BC Hydro
Power smart

Tom A. Loski
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

February 18, 2016

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698781
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application (2015 RDA)
Load Resource Balance and Long-Run Marginal Cost

BC Hydro writes in compliance with Commission Order No. G-12-16 and submits its Evidentiary update of BC Hydro's Load Resource Balance and Long-Run Marginal Cost.

The energy Long-Run Marginal Cost determination is an important reference point for a number of BC Hydro's rate structures, most notably the Residential Inclining Block Rate and the Transmission Service Stepped Rate.

The Long-Run Marginal Cost is determined by the cost of BC Hydro's marginal energy resources. Consistent with the 2013 IRP, over the planning horizon the marginal need for new energy resources is expected to be met by Demand Side Management and Independent Power Producer Energy Purchase Agreement renewals. Given the updated Load Resource Balance and cost of supply outlook, BC Hydro's current view on the energy Long-Run Marginal Cost has shifted towards $85/MWh from $85 to $100/MWh. The potential further changes to the Load Resource Balance noted below are not expected to impact the Long-Run Marginal Cost any further because those changes are unlikely to result in a change to the marginal resources over the planning horizon.

The Load Resource Balance and Load Forecast provided in this Evidentiary Update are 20-year forecasts which were finalized in October 2015. The Load Forecast continues to show long-term load growth across the residential, commercial and industrial customer classes; however, the load is forecast at a lower level compared to the 2013 Integrated Resource Plan.

The Load Forecast and Load Resource Balance do not reflect more recent information that is expected to be material.

In certain sectors, our industrial customers have been faced with significant declines in prices for the commodities they produce. There have also been more recent

developments with respect to liquefied natural gas load including the announcement of the deferral of a final investment decision on a liquefied natural gas project. Additionally, on February 5, 2016 the Government of British Columbia announced a program to allow mining companies to defer a portion of their electricity payments, to help mines stay open.

Given the possible significance of these recent developments, BC Hydro believes it is prudent to undertake an additional update. Accordingly, the Load Resource Balance and Load Forecast provided in this Evidentiary Update are under review with an update to be completed this summer, including changes in the mining and liquefied natural gas sectors. BC Hydro will file the updated Load Resource Balance and Load Forecast as an Evidentiary Update.

For further information, please contact Gordon Doyle at 604-623-3815 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

gd/ma

Copy to: BCUC Project No. 3698781 (2015 RDA) Registered Intervener Distribution List.

BC Hydro
Power smart

Rate Design Application

Evidentiary Update on Load Resource Balance and Long Run Marginal Cost

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1 Introduction

BC Hydro's Long-Run Marginal Cost (**LRMC**) for energy in British Columbia is updated to $85/MWh ($F2013) from $85 to $100/MWh ($F2013) and for capacity it remains at $50 to 55/kW-year($F2013).

The October 2015 Load Resource Balance (**LRB**) and Load Forecast referenced in this submission reflect BC Hydro's most recent detailed analysis. The Load Forecast continues to show long-term load growth across the residential, commercial and industrial customer classes; however, load is forecast at a lower level compared to the 2013 IRP. These forecasts do not reflect more recent information that is expected to materially change the Load Forecast and LRB.

In certain sectors, our industrial customers have been faced with significant declines in prices for the commodities they produce. There have also been more recent developments with respect to liquefied natural gas (**LNG**) load including the announcement of the deferral of a final investment decision on a LNG project. Additionally, on February 5, 2016 the Government of British Columbia announced a program to allow mining companies to defer a portion of their electricity payments, to help mines stay open. The LRB and Load Forecast referenced in this document are under review with an update to be completed in summer of 2016, including changes in the mining and LNG sectors. BC Hydro will file the updated LRB and Load Forecast as an Evidentiary Update.

The energy LRMC of $85/MWh is based on BC Hydro's assessment that it can acquire what it needs in the plan from its marginal resources, Demand Side Management (**DSM**) and electricity purchase agreement (**EPA**) renewals with IPPs at or below $85/MWh. The energy LRMC has changed to the lower end of the previous range based upon updated information on both the reduced need for new resources and the

anticipated costs of IPP EPA renewals. The capacity LRMC continues to be based upon the cost of Revelstoke Unit 6.

The potential further changes to the LRB noted above are not expected to impact the LRMC because those changes are unlikely to result in DSM, IPP EPA renewals and Revelstoke Unit 6 no longer being the marginal resources over the next ten years.

1.1 LRMC Definition, Determination and Application

The Integrated Resource Plan (**IRP**) is BC Hydro's long term planning document that sets out recommended actions to ensure our customers will continue to receive cost effective, reliable electricity with manageable risks, consistent with the requirements and objectives of the *Clean Energy Act*. BC Hydro's 2013 IRP has 18 Recommended Actions that BC Hydro is taking to ensure we can reliably and cost effectively supply our customers' load requirements under expected (or base) conditions and contingency conditions. The 2013 IRP was approved by the Lieutenant Governor in Council in November 2013.

The LRB gap is the difference between BC Hydro's forecast load and forecast supply. The LRB gap with existing and committed resources[1] in the context of the approved IRP drives the need for resources such as DSM savings, IPP contract renewals and acquisitions.

In general, LRMC can be defined as the price of the most cost-effective way of satisfying incremental customer demand beyond existing and committed resources[2] as guided by the government approved IRP which ensures reliable and cost effective electricity service both in the near and long-term while balancing multiple policy objectives. BC Hydro typically expresses this as a levelized unit cost (i.e., Unit Energy

[1] Existing supply-side resources include BC Hydro's Heritage hydroelectric and thermal generating resources, as well as IPP facilities delivering electricity to BC Hydro. Committed supply-side resources are resources for which material regulatory and BC Hydro executive approvals have been secured (including Site C).

[2] 2013 IRP, page 9-51.

Cost or Unit Capacity Cost). Once established, the LRMC is used as a reference price by BC Hydro to inform the value that should be placed upon acquiring new resources such as IPP acquisitions, DSM savings, Resource Smart; and equipment efficiency and loss valuations, where there is a need.

The LRMC is meant to set a steady price signal to allow consistency in determining/screening the cost effectiveness of different resources. BC Hydro also uses LRMC as a basis for the step 2 rate of certain rate structures to maintain a steady price signal encouraging conservation.

BC Hydro does not expect to acquire all available resources up to the LRMC nor does it expect the LRMC to be the clearing price. This approach is consistent with previous acquisition processes where BC Hydro did not acquire all energy that could be purchased at a particular price; rather acquisitions were made for particular volumes of energy informed by need. Given the reduced need for new energy resources going forward, BC Hydro is not expecting to further adjust the LRMC to reduce resource acquisitions, but is increasingly focusing on non-price factors (e.g., non-price factors for supply-side resource include benefits to the system and non-price factors for demand-side resource include providing opportunities for customers across rate classes). We have also shifted the focus of our DSM efforts in consideration of opportunities to reduce costs, be innovative and take advantage of new technologies, and respond to changing customer expectations and system needs. Details of our DSM plan for F2017 to F2019 will be provided in the revenue requirements application.

1.2 LRB – October 2015 Load Forecast

Table 1 to Table 4 show the LRB that includes the October 2015 Load Forecast. Table 1 and Table 2 show the LRB with only existing and committed resources prior to additional planned resource acquisitions. New resources are needed both for energy

and capacity at the start of the planning horizon (F2020)[3] on an expected basis. Table 3 and Table 4 show the LRB including planned resource acquisitions. Given uncertainty in input assumptions that drive the LRB gap and future resource requirements, each table shows an expected LRB gap as well as a range of results reflecting load forecast and DSM savings uncertainty where applicable.[4] Note that in all cases, the same forecast LNG load is shown.

Since the 2013 IRP, the LRB has evolved. The load forecast continues to show long-term load growth across all three customer classes; however, load is forecast at a lower level compared to the 2013 IRP. DSM savings from conservation rate structures are lower than expected, energy savings from codes and standards have increased, and the IPP energy delivery forecast has increased. The capacity LRB has further evolved with major maintenance requirements on the existing system related to the required refurbishment of generating units 1 to 4 at the Mica generating station. The overall result is a reduced need for energy resources, a reduced need for capacity resources prior to Site C and an increased need for capacity resources after Site C.

Load Forecast

The October 2015 Load Forecast predicts long-term load growth for all three customer sectors. Residential and commercial loads are growing steadily albeit at a slower rate since the 2009 recession, primarily driven by increasing population and general economic trends. Large industrial load growth continues to be subject to volatility and will require continued evaluation. Overall, however, load is forecast at a lower level relative to the 2013 IRP:

[3] BC Hydro shows the load resource balance in two views. The planning horizon (F2020 and beyond) reflects the forecast of system need under prescribed water conditions set out in the self-sufficiency requirement contained in subsection 6(2) of the *Clean Energy Act*. The forecast in the operating horizon (F2017 to F2019) provides the forecasted optimal reliance on resources in the short-term given near-term market conditions, system constraints, planned outages and expected hydro reservoir inflows.

[4] BC Hydro quantified a range of uncertainty for load forecast (prior to LNG) and DSM savings. The high and low load forecast estimates and DSM estimates are the mean of the upper and lower twentieth percentile tails of the respective distributions. High load forecast and Low DSM estimate are combined in the large gap scenario. Low load forecast and Low DSM estimate are combined in the small gap scenario.

- For the residential and commercial sectors, the lower forecast is primarily due to lower growth projections in economic drivers such as housing starts; and
- For the industrial sector, the lower forecast is due to factors including delays of in service dates for several mining, and oil and gas projects, reduced expectations for potential new mining and oil and gas loads given current low commodity prices, the closure of Paper Excellence's Howe Sound Thermo-Mechanical Pulp Facility, and a reduced outlook for the pulp and paper sector.

DSM Savings

DSM continues to be a key resource in the LRB and there have been two changes since the 2013 IRP. First, energy savings from conservation rate structures have been less than forecast, but energy savings from codes and standards have increased. In particular, customers' response to the Large General Service and Medium General Service two part baseline rates was considerably lower than forecast in the 2013 IRP. Most of the incremental energy savings from the LGS and MGS rates were forecasted to occur prior to F2015 and that impact is reflected in the current load forecast. Second, BC Hydro has decided to extend the moderation of DSM spending recommended in the 2013 IRP through F2017 – F2019.

IPP Forecasts

The forecast of IPP supply from existing electricity purchase agreements has increased largely due to higher than expected project advancements and completions.

Major Maintenance

BC Hydro's heritage assets are aging, requiring major maintenance work to ensure reliable operation. Given the capacity need and the cost effective strategy to rely on market as a bridging resource to Site C, BC Hydro has to delay major maintenance work to avoid taking major units out of service during the period when capacity is tight prior to Site C. The updated capacity LRB reflects the current view of scheduling

maintenance outages for generating units 1 to 4 (410 MW each for dependable capacity) at the Mica generating station when Site C comes online. It is currently estimated that the units will be out of service for 12 to 18 months each. The resulting impact is a 410 MW reduction in capacity contribution from BC Hydro's heritage resources for a period of approximately six years which will advance BC Hydro's need for new capacity resources after Site C. The impact of the outage on energy is minimal.

2 Energy LRMC

Currently and still consistent with the 2013 IRP, BC Hydro's actions to meet future energy demand include Site C and the Standing Offer Program (**SOP**), along with DSM and IPP EPA renewals. Site C is a committed resource under construction and is not a marginal resource. Similarly, while the SOP is targeting new resources, it is not considered a marginal resource because it is required pursuant to subsection 15(2) of the *Clean Energy Act*.

As a result, DSM and IPP EPA renewals continue to be the marginal resources (energy volume adjustable) in the plan. As shown in Table 1, without DSM and IPP EPA renewals, there would be a need for new resources at the beginning of the planning horizon (i.e., F2020).

BC Hydro anticipates that it will continue to be able to acquire a sufficient volume of energy from these resources to meet its needs as identified in the 2013 IRP and updated in the LRB shown at Table 3 at a lower price than greenfield IPPs.[5] Since the DSM and IPP renewal resource supply curves (price and volume relationship) are not easily visible until the actions have been undertaken and as their prices are expected

[5] Current greenfield IPP prices are expected to be $100/MWh ($2015) based upon recent wind cost estimates reflecting adjusted unit energy cost including delivery to the LM/VI region.

to overlap, BC Hydro used a LRMC of $85/MWh to establish that there would be sufficient supply available from planned DSM initiatives and IPP EPA renewals.

BC Hydro's current outlook on the LRMC has shifted towards $85/MWh because the need for new resources has reduced and the price outlook for marginal resources has dropped since the 2013 IRP.

EPA Renewals

Consistent with the 2013 IRP, BC Hydro continues to plan to acquire through renewed EPAs 50 per cent of the energy and capacity contributions of existing bioenergy EPAs and 75 per cent of the contributions of the existing run-of-river hydroelectric EPAs that are due to expire by F2024.

In its EPA renewal negotiations, BC Hydro will consider the seller's opportunity cost, the electricity spot market, the cost of service for the seller's plant and other factors such as the attributes of the energy produced (e.g., dependable capacity) and other non-energy benefits.

BC Hydro notes that the costs of service for IPPs could vary significantly. BC Hydro expects there will be cost differences between biomass EPA renewals and run-of-river EPA renewals because run-of-river hydroelectric projects are primarily civil works with costs that have been fully or largely recovered during the first EPA term and likely have minimal sustaining capital costs. Bioenergy projects will have greater ongoing costs for operations including the cost of biomass fuel. Bioenergy facilities contribute dependable capacity which has additional system value.

Since the 2013 IRP, BC Hydro has carried out further analysis of the expected cost of service for existing biomass (including the cost and availability of fuel supply) and run-of-river projects. Based upon this further information and a reduced need for new resources, BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below the LRMC of $85/MWh although the relationship between price,

volume, contract terms and other non-energy benefits has yet to be established through bilateral negotiation.

DSM

The $85/MWh LRMC upper limit was used to inform the development of the DSM plan including by ensuring that all DSM initiatives were cost effective in a Total Resource Cost (**TRC**) test against the $85/MWh threshold.

Details of BC Hydro's DSM plan for F2017 to F2019 will be included in the revenue requirements application. The DSM savings shown in the LRB beyond F2019 are an outlook for DSM activities, which will be further explored in the next IRP due in November 2018.

Capacity

Consistent with the 2013 IRP, the capacity LRB outlook in this document continues to show a need to acquire additional capacity resources over and above the other resource acquisitions in the plan. BC Hydro continues to base the LRMC for capacity resources on Revelstoke Unit 6 which is the most cost effective generation capacity resource on a unit cost basis (Unit Capacity Cost of $50 to $55/kW-year). The updated capacity LRB outlook in this document shows that the expected need for Revelstoke Unit 6 has been advanced to F2026 from F2030 in the 2013 IRP. At the same time, Revelstoke Unit 6 continues to be a contingency resource for capacity needs prior to Site C, requiring its earliest in service date (now estimated at F2022) to be maintained.

3 Conclusion

Consistent with the 2013 IRP, over the next ten years the marginal need for new energy resources is expected to be met by DSM and IPP EPA renewals. Given the LRB outlook, BC Hydro's current outlook on the energy LRMC has shifted towards

$85/MWh because the need for new resources has reduced and the price outlook for marginal resources has dropped since the 2013 IRP.

The price signal provided to set the upper limit on those acquisitions is $85/MWh ($F2013) and BC Hydro expects it will be able to acquire sufficient resources to meet its need at or below the LRMC.

Revelstoke Unit 6 continues to be the marginal resource to meet the need for capacity resources. While Revelstoke Unit 6 is expected to be needed shortly after Site C, it is not yet a committed resource. As such, the current capacity LRMC will continue to be $50-55/kW-year($F2013) based on the levelized unit cost of Revelstoke Unit 6.

The potential further changes to the LRB noted in this document are not expected to impact the LRMC any further because those changes are unlikely to change the marginal energy and capacity resources over the next ten years. Furthermore, managing overall acquisitions can be done by limiting acquired volumes without modifying price limits

Updating the energy LRMC to $85/MWh may result in questions about what if any changes should be made to the Residential Inclining Block rate design. BC Hydro notes that a steady price signal is beneficial for encouraging a conservation culture. Additionally, as there is a continued need for capacity resources in the system, there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the Residential Inclining Block Step 2 rate. The addition of a generation capacity value to the energy LRMC could increase the LRMC for Residential Inclining Block from $95/MWh (based on $85/MWh in $F2013 adjusted for distribution losses and inflated to $2017) to $106/MWh in $F2017. BC Hydro proposes that these matters be explored further through this proceeding.

Table 1 Energy LRB with Existing and Committed Resources[6]

				Operating	Planning														
(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		46,935	46,054	46,228	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,928	11,818	11,500	10,963	10,187	9,723	9,654	9,608	9,447
Total Supply	(c) = a + b	60,853	60,789	60,436	64,876	64,619	64,031	61,897	61,748	65,425	65,699	65,589	65,271	64,734	63,958	63,494	63,426	63,379	63,218
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,832	-65,432	-66,676	-67,843	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(d)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,005
Sub-total	(e)	1,536	1,582	1,560	1,528	1,550	1,576	1,585	1,594	1,590	1,435	1,300	1,301	1,265	1,214	1,196	1,211	1,209	1,198
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(f) = c + d + e	**1,869**	**150**	**(2,355)**	**(1,048)**	**(3,051)**	**(4,807)**	**(8,369)**	**(9,308)**	**(6,405)**	**(7,306)**	**(8,398)**	**(9,743)**	**(11,277)**	**(13,120)**	**(14,690)**	**(15,879)**	**(16,853)**	**(17,934)**
Low Load Forecast Surplus / Deficit		4,842	4,479	3,333	5,833	4,584	3,507	224	(534)	2,673	2,101	1,387	234	(977)	(2,783)	(3,825)	(4,779)	(5,247)	(6,378)
High Load Forecast Surplus / Deficit		(1,110)	(4,340)	(8,496)	(8,635)	(11,547)	(13,752)	(17,783)	(18,964)	(16,645)	(17,942)	(19,324)	(20,974)	(22,804)	(24,962)	(26,687)	(28,317)	(29,754)	(31,135)

6 BC Hydro typically shows the load resource balance in two views. The planning horizon (F2020 and beyond) reflects the forecast of system need under prescribed water conditions set out in the self-sufficiency requirement contained in subsection 6(2) of *the Clean Energy Act*. The start year is F2020 to reflect typical lead time considerations for making new long-term acquisitions. The forecast in the operating horizon (F2017 to F2019) provides the forecasted optimal reliance on resources in the short-term given near-term market conditions, system constraints, planned outages and inflows. Operational shortfalls may also be met through economic market purchases, greater use of natural gas-fired (thermal) generation resources or greater drawdown of major reservoirs.

Table 2 Peak Capacity LRB with Existing and Committed Resources

				Operating	Planning														
(MW)		**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Existing and Committed Heritage Resources		11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
14% of Supply Requiring Reserves	(c)	-1,806	-1,808	-1,801	-1,794	-1,790	-1,787	-1,746	-1,742	-1,837	-1,831	-1,831	-1,824	-1,819	-1,800	-1,858	-1,857	-1,857	-1,853
Effective Load Carrying Capability	(d) = a + b + c	11,300	11,312	11,263	11,221	11,203	11,193	10,945	10,905	11,435	11,399	11,399	11,357	11,325	11,211	11,567	11,563	11,558	11,537
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(e)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,898	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	185
Sub-total	(f)	293	295	286	279	288	288	285	283	279	258	239	237	230	222	218	217	214	212
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**526**	**160**	**(173)**	**(592)**	**(856)**	**(1,031)**	**(1,489)**	**(1,693)**	**(1,356)**	**(1,603)**	**(1,826)**	**(2,084)**	**(2,342)**	**(2,698)**	**(2,581)**	**(2,822)**	**(3,072)**	**(3,332)**
Low Load Forecast Surplus / Deficit		1,072	962	872	658	529	468	55	(117)	279	91	(59)	(281)	(475)	(816)	(599)	(792)	(939)	(1,198)
High Load Forecast Surplus / Deficit		(22)	(673)	(1,301)	(1,970)	(2,398)	(2,644)	(3,181)	(3,428)	(3,200)	(3,518)	(3,799)	(4,115)	(4,433)	(4,853)	(4,770)	(5,096)	(5,442)	(5,770)

Table 3 Energy LRB After Planned Resources

					Operating	Planning													
(GWh)		**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Existing and Committed Heritage Resources		46,935	46,054	46,228	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671	48,671
Site-C									388	4,435	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
Sub-total	(a)	46,935	46,054	46,228	48,671	48,671	48,671	48,671	49,059	53,106	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771	53,771
Existing and Committed IPP Resources	(b)	13,919	14,735	14,208	16,205	15,948	15,359	13,225	12,688	12,319	11,928	11,818	11,500	10,963	10,187	9,723	9,654	9,608	9,447
Future Supply-Side Resources																			
IPP Renewals		84	241	569	683	811	1,108	3,168	3,586	3,850	4,171	4,255	4,442	4,850	5,583	6,048	6,099	6,141	6,302
Standing Offer Program		75	168	279	389	500	611	721	832	943	1,053	1,164	1,275	1,385	1,496	1,607	1,717	1,828	1,939
North Coast Capacity Additions		0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154
Sub-total	(c)	159	409	848	1,072	1,311	1,873	4,043	4,572	4,947	5,378	5,573	5,871	6,389	7,233	7,808	7,970	8,123	8,395
Total Supply	(d) = a + b + c	61,012	61,198	61,284	65,948	65,930	65,903	65,940	66,320	70,372	71,077	71,162	71,142	71,123	71,192	71,302	71,396	71,503	71,613
Demand - Integrated System Total Gross Requirements																			
2015 Oct Mid Load Forecast Before DSM*		-60,231	-61,866	-63,832	-65,432	-66,676	-67,843	-68,850	-69,650	-70,420	-71,440	-72,288	-73,316	-74,277	-75,292	-76,381	-77,515	-78,441	-79,350
Expected LNG Load		-289	-355	-518	-2,020	-2,544	-2,570	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000	-3,000
Sub-total	(e)	-60,520	-62,221	-64,350	-67,452	-69,220	-70,413	-71,850	-72,650	-73,420	-74,440	-75,288	-76,316	-77,277	-78,292	-79,381	-80,515	-81,441	-82,350
Demand Side Management & Other Measures																			
SMI Theft Reduction		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
Voltage and VAR Optimization		111	200	220	237	268	289	302	307	312	316	334	339	344	348	353	358	363	369
2016 DSM Plan F15 and F16 savings		1,343	1,390	1,367	1,335	1,357	1,383	1,391	1,401	1,397	1,242	1,107	1,108	1,072	1,021	1,003	1,018	1,016	1,005
2016 DSM Plan F2017+ savings		680	1,289	1,785	2,448	2,968	3,415	3,814	4,153	4,423	4,853	5,203	5,399	5,626	5,869	6,082	6,178	6,095	6,077
Sub-total	(f)	2,328	3,072	3,564	4,212	4,786	5,279	5,701	6,054	6,325	6,604	6,837	7,039	7,235	7,431	7,632	7,746	7,667	7,643
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(g) = d + e + f	**2,819**	**2,048**	**498**	**2,709**	**1,496**	**769**	**(209)**	**(276)**	**3,277**	**3,241**	**2,711**	**1,866**	**1,082**	**331**	**(447)**	**(1,373)**	**(2,272)**	**(3,094)**
Small Gap Surplus / Deficit		5,611	6,137	5,903	9,251	8,743	8,654	7,917	8,001	11,833	12,102	11,931	11,260	10,782	10,050	9,784	9,082	8,698	7,829
Large Gap Surplus / Deficit		*(341)*	*(2,682)*	*(5,926)*	*(5,217)*	*(7,388)*	*(8,606)*	*(10,090)*	*(10,429)*	*(7,484)*	*(7,942)*	*(8,780)*	*(9,947)*	*(11,045)*	*(12,128)*	*(13,078)*	*(14,456)*	*(15,808)*	*(16,927)*

Table 4 Peak Capacity LRB After Planned Resources

				Operating	Planning														
(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Existing and Committed Heritage Resources		11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	11,113	11,113	11,113	11,113	11,113	11,113	11,527	11,527	11,527	11,527
Site-C									0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Sub-total	(a)	11,419	11,457	11,463	11,463	11,463	11,527	11,527	11,527	12,213	12,213	12,213	12,213	12,213	12,213	12,627	12,627	12,627	12,627
Existing and Committed IPP Resources	(b)	1,688	1,664	1,601	1,552	1,530	1,453	1,165	1,121	1,059	1,017	1,017	968	930	798	798	794	788	764
Future Supply-Side Resources																			
IPP Renewals		10	23	55	79	92	135	419	436	446	480	480	508	532	665	665	668	674	699
Standing Offer Program		5	11	19	26	34	41	49	56	63	71	78	86	93	101	108	116	123	130
North Coast Capacity Additions							100	100	100	100	100	100	100	100	100	100	100	100	100
Revolstoke 6											488	488	488	488	488	488	488	488	488
Sub-total	(c)	15	35	73	106	126	276	568	592	609	1,139	1,146	1,182	1,213	1,353	1,361	1,372	1,385	1,417
Total Supply	(d) = a + b + c	13,122	13,155	13,137	13,120	13,119	13,256	13,259	13,240	13,881	14,369	14,376	14,362	14,357	14,364	14,785	14,792	14,800	14,807
14% of Supply Requiring Reserves	(e)	-1,809	-1,813	-1,811	-1,808	-1,808	-1,826	-1,825	-1,825	-1,922	-1,990	-1,991	-1,989	-1,988	-1,989	-2,048	-2,049	-2,050	-2,051
Effective Load Carrying Capability	(f) = d + e	11,313	11,342	11,327	11,312	11,311	11,430	11,433	11,415	11,959	12,379	12,385	12,373	12,369	12,375	12,737	12,743	12,750	12,756
Demand - Integrated System Peak																			
2015 Oct Mid Load Forecast Before DSM*		-11,022	-11,402	-11,628	-11,807	-12,021	-12,186	-12,340	-12,502	-12,690	-12,879	-13,084	-13,299	-13,518	-13,750	-13,985	-14,223	-14,464	-14,701
Expected LNG Load		-45	-45	-95	-285	-326	-326	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380	-380
Sub-total	(g)	-11,067	-11,447	-11,723	-12,092	-12,347	-12,512	-12,720	-12,882	-13,070	-13,259	-13,464	-13,679	-13,898	-14,130	-14,365	-14,603	-14,844	-15,081
Demand Side Management & Other Measures																			
SMI Theft Reduction		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F15 and F16 savings		266	268	259	252	261	261	258	256	252	231	212	210	203	195	191	190	187	185
2016 DSM Plan F2017+ savings		119	224	311	444	550	622	683	732	768	825	871	897	926	956	980	991	982	990
Sub-total	(h)	412	519	598	723	837	910	968	1,015	1,047	1,083	1,110	1,135	1,157	1,177	1,198	1,208	1,196	1,202
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**
Surplus / Deficit	(i) = f + g + h	**658**	**414**	**201**	**(58)**	**(199)**	**(172)**	**(318)**	**(452)**	**(64)**	**202**	**31**	**(170)**	**(372)**	**(578)**	**(431)**	**(651)**	**(898)**	**(1,123)**
Small Gap Surplus / Deficit		1,177	1,176	1,194	1,125	1,106	1,232	1,120	1,011	1,450	1,754	1,640	1,463	1,311	1,110	1,349	1,180	1,048	833
Large Gap Surplus / Deficit		83	(459)	(979)	(1,503)	(1,820)	(1,880)	(2,116)	(2,300)	(2,030)	(1,855)	(2,101)	(2,371)	(2,647)	(2,926)	(2,822)	(3,124)	(3,455)	(3,739)