 50	2068 51
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		1,006.4	1,028.2	1,074.9	1,107.1	1,120.1	1,149.9	1,184.2	1,211.8	1,234.0	1,254.7	1,285.9	1,322.1	1,348.4	1,375.4	1,402.9	1,431.0	1,459.6	1,488.8	1,518.5	1,548.9	1,579.9	1,611.5	1,643.7	1,676.6	1,710.1	1,744 3
2	**Operating Costs**		(37.8)	(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95 0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120.5)	(122.9)	(125.4)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119 2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)
4	**Finance Charges**		(217.5)	(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138.8)	(134.1)	(129.4)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
	DSM Account																											
6	DSM Additions		(38.6)	(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
7	DSM Recoveries		(25.9)	(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16 9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0 2
8	**Estimated Total Change in Revenue Requirement:**		567.5	590.5	645.6	686.1	708.2	747.1	789.9	826.8	858.2	887.6	924.4	963 5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353 2
9	**Estimated Revenue Requirement - Base Case**		10,877	11,201	11,413	11,645	11,900	12,138	12,381	12,628	12,881	13,138	13,401	13,669	13,943	14,221	14,506	14,796	15,092	15,394	15,702	16,016	16,336	16,663	16,996	17,336	17,683	18,036
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,445	11,792	12,059	12,331	12,608	12,885	13,170	13,455	13,739	14,026	14,326	14,633	14,935	15,243	15,556	15,875	16,199	16,527	16,864	17,207	17,558	17,897	18,243	18,618	19,000	19,389
11	**Domestic Revenues**		(10,757)	(11,072)	(11,316)	(11,565)	(11,821)	(12,071)	(12,329)	(12,588)	(12,847)	(13,109)	(13,384)	(13,669)	(13,943)	(14,221)	(14,506)	(14,796)	(15,092)	(15,394)	(15,702)	(16,016)	(16,336)	(16,663)	(16,996)	(17,336)	(17,683)	(18,036)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	688.1	720.0	742.5	765.5	786.6	814.0	841.1	867.1	892.2	916.8	941.8	963 5	992.2	1,021.1	1,050.5	1,079.2	1,106.7	1,133.7	1,162.3	1,191.5	1,221.8	1,234.0	1,247.3	1,281.8	1,317.1	1,353 2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.40%	6.50%	6.56%	6.62%	6.65%	6.74%	6 82%	6.89%	6.94%	6.99%	7.04%	7.05%	7.12%	7.18%	7.24%	7.29%	7.33%	7.36%	7.40%	7.44%	7.48%	7.41%	7.34%	7.39%	7.45%	7.50%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		176.6	180.1	183.7	187.4	191.1	194.9	198.8	202.8	206.9	211.0	215.2	219 5	223.9	228.4	233.0	237.6	242.4	247.2	252.2	257.2	262.4	267.6	273.0	278.4	284.0	289.7
15	Scenario	Line 14 * (1+Line 13)	187.9	191.8	195.8	199.8	203.8	208.1	212.4	216.8	221.2	225.8	230.4	235 0	239.9	244.8	249.9	255.0	260.2	265.4	270.9	276.4	282.0	287.4	293.0	299.0	305.2	311.4
16	Base Case	(Line 14 - 100) / 100	76.6%	80.1%	83.7%	87.4%	91.1%	94.9%	98.8%	102.8%	106.9%	111.0%	115.2%	119.5%	123.9%	128.4%	133.0%	137.6%	142.4%	147.2%	152.2%	157.2%	162.4%	167.6%	173.0%	178.4%	184.0%	189.7%
17	Scenario	(Line 15 - 100) / 100	87.9%	91.8%	95.8%	99.8%	103.8%	108.1%	112.4%	116.8%	121.2%	125.8%	130.4%	135.0%	139.9%	144.8%	149.9%	155.0%	160.2%	165.4%	170.9%	176.4%	182.0%	187.4%	193.0%	199.0%	205.2%	211.4%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	11.3%	11.7%	12.1%	12.4%	12.7%	13.1%	13.6%	14.0%	14.4%	14.8%	15.1%	15.5%	15.9%	16.4%	16.9%	17.3%	17.8%	18.2%	18.7%	19.1%	19.6%	19.8%	20.0%	20.6%	21.2%	21.7%

BC Hydro
Rate Impact Analysis

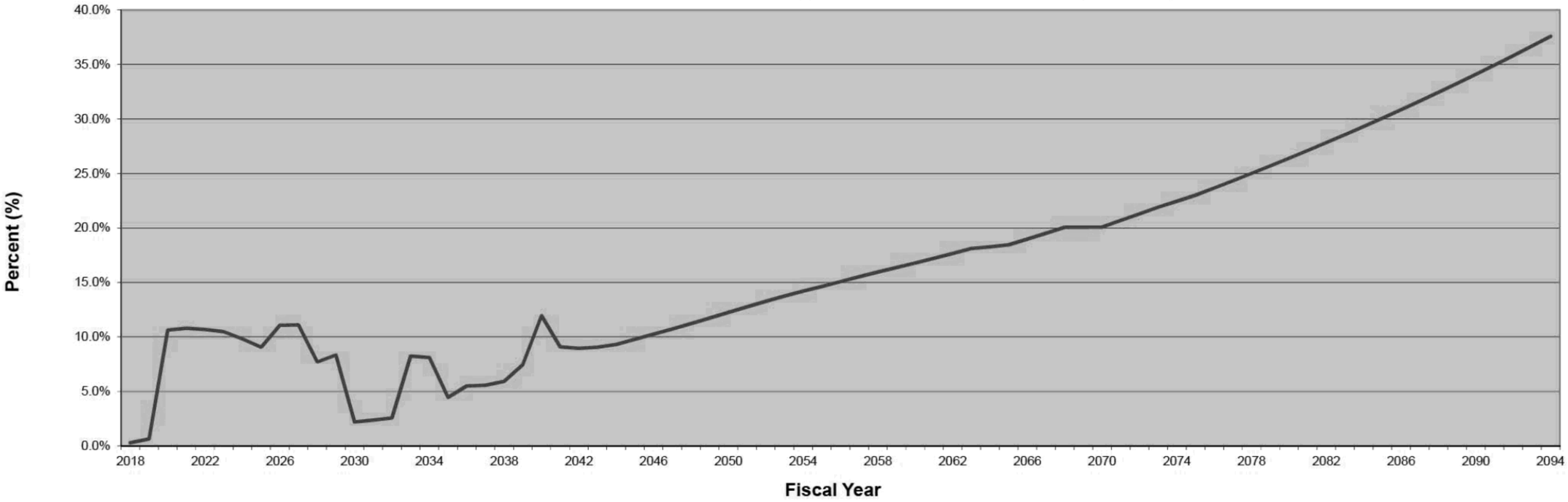
Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Summary
Page 4

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2069 / 52	2070 / 53	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																										
1	**Domestic Energy Costs**		1,779.2	1,814.8	1,851.1	1,888.1	1,925.9	1,964.4	2,003.7	2,043.8	2,084.6	2,126.3	2,168.9	2,212 2	2,256.5	2,301.6	2,347.6	2,394.6	2,442.5	2,491.3	2,541.2	2,592.0	2,643.8	2,696.7	2,750.6	2,805.6	2,861.8	2,919 0
2	**Operating Costs**		(127.9)	(130.5)	(133.1)	(135.7)	(138.5)	(141.2)	(144.1)	(146.9)	(149.9)	(152.9)	(155.9)	(159 0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209 9)
3	**Amortization**		(150.1)	(163.8)	(163.8)	(163.8)	(163.8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(145.7)	(161.5)	(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111 2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
	DSM Account																										
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
8	**Estimated Total Change in Revenue Requirement:**		1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774 3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
9	**Estimated Revenue Requirement - Base Case**		18,397	18,765	19,140	19,523	19,913	20,312	20,718	21,132	21,555	21,986	22,426	22,874	23,332	23,798	24,274	24,760	25,255	25,760	26,275	26,801	27,337	27,884	28,441	29,010	29,590	30,182
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	19,752	20,124	20,539	20,961	21,392	21,827	22,270	22,727	23,194	23,669	24,154	24,649	25,153	25,667	26,192	26,726	27,272	27,828	28,395	28,974	29,563	30,165	30,779	31,404	32,042	32,693
11	**Domestic Revenues**		(18,397)	(18,765)	(19,140)	(19,523)	(19,913)	(20,312)	(20,718)	(21,132)	(21,555)	(21,986)	(22,426)	(22,874)	(23,332)	(23,798)	(24,274)	(24,760)	(25,255)	(25,760)	(26,275)	(26,801)	(27,337)	(27,884)	(28,441)	(29,010)	(29,590)	(30,182)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,355.5	1,359.0	1,398.3	1,438.3	1,479.0	1,515.1	1,551.9	1,594.9	1,638.6	1,683.0	1,728.2	1,774 3	1,821.1	1,868.7	1,917.2	1,966.5	2,016.7	2,067.8	2,119.8	2,172.7	2,226.6	2,281.4	2,337.2	2,394.0	2,451.9	2,510.7
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	7.37%	7.24%	7.31%	7.37%	7.43%	7.46%	7.49%	7.55%	7.60%	7.65%	7.71%	7.76%	7.81%	7.85%	7.90%	7.94%	7.99%	8.03%	8.07%	8.11%	8.14%	8.18%	8.22%	8.25%	8.29%	8.32%
	Typical Customer Bill (F2017 = 100)																										
14	Base Case		295.5	301.4	307.4	313.6	319.8	326.2	332.8	339.4	346.2	353.1	360.2	367.4	374.7	382.2	389.9	397.7	405.6	413.7	422.0	430.5	439.1	447.8	456.8	465.9	475.3	484 8
15	Scenario	Line 14 * (1+Line 13)	317.2	323.2	329.9	336.7	343.6	350.6	357.7	365.0	372.5	380.2	387.9	395 9	404.0	412.2	420.7	429.3	438.0	446.9	456.1	465.3	474.8	484.5	494.3	504.4	514.6	525.1
16	Base Case	(Line 14 - 100) / 100	195.5%	201.4%	207.4%	213.6%	219.8%	226.2%	232.8%	239.4%	246.2%	253.1%	260.2%	267.4%	274.7%	282.2%	289.9%	297.7%	305.6%	313.7%	322.0%	330.5%	339.1%	347.8%	356.8%	365.9%	375.3%	384.8%
17	Scenario	(Line 15 - 100) / 100	217.2%	223.2%	229.9%	236.7%	243.6%	250.6%	257.7%	265.0%	272.5%	280.2%	287.9%	295.9%	304.0%	312.2%	320.7%	329.3%	338.0%	346.9%	356.1%	365.3%	374.8%	384.5%	394.3%	404.4%	414.6%	425.1%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	21.8%	21.8%	22.5%	23.1%	23.8%	24.3%	24.9%	25.6%	26.3%	27.0%	27.8%	28.5%	29.2%	30.0%	30.8%	31.6%	32.4%	33.2%	34.0%	34.9%	35.8%	36.6%	37.5%	38.5%	39.4%	40.3%

Incremental Cumulative Rate Impact
Mid Load / Terminate & 10 Yr Recovery / Low Cost vs. Mid Load Base (Low Cost)



Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		(1.1)	(2.1)	(3.4)	(5.7)	(20.0)	(46.7)	(95.1)	265.6	370.6	381.5	213.7	248.6	262.1	281.3	307.2	623.8	649.4	462.2	540.2	572.0	606.9	704 3	983.1	838.7	854.3	872.0
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128 0	125.5	93.1	(13.3)	42.2	(49 8)	(71.0)	(86.1)	(104.6)	(129.4)	(152.6)	(154.9)	(157.5)	(118.8)	(86.3)	(81 0)	(77.7)	(80.5)	(62.7)	(37.8)
3	**Amortization**		0.0	0 0	318.6	318.6	318.6	318.6	318.6	199.5	199.5	199.5	199.5	199 5	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	121.4	109.2	94.6	86.7	78 8	(212.8)	(216.8)	(222.7)	(229.4)	(236.9)	(241.0)	(240.1)	(239.8)	(240.0)	(240 9)	(241.8)	(242.3)	(241.7)	(239.4)	(236.1)	(232.3)	(228.1)	(223.3)	(217.5)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(133.0)	(42.4)	(99.0)	(8 2)	12.0	25.8	43.1	66.7	88.7	89.7	91.0	50.9	17.0	10.3	5.7	7.1	(12.3)	(38.6)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	65.9	68.7	75 3	75.9	75.1	73.4	70.5	61.4	50.3	38.0	24.6	13.5	4.4	(4.8)	(14.6)	(23.9)	(25.9)
8	**Estimated Total Change in Revenue Requirement:**		0.3	6.6	446.5	438.3	416.6	389.7	341.4	284.5	370.5	368.5	195.7	228.6	(81.1)	(63.0)	(39.8)	272.5	286 9	86.4	150.3	167.9	192.7	282 9	554.9	403.5	413.1	433.1
9	**Estimated Revenue Requirement - Base Case**		4,638	4,844	5,004	5,219	5,464	5,695	5,944	6,153	6,357	6,559	6,781	6,995	7,220	7,444	7,691	7,933	8,179	8,436	8,688	8,943	9,186	9,466	9,774	10,062	10,293	10,713
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,638	4,850	5,451	5,657	5,881	6,085	6,286	6,437	6,728	6,928	6,977	7,223	7,139	7,381	7,651	8,206	8,466	8,522	8,839	9,111	9,379	9,749	10,329	10,465	10,706	11,146
11	**Domestic Revenues**		(4,625)	(4,821)	(4,968)	(5,160)	(5,381)	(5,589)	(5,814)	(5,998)	(6,185)	(6,377)	(6,590)	(6,799)	(7,026)	(7,257)	(7,515)	(7,764)	(8,025)	(8,277)	(8,532)	(8,797)	(9,042)	(9,320)	(9,629)	(9,927)	(10,169)	(10,594)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	13.0	29.1	482.8	497.0	499.5	495.6	471.4	439.5	543.1	550.6	387.2	424 2	113.5	123.9	136.0	442.0	440.7	244.7	306.5	313.5	336.8	428.7	699.2	537.8	537.5	552.0
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.28%	0.60%	9.72%	9.63%	9.28%	8.87%	8.11%	7.33%	8.78%	8.63%	5.87%	6.24%	1.62%	1.71%	1.81%	5.69%	5.49%	2.96%	3.59%	3.56%	3.72%	4.60%	7.26%	5.42%	5.29%	5.21%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		103.5	106.6	109.4	112.2	115.1	118.1	121 2	123.6	126.1	128.6	131.2	133 8	136.5	139.2	142.0	144.8	147.7	150.7	153.4	156.5	158.9	161 9	164.7	167.7	169.4	173.9
15	Scenario	Line 14 * (1+Line 13)	103.8	107.2	120.0	123.0	125.8	128.6	131 0	132.7	137.2	139.7	138.9	142 2	138.7	141.6	144.6	153.1	155 9	155.2	158.9	162.1	164.9	169 3	176.7	176.8	178.3	183.0
16	Base Case	(Line 14 - 100) / 100	3.5%	6.6%	9.4%	12.2%	15.1%	18.1%	21 2%	23.6%	26.1%	28.6%	31.2%	33 8%	36.5%	39.2%	42.0%	44.8%	47.7%	50.7%	53.4%	56.5%	58.9%	61 9%	64.7%	67.7%	69.4%	73.9%
17	Scenario	(Line 15 - 100) / 100	3.8%	7 2%	20.0%	23.0%	25.8%	28.6%	31 0%	32.7%	37.2%	39.7%	38.9%	42 2%	38.7%	41.6%	44.6%	53.1%	55 9%	55.2%	58.9%	62.1%	64.9%	69 3%	76.7%	76.8%	78.3%	83.0%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.3%	0.6%	10.6%	10.8%	10.7%	10.5%	9 8%	9.1%	11.1%	11.1%	7.7%	8 3%	2.2%	2.4%	2.6%	8.2%	8.1%	4.5%	5.5%	5.6%	5.9%	7.4%	12.0%	9.1%	9.0%	9.1%

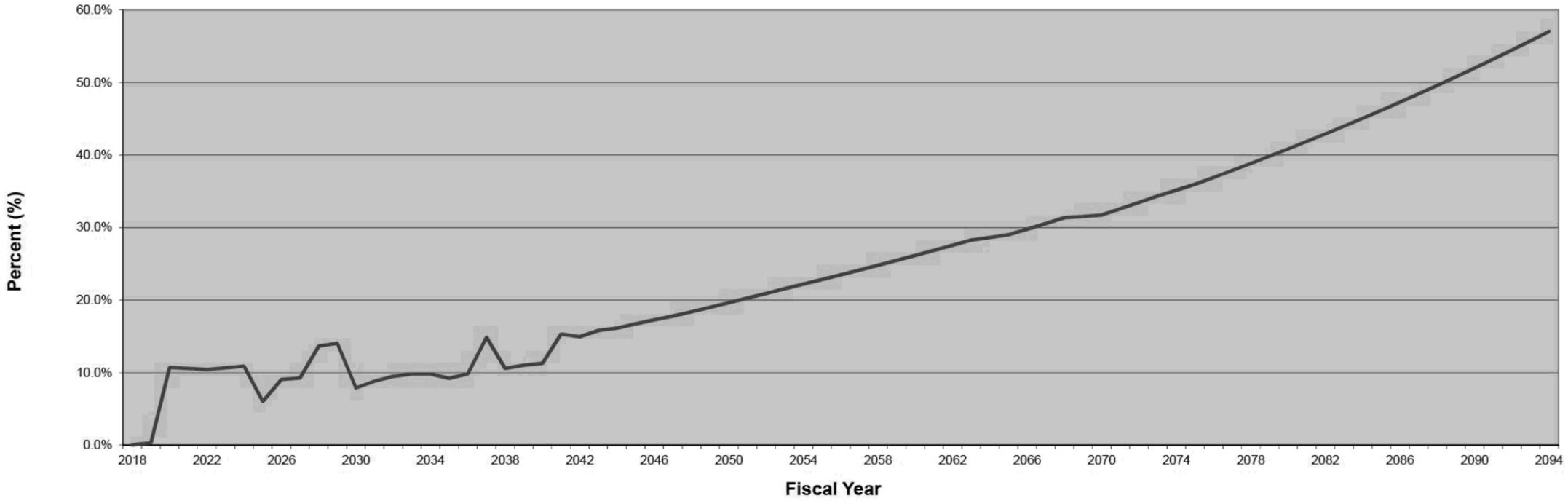
Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51	2069 / 52	2070 / 53
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		889.4	907.2	925.4	943.9	962.7	982.0	1,001.6	1,021.7	1,042.1	1,062.9	1,084.2	1,105.9	1,128.0	1,150.6	1,173.6	1,197.1	1,221.0	1,245.4	1,270.3	1,295.7	1,321.6	1,348.1	1,375 0	1,402.5	1,430.6	1,459.2	1,488.4
2	**Operating Costs**		(21.2)	(38.0)	(38.8)	(46.4)	(70.6)	(74.3)	(78.1)	(82.7)	(87.5)	(90.9)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120 5)	(122.9)	(125.4)	(127.9)	(130.5)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119 2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)	(150.1)	(163.8)
4	**Finance Charges**		(210.8)	(204.1)	(197.7)	(191.5)	(186.0)	(181.2)	(176.7)	(172.4)	(168.4)	(164.7)	(161.1)	(157.6)	(154.1)	(150.7)	(147.2)	(143.7)	(140.0)	(136.3)	(132.4)	(128.5)	(136.1)	(143.4)	(138 8)	(134.1)	(129.4)	(145.7)	(161.5)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(56.8)	(41.5)	(42.3)	(36.4)	(13.8)	(11.7)	(9.7)	(6.9)	(3.9)	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		(29.9)	(26.7)	(23.1)	(18.6)	(13.3)	(7.9)	(1.2)	5.4	11.9	15.6	16.9	17.5	17.9	18.4	17.6	15.0	11.2	8.5	5.6	3.2	2.3	1.5	0.9	0.4	0.2	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		451.7	477.9	504.4	531.9	560.0	587.6	616.7	645.9	675.0	701.4	725.7	749.6	773.7	798.2	821.9	844.2	865.9	889.2	912.9	937.6	944.2	951.6	980.2	1,009.5	1,039.5	1,035.5	1,032.6
9	**Estimated Revenue Requirement - Base Case**		11,036	11,271	11,510	11,753	11,996	12,247	12,496	12,744	12,995	13,261	13,536	13,807	14,083	14,365	14,652	14,945	15,244	15,549	15,860	16,177	16,500	16,830	17,167	17,510	17,861	18,218	18,582
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	11,487	11,748	12,014	12,285	12,556	12,835	13,112	13,390	13,670	13,962	14,262	14,556	14,857	15,163	15,474	15,789	16,110	16,438	16,773	17,114	17,445	17,782	18,147	18,520	18,900	19,253	19,615
11	**Domestic Revenues**		(10,914)	(11,147)	(11,383)	(11,624)	(11,864)	(12,112)	(12,359)	(12,604)	(12,852)	(13,115)	(13,388)	(13,655)	(13,928)	(14,207)	(14,491)	(14,781)	(15,076)	(15,378)	(15,686)	(15,999)	(16,319)	(16,646)	(16,979)	(17,318)	(17,664)	(18,018)	(18,378)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	572.9	601.9	631.0	661.0	691.6	722.1	753.9	785.8	817.7	847.0	874.3	901.2	928.3	955.9	982.7	1,008.3	1,033.3	1,059.9	1,087.0	1,115.2	1,125.3	1,136.4	1,168.7	1,201.7	1,235.6	1,235.5	1,236.6
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	5.25%	5.40%	5.54%	5.69%	5.83%	5.96%	6.10%	6.23%	6.36%	6.46%	6.53%	6.60%	6.66%	6.73%	6.78%	6.82%	6.85%	6.89%	6.93%	6.97%	6.90%	6.83%	6 88%	6.94%	6.99%	6.86%	6.73%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		177.4	181.4	185.2	188.8	192.7	196.7	200.7	204.7	208.7	213.0	217.4	221.8	226.2	230.7	235.3	240.0	244.8	249.7	254.7	259.8	265.0	270.3	275.7	281.2	286.9	292.6	298.5
15	Scenario	Line 14 * (1+Line 13)	186.8	191.2	195.5	199.5	203.9	208.4	212.9	217.4	222.0	226.7	231.6	236.4	241.3	246.2	251.3	256.4	261.6	266.9	272.4	277.9	283.3	288.8	294.7	300.8	306.9	312.7	318.5
16	Base Case	(Line 14 - 100) / 100	77.4%	81.4%	85.2%	88.8%	92.7%	96.7%	100.7%	104.7%	108.7%	113.0%	117.4%	121.8%	126.2%	130.7%	135.3%	140.0%	144.8%	149.7%	154.7%	159.8%	165.0%	170.3%	175.7%	181.2%	186.9%	192.6%	198.5%
17	Scenario	(Line 15 - 100) / 100	86.8%	91.2%	95.5%	99.5%	103.9%	108.4%	112.9%	117.4%	122.0%	126.7%	131.6%	136.4%	141.3%	146.2%	151.3%	156.4%	161.6%	166.9%	172.4%	177.9%	183.3%	188.8%	194.7%	200.8%	206.9%	212.7%	218.5%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	9.3%	9.8%	10.3%	10.7%	11.2%	11.7%	12.2%	12.8%	13.3%	13.8%	14.2%	14.6%	15.1%	15.5%	16.0%	16.4%	16.8%	17.2%	17.7%	18.1%	18.3%	18.5%	19.0%	19.5%	20.1%	20.1%	20.1%

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																								
1	**Domestic Energy Costs**		1,518.2	1,548.5	1,579 5	1,611.1	1,643.3	1,676.2	1,709.7	1,743 9	1,778.8	1,814.3	1,850.6	1,887.6	1,925.4	1,963.9	2,003.2	2,043.2	2,084.1	2,125.8	2,168.3	2,211.7	2,255.9	2,301.0	2,347 0	2,394.0
2	**Operating Costs**		(133.1)	(135.7)	(138 5)	(141.2)	(144.1)	(146.9)	(149.9)	(152 9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(163.8)	(163.8)	(163 8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,065.4	1,098.7	1,132.6	1,161.7	1,191.5	1,227.3	1,263.6	1,300.6	1,338.1	1,376.4	1,415.2	1,454.7	1,494.9	1,535.8	1,577.4	1,619.7	1,662.7	1,706.5	1,751.1	1,796.4	1,842.5	1,889.4	1,937.1	1,985.7
9	**Estimated Revenue Requirement - Base Case**		18,954	19,333	19,720	20,114	20,516	20,927	21,345	21,772	22,207	22,652	23,105	23,567	24,038	24,519	25,009	25,509	26,019	26,540	27,071	27,612	28,164	28,728	29,302	29,888
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	20,019	20,432	20,852	21,276	21,708	22,154	22,609	23,073	23,546	24,028	24,520	25,021	25,533	26,055	26,587	27,129	27,682	28,246	28,822	29,408	30,007	30,617	31,239	31,874
11	**Domestic Revenues**		(18,746)	(19,121)	(19,503)	(19,893)	(20,291)	(20,697)	(21,111)	(21,533)	(21,964)	(22,403)	(22,851)	(23,308)	(23,774)	(24,250)	(24,735)	(25,229)	(25,734)	(26,249)	(26,773)	(27,309)	(27,855)	(28,412)	(28,980)	(29,560)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,273.4	1,310.9	1,349 0	1,382.5	1,416.8	1,457.0	1,497.9	1,539.6	1,581.9	1,625.0	1,668.9	1,713.4	1,758.8	1,805.0	1,852.0	1,899.7	1,948.4	1,997.9	2,048.2	2,099.5	2,151.7	2,204.8	2,258 8	2,313.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	6.79%	6.86%	6.92%	6.95%	6.98%	7.04%	7.10%	7.15%	7.20%	7.25%	7.30%	7.35%	7.40%	7.44%	7.49%	7.53%	7.57%	7.61%	7.65%	7.69%	7.72%	7.76%	7.79%	7.83%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		304.4	310.5	316.7	323.1	329.5	336.1	342.8	349.7	356.7	363.8	371.1	378.5	386.1	393.8	401.7	409.7	417.9	426.3	434.8	443.5	452.4	461.4	470.6	480.0
15	Scenario	Line 14 * (1+Line 13)	325.1	331.8	338.6	345.5	352.5	359.8	367.2	374.7	382.4	390.2	398.2	406.3	414.6	423.1	431.7	440.6	449.5	458.7	468.0	477.6	487.3	497.2	507.3	517.6
16	Base Case	(Line 14 - 100) / 100	204.4%	210.5%	216.7%	223.1%	229.5%	236.1%	242.8%	249.7%	256.7%	263.8%	271.1%	278.5%	286.1%	293.8%	301.7%	309.7%	317.9%	326.3%	334.8%	343.5%	352.4%	361.4%	370.6%	380.0%
17	Scenario	(Line 15 - 100) / 100	225.1%	231.8%	238.6%	245.5%	252.5%	259.8%	267.2%	274.7%	282.4%	290.2%	298.2%	306.3%	314.6%	323.1%	331.7%	340.6%	349.5%	358.7%	368.0%	377.6%	387.3%	397.2%	407 3%	417.6%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	20.7%	21.3%	21.9%	22.5%	23.0%	23.7%	24.3%	25.0%	25.7%	26.4%	27.1%	27.8%	28.6%	29.3%	30.1%	30.9%	31.6%	32.4%	33.3%	34.1%	34.9%	35.8%	36.7%	37.6%

Incremental Cumulative Rate Impact
Low Load / Terminate & 10 Yr Recovery / Low Cost vs. Low Load Base (Low Cost)



Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		(22.4)	(19.1)	(39.0)	(53.3)	(60.8)	(67.5)	(72.6)	108.3	238.6	243.3	439.6	446.6	459.2	474.1	483.5	491.0	490.1	467.4	474.7	721.2	488.9	495 5	499.0	707.4	686.7	718.2
2	**Operating Costs**		69.6	78.4	94.6	110.2	114.8	119.1	128 0	125.5	103.4	60.7	49.1	45 8	44.3	48.2	35.3	15.8	3.4	16.9	17.2	23.2	42.8	45.5	48.3	51.7	55.3	57.8
3	**Amortization**		0.0	0 0	318.6	318.6	318.6	318.6	318.6	199.5	199.5	199.5	199.5	199 5	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		1.4	4.1	121.4	109.2	94.6	86.7	78 8	(212.8)	(216.6)	(221.1)	(226.6)	(232.5)	(233.2)	(228.6)	(224.4)	(221.0)	(218.1)	(215.2)	(212.0)	(208.6)	(204.6)	(200.2)	(195.6)	(190.9)	(185.9)	(180.7)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(69.6)	(78.4)	(94.6)	(110.2)	(114.8)	(119.1)	(128.0)	(140.9)	(143.3)	(116.4)	(105.8)	(103.7)	(103.4)	(108.5)	(96.8)	(78.5)	(67 3)	(82.1)	(83.8)	(91.0)	(112.0)	(116.1)	(120.3)	(125.2)	(130.3)	(134.2)
7	DSM Recoveries		0.0	4.6	9.9	16.2	23.5	31.2	39.1	47.6	57.0	66.6	74.4	81.4	88.3	95.2	102.5	108.9	109 5	108.8	107.9	106.2	104.6	104.1	103.3	101.9	100.7	101.7
8	**Estimated Total Change in Revenue Requirement:**		(21.0)	(10.4)	410.8	390.7	375.9	369.0	363 9	127.2	238.6	232.6	430.1	437.1	136.2	161.3	181.0	197.2	198.4	176.7	185.0	431.8	200.5	209.7	215.6	425.9	407.5	443.6
9	**Estimated Revenue Requirement - Base Case**		4,558	4,738	4,888	5,078	5,276	5,462	5,648	5,881	6,036	6,215	6,213	6,401	6,586	6,779	6,987	7,186	7,397	7,403	7,595	7,796	8,221	8,446	8,697	8,822	9,032	9,423
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,538	4,728	5,299	5,468	5,652	5,831	6,012	6,009	6,275	6,448	6,643	6,838	6,722	6,940	7,168	7,383	7,595	7,579	7,780	8,227	8,422	8,656	8,913	9,248	9,439	9,867
11	**Domestic Revenues**		(4,536)	(4,714)	(4,838)	(5,011)	(5,197)	(5,363)	(5,530)	(5,740)	(5,869)	(6,029)	(6,020)	(6,191)	(6,356)	(6,526)	(6,718)	(6,912)	(7,119)	(7,128)	(7,294)	(7,487)	(7,890)	(8,097)	(8,333)	(8,451)	(8,653)	(9,025)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1.7	13.7	461.3	456.9	454.7	467.7	481 8	268.2	405.6	418.5	623.0	647.4	366.2	414.7	450.0	470.7	476 2	450.8	485.8	740.1	531.7	558 9	579.8	796.3	785.9	842.0
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.04%	0.29%	9.54%	9.12%	8.75%	8.72%	8.71%	4.67%	6.91%	6.94%	10.35%	10.46%	5.76%	6.35%	6.70%	6.81%	6.69%	6.32%	6.66%	9.88%	6.74%	6.90%	6.96%	9.42%	9.08%	9.33%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		105.3	109.0	112.1	115.8	119.1	122.1	124 8	128.8	130.8	133.3	131.8	134.4	136.6	138.8	141.4	144.0	146.6	145.6	147.5	150.2	156.7	159 3	162.1	162.6	164.4	169.2
15	Scenario	Line 14 * (1+Line 13)	105.3	109.3	122.8	126.3	129.5	132.8	135.7	134.8	139.8	142.5	145.4	148.4	144.5	147.7	150.8	153.8	156.4	154.8	157.3	165.1	167.2	170 3	173.4	177.9	179.3	185.0
16	Base Case	(Line 14 - 100) / 100	5.3%	9 0%	12.1%	15.8%	19.1%	22.1%	24 8%	28.8%	30.8%	33.3%	31.8%	34.4%	36.6%	38.8%	41.4%	44.0%	46.6%	45.6%	47.5%	50.2%	56.7%	59 3%	62.1%	62.6%	64.4%	69.2%
17	Scenario	(Line 15 - 100) / 100	5.3%	9 3%	22.8%	26.3%	29.5%	32.8%	35.7%	34.8%	39.8%	42.5%	45.4%	48.4%	44.5%	47.7%	50.8%	53.8%	56.4%	54.8%	57.3%	65.1%	67.2%	70 3%	73.4%	77.9%	79.3%	85.0%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.0%	0 3%	10.7%	10.6%	10.4%	10.7%	10 9%	6.0%	9.0%	9.2%	13.6%	14.1%	7.9%	8.8%	9.5%	9.8%	9 8%	9.2%	9.8%	14.8%	10.6%	11 0%	11.3%	15.3%	14.9%	15.8%

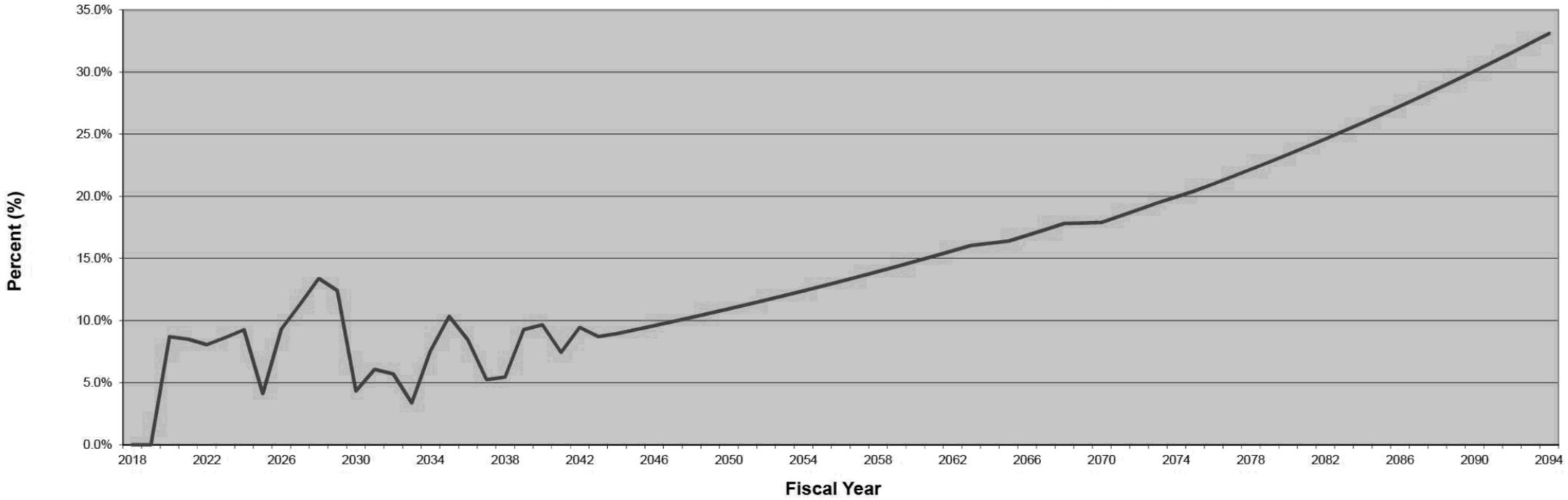
Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51	2069 / 52	2070 / 53
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		732.5	747.2	762.1	777.4	792.9	808.8	825.0	841.5	858.3	875.5	893.0	910.8	929.0	947.6	966.6	985.9	1,005.6	1,025.7	1,046.3	1,067.2	1,088.5	1,110.3	1,132 5	1,155.2	1,178.3	1,201.8	1,225.9
2	**Operating Costs**		60.9	62.1	63.3	64.6	65.9	67.2	68.5	69.9	71.3	72.7	74.2	75.7	77.2	78.7	80.3	81.9	83.6	85.2	86.9	88.7	90.4	92.2	94.1	96.0	97.9	99.9	101.9
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119 2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)	(150.1)	(163.8)
4	**Finance Charges**		(175.5)	(170.2)	(164 9)	(159.5)	(154.2)	(149.0)	(143.8)	(138.7)	(133.6)	(128.6)	(123.6)	(118.6)	(113.6)	(108.7)	(103.7)	(98.7)	(93.7)	(88.6)	(83.6)	(78.5)	(85.0)	(91.2)	(85.5)	(79.8)	(74.0)	(89.1)	(103.8)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		(138.8)	(141.6)	(144.4)	(147.3)	(150.3)	(153.3)	(156.3)	(159 5)	(162.7)	(165.9)	(169.2)	(172.6)	(176.1)	(179.6)	(183.2)	(186.9)	(190.6)	(194.4)	(198.3)	(202.3)	(206.3)	(210.4)	(214.6)	(218.9)	(223.3)	(227.8)	(232.3)
7	DSM Recoveries		103.6	105.9	108.4	110.8	114.2	119.0	124.7	129.7	134.7	139.5	143.1	146.6	150.1	153.5	156.8	160.1	163.3	166.5	169.9	173.3	176.7	180.3	183.9	187.5	191.3	195.1	199.0
8	**Estimated Total Change in Revenue Requirement:**		463.6	484.3	505.5	526.9	549.5	573.5	598.8	623.6	648.8	673.9	698.2	722.6	747.4	772.4	797.6	823.1	849.0	875.2	902.0	929.1	936.6	944.8	973.9	1,003.6	1,033.8	1,029.8	1,026.8
9	**Estimated Revenue Requirement - Base Case**		9,719	9,933	10,151	10,373	10,594	10,820	11,044	11,267	11,492	11,728	11,973	12,211	12,454	12,702	12,954	13,210	13,469	13,735	14,007	14,284	14,569	14,859	15,156	15,458	15,767	16,082	16,404
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	10,182	10,417	10,656	10,900	11,143	11,394	11,643	11,890	12,140	12,402	12,671	12,934	13,201	13,475	13,752	14,033	14,318	14,611	14,909	15,213	15,505	15,804	16,130	16,462	16,801	17,112	17,431
11	**Domestic Revenues**		(9,312)	(9,517)	(9,726)	(9,940)	(10,151)	(10,368)	(10,582)	(10,796)	(11,012)	(11,238)	(11,473)	(11,701)	(11,934)	(12,171)	(12,413)	(12,658)	(12,906)	(13,161)	(13,421)	(13,687)	(13,960)	(14,238)	(14,522)	(14,812)	(15,108)	(15,410)	(15,719)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	870.2	900.3	930.6	960.3	992.1	1,025.7	1,060.3	1,094.4	1,129.0	1,164.0	1,198.4	1,232.9	1,267 8	1,303.1	1,338.9	1,375.1	1,411.8	1,449.2	1,487.2	1,526.0	1,545.3	1,565.6	1,607 2	1,649.5	1,692.6	1,701.8	1,712.2
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	9.34%	9.46%	9.57%	9.66%	9.77%	9.89%	10.02%	10.14%	10.25%	10.36%	10.45%	10.54%	10.62%	10.71%	10.79%	10.86%	10.94%	11.01%	11.08%	11.15%	11.07%	11.00%	11.07%	11.14%	11.20%	11.04%	10.89%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		172.7	176.7	180.5	184.1	188.0	192.0	196.0	200.0	204.0	208.2	212.5	216.7	221.0	225.4	229.9	234.4	239.1	243.8	248.6	253.5	258.6	263.7	269.0	274.4	279.8	285.4	291.1
15	Scenario	Line 14 * (1+Line 13)	188.8	193.4	197.8	201.9	206.4	211.0	215.6	220.2	224.9	229.7	234.7	239.6	244.5	249.6	254.7	259.9	265.2	270.6	276.1	281.8	287.2	292.7	298.8	304.9	311.2	317.0	322.9
16	Base Case	(Line 14 - 100) / 100	72.7%	76.7%	80 5%	84.1%	88.0%	92.0%	96.0%	100 0%	104.0%	108.2%	112.5%	116.7%	121.0%	125.4%	129.9%	134.4%	139.1%	143.8%	148.6%	153.5%	158.6%	163.7%	169 0%	174.4%	179.8%	185.4%	191.1%
17	Scenario	(Line 15 - 100) / 100	88.8%	93.4%	97 8%	101.9%	106.4%	111.0%	115.6%	120 2%	124.9%	129.7%	134.7%	139.6%	144.5%	149.6%	154.7%	159.9%	165.2%	170.6%	176.1%	181.8%	187.2%	192.7%	198 8%	204.9%	211.2%	217.0%	222.9%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	16.1%	16.7%	17 3%	17.8%	18.4%	19.0%	19.6%	20.3%	20.9%	21.6%	22.2%	22.8%	23.5%	24.1%	24.8%	25.5%	26.1%	26.8%	27.5%	28.3%	28.6%	29.0%	29.8%	30.6%	31.4%	31.5%	31.7%

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																								
1	**Domestic Energy Costs**		1,250.4	1,275.4	1,300 9	1,326.9	1,353.4	1,380.5	1,408.1	1,436 3	1,465.0	1,494.3	1,524.2	1,554.7	1,585.8	1,617.5	1,649.8	1,682.8	1,716.5	1,750.8	1,785.8	1,821.6	1,858.0	1,895.2	1,933.1	1,971.7
2	**Operating Costs**		103.9	106.0	108.1	110.2	112.5	114.7	117.0	119.3	121.7	124.2	126.6	129.2	131.8	134.4	137.1	139.8	142.6	145.5	148.4	151.3	154.4	157.5	160.6	163.8
3	**Amortization**		(163.8)	(163.8)	(163 8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(97.0)	(90.2)	(83.4)	(79.9)	(76.3)	(69.2)	(62.2)	(55.1)	(48.0)	(40.9)	(33.7)	(26.5)	(19.3)	(12.1)	(4.8)	2.5	9.8	17.2	24.6	32.0	39.5	47.0	54.6	62.1
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		(237.0)	(241.7)	(246 5)	(251.5)	(256.5)	(261.6)	(266.9)	(272.2)	(277.6)	(283.2)	(288.9)	(294.6)	(300.5)	(306.5)	(312.7)	(318.9)	(325.3)	(331.8)	(338.5)	(345.2)	(352.1)	(359.2)	(366.4)	(373.7)
7	DSM Recoveries		203.0	207.1	211.2	215.4	219.7	224.1	228.6	233.2	237.8	242.6	247.4	252.4	257.4	262.6	267.8	273.2	278.7	284.2	289.9	295.7	301.6	307.7	313.8	320.1
8	**Estimated Total Change in Revenue Requirement:**		1,059.4	1,092.6	1,126.4	1,155.4	1,185.1	1,220.7	1,256.9	1,293 8	1,331.2	1,369.3	1,408.0	1,447.4	1,487.4	1,528.1	1,569.6	1,611.7	1,654.6	1,698.2	1,742.6	1,787.7	1,833.7	1,880.4	1,928 0	1,976.4
9	**Estimated Revenue Requirement - Base Case**		16,732	17,067	17,408	17,756	18,111	18,474	18,843	19,220	19,604	19,996	20,396	20,804	21,220	21,645	22,078	22,519	22,970	23,429	23,898	24,376	24,863	25,360	25,868	26,385
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	17,792	18,159	18,535	18,912	19,297	19,694	20,100	20,514	20,936	21,366	21,804	22,252	22,708	23,173	23,647	24,131	24,624	25,127	25,640	26,163	26,697	27,241	27,796	28,361
11	**Domestic Revenues**		(16,033)	(16,354)	(16,681)	(17,014)	(17,355)	(17,702)	(18,056)	(18,417)	(18,785)	(19,161)	(19,544)	(19,935)	(20,334)	(20,740)	(21,155)	(21,578)	(22,010)	(22,450)	(22,899)	(23,357)	(23,824)	(24,301)	(24,787)	(25,282)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,758.6	1,805.8	1,853 8	1,897.4	1,941.9	1,992.7	2,044.3	2,096 9	2,150.4	2,204.8	2,260.2	2,316.7	2,374.1	2,432.6	2,492.1	2,552.7	2,614.4	2,677.2	2,741.1	2,806.3	2,872.6	2,940.1	3,008 8	3,078.9
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	10.97%	11.04%	11.11%	11.15%	11.19%	11.26%	11.32%	11.39%	11.45%	11.51%	11.56%	11.62%	11.68%	11.73%	11.78%	11.83%	11.88%	11.93%	11.97%	12.01%	12.06%	12.10%	12.14%	12.18%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		297.0	302.9	309.0	315.1	321.4	327.9	334.4	341.1	347.9	354.9	362.0	369.2	376.6	384.2	391.8	399.7	407.7	415.8	424.1	432.6	441.3	450.1	459.1	468.3
15	Scenario	Line 14 * (1+Line 13)	329.5	336.4	343.3	350.3	357.4	364.8	372.3	380.0	387.8	395.7	403.9	412.2	420.6	429.2	438.0	447.0	456.1	465.4	474.9	484.6	494.5	504.6	514.8	525.3
16	Base Case	(Line 14 - 100) / 100	197.0%	202.9%	209 0%	215.1%	221.4%	227.9%	234.4%	241.1%	247.9%	254.9%	262.0%	269.2%	276.6%	284.2%	291.8%	299.7%	307.7%	315.8%	324.1%	332.6%	341.3%	350.1%	359.1%	368.3%
17	Scenario	(Line 15 - 100) / 100	229.5%	236.4%	243 3%	250.3%	257.4%	264.8%	272.3%	280.0%	287.8%	295.7%	303.9%	312.2%	320.6%	329.2%	338.0%	347.0%	356.1%	365.4%	374.9%	384.6%	394.5%	404.6%	414 8%	425.3%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	32.6%	33.4%	34.3%	35.1%	36.0%	36.9%	37.9%	38.8%	39.8%	40.8%	41.9%	42.9%	44.0%	45.1%	46.2%	47.3%	48.4%	49.6%	50.8%	52.0%	53.2%	54.5%	55.7%	57.0%

Incremental Cumulative Rate Impact
High Load / Terminate & 10 Yr Recovery / Low Cost vs. High Load Base (Low Cost)



Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2018 1	2019 2	2020 3	2021 4	2022 5	2023 6	2024 7	2025 8	2026 9	2027 10	2028 11	2029 12	2030 13	2031 14	2032 15	2033 16	2034 17	2035 18	2036 19	2037 20	2038 21	2039 22	2040 23	2041 24	2042 25	2043 26
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		0.0	0 0	0.0	15.2	21.0	75.0	129 0	280.0	611.9	756.3	897.5	861 0	705.0	814.7	795.0	648.1	922 0	1,106.4	989.9	776.9	792.3	1,062.7	1,098.8	945.6	1,099.5	1,052.7
2	**Operating Costs**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	(15.4)	(39.9)	(55.7)	(56.8)	(57 9)	(59.1)	(60.3)	(61.5)	(62.7)	(64 0)	(65.2)	(66.5)	(67.9)	(69.2)	(70.6)	(72.0)	(73.5)	(74.9)	(76.4)
3	**Amortization**		0.0	0 0	318.6	318.6	318.6	318.6	318.6	199.5	199.5	199.5	199.5	199 5	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.1)
4	**Finance Charges**		0.0	0 0	114.4	99.1	82.0	71.0	60.1	(234.7)	(241.5)	(248.4)	(255.2)	(262.0)	(263.4)	(259.3)	(255.3)	(251.2)	(247.1)	(243.0)	(238.9)	(234.8)	(230.8)	(226.7)	(222.6)	(218.5)	(214.4)	(210.3)
5	**Return on Equity**		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		0.0	0 0	433.0	432.9	421.6	464.6	507.7	229.5	530.0	651.8	785.0	740 5	263.4	376.1	359.2	215.1	491 9	679.1	565.4	355.1	373.2	646 3	685.1	534.6	691.1	646.8
9	**Estimated Revenue Requirement - Base Case**		4,802	5,033	5,237	5,474	5,790	6,075	6,748	7,099	7,328	7,580	7,718	8,066	8,607	8,897	9,362	9,879	10,227	10,375	10,873	11,470	11,914	12,369	12,865	13,425	13,810	14,255
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	4,802	5,033	5,670	5,907	6,212	6,539	7,255	7,328	7,858	8,231	8,503	8,807	8,870	9,273	9,721	10,094	10,719	11,055	11,438	11,825	12,287	13,015	13,550	13,960	14,501	14,901
11	**Domestic Revenues**		(4,802)	(5,033)	(5,237)	(5,474)	(5,790)	(6,075)	(6,748)	(7,099)	(7,328)	(7,580)	(7,718)	(8,066)	(8,607)	(8,897)	(9,362)	(9,879)	(10,227)	(10,375)	(10,873)	(11,470)	(11,914)	(12,369)	(12,865)	(13,425)	(13,810)	(14,255)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	0.0	0 0	433.0	432.9	421.6	464.6	507.7	229.5	530.0	651.8	785.0	740 5	263.4	376.1	359.2	215.1	491 9	679.1	565.4	355.1	373.2	646 3	685.1	534.6	691.1	646.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	0.00%	0.00%	8.27%	7.91%	7.28%	7.65%	7.52%	3.23%	7.23%	8.60%	10.17%	9.18%	3.06%	4.23%	3.84%	2.18%	4.81%	6.55%	5.20%	3.10%	3.13%	5.23%	5.33%	3.98%	5.00%	4.54%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		100.9	103.4	105.2	107.6	110.6	113.0	123 0	127.2	128.9	131.5	131.6	135 2	141.5	143.8	148.6	154.6	157.7	158.0	162.8	169.5	173.9	177.4	181.4	186.9	189.0	191.8
15	Scenario	Line 14 * (1+Line 13)	100.9	103.4	113.9	116.1	118.7	121.6	132 3	131.3	138.3	142.8	145.0	147.7	145.8	149.9	154.3	158.0	165 3	168.3	171.3	174.8	179.3	186.7	191.0	194.3	198.5	200.5
16	Base Case	(Line 14 - 100) / 100	0.9%	3.4%	5.2%	7.6%	10.6%	13.0%	23.0%	27.2%	28.9%	31.5%	31.6%	35 2%	41.5%	43.8%	48.6%	54.6%	57.7%	58.0%	62.8%	69.5%	73.9%	77.4%	81.4%	86.9%	89.0%	91.8%
17	Scenario	(Line 15 - 100) / 100	0.9%	3.4%	13.9%	16.1%	18.7%	21.6%	32 3%	31.3%	38.3%	42.8%	45.0%	47.7%	45.8%	49.9%	54.3%	58.0%	65 3%	68.3%	71.3%	74.8%	79.3%	86.7%	91.0%	94.3%	98.5%	100.5%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	0.0%	0 0%	8.7%	8.5%	8.1%	8.6%	9 3%	4.1%	9.3%	11.3%	13.4%	12.4%	4.3%	6.1%	5.7%	3.4%	7.6%	10.3%	8.5%	5.2%	5.4%	9 3%	9.7%	7.4%	9.5%	8.7%

Revenue Requirement (Ratepayer Costs) Summary
($ million)

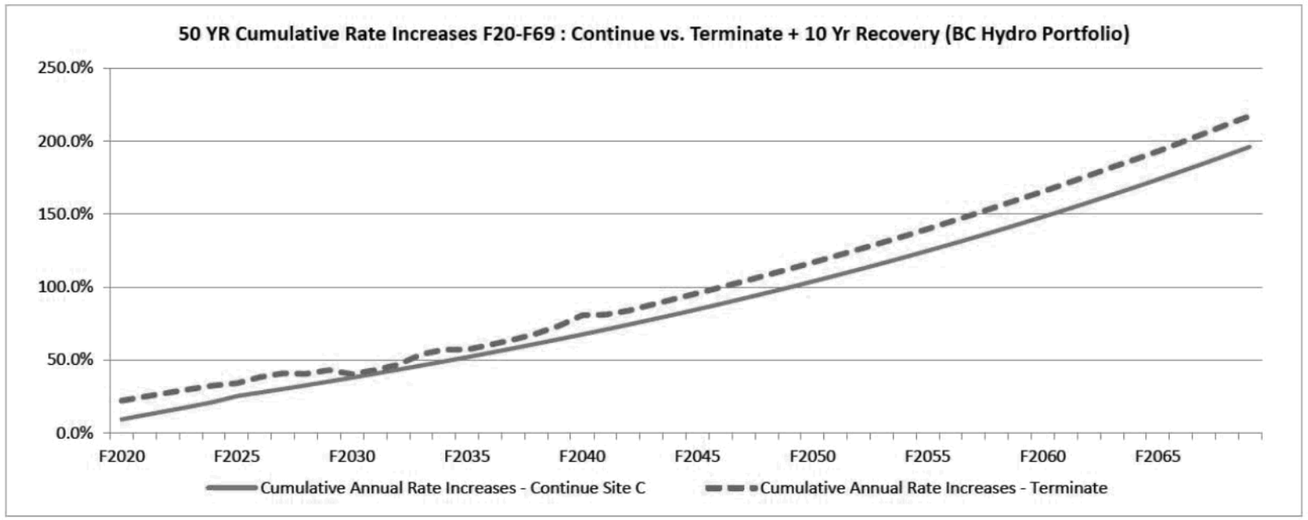
Line		Fiscal Year / Column Reference	2044 / 27	2045 / 28	2046 / 29	2047 / 30	2048 / 31	2049 / 32	2050 / 33	2051 / 34	2052 / 35	2053 / 36	2054 / 37	2055 / 38	2056 / 39	2057 / 40	2058 / 41	2059 / 42	2060 / 43	2061 / 44	2062 / 45	2063 / 46	2064 / 47	2065 / 48	2066 / 49	2067 / 50	2068 / 51	2069 / 52	2070 / 53
	Change in Revenue Requirement (Ratepayer Costs):																											
1	**Domestic Energy Costs**		1,073.7	1,095.2	1,117.1	1,139.5	1,162.2	1,185.5	1,209.2	1,233.4	1,258.1	1,283.2	1,308.9	1,335.1	1,361.8	1,389.0	1,416.8	1,445.1	1,474.0	1,503.5	1,533.6	1,564.2	1,595.5	1,627.4	1,660 0	1,693.2	1,727.0	1,761.6	1,796.8
2	**Operating Costs**		(78.0)	(79.5)	(81.1)	(82.7)	(84.4)	(86.1)	(87.8)	(89.6)	(91.4)	(93.2)	(95.0)	(96.9)	(98.9)	(100.9)	(102.9)	(104.9)	(107.0)	(109.2)	(111.4)	(113.6)	(115.9)	(118.2)	(120 5)	(122.9)	(125.4)	(127.9)	(130.5)
3	**Amortization**		(119.1)	(119.1)	(119.1)	(119.1)	(119.1)	(119.2)	(119.2)	(119 2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(119.2)	(127.8)	(136.4)	(136.4)	(136.4)	(136.4)	(150.1)	(163.8)
4	**Finance Charges**		(206.2)	(202.2)	(198.1)	(194.0)	(189.9)	(185.9)	(181.9)	(177 8)	(173.7)	(169.6)	(165.5)	(161.4)	(157.3)	(153.3)	(149.2)	(145.1)	(141.0)	(136.9)	(132.8)	(128.7)	(136.2)	(143.5)	(138 8)	(134.1)	(129.4)	(145.7)	(161.5)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																											
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		670.4	694.4	718.8	743.6	768.9	794.4	820.3	846.8	873.8	901.2	929.1	957.4	986.3	1,015.6	1,045.5	1,075.9	1,106.7	1,138.2	1,170.2	1,202.7	1,215.6	1,229.4	1,264 2	1,299.7	1,335.8	1,337.8	1,341.0
9	**Estimated Revenue Requirement - Base Case**		14,647	14,959	15,278	15,603	15,928	16,261	16,594	16,927	17,266	17,618	17,980	18,338	18,704	19,077	19,457	19,842	20,234	20,636	21,045	21,463	21,891	22,328	22,774	23,229	23,694	24,167	24,651
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	15,317	15,654	15,997	16,347	16,697	17,055	17,414	17,774	18,139	18,519	18,909	19,296	19,690	20,093	20,502	20,918	21,341	21,774	22,215	22,666	23,107	23,558	24,038	24,529	25,029	25,505	25,992
11	**Domestic Revenues**		(14,647)	(14,959)	(15,278)	(15,603)	(15,928)	(16,261)	(16,594)	(16,927)	(17,266)	(17,618)	(17,980)	(18,338)	(18,704)	(19,077)	(19,457)	(19,842)	(20,234)	(20,636)	(21,045)	(21,463)	(21,891)	(22,328)	(22,774)	(23,229)	(23,694)	(24,167)	(24,651)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	670.4	694.4	718.8	743.6	768.9	794.4	820.3	846.8	873.8	901.2	929.1	957.4	986.3	1,015.6	1,045.5	1,075.9	1,106.7	1,138.2	1,170.2	1,202.7	1,215.6	1,229.4	1,264 2	1,299.7	1,335.8	1,337.8	1,341.0
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	4.58%	4.64%	4.71%	4.77%	4.83%	4.89%	4.94%	5.00%	5.06%	5.12%	5.17%	5.22%	5.27%	5.32%	5.37%	5.42%	5.47%	5.52%	5.56%	5.60%	5.55%	5.51%	5 55%	5.60%	5.64%	5.54%	5.44%
	Typical Customer Bill (F2017 = 100)																											
14	Base Case		195.6	199.9	204.1	208.1	212.5	216.9	221.4	225.8	230.3	235.0	239.8	244.6	249.5	254.5	259.5	264.7	269.9	275.3	280.7	286.3	292.0	297.9	303.8	309.9	316.1	322.4	328.8
15	Scenario	Line 14 * (1+Line 13)	204.5	209.2	213.7	218.1	222.7	227.5	232.3	237.1	242.0	247.0	252.2	257.4	262.7	268.0	273.5	279.0	284.7	290.5	296.3	302.4	308.2	314.3	320.7	327.2	333.9	340.2	346.7
16	Base Case	(Line 14 - 100) / 100	95.6%	99.9%	104.1%	108.1%	112.5%	116.9%	121.4%	125 8%	130.3%	135.0%	139.8%	144.6%	149.5%	154.5%	159.5%	164.7%	169.9%	175.3%	180.7%	186.3%	192.0%	197.9%	203 8%	209.9%	216.1%	222.4%	228.8%
17	Scenario	(Line 15 - 100) / 100	104.5%	109.2%	113.7%	118.1%	122.7%	127.5%	132.3%	137.1%	142.0%	147.0%	152.2%	157.4%	162.7%	168.0%	173.5%	179.0%	184.7%	190.5%	196.3%	202.4%	208.2%	214.3%	220.7%	227.2%	233.9%	240.2%	246.7%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	9.0%	9.3%	9.6%	9.9%	10.3%	10.6%	10.9%	11.3%	11.7%	12.0%	12.4%	12.8%	13.2%	13.5%	13.9%	14.4%	14.8%	15.2%	15.6%	16.0%	16.2%	16.4%	16.9%	17.3%	17.8%	17.8%	17.9%

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line		Fiscal Year / Column Reference	2071 / 54	2072 / 55	2073 / 56	2074 / 57	2075 / 58	2076 / 59	2077 / 60	2078 / 61	2079 / 62	2080 / 63	2081 / 64	2082 / 65	2083 / 66	2084 / 67	2085 / 68	2086 / 69	2087 / 70	2088 / 71	2089 / 72	2090 / 73	2091 / 74	2092 / 75	2093 / 76	2094 / 77
	Change in Revenue Requirement (Ratepayer Costs):																								
1	**Domestic Energy Costs**		1,832.7	1,869.4	1,906 8	1,944.9	1,983.8	2,023.5	2,064.0	2,105 2	2,147.4	2,190.3	2,234.1	2,278.8	2,324.4	2,370.9	2,418.3	2,466.6	2,516.0	2,566.3	2,617.6	2,670.0	2,723.4	2,777.8	2,833.4	2,890.1
2	**Operating Costs**		(133.1)	(135.7)	(138 5)	(141.2)	(144.1)	(146.9)	(149.9)	(152 9)	(155.9)	(159.0)	(162.2)	(165.5)	(168.8)	(172.2)	(175.6)	(179.1)	(182.7)	(186.3)	(190.1)	(193.9)	(197.8)	(201.7)	(205.7)	(209.9)
3	**Amortization**		(163.8)	(163.8)	(163 8)	(165.8)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)	(167.7)
4	**Finance Charges**		(155.9)	(150.3)	(144.6)	(142.3)	(140.0)	(134.2)	(128.5)	(122.7)	(117.0)	(111.2)	(105.5)	(99.7)	(94.0)	(88.2)	(82.5)	(76.7)	(70.9)	(65.2)	(59.4)	(53.7)	(47.9)	(42.2)	(36.4)	(30.7)
5	**Return on Equity**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DSM Account																									
6	DSM Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	DSM Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Estimated Total Change in Revenue Requirement:**		1,380.0	1,419.6	1,459 9	1,495.6	1,532.1	1,574.6	1,617.9	1,661 9	1,706.7	1,752.3	1,798.7	1,845.9	1,893.9	1,942.8	1,992.5	2,043.1	2,094.6	2,147.0	2,200.4	2,254.7	2,310.0	2,366.2	2,423 5	2,481.8
9	**Estimated Revenue Requirement - Base Case**		25,144	25,646	26,159	26,683	27,216	27,761	28,316	28,882	29,460	30,049	30,650	31,263	31,888	32,526	33,176	33,840	34,517	35,207	35,911	36,629	37,362	38,109	38,872	39,649
10	**Estimated Revenue Requirement - Scenario**	Line 8 + Line 9	26,524	27,066	27,619	28,178	28,748	29,335	29,934	30,544	31,166	31,801	32,449	33,109	33,782	34,469	35,169	35,883	36,611	37,354	38,112	38,884	39,672	40,476	41,295	42,131
11	**Domestic Revenues**		(25,144)	(25,646)	(26,159)	(26,683)	(27,216)	(27,761)	(28,316)	(28,882)	(29,460)	(30,049)	(30,650)	(31,263)	(31,888)	(32,526)	(33,176)	(33,840)	(34,517)	(35,207)	(35,911)	(36,629)	(37,362)	(38,109)	(38,872)	(39,649)
12	**Revenue Shortfall (Surplus)**	Line 10 + Line 11	1,380.0	1,419.6	1,459 9	1,495.6	1,532.1	1,574.6	1,617.9	1,661 9	1,706.7	1,752.3	1,798.7	1,845.9	1,893.9	1,942.8	1,992.5	2,043.1	2,094.6	2,147.0	2,200.4	2,254.7	2,310.0	2,366.2	2,423 5	2,481.8
13	**Estimated Incremental Impact on Future Rates**	-Line 12 / Line 11	5.49%	5.54%	5.58%	5.61%	5.63%	5.67%	5.71%	5.75%	5.79%	5.83%	5.87%	5.90%	5.94%	5.97%	6.01%	6.04%	6.07%	6.10%	6.13%	6.16%	6.18%	6.21%	6 23%	6.26%
	Typical Customer Bill (F2017 = 100)																									
14	Base Case		335.4	342.1	349.0	355.9	363.1	370.3	377.7	385.3	393.0	400.8	408.9	417.0	425.4	433.9	442.6	451.4	460.4	469.7	479.1	488.6	498.4	508.4	518.5	528.9
15	Scenario	Line 14 * (1+Line 13)	353.8	361.1	368.4	375.9	383.5	391.3	399.3	407.5	415.8	424.2	432.9	441.7	450.6	459.8	469.1	478.7	488.4	498.3	508.4	518.7	529.2	539.9	550.9	562.0
16	Base Case	(Line 14 - 100) / 100	235.4%	242.1%	249 0%	255.9%	263.1%	270.3%	277.7%	285.3%	293.0%	300.8%	308.9%	317.0%	325.4%	333.9%	342.6%	351.4%	360.4%	369.7%	379.1%	388.6%	398.4%	408.4%	418 5%	428.9%
17	Scenario	(Line 15 - 100) / 100	253.8%	261.1%	268.4%	275.9%	283.5%	291.3%	299.3%	307.5%	315.8%	324.2%	332.9%	341.7%	350.6%	359.8%	369.1%	378.7%	388.4%	398.3%	408.4%	418.7%	429.2%	439.9%	450 9%	462.0%
18	**Estimated Incremental Cumulative Rate Impact**	Line 17 - Line 16	18.4%	18.9%	19.5%	20.0%	20.4%	21.0%	21.6%	22.2%	22.8%	23.4%	24.0%	24.6%	25.3%	25.9%	26.6%	27.3%	27.9%	28.6%	29.4%	30.1%	30.8%	31.6%	32.3%	33.1%

BC Hydro Portfolio	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041	F2042	F2043
Cumulative Annual Rate Increases - Continue Site C	3%	7%	9%	12%	15%	18%	21%	25%	28%	30%	33%	35%	38%	41%	43%	46%	49%	52%	55%	58%	61%	64%	68%	71%	74%	78%
Cumulative Annual Rate Increases - Terminate	4%	7%	22%	25%	27%	30%	33%	34%	38%	41%	40%	43%	40%	43%	47%	54%	57%	57%	60%	64%	68%	73%	81%	81%	84%	88%

F2044	F2045	F2046	F2047	F2048	F2049	F2050	F2051	F2052	F2053	F2054	F2055	F2056	F2057	F2058	F2059	F2060	F2061	F2062	F2063	F2064	F2065	F2066	F2067	F2068	F2069
81%	85%	88%	92%	96%	100%	104%	108%	112%	116%	120%	125%	129%	134%	139%	143%	148%	153%	158%	163%	168%	174%	179%	185%	190%	196%
92%	96%	100%	104%	108%	112%	117%	121%	126%	130%	135%	140%	145%	150%	155%	160%	165%	171%	176%	182%	187%	193%	199%	205%	211%	217%



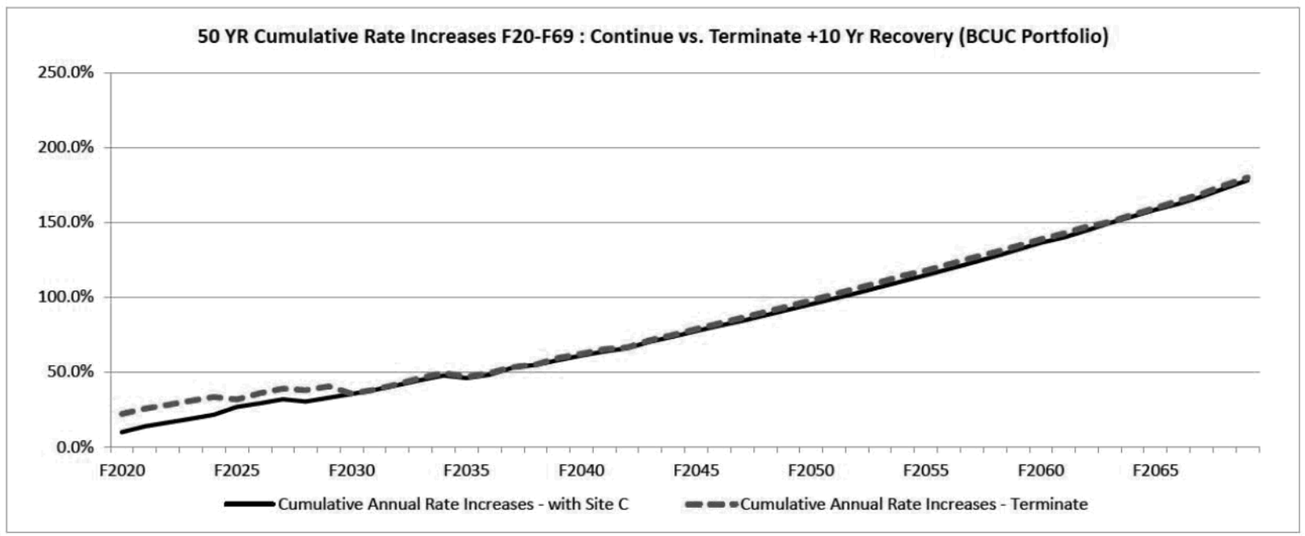
Assumptions:

Mid Load Scenario
Total Site C costs of $10 billion
Termination Costs of $1.8 billion
10 year recovery of Termination and Sunk Costs
In 'Continue Site C', assumes Rates Plan annual rate increases through F2024 (3.5% in F18; 3.0% in F19; 2.6% in F20-F24)
For F25 and thereafter, assumes annual rate increases of 2%, but adjusted to reflect Site C cost increase to $10 billion
Does not consider rate freeze
Cost and availability of alternative resources based on BC Hydro's August 30th submission
Portfolio includes accelerated enhanced DSM, as well as wind and pumped storage
Alternative resources financed by IPPs

Cumulative Rate Increases	F20	F24	F44	F69
Continue Site C	9%	21%	81%	196%
Terminate (10 year Recovery)	22%	33%	92%	217%
Incremental Cumulative Rate Impact	13%	11%	11%	21%

BCUC Portfolio	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041	F2042	F2043
Cumulative Annual Rate Increases - Continue Site C	3%	6%	10%	14%	16%	19%	22%	27%	29%	32%	30%	33%	35%	38%	41%	45%	48%	46%	48%	53%	55%	58%	61%	64%	66%	70%
Cumulative Annual Rate Increases - Terminate	3%	6%	22%	26%	28%	31%	33%	32%	36%	39%	38%	41%	36%	38%	42%	46%	49%	47%	49%	53%	55%	60%	62%	65%	66%	71%

F2044	F2045	F2046	F2047	F2048	F2049	F2050	F2051	F2052	F2053	F2054	F2055	F2056	F2057	F2058	F2059	F2060	F2061	F2062	F2063	F2064	F2065	F2066	F2067	F2068	F2069
74%	77%	81%	84%	88%	92%	95%	99%	103%	107%	111%	115%	119%	123%	127%	132%	136%	140%	145%	149%	154%	159%	162%	167%	173%	178%
75%	79%	83%	86%	90%	94%	98%	102%	106%	110%	114%	118%	122%	126%	130%	134%	139%	143%	147%	150%	155%	160%	164%	169%	175%	180%



Assumptions:

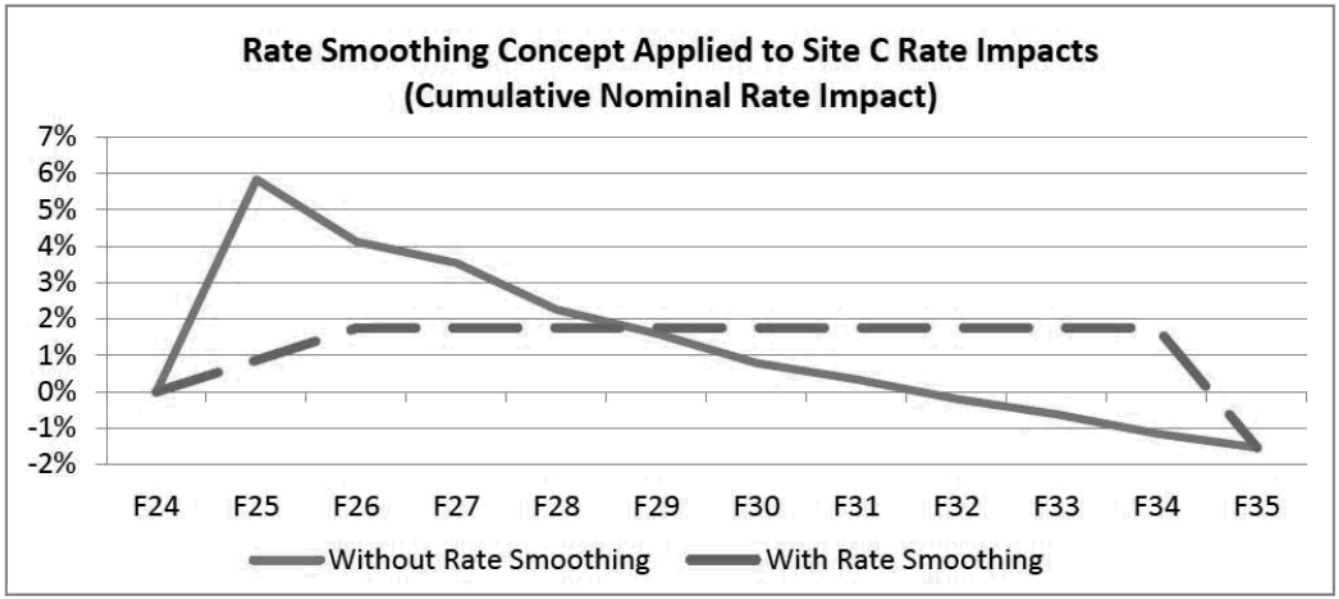
Mid Load Scenario
Total Site C costs of $10 billion
Termination Costs of $1.8 billion
10 year recovery of Termination and Sunk Costs
In 'Continue Site C', assumes annual rate increases as above, except modified to reflect the estimated impact of BCUC portfolio on forecast rate increases
Does not consider rate freeze
Cost and availability of alternative resources based on BCUC portfolio assumptions
Portfolio includes accelerated enhanced DSM, additional capacity DSM as well as wind and pumped storage in longer term.
Alternative resources financed by BC Hydro

Cumulative Rate Increases	F20	F24	F44	F69
Continue Site C	10%	22%	74%	178%
Terminate (10 year Recovery)	22%	33%	75%	180%
Incremental Cumulative Rate Impact	12%	12%	1%	2%

JRP (refreshed) Approach to Estimating Site C Rate Impact

	F24	F25	F26	F27	F28	F29	F30	F31	F32	F33	F34	F35
Without Rate Smoothing	0.00%	5.83%	4.12%	3.53%	2.26%	1.59%	0.78%	0.34%	-0.20%	-0.62%	-1.15%	-1.54%
With Rate Smoothing	0.00%	0.87%	1.75%	1.75%	1.75%	1.76%	1.76%	1.75%	1.76%	1.76%	1.75%	-1.54%

Assumes total Site C costs of $10 billion



From:	MacLaren, Les MEM:EX
To:	Sanderson, Melissa MEM:EX
Cc:	Nikolejsin, Dave MNGD:EX; McNish, James EMPR:EX; Wieringa, Paul MEM:EX; Rowe, Katherine MEM:EX
Subject:	Site C
Date:	Tuesday, October 17, 2017 7:22:00 AM
Attachments:	12 Site C Update (Dias) - ADM Approved.docx

Hi Melissa:

Further to our discussion last evening about the staff briefings on Site C that the Minister has requested, to get started attached is our Estimates Briefing Note which includes a high level overview of the current status of various aspects of the project. The link below is to a 5 minute video BC Hydro produced in 2014 that provides a good overview of the intended construction sequencing.

https://www.youtube.com/watch?v=hSHvWSMtls4

Les

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES
ELECTRICITY AND ALTERNATIVE ENERGY DIVISION
ESTIMATES NOTE 2017

ISSUE: Site C Update (Construction, Permitting, Litigation, Audit)

KEY MESSAGES:

- Site C is still on track to be completed by November 2024. The updated forecast cost of the project is $8.945 billion, $610 million over the original $8.335 billion project budget[1]
    - On October 4, 2014, BC Hydro advised the BC Utilities Commission (BCUC) that the start of the river diversion would be delayed by one year due to geotechnical and construction challenges related to tension cracks on the left (north) bank of the Peace River. The river diversion is now expected to occur in September to October 2020, but the delay related to the river diversion is not anticipated to impact the in-service date of November 2024.
    - BC Hydro estimates the delay will increase costs by $610 million (a 7.3 percent budget increase), for a total forecast project cost of $8.945 billion.
- More than $4.5 billion in financial commitments have been made to date, including contracts and agreements.

- This includes the $1.75 billion main civil works contract awarded on December 21, 2015. This contract comprises the majority of earthworks to construct the project and includes the construction of an earthfill dam, two diversion tunnels, and a concrete foundation for the generating station and spillways.

- In August 2017, Peace River Hydro Partners (PRHP) announced the withdrawal of Petrowest Corporation from its structure. PRHP has confirmed that the remaining partners intend to continue with the work, and meet the obligations in the contract.

- Until the Site C Inquiry is completed and government makes its decision on Site C:

[1] Excludes a $440 million project reserve approved by the previous government in December 2014.

  - construction and procurement to maintain the project schedule will continue, but no major contract awards will be made;
  - BC Hydro will be taking no action to remove landowners or their tenants from homes impacted by Site C; and
  - the planned Highway 29 Bear Flats/Cache Creek relocation road and bridge contracts will be deferred.

- To address concerns raised by First Nations and others regarding potential impacts to grave sites and cultural heritage sites, BC Hydro is willing to look at changes within the approved highway alignment that was reviewed as part of Environmental Impact Assessment process and is included in the Site C Environmental Assessment Certificate.

BACKGROUND:

Overview

- Subject to Government's decision regarding the future of the project, Site C would be the third dam and hydroelectric generating station on the Peace River in northeastern British Columbia, and would generate reliable and clean electricity for more than 100 years. Site C is designed to provide 5,100 gigawatt hours of electricity each year and 1,100 megawatts of capacity, which is enough power for 450,000 homes;
- Large hydro projects, such as Site C, have the ability to provide a reliable supply of both dependable capacity and energy without ongoing cost volatility. Site C would provide significant benefits:
  - Use the existing Williston reservoir — so it can generate a third of the electricity produced at WAC Bennett dam with a reservoir one-twentieth of the size;
  - Help integrate additional intermittent, clean and renewable projects — such as wind, run-of-river hydro and solar; and
  - Provide 10,000 person-years of direct construction employment over the construction period.
- The approved budget for Site C, at the time of the 2014 investment decision, was $8.335 billion[2]. On October 4, 2017, BC Hydro advised the BCUC that it now forecasts that the project will cost $8.945 billion, $610 million over the approved capital cost estimate of $8.335 billion.
- If completed, Site C would have very low operating costs and low emissions over a 70 to 100 year project life. At the time of the final investment decision (FID), the energy cost for Site C for power delivered to the Lower Mainland was estimated at $64 per megawatt-hour (MWh) compared to a cost of $110 per MWh for independent power projects.

[2] Excludes an additional $440 million government holds as a project reserve to account for events outside of BC Hydro's control that could occur over an eight-year construction period.

- The Joint Review Panel that undertook the environmental assessment of the project stated in its report that, “a few decades from now…Site C could appear as a wonderful gift from the ancestors of that future society, just as BC consumers today thank the dam-builders of the 1960s.” Among the conclusions, the Panel’s report stated that, “Site C would be the least expensive of alternatives and its cost advantages would increase with passing decade as inflation makes alternatives more costly.”

Construction:

- The Site C FID announcement followed provincial and federal environmental certification in October 2014. Construction started in July 2015.,with an in-service date of November 2024.
- A significant amount of work has been undertaken since the construction start in July 2015:
  - More than 900 hectares of land cleared for site preparation;
  - A 1,600-person worker lodge is complete;
  - Millions of cubic metres of material have been excavated on the north and south banks of the dam site;
  - Road improvements are substantially complete;
  - A 325-metre-long temporary construction bridge across the Peace River was completed at the end of March 2016; and
  - Main civil works mobilized to the Site C dam site in March 2016 and started physical work in June 2016.
- Several procurements have been completed or are underway, including contracts for the Worker Accommodation Lodge (to ATCO Two Rivers Lodging Group, $470 million), for the main civil works (to PRHP, $1.75 billion), and for turbines and generator (to Voith Hydro, $470 million);
- Key milestones include river diversion, finalization and award of the Generating Station and Spillway (GSS) contract, and site handover between the Main Civic Works and GSS vendors.
- As can be expected on a project of this size, some issues have arisen during construction. The dam site has been extensively studied and known geotechnical risks were identified at the FID. A tension crack that developed in February 2017 at the Left (North) Bank Excavation that resulted in work stoppage has been addressed and work recommenced on April 24, 2017.
- In May 2017, a smaller tension crack was observed. BC Hydro and the contractor developed a plan to continue excavation and the contractor is resolving the tension crack. However, this tension crack has impacted the Start of River Diversion which had been scheduled for September 2019.
  - On October 4, 2017, BC Hydro announced it determined that the Start of the River Diversion will be missed, and as a result, this milestone will slip a year, to September 2020. BC Hydro estimates a cost impact of 7.3 percent or $610 million.

- Award of the GSS contract is delayed due to updates to the contract and changes to the construction schedule. BC Hydro has acknowledged further budgetary risks related the GSS procurement and the highway realignment.
- On September 15, BC Hydro posted a Request for Proposals (RFP) on BC Bid for the construction of two new transmission lines for the Site C Clean Energy Project. The RFP does not create a binding contract commitment.

Permitting/Licences/Land Related Issues:

- While a number of key authorizations and certificates, such as the Environmental Assessment Certificate and the main Water License for Site C are in place, additional authorizations will be required at both the provincial and federal levels as construction progresses. Several hundred separate authorizations will be required over the life of construction. The Province continues to consult with First Nations on all authorizations that will be required for the project;

s.16

- Blueberry River First Nations has requested to meet with Ministers to discuss potential grave sites and steps that could be taken to avoid harm.
- While the review of Site C by the BCUC is underway, the Province has committed to continuing construction on Site C. As a result, operational permitting for Site C will continue. West Moberly and Prophet River have discontinued their appeal to the Environmental Appeal Board of the water licence.
- BC Hydro transferred funds for the dam site Crown Grant in Fiscal 2016/17. The necessary ministerial orders and orders-in-council are to be advanced subject to Government decision on the project after completion of the Site C review by the BCUC.

First Nations Benefits

- Agreements are in place with a number of Treaty 8 First Nations. Typically, the components include an Impact and Benefits Agreement, a Contracting Agreement and a Tripartite Land Agreement, to which British Columbia is also a party. Benefits to First Nations include cash payments, procurement opportunities, and the selection and transfer of provincial Crown lands and/or commitments to develop recommendations for enhanced land management initiatives. Consultations with the public, stakeholders and First Nations will occur before the Ministry of Forests, Lands, Natural Resource Operations and Regional Development confirms Crown land parcels for transfer or protection;
- The West Moberly and Prophet River First Nations are not engaging.

Community Benefits and Employment

- BC Hydro has achieved Community Agreements with the Districts of Taylor, Chetwynd and Hudson's Hope and the City of Fort St. John. A separate Legacy Benefit Agreement was reached with the PRRD in 2014 that will provide legacy benefit payments to the District and its member municipalities for 70 years once the project is operational.
- BC Hydro is utilizing an inclusive labour approach with a managed open site. This allows BC Hydro and the contractors for large work packages to accept bids from any qualified contractor, regardless of union affiliation.
- In July 2017, BC Hydro reported 2,549 workers were employed on the project, with 2,059 (81 percent) identified as being from British Columbia and 703 (33 percent) on site were identified as being from the Peace River Regional District (PRRD). In addition, during the month, 62 apprentices were employed and 193 aboriginal people and 374 women were working for construction and non-construction contractors. Subsequently, due to reduced activity over the winter months, PRHP, contractor for the Main Civil Works, has laid off workers at the project.

Litigation:

The following table summarizes the status of active Site C litigation:

Proceeding/Outcome		Date
Federal Court: Federal Environmental Approval		
Prophet River First Nation West Moberly First Nations	Dismissed Appeal Dismissed **Leave to appeal to Supreme Court of Canada dismissed**	August 28, 2015 January 23, 2017 **June 29, 2017**
Federal Court: Federal Permits		
BC Hydro Ratepayers Association	**Notice of Application filed** **Discontinued**	September 19, 2016 January 23, 2017
B.C. Court: Provincial Environmental Assessment Certificate		
Prophet River First Nation West Moberly First Nations	Petition Dismissed Appeal Dismissed **Leave to appeal to Supreme Court dismissed**	September 18, 2015 February 2, 2017 **June 29, 2017**
B.C. Court: Provincial Permits		
Prophet River First Nation West Moberly First Nations	Injunction **Dismissed** **Petition Dismissed** Appeal filed Hearing date	August 28, 2015 October 31, 2016 November 30, 2016 To Be Determined
Sierra Club of British Columbia	Judicial review filed **Discontinued**	July 20, 2016 January 27, 2017

Proceeding/Outcome		Date
Environmental Appeal Board		
Prophet River First Nation & West Moberly First Nations C. London	Water Licence appeals filed Appeal withdrawn Appeal withdrawn	March 29, 2016 July 12, 2017 September, 2017
Other Proceedings		
Building Trades v. BC Hydro	Civil claim filed Response to claim filed	March 2, 2015 April 10, 2015

- On June 29, 2017, the Supreme Court of Canada denied two leave to appeal applications filed by West Moberly and Prophet River First Nations related to the provincial and federal environmental approvals. This was the last chance to overturn the Federal and Provincial Site C environmental approval decisions.
- Of nine legal challenges of major environmental approvals and permits, four were discontinued and five dismissed by the courts. Four of the court decisions dismissing the legal challenges were appealed: three appeals were dismissed with one still pending.

Audit:

- In November 2015, the Office of Auditor General (OAG) of BC informed the Ministry and BC Hydro that the office is in the early stages of planning a performance audit of Site C identified in their July 2015 plan. The plan stated the audit would cover, "whether BC Hydro's recommendation and government's decision to build Site C was supported by sufficient information and analysis to demonstrate that it would meet government's economic, social and environmental goals."
- In August 2016, at a meeting to update Ministry staff regarding the audit, OAG staff indicated that a final decision on the audit focus had not been made, and that they would consider refocusing the audit to review procurement practices related to Site C.
- In April 2017, OAG staff indicated that information relating to the context for the exemption of Site C for a Certificate of Public Convenience and Necessity will be reviewed, such as the development of the *Clean Energy Act,* and BC Hydro's load demand forecast and financial oversight of the Site C project;
- On August 9, 2017, the OAG publicly indicated that, given the launch of the Site C review, the OAG has moved to a "watching brief" and will assess the value of continuing the performance audit after the review is complete.

Agriculture Fund:

- On July 27, 2016 BC Hydro submitted to the BC Environmental Assessment Office an Agriculture Mitigation and Compensation Plan (final) (Plan), as required by the Environmental Assessment Certificate. The Plan built on a Framework and Draft Plan that underwent public consultation. The Plan addresses four components: construction management practices, as they pertain to agriculture; development of individual farm

mitigation plans; management of residual agricultural land; and establishment of a $20 million agricultural compensation fund.

- On September 25, 2017, BC Hydro submitted a revised Plan that notes that the establishment of the agricultural fund and the stakeholder board proposed to govern the fund will proceed, subject to Government's decision regarding the future of Site C.
  - If government decides that Site C is to proceed, BC Hydro will, within 45 days from the decision, issue requests for nomination of board members, and a Request For Proposals for the fund administrator. BC Hydro would target filling all board positions filled contracting with an administrator by Summer 2018. The Agricultural funds would be transferred to the administrator by the end of Summer/early Fall 2018 for disbursement according to guidelines approved by the fund's Board of Directors.
  - If Site C is suspended by government, BC Hydro anticipates revising the current Plan. If Site C is cancelled, the Fund would not be established.
- A Consultation Steering Committee consisting of staff from BC Hydro, the Ministry of Energy, Mines and Petroleum Resources, and the Ministry of Agriculture, helped develop the Agriculture Mitigation and Compensation Plan.

Reporting:

- The Site C Reporting and Accountability Framework includes quarterly reporting to the Minister of Energy, Mines and Petroleum Resources, and is now aligned with separate reporting every six months to Treasury Board.

From:	MacLaren, Les EMPR:EX
To:	Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX
Cc:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Haslam, David GCPE:EX
Subject:	s.12,s.13
Date:	Thursday, October 26, 2017 3:52:04 PM
Attachments:	s.12,s.13

Melissa and James:

s.12,s.13

Les

Page 567 to/à Page 582

Withheld pursuant to/removed as

s.12;s.13

From:	MacLaren, Les EMPR:EX
To:	Sanderson, Melissa EMPR:EX; McNish, James EMPR:EX
Cc:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX; Cutler, Scott EMPR:EX; Haslam, David GCPE:EX
Subject:	s.12,s.13
Date:	Thursday, October 26, 2017 11:11:18 AM
Attachments:	s.12,s.13

Melissa and James:
s.12,s.13

As discussed, we will also spend some time on residential 2-tier rates in advance of MMM's CBC interview tomorrow.
Les

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Withheld pursuant to/removed as

s.12;s.13

From:	MacLaren, Les MEM:EX
To:	Foster, Doug FIN:EX
Cc:	Nikolejsin, Dave MNGD:EX; Wieringa, Paul MEM:EX
Subject:	Site C Revised Budget
Date:	Friday, October 6, 2017 9:29:00 AM

Hi Doug:

I spoke with Mike Savidant. As I surmised, BC Hydro has just calculated to cost of using their schedule float and moving the in service date from November 2023 to November 2024. They set out these costs in their response to BCUC_2_15_00 in their October 4 submissions (http://www.sitecinquiry.com/wp-content/uploads/2017/10/00308_F1-8_BCHydro_SiteC_Submissions.pdf). The $610M is made up of $397M in direct costs and inflation, $162M in IDC, and an additional $51M of contingency. The response also assesses factors that could cause further increases to the budget, based on the Low (2024 in service), Moderate (2025) and High impact (more than two years' delay) scenarios used by Deloitte.

They just added the delay costs to the budget without any indication how this increase would be funded. It could be covered by the $800+M of contingency, leaving a small amount of contingency and the project reserve to manage risks associated with the ongoing and remaining components of the project. In Mike's view, the remaining contingency would not be adequate to cover the remaining risks.

Mike suggested that if we want to discuss further why BCH made this conservative choice, we should speak to Chris O'Riley and Diane McSherry. I can arrange a call if you want to pursue this further.

Les MacLaren
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