Clean Energy BC

CEBC Information Requests with BCH Responses:
BC Hydro – F2023-F2025 Revenue Requirements Application
Responses Issued: December 16, 2021

1.0 Reference: Exhibit B-2, Page 4-17

BC Hydro states that "Consistent with the Draft 2021 Integrated Resource Plan, the planned Cost of Energy for the Test Period assumes that any potential EPA renewals during the Test Period will be at market-based prices…"

1.1.1

Please explain what BC Hydro means by "market-based prices".

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.32.1.

1.1.2

If by "market-based prices" BC Hydro means that pricing will be in reference to the Mid-Columbia market (or similar), please set out the economic principles that make this the appropriate price for IPP contract renewals. In answering this question, please address the different pricing principles and considerations applicable to short-term or spot markets as compared to the pricing principles and considerations that underpin long-term energy supply contracts.

RESPONSE:

BC Hydro notes that the 2021 Integrated Resource Plan, which BC Hydro expects to file with the BCUC later this month, will discuss its approach for market-based pricing for EPA renewals in the next five years. Please refer to BC Hydro's response to BCUC IR 1.32.1 which discusses the meaning of "market-based prices".

BC Hydro's general approach to EPA pricing considers BC Hydro's load resource balance and a number of cost-effectiveness benchmarks which include an estimate of the IPP's cost of service (including a rate of return), as well as BC Hydro's opportunity cost, and the IPP's opportunity cost. In determining an energy price for an EPA, the economic principle generally applied by BC Hydro, whether the EPA is a shorter-term agreement or a longer-term agreement, is cost-effectiveness.

1.1.3

Please describe the steps that BC Hydro has taken to understand the economic viability of IPPs facing renewals at "market-based" prices.

RESPONSE:

We expect that most IPP projects with expiring EPAs will have a low cost of service because they have remaining asset life, have had time to pay off their fixed investments and have low operating costs. Accordingly, we believe IPPs will be able to operate economically at market-based prices and will want to continue operating. We also note that recently BC Hydro has entered into EPAs with projects for short terms at market-based prices (e.g., Robson Valley and Coats), which supports our belief that the approach is viable.

1.1.4

In making its decision to renew IPP contracts at market-based prices, did BC Hydro quantify the expected loss of economic or social benefits to First Nations that have ownership or other economic interests in the affected IPPs. If so, please provide that quantification. If not, please explain why BC Hydro did not consider this impact.

RESPONSE:

BC Hydro cannot quantify the expected loss of economic or social benefits to owners of IPP projects as explained below.

EPAs are commercial arrangements, as between BC Hydro and an IPP. Owners of IPP projects, including First Nation owners, generally do not disclose to BC Hydro the economic or social benefits they may receive as an owner of a particular project, because in most circumstances this will be an IPP's commercially sensitive information.

Moreover, IPPs generally do not disclose to BC Hydro details concerning a First Nation's involvement with their clean energy projects, and BC Hydro's knowledge with respect to such participation is a function of what a particular IPP has chosen to share with BC Hydro. For these reasons, BC Hydro cannot quantify any potential losses as a result BC Hydro's approach of offering EPA renewals at market-based prices.

1.1.5

In respect of BC Hydro's answer to question 1.1.4, please describe how any such loss of economic or social benefits aligns or conflicts with BC Hydro's Statement of Indigenous Principles or BC Hydro's other obligations, goals, and commitments in furtherance of reconciliation.

RESPONSE:

Our approach to EPA renewals does not conflict with our Statement of Indigenous Principles or our commitment to advancing reconciliation with Indigenous peoples within our mandate as a regulated utility. We note that EPA renewals are commercial agreements which will be filed with the BCUC as energy supply contracts in accordance with section 71 of the Utilities Commission Act. BC Hydro can maintain its commitment to reconciliation while making prudent decisions on behalf of its ratepayers.

1.1.6

On June 23, 2020, the BC Government introduced the Clean Energy Act Amendment Act. This Act, had it become law, would have removed the requirement for BC Hydro to achieve electricity self-sufficiency. To the extent that some or all IPPs facing re-contracting at "market-based prices" become inviable such that contract renewals are not possible, and if BC Hydro's self-sufficiency obligations are not ultimately repealed, please describe BC Hydro's access to long-term supply alternatives at "market-base prices" that are consistent with self-sufficiency.

RESPONSE:

The 2021 Integrated Resource Plan, which BC Hydro expects to file with the BCUC later this month, will discuss BC Hydro's approach to EPA renewals in the next five years and long-term supply alternatives for when additional supply is needed in the future.

For those EPAs that are expiring during the Test Period, BC Hydro expects that IPPs will want to continue operating and will be able to operate economically with market-based prices as we believe these projects should have a low cost of service.

2.0 Reference: Exhibit B-2, Page 4-21

BC Hydro states that it "actively look[s] for opportunities to displace diesel generation with clean or renewable resources in Non-Integrated Area communities when it is cost effective to do so."

1.2.1

Please define what BC Hydro means by "cost effective" in this context. In BC Hydro's answer, please explain how social, environmental, and reconciliation objectives are priced or otherwise taken into consideration.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.33.5 which explains that generally an EPA energy price in a Non-Integrated Area is the lower of BC Hydro diesel generation or the expected cost of service of an IPP. If an EPA energy price is lower or equivalent to BC Hydro's diesel generation in a particular Non-Integrated Area, then the EPA will generally be cost effective.

Socio-economic, environmental and First Nations objectives are also some of the factors and criteria taken into account when assessing whether an EPA meets British Columbia's energy objectives as prescribed in the Clean Energy Act. Section 71 (2.21) of the Utilities Commission Act specifies the factors and criteria the BCUC must consider in determining whether an energy supply contract filed by BC Hydro is in the public interest. BC Hydro is guided by the section 71 (2.21) criteria and does not apply weighting to these criteria. Generally, we believe that it is not practical or feasible (with a reasonable level of confidence) to apply quantitative weighting to the section 71 (2.21) factors and criteria.

1.2.1

Please provide copies of all business cases (or similar) that BC Hydro has undertaken in the past five years aimed at displacing diesel generation with clean or renewable resources.

RESPONSE:

BC Hydro has no business cases which it has undertaken in the past five years aimed at displacing diesel generation with clean or renewable resources, as such business cases are generally undertaken by the proponent of the clean or renewable resource.

Please also refer to BC Hydro's response to BCUC IR 1.33.7 which explains BC Hydro's existing approach to exploring other alternative generative generation options and BC Hydro's response to NTC IR 1.10.1 which provides further details in relation to the development of BC Hydro's Non-Integrated Areas Diesel Reduction Strategy.

3.0 Reference: Exhibit B-2, Pages 4-8 and 4-22

At referenced Page 4-8, BC Hydro states that the cost of its Electrification Plan, if fully realized, would be $87.8 million. At page 4-22, BC Hydro states that the Cost of Market Energy due to increased load from the Electrification Plan is $89.8 million, if fully realized.

1.3.1

Please confirm if these numbers are reflecting the same cost (i.e., if the difference is inadvertent), or if there is an intended difference between these figures. If there is an intended difference, please describe the source of that difference.

RESPONSE:

Please refer to BC Hydro's response to NTC IR 1.24.1 which explains the difference between the $87.8 million, the total planned Cost of Energy for the Electrification Plan in fiscal 2025, and the $89.8 million, the total planned Market Energy costs for the Electrification Plan in fiscal 2025.

<u>4.0 Reference: Exhibit B-2, Page 4-23</u>

BC Hydro states that its Electrification Plan, if fully realized, would result in approximately 2,200 GWh of additional load, at a Cost of Market Energy equal to $89.8 million. BC Hydro states further that the higher forecast load results in an increase to the Cost of Market Energy because there is less surplus to export, and because more imports are required.

1.4.1

Please provide the calculations, including assumed costs, opportunity costs, and volumes, that show the derivation of the $89.8 million figure.

RESPONSE:

As stated on page 10-42 of the Application, the increase in Cost of Energy was calculated as the difference between an April 2021 Energy Study with and without the incremental load associated with the Electrification Plan. The table below provides a breakdown of the volumes and costs that derive the $89.8 million of Market Energy costs associated with the Electrification Plan in the Fiscal 2025 Plan.

Market Energy	With Electrification Plan			Without Electrification Plan			Difference	
Fiscal 2025	GWh	$ million	$/MWh	GWh	$ million	$/MWh	GWh	$ million
System Imports	5,069	218.1	*$ 43.04*	3,667	157.9	*$ 43.05*	1,401	60.3
System Exports	(3,425)	(131.4)	*$ 38.36*	(4,560)	(160.9)	*$ 35.29*	1,135	29.5
Total	**1,644**	**86.8**		**(892)**	**(3.0)**		**2,536**	**89.8**

1.4.2

Is it correct to conclude that the average cost per megawatt hour for the Electrification Plan is approximately $41 using BC Hydro's approach? If not, please provide the correct figure, and explain how it is calculated.

RESPONSE:

No, BC Hydro does not believe that the average cost per megawatt hour for the Electrification Plan, as calculated in the question using the incremental Cost of Market Energy, is an appropriate measure. In contrast to the measure calculated in the question, what is important for the Electrification Plan is the absolute cost.

The absolute cost is what is included in rate impact analysis. The Electrification Plan is based on all of the costs and all of the revenue related to the change in load due to the Electrification Plan as shown in Figure 10-1 of Chapter 10 of the Application.

1.4.3

If a single 2,200 GWh per year industrial load were being added to the BC Hydro system in the normal course, would BC Hydro's calculation of the costs and benefits of that load be found using the same methodology as described in BC Hydro's answer to question 1.4.1?

RESPONSE:

BC Hydro connects and serves customers in accordance with the applicable tariff. Tariff Supplement 6 specifies a formula to determine a new industrial customer's required contribution or security toward system reinforcement but otherwise, a cost/benefit analysis of connecting a new load is not undertaken.

That said, the calculation of the Market Energy costs for an equivalent load would be the same as shown in BC Hydro's response to CEBC IR 1.4.1 for fiscal 2025 Plan, regardless of whether that load was coming from a single source (i.e., a single industrial load) or multiple sources (i.e., incremental load from the Electrification Plan).

1.4.4

If BC Hydro were undertaking the same Electrification Plan in the absence of a surplus, how would BC Hydro determine the cost of that Electrification Plan. For example, would it use the marginal cost of new domestic supply, or some other metric?

RESPONSE:

BC Hydro plans its resources to meet its planning criteria, and then in the operating timeframe, makes decisions to dispatch resources and to undertake System Imports or System Exports.

This means that for the Test Period, regardless of whether BC Hydro is in surplus or deficit, incremental load would generally result in an increase to the Cost of Market Energy.

Beyond the Test Period and in the planning timeframe, and all else equal, BC Hydro may need to add additional domestic resources sooner as a result of advancing the actions in the Electrification Plan. In the absence of a surplus, the cost of these additional domestic resources would be realized sooner.

Please also refer to BC Hydro's response to BCUC IR 1.122.4 where we discuss the impacts of additional load from the Electrification Plan on BC Hydro's load resource balance.

1.4.5

Would BC Hydro's answer to question 1.4.4 be different if the BC Government were to amend the Clean Energy Act to remove BC Hydro's self-sufficiency obligations? Please explain the basis for any difference.

RESPONSE:

In the operating timeframe, the self-sufficiency requirement in the Clean Energy Act does not impact BC Hydro's decisions, to dispatch resources and to undertake System Imports or System Exports.

Beyond the Test Period and into the planning timeframe, and all else equal, BC Hydro may need to add additional domestic resources sooner as a result of advancing the actions in the Electrification Plan. BC Hydro cannot speculate on how its planning criteria to meet future electricity needs might change in the absence of the electricity self-sufficiency requirement in the Clean Energy Act.

Please refer to BC Hydro's response to BCUC IR 1.122.4 where we discuss the impacts of additional load from the Electrification Plan on BC Hydro's load resource balance.

5.0 Reference: Exhibit B-2, Section 5.5.3.1

BC Hydro states that 45.7 per cent of Test Period cost increases are "uncontrollable". These "uncontrollable costs" includes labour, pension, insurance, and certain technology costs. BC Hydro states, further, that it did, for example, control such costs in 2022, by not providing Management and Professional staff with pay increases.

1.5.1

How does BC Hydro determine which cost increases it labels as "uncontrollable"?

RESPONSE:

In determining whether particular cost increases are uncontrollable BC Hydro does not apply a specific test but considers factors such as whether the cost pressure is non-discretionary and/or beyond BC Hydro's control.

The "uncontrollable" cost category includes Test Period cost increases as follows:

1. Salary and wage increase for Union employees which is consistent with the bargaining mandate set the Public Sector Employers' Council and supported by collective agreements;

2. Salary increase for Management and Professional employees which aligns with market trends as described in the Application. Notwithstanding the salary freeze in fiscal 2022 related to the COVID-19 pandemic, as noted in Chapter 5, page 5-28 of the Application "BC Hydro considers management and professional compensation increases, which are essentially cost of living increases, to be a priority akin to non-controllable costs given how BC Hydro's employee compensation compares to median market.";

3. Benefit costs increase annually due to prescribed increases to statutory benefits and increases to health benefit costs (e.g., Employment Insurance premiums, Canada Pension Plan premiums and health and dental fees);

4. Mandatory fees levied by third parties (e.g., BCUC and Canada Energy Regulator (CER) Cost Recovery Levies);

5. Legislated requirements to maintain compliance under the Fisheries Act (e.g., Water Use Plan Order Review);

6. Market driven changes in the discount rate which are outside of BC Hydro's control. The discount rate is calculated in accordance with accounting rules BC Hydro must follow (in this case International Accounting Standards 19) by BC Hydro's external actuary for Current Service Pension costs;

7. Constrained market conditions causing an upward pressure on premiums resulting in an increase in insurance costs; and

8. Technology licensing and application support costs that are driven by market pricing and changing licensing models.

1.5.2

In its proposed “market-based” IPP re-contracting, is BC Hydro proposing to recognize such IPP costs as uncontrollable and subject to flow through to ratepayers? If not, why not?

RESPONSE:

EPA costs are defined and subject to the terms and conditions of each respective EPA with an IPP. Whether an EPA’s pricing is market-based, or not, does not impact how the costs related to such agreement are treated from a revenue requirements perspective. IPP costs are component of Non-Heritage Energy costs and variances between planned and actual IPP costs are captured in the Non-Heritage Deferral Account as part of the Cost of Energy Variance accounts approved by the BCUC.

6.0 Reference: Exhibit B-2-3, Section 10.2.1

BC Hydro states that the Electrification Plan will result in lower customer rates because domestic sales generate more revenue than exporting surplus energy. BC Hydro states further that “As BC Hydro’s surplus declines and new energy and capacity resources are required to serve the incremental load, this benefit is reduced but remains positive in the forecast period (fiscal 2022 to fiscal 2031).”

1.6.1

Using a format similar to Tables 3-6 (Energy Load Resource Balance with Existing and Committed Resources) and 3-8 (Energy Load Resource Balance after Planned Resources) from BC Hydro’s F2017 to F2019 Revenue Requirement, please provide the current derivation of BC Hydro’s surplus.

RESPONSE:

BC Hydro no longer uses the referenced format from the F2017-F2019 RRA. The derivation of BC Hydro’s surplus is shown in Tables 1 and 2 (*next page*) and is based on BC Hydro’s Draft 2021 Integrated Resource Plan released in June 2021.

Clean Energy BC

Table 1: System energy Load Resource Balance with existing and committed resources and Base Resource Plan

	(GWh)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed IPP Resources***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Dec 2020 Reference Load Forecast before DSM	(d)	(58,526)	(60,140)	(61,545)	(63,029)	(64,573)	(65,696)	(66,789)	(67,435)	(68,127)	(68,811)	(69,594)	(70,214)	(70,903)	(71,612)	(72,371)	(73,002)	(73,698)	(74,379)	(75,121)	(75,829)
	Existing and Committed Demand Side Management																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards		563	824	1,077	1,316	1,543	1,750	1,938	2,118	2,288	2,451	2,607	2,756	2,905	3,056	3,206	3,357	3,507	3,657	3,807	3,870
7	Energy Conservation Rate Structures		138	177	210	239	268	296	325	354	383	396	396	396	396	396	396	396	396	396	396	333
8	Sub-total	(e)	806	1,118	1,404	1,673	1,922	2,159	2,375	2,582	2,775	2,917	3,063	3,200	3,349	3,495	3,619	3,764	3,915	4,065	4,215	4,213
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**4,937**	**1,643**	**97**	**(957)**	**1,042**	**1,492**	**552**	**(286)**	**(1,958)**	**(3,454)**	**(4,535)**	**(5,136)**	**(5,877)**	**(6,881)**	**(8,264)**	**(9,037)**	**(9,639)**	**(10,346)**	**(10,886)**	**(11,698)**
	Base Resource Plan																					
	Future Demand Side Management																					
11	Base Energy Efficiency		161	296	472	649	814	948	1,090	1,224	1,347	1,483	1,558	1,616	1,666	1,706	1,768	1,779	1,788	1,794	1,795	1,795
12	Higher Energy Efficiency		-	-	-	-	-	35	118	222	327	448	576	709	813	926	1,025	1,108	1,192	1,255	1,320	1,387
13	Time-Varying Rates & Demand Response		-	-	-	-	46	46	47	47	47	47	48	48	48	48	48	49	49	49	49	49
14	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Sub-total	(h)	161	296	472	649	860	1,029	1,255	1,493	1,721	1,979	2,181	2,372	2,527	2,680	2,842	2,935	3,029	3,098	3,164	3,231
17	**Surplus / (Deficit) after planned DSM**	**(i) = g + h**	**5,099**	**1,939**	**570**	**(307)**	**1,902**	**2,521**	**1,806**	**1,206**	**(237)**	**(1,475)**	**(2,354)**	**(2,764)**	**(3,350)**	**(4,201)**	**(5,423)**	**(6,101)**	**(6,610)**	**(7,249)**	**(7,722)**	**(8,467)**
18	***Electricity Purchase Agreement Renewals***	(j)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
19	***Future Resources***	(k)	-	-	-	-	-	-	-	-	-	580	1,458	1,869	2,454	3,306	4,527	5,206	5,714	6,353	6,826	7,572
20	**Surplus / (Deficit) after planned resources**	(l) = i + j + k	**5,099**	**1,998**	**882**	**227**	**2,718**	**3,417**	**2,701**	**2,102**	**659**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**0**

Table 2: System capacity Load Resource Balance with existing and committed resources and Base Resource Plan

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																						
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,628	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed IPP Resources***	(b)	1,663	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,537)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	11,754	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																						
5	Dec 2020 Reference Load Forecast before DSM	(e)	(10,478)	(10,862)	(11,140)	(11,363)	(11,560)	(11,753)	(11,936)	(12,100)	(12,247)	(12,399)	(12,550)	(12,718)	(12,882)	(13,052)	(13,230)	(13,420)	(13,605)	(13,788)	(13,970)	(14,149)	(14,318)
	Existing and Committed Demand Side Management																						
6	F21 Energy Conservations Programs Savings		21	21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards		49	118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		5	11	16	19	23	26	29	31	34	37	38	38	37	37	37	37	37	37	37	37	33
9	Sub-total	(f)	75	150	203	252	297	337	375	410	442	472	495	517	538	566	593	617	644	672	700	728	736
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,351**	**1,327**	**853**	**662**	**496**	**1,274**	**1,130**	**686**	**545**	**317**	**107**	**(70)**	**(80)**	**(254)**	**(675)**	**(933)**	**(1,091)**	**(1,283)**	**(1,437)**	**(1,596)**	**(1,756)**
	Base Resource Plan																						
	Future Demand Side Management																						
12	Base Energy Efficiency		-	30	56	85	115	142	164	187	209	229	248	261	272	281	290	299	302	303	304	302	302
13	Higher Energy Efficiency		-	-	-	-	-	-	10	23	39	57	75	94	115	132	151	168	184	199	212	226	240
14	Time-Varying Rates & Demand Response		-	-	-	-	-	136	145	173	201	221	225	227	229	231	232	234	236	237	239	240	242
15	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98
16	Electric Vehicle Peak Reduction		-	-	-	-	24	40	60	73	87	102	119	138	157	178	201	224	247	270	293	315	339
17	Sub-total	(i)	-	30	56	85	139	318	380	456	536	707	765	818	871	920	972	1,023	1,066	1,107	1,146	1,182	1,222
18	**Surplus / (Deficit) after planned DSM**	(j) = h + i	**1,351**	**1,357**	**909**	**747**	**635**	**1,593**	**1,510**	**1,142**	**1,081**	**1,023**	**872**	**748**	**791**	**667**	**296**	**90**	**(25)**	**(176)**	**(291)**	**(414)**	**(534)**
19	***Electricity Purchase Agreement Renewals*** [3]	(k)	0	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
20	***Future Resources*** [3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	225	348	467
22	**Surplus / (Deficit) after planned resources**	(n) = j + k + l + m	**1,351**	**1,357**	**916**	**771**	**673**	**1,659**	**1,576**	**1,208**	**1,147**	**1,090**	**938**	**814**	**857**	**733**	**363**	**156**	**41**	**(0)**	**(0)**	**0**	**(1)**

Notes:

[1] Includes outages for Mica and Seven Mile for the period F2029 to F2032

[2] The 12% reserve margin is applied to dependable capacity resources only.

[3] The numbers shown include the 12% reserve margin.

7.0 Reference: CleanBC Roadmap to 2030, Page 30

The CleanBC Roadmap to 2030 states, under the heading "Advancing BC Hydro's Electrification Plan", that: "To help support and drive BC Hydro's focus on GHG reductions, we will add electrification and fuel-switching to its mandate, introduce an internal carbon price to evaluate electrification initiatives in regulatory applications, and enable investments in green hydrogen production and commercial vehicle incentives in green hydrogen production and commercial vehicle incentives and infrastructure."

1.7.1

Please describe BC Hydro's understanding of how its mandate will be changing with respect to electrification and fuel switching, including the legal or regulatory mechanisms that will be put in place to effect that change in mandate.

RESPONSE:

This response also answers:

CEBC IR 1.7.2.

"Please explain if this mandate change will result in any changes to BC Hydro's Electrification Plan as set out in this proceeding, or if these mandate changes are already reflected in the current Electrification Plan."

The CleanBC Roadmap to 2030 was recently released, and BC Hydro's assessment of its implications is preliminary and ongoing.

Please refer to BC Hydro's response to MOVEUP IR 1.1.1 where we provide a table listing the measures set out on page 68 of the CleanBC Roadmap to 2030 along with comments about the potential impact of each measure with regard to BC Hydro.

Please also refer to BC Hydro's response to BCSEA IR 1.1.2 where we state that the CleanBC Roadmap to 2030 confirms the direction taken by BC Hydro in the Five-Year Strategy and the Electrification Plan.

Lastly, please refer to BC Hydro's response to BCSEA IR 1.1.3 where we explain that, in cases where actions identified in the CleanBC Roadmap to 2030 include a role for BC Hydro, BC Hydro is guided by the roadmap and is pursuing those actions in response to the policy guidance it provides.

8.0 Reference: Exhibit B-2-3, Section 10.2.3

BC Hydro states that the Electrification Plan supports the province's economic growth.

1.8.1

Please provide all economic or other studies undertaken in the preparation of the Electrification Plan that quantify this statement.

RESPONSE:

BC Hydro did not undertake any economic or other studies in the preparation of the Electrification Plan that quantify the statement that the Electrification Plan supports the province's economic growth.

However, as explained in section 10.2.3 of Chapter 10, the Electrification Plan may support the province's economic growth by attracting new customers to B.C. and creating jobs and economic opportunities in communities that have experienced downturns in industries such as forestry and mining.

1.8.2

Did BC Hydro design its Electrification Plan with a target contribution to BC's economic growth in mind? If so, how was this target defined?

RESPONSE:

No. BC Hydro did not design its Electrification Plan with a target contribution to B.C.'s economic growth in mind.

1.8.3

In preparing the Electrification Plan, did BC Hydro evaluate the economic, employment, and GHG mitigation benefits of a more aggressive Electrification Plan that included the addition of new domestic generation resources? If so, please provide these evaluations. If not, why was this evaluation not undertaken?

RESPONSE:

At this time, BC Hydro has not assessed a more aggressive Electrification Plan. BC Hydro considers its Five-Year Strategy targets to be aggressive, but achievable and the Electrification Plan was designed to support the achievement of the Five-Year Strategy targets.

BC Hydro also notes that, all else equal, we may need to add additional domestic resources sooner as a result of advancing the actions in the Electrification Plan. For further discussion on this point, please refer to BC Hydro's response to BCUC IR 1.122.4.

9.0 Reference: Exhibit B-2-3, Section 10.3

BC Hydro sets out six "guiding principles" for its Electrification Plan.

1.9.1

The fifth listed principle is "Maintain the ability to respond to changing market, load resource balance, and customer conditions by being able to ramp up, ramp down, and shift focus as required." Please discuss possible scenarios that would see BC Hydro exercise its response flexibility by "ramping down" its Electrification Plan.

RESPONSE:

The principle referenced in the preamble to the question is intended to reflect a range of potential scenarios under which BC Hydro may adjust the Electrification Plan.

As referenced in the preamble to the question, in general, BC Hydro may ramp up or ramp down the Electrification Plan in response to changing market, load resource balance and customer conditions. For example, if there was a change in the load resource balance that decreased the amount of resources available at market prices, BC Hydro may ramp down activities. Similarly, BC Hydro may ramp up Electrification Plan activities to mitigate downside risks to the load forecast.

Additional examples of potential scenarios that may result in BC Hydro ramping down its programs in the Electrification Plan include:

1. Addition of new programs by the Government or change to program requirements of existing Government programs and associated funding;

2. Changes to regulations or codes and standards that transform the market and BC Hydro programs are no longer needed to support customers; or,

3. New investments are made by industries in the sectors targeted by Load Attraction programs without the need for incentives from BC Hydro.

Additional examples of potential scenarios that may result in BC Hydro ramping up its programs in the Electrification Plan include a reduction or discontinuation of government funding for CleanBC initiatives.

1.9.2

Did BC Hydro consider enhancing First Nations' economic opportunities in the clean energy sector as a "guiding principle" for the purposes of developing its Electrification Plan. If not, why not?

RESPONSE:

The Electrification Plan did not specifically include enhancing First Nations economic opportunities in the clean energy sector as one of the six guiding principles. The focus of the Electrification Plan is addressing barriers to customers to electrify, including Indigenous customers.

Specific economic development opportunities associated with future interconnection projects will be identified through engagement with First Nations during the interconnection process for individual customers.

Please refer to BC Hydro's response to BCUC IR 1.129.1 for more information on BC Hydro's approach to Indigenous opportunities associated with interconnection projects.

1.9.3

In developing its Electrification Plan, was BC Hydro guided in any way by the record and recommendations in the Commission's Indigenous Utilities Regulation Inquiry? If this record was not considered, please explain why not.

RESPONSE:

BC Hydro has not specifically considered the recommendations from the Commission's Indigenous Utilities Inquiry in developing the Electrification Plan.

The Commission's recommendations were submitted to the Government of B.C. BC Hydro understands that the recommendations are the subject of ongoing engagement between the Government of B.C. and Indigenous Nations through the Indigenous Clean Energy Opportunities (ICEO) process. The ICEO process was jointly designed and is co-led by the Government of B.C. and the British Columbia First Nations Energy and Mining Council, on behalf of the First Nations Leadership Council. The ICEO process is a result of the draft Action Plan to implement the Declaration on the Rights of Indigenous Peoples Act.

1.9.4

In developing its Electrification Plan, please describe how BC Hydro was guided by the reconciliation aims of it or government, including being guided by (1) the United Nations Declarations on the Rights of Indigenous Peoples, (2) the Calls to Action of the Truth and Reconciliation Commission, (3) the

Declaration on the Rights of Indigenous Peoples Act, (4) BC Hydro's Statement of Indigenous Principles, and (5) BC's Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples. If BC Hydro was not guided by these reconciliation aims, please explain why not.

RESPONSE:

The Province enacted the Declaration on the Rights of Indigenous Peoples Act as a framework for reconciliation and adopted B.C.'s Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples which are about renewing Crown Indigenous Relationships. As a Crown utility, BC Hydro has an important role to play in supporting this broader societal effort of reconciliation. Reconciliation is one of the four goals of BC Hydro's Five-Year strategy. BC Hydro's Statement of Indigenous Principles guides our approach to the ongoing work of reconciliation, and the implementation of United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Commission Calls to Action.

The Electrification Plan contributes to reconciliation with Indigenous Peoples within its specific area of focus. The Electrification Plan is focused on addressing barriers to customers seeking to electrify, including Indigenous customers and we engaged Indigenous organizations in its development. The Electrification Plan identified an interest in addressing barriers to electrification in Indigenous communities and includes funding for an Energy Program Specialist position for one year as a first step to support Indigenous communities in this area and inform potential adjustments to programs.

10.0 Reference: Exhibit B-2-3, Section 10.3.2.4; Exhibit B-2-3, Table 10-5

BC Hydro states that it is partnering with the First Nations Energy and Mining Council, FortisBC Energy Inc., and the Government of BC to support an energy program specialist position at the First Nations Energy and Mining Council for a one-year term with the possibility of renewal. The position will connect First Nations communities with BC Hydro programs, provide education and training, and help First Nations communities overcome barriers to demand-side management, electrification, and climate change.

At Table 10-5, BC Hydro indicates that it is adding 53 FTEs over the Test Period to "implement the Electrification Plan".

1.10.1

Please explain how BC Hydro determined the relative resourcing requirements between the FTE compliment set out in Table 10-5 (53), and the resources employed in furtherance of the task of "helping First Nations overcome barriers to demand-side management, electrification, and climate change" (one FTE, for one year).

RESPONSE:

To clarify, the Energy Program Specialist with the BC First Nations Energy and Mining Council is a position supported by BC Hydro and is not part of the FTE compliment set out in Table 10-5 in support of the Electrification Plan. The position was created in response to a specific request from the British Columbia First Nation Energy and Mining Council.

The position is not intended to duplicate FTE resources allocated to support the Electrification Plan but rather to provide additional support for communities in accessing our programs.

The desired result or outcome of this position includes providing support to First Nations by sharing information about available programs, helping communities to decide which programs meet their needs, assisting in determining eligibility requirements and helping communities to apply to these programs.

Through direct engagement with communities the Energy Program Specialist position can provide input to BC Hydro to inform potential adjustments to programs.

1.10.2

Please provide any studies or evaluations undertaken by BC Hydro that underpinned the conclusion that one FTE is appropriate resourcing for the task referenced in question 1.10.1. In answering this question, please make reference to any specific results or outcomes that BC Hydro expects or intends under the general objective referenced in question 1.10.1.

RESPONSE:

Please refer to BC Hydro's response to CEBC IR 1.10.1 where we explain the energy program specialist position.

<u>11.0 Reference: Exhibit B-2-3, Section 10.2.2</u>

BC Hydro sets out BC's legislated GHG targets for 2025, 2030, 2040, and 2050. It states, further, that the Electrification Plan will reduce GHG emissions, helping to achieve these GHG emission reduction targets.

1.11.1

Recognizing GHG mitigation possibilities in areas such as vehicles and buildings, does BC Hydro have a view about the level of carbon elimination that must be achieved through Low Carbon Electrification if BC is to achieve each of these legislated targets?

RESPONSE:

BC Hydro does not have a view about the level of carbon elimination that must be achieved through Low Carbon Electrification (LCE) actions to achieve GHG reduction targets. There are many possible combinations of LCE actions and other emission reduction options (including energy efficiency, renewable natural gas and renewable liquid fuels, and negative emissions technologies) that could achieve the GHG reduction targets.

One possible combination of actions to achieve legislated GHG reduction targets is set out in Appendix F, "Electric Load Forecast Report F2021-F2041," section 8.5.2, "Accelerated Electrification Scenario," and Sub-Appendix F of Appendix F, "Navius Report." BC Hydro engaged Navius Research to develop an electrification scenario that estimates the impact on load growth if all of the provincial GHG reduction targets are met over the milestone years of 2025, 2030 and 2040.

1.11.2

Table 10-2 sets out the tonnes of CO_2e per year that will be removed under the Low Carbon Electrification Initiative in 2025. Please provide this figure as a percentage of the total carbon that BC must eliminate if the province is to achieve its 2025 target.

RESPONSE:

Taking the provincial total emissions reported for 2007 as a baseline of 65,671 kt and applying a 16% reduction by 2025 results in a target reduction of 10,507 kt. Table 10-2 sets out the tonnes of CO_2e per year that are estimated to be reduced by 2025 as 583 kt: 583 kt divided by 10,507 kt = 5.5%.

1.11.3

Did BC Hydro consider and reject Electrification Plan alternatives that made a greater contribution to the legislated targets than the Electrification Plan filed in this proceeding? If so, please describe options that were considered and rejected. If not, please explain why not.

RESPONSE:

At this time, BC Hydro has not assessed a more aggressive Electrification Plan.

In developing the Electrification Plan, BC Hydro focused on cost-effectively helping customers to overcome the barriers to electrification within the context of the Five-Year Strategy. While BC Hydro can support the achievement of legislated GHG targets, we are not the only party who will help achieve the legislated GHG targets.

BC Hydro considers its Five-Year Strategy targets to be aggressive, but achievable and the Electrification Plan was designed to support the achievement of the Five-Year Strategy targets. Please refer to section 10.3.1 in Chapter 10 of the Application where we explain our approach to developing the Electrification Plan.

12.0 Reference: Exhibit B-2-1, Pages 12, 26, 33, 41, and 51.

BC Hydro states that its DSM savings will be 4,939GWh per year by 2041. It provides further DSM savings estimates for 2021 and 2031, by customer class, at the referenced pages. As CEBC understands BC Hydro's Application, a summary of these tables could be shown as follows:

GWh/year	**2021**	**2031**	**2041**
Residential	152	1441	2150
Commercial	97	1145	1650
Light Industrial	24	298	375
Large Industrial	111	753	764
Total	384	3637	4939

1.12.1

Is this table correct? If not, please correct the table.

RESPONSE:

Yes, the values in the table correctly match the DSM savings included in the December 2020 Load Forecast, as presented in the sector build-up tables provided in Appendix F to the Application.

1.12.2

If correct, please show the DSM total for each of 2021, 20312, and 2041 as a percentage the energy surplus or deficit from domestic resources that BC Hydro is projecting for each of these years.

RESPONSE:

The DSM totals, which have been correctly captured in the table above, represent 7 per cent of the system energy surplus in fiscal 2021, and 57 per cent and 31 per cent of the system energy deficit in fiscal 2031 and fiscal 2041, respectively. This analysis is based on the system energy Load Resource Balance with existing and committed resources shown in BC Hydro's Draft 2021 Integrated Resource

Plan which was released in June 2021. The surplus/deficit amounts in this Load Resource Balance were modified to exclude the existing and committed DSM since the DSM savings shown in the table above also include existing and committed DSM.

BC Hydro's DSM energy savings level in the long term will be explained in BC Hydro's 2021 Integrated Resource Plan to be filed with the BCUC on December 21, 2021.

1.12.3

Please provide the data to extend the table above back, annually, to 2011.

RESPONSE:

The DSM savings shown in the above table in the preamble of this IR represent the savings and their persistence from DSM activities starting with the first forecast year of the load forecast. In this instance, the first forecast year of the December 2020 Load Forecast is fiscal 2021. As such, the DSM savings shown above are the savings and the associated persistence of the savings for DSM activities from fiscal 2021 and onwards.

Savings and associated persistence of savings from DSM activities prior to the first forecast year of the load forecast (i.e., prior to fiscal 2021) are reflected in BC Hydro's actual sales, which also form part of the load forecast before (incremental) DSM.

The following tables show cumulative DSM savings and the associated persistence of those savings based on actuals for activities from fiscal 2011 to fiscal 2020. The cumulative DSM savings in the table below are incremental to those savings shown above and any existing past savings would be reflected in the actual sales of the base year of the load forecast.

Energy Savings (GWh)	F2011	F2012	F2013	F2014	F2015
Residential	96	301	514	713	891
Commercial	119	435	695	726	785
Light Industrial	33	106	152	158	169
Large Industrial	315	494	678	749	930
TOTAL	564	1,336	2,038	2,345	2,775

Energy Savings (GWh)	F2016	F2017	F2018	F2019	F2020
Residential	1,087	1,302	1,552	1,816	2,075
Commercial	908	1,047	1,173	1,313	1,465
Light Industrial	212	250	277	308	350
Large Industrial	1,089	1,222	1,196	1,626	1,708
TOTAL	3,296	3,821	4,198	5,063	5,599

Energy Savings (GWh)	F2021	F2022	F2023	F2024	F2025
Residential	2,159	2,135	2,119	2,110	2,099
Commercial	1,531	1,493	1,456	1,397	1,327
Light Industrial	367	355	343	326	306
Large Industrial	1,578	1,097	1,056	1,014	973
TOTAL	5,636	5,079	4,973	4,846	4,705

Energy Savings (GWh)	F2026	F2027	F2028	F2029	F2030
Residential	2,083	2,069	2,058	2,052	2,047
Commercial	1,286	1,219	1,120	1,010	931
Light Industrial	295	272	248	222	198
Large Industrial	924	860	703	607	538
TOTAL	4,587	4,420	4,128	3,892	3,713

Energy Savings (GWh)	F2031	F2032	F2033	F2034	F2035
Residential	2,027	2,010	1,979	1,949	1,932
Commercial	868	814	768	731	700
Light Industrial	175	152	141	133	122
Large Industrial	470	448	437	366	285
TOTAL	3,541	3,423	3,324	3,178	3,039

Energy Savings (GWh)	F2036	F2037	F2038	F2039	F2040
Residential	1,911	1,887	1,851	1,827	1,804
Commercial	674	666	660	658	657
Light Industrial	101	91	90	88	85
Large Industrial	220	150	132	127	127
TOTAL	2,907	2,795	2,733	2,700	2,673

1.12.4

Will the DSM Plan be filed by BC Hydro later in this proceeding explain the programs and costs associated with the material increase in DSM necessary to achieve these 2031 and 2041 targets?

RESPONSE:

The DSM Plan, which BC Hydro expects to file in this proceeding later this month, will provide the programs, expenditures and energy savings planned over the Test Period (i.e., fiscal 2023 to fiscal 2025) that are consistent with the pathway to reach the longer-term energy savings levels identified in BC Hydro's 2021 Integrated Resource Plan. The DSM Plan will not discuss the programs and expenditures associated with the increase in DSM in the years subsequent to the Test Period, which are necessary to achieve those longer-term levels.

The resource costs and energy savings associated with the increase in DSM necessary in the long term will be explained in BC Hydro's 2021 Integrated Resource Plan to be filed with the BCUC on December 21, 2021.

Information Requests & Materials Referred to in BC Hydro's Responses

BCUC IR 1.32.1

With respect to IPP renewals, please provide further clarity to the meaning of "market-based prices."

RESPONSE:

BC Hydro is developing contract pricing and details for those EPAs it will be potentially renewing with a market-based pricing approach. For these EPA renewals, market-based pricing will likely rely on Mid-C market prices adjusted for transmission losses and wheeling costs from the border to Mid-C (and potentially for other adjustments such as proximity of load centres and the shape of the energy to be delivered).

There are various approaches by which to establish market pricing in an agreement with an IPP. For example, a market price could either be determined using the index Mid-C pricing, as posted for each hour, or alternatively the pricing could be based on a forecast of Mid-C prices as defined in the EPA. The EPA for the Robson Valley IPP, which was recently filed and approved by BCUC Order No. G-164-20, has a fixed energy priced generally based on a Mid-C market price forecast including adjustments for transmission losses and wheeling costs from the border to Mid-C. BC Hydro is exploring various options for its upcoming EPA renewals and the options which may be available are not limited to the examples included in this response.

Executed electricity purchase agreements will be filed with the Commission pursuant to section 71 of the Utilities Commission Act.

BCUC IR 1.33.3

Please describe the competitive landscape of the NIAs and explain the reasons for limited opportunities to reduce supply costs.

RESPONSE:

Since the Non-Integrated Areas are not connected to BC Hydro's integrated system, the opportunities for cost-effective energy supply are often limited by the size and the location of the community. Diesel generation is often the primary energy source in the Non-Integrated Areas because it is cost-effective and reliable, and it is challenging for an alternative energy resource to compete with the cost and reliability of diesel generation.

Typically, no single renewable energy source is capable of exclusively supplying electricity and replacing the existing diesel generators. Instead, a combined system of various renewable technologies would be required. In addition, energy storage systems may need to be used to facilitate capacity firming, allowing intermittent sources to be stored and provide dispatchable power.

As these renewable energy projects are small scale, located in remote areas, and require firming to shape the intermittent generation to match the local load, their costs are higher than for similar utility scale projects on BC Hydro's integrated grid and are typically higher than the cost of diesel. Additionally, until such time as renewable generation provides both reliable power and reliable backup power, diesel generation will need to remain in remote communities as a source of backup power. Therefore, cost savings for the overall system are generally limited to the cost of diesel that is displaced with renewable power generation.

BCUC IR 1.33.5

Please explain whether the NIA EPAs are being renewed at “market-based prices.” If not, please explain the reasons why.

RESPONSE:

In the Non-Integrated Areas, BC Hydro uses diesel generating stations as the primary energy source, as an energy source that co-generates with a clean or renewable energy source, or as a back-up supply to a clean or renewable energy source. As a Non-Integrated Area is not connected to BC Hydro’s integrated system, there is no access to energy markets other than what may be available in each Non-Integrated Area. Generally, an EPA energy price in a Non-Integrated Area is the lower of BC Hydro’s diesel generation or the expected cost of service of an IPP. Accordingly, it is unlikely that Non-Integrated Area EPAs would be renewed at market-based prices as that term is used to describe energy pricing on the integrated system.

Utilities Commission Act Section 71 (2.21)

In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider

(a) British Columbia's energy objectives,

(b) the most recent of the following documents:

(i) an integrated resource plan approved under section 4 of the *Clean Energy Act* before the repeal of that section;

(ii) a long-term resource plan filed by the authority under section 44.1 of this Act,

(c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,

(d) the quantity of the energy to be supplied under the contract,

(e) the availability of supplies of the energy referred to in paragraph (d),

(f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and

(g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d).

BCUC IR 1.33.6

Please explain whether BC Hydro has explored other alternatives to diesel and IPP generation to reduce supply cost for the NIAs.

RESPONSE:

BC Hydro has undertaken a number of current and historical initiatives other than diesel and IPP generation to reduce supply costs while maintaining reliability in the Non-Integrated Areas. These include the initiatives below and, if applicable and available, we have provided information related to projected costs:

- Demand-side management (DSM) programs – Appendix AA to the Application summarizes NIA DSM program expenditures for fiscal 2020 and fiscal 2021. NIA DSM program expenditures for the Test Period will be included in BC Hydro’s fiscal 2023 to fiscal 2025 DSM expenditure request, which will be filed with the BCUC in December 2021;

- Connection of remote communities to the integrated BC Hydro grid, to allow for the provision of clean electricity to these communities, as was done with the Southern St'at'imc as part of BC Hydro's Remote Community Electrification program;
- BC Hydro's Net Metering Program is available in the Non-Integrated Areas;
- BC Hydro's ownership and operation of the hydro facility at Clayton Falls; and
- Ongoing work related to community-owned clean generation in the Non-Integrated Areas as described in BC Hydro's response to NTC IR 1.10.1.

BCUC IR 1.33.7

Please explain whether BC Hydro has explored other alternatives to diesel generation that may improve environmental performance at comparable cost or better.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.33.6 which describes certain current and historical initiatives other than diesel generation to reduce supply costs. These initiatives would also reduce greenhouse gas emissions in the Non-Integrated Areas.

We also note that through our Non-Integrated Areas Diesel Reduction Strategy, BC Hydro is developing a more comprehensive approach to cost-effectively reduce the amount of diesel used for electricity generation in the Non-Integrated Areas. This is in support of Indigenous and community interests and needs, greenhouse gas reduction efforts, and the objectives in the Government of B.C.'s CleanBC plan.

Please refer to BC Hydro's response to NTC IR 1.10.1 which provides an explanation of the factors involved in creating this strategy and the work that BC Hydro is doing to support renewable energy development in parallel to the creation of this long-term strategy. Please also refer to BC Hydro's response to BCUC IR 1.33.3 which provides a discussion regarding why it is challenging for an alternative energy resource to compete with the cost and reliability of diesel generation.

NTC IR 1.10.1

CleanBC was publicly announced on December 5, 2018. Why will it take so long to develop a strategy at a cost of $1 million over the Test Period which ends in F2025?

RESPONSE:

In this response, BC Hydro is providing a detailed description of the evolution of its Diesel Reduction Strategy for Non-Integrated Areas including the factors involved in creating this strategy and the work that BC Hydro is advancing to support renewable energy development in the Non-Integrated Areas while this longer-term strategy is being finalized.

BC Hydro has long supported the development of clean energy generation in our Non-Integrated Areas. Approximately half of the energy produced in the Non-Integrated Areas already comes from clean and renewable resources such as stored hydro, run-of-river hydro, solar and biomass, with the other half supplied by diesel generation.

In the past few years, new sources of funding from provincial and federal agencies for clean energy projects have driven increasing interest in, and development of, renewable energy for the Non-Integrated Areas. BC Hydro has continued to respond to these development opportunities and has been working with communities in the Non-Integrated Areas to move projects forward. Specific activities currently underway include:

- Working with Indigenous communities on the development of Community Energy Plans, Load Forecasts, and Resource Assessments to support clean energy development;
- Sharing data and information with project developers to size and plan for clean energy project integration into BC Hydro's isolated microgrids;
- Providing subject matter expertise to communities on the development of specific clean energy projects;
- Coordinating with Provincial and Federal Government agencies to align funding programs and policies;
- Exploring the impacts of new and emerging technologies on existing operations; and,
- Advancing projects in a number of communities

In 2019, BC Hydro assigned a dedicated project manager supporting diesel reduction activities in the Non-Integrated Areas. This was in response to an increased demand for BC Hydro's input into renewable energy development in the Non-Integrated Areas. Many subject matter experts across BC Hydro are contributing to the ongoing activities and projects, including staff from Indigenous Relations, Operations, Integrated Planning, Finance, Customer Service and Engineering.

Additional resources are now required to advance the activities to support renewable energy development in the Non-Integrated Areas. Accordingly, the Application includes an incremental $2.7 million, including funding for three FTEs, over the Test Period.

These additional resources are expected to support the following activities over the Test Period:

- Continued support for ongoing activities, projects, trials and government coordination related to diesel reduction in the Non-Integrated Areas.
- Technical engineering analysis to assess renewable energy proposals and options, provide guidance to proponents, and explore integration complexities with existing NIA generation and distribution systems.
- Development and implementation of a diesel reduction strategy for the Non-Integrated Areas.

The overall strategy for diesel reduction is being developed and will be informed by our learnings from our ongoing work with Indigenous communities and governments on clean energy projects as well as consultation led by the Government of B.C.

We expect that this strategy may include some or all of the following components:

- Coordination with government agencies;
- Demand-side management efforts in remote Indigenous communities;
- Vendor education and technical review;
- Working with communities on clean energy project development; and
- Trials and pilots for emerging technology and low-carbon fuels.

While BC Hydro is in the process of developing the strategy, significant work is underway to advance a number of opportunities in the Non-Integrated Areas. The strategy is complex and the following provides a summary of its development and next steps.

- In December 2018, the Government of B.C. released its CleanBC plan which outlined various initiatives for remote communities, including energy efficiency, renewable heat, training, and renewable energy generation. The scope of renewable energy generation activities includes all remote communities in B.C., including those that are not serviced by BC Hydro. CleanBC is a provincial strategy and does not provide specific direction or targets for BC Hydro. For further information, please refer to: https://www2.gov.bc.ca/assets/gov/environment/climatechange/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf.
- In February 2019, the Government of B.C. released its report on Phase 1 of the Comprehensive Review of BC Hydro. This phase did not provide recommendations to BC Hydro on diesel reduction for the Non-Integrated Areas; however, a key outcome of this review was the indefinite suspension of the Standing Offer Program (SOP), under which many Indigenous communities had expressed an interest in participating. As a result, the Government of B.C. committed "to engage with Indigenous nations and organizations to explore how the indefinite suspension of the SOP may affect the economic interests of individual Indigenous nations, and to explore alternate opportunities to meet those interests, where they exist." For further information, please refer to: https://www2.gov.bc.ca/gov/content/industry/electricity-alternativeenergy/electricity/bc-hydro-review-phase-1.
- In Phase 2 of the Comprehensive Review of BC Hydro, the Government of B.C. determined that more engagement was required with Indigenous communities to inform diesel-reduction targets and strategies for BC Hydro's Non-Integrated Areas. Additional engagement is being initiated by the Government of B.C., and BC Hydro expects to participate in this process. This is a key input in informing the diesel reduction strategy for the Non-Integrated Areas. For further information, please refer to https://www2.gov.bc.ca/gov/content/industry/electricityalternative-energy/electricity/bc-hydro-review-phase-2.

NTC IR 1.24.1

The line "Cost of Energy for Electrification Plan" reports that this cost in F2025 increases to $87.7 million (on Table 4-2) or $89.8 million (on Table 4-9). What are these costs, and why are they different values on the two tables? Do they represent the costs of actually purchasing energy or are they other costs related to the development or administration of the Electrification Plan?

RESPONSE:

Table 4-9 of the Application provides the breakdown of the Cost of Market Energy. For clarity, the line item in Table 4-9 is more appropriately labelled "Cost of Energy for Electrification Plan (Market Energy)" to distinguish from Table 4-2, which shows the breakdown for the Cost of Energy that is made up of the three categories: Heritage Energy, Non-Heritage Energy, and Market Energy.

The difference in the two tables is a result of water rental costs and costs associated with Columbia River Treaty Related Agreements. The table below provides a breakdown of the Cost of Energy for Electrification Plan and reconciles the fiscal 2025 costs of $87.7 million and $89.8 million referred to in the question.

Cost of Energy for Electrification Plan ($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Heritage Energy:							
Electrification Plan - Water rentals	4.0 L44	-	-	-	(0.4)	(1.3)	0.0
Electrification Plan - Columbia River Treaty Related Agreements	4.0 L45	-	-	-	2.9	(5.1)	(2.1)
		0.0	0.0	0.0	2.5	(6.5)	(2.1)
Market Energy:							
Electrification Plan - Market Energy	4.0 L59	-	-	-	1.1	77.1	89.8
Total		-	-	-	3.6	70.7	87.7

BCUC IR 1.119.3

Please expand Table U-3 to include for each fiscal year of the Electrification Plan, a breakdown of each component's cost by sector (residential, commercial, industrial) and by the sub-programs shown in Table 10-12, and by major cost category (e.g. labour, administration, consultant fees, incentive payments, etc.).

RESPONSE:

The expanded Table U-3 below includes Low Carbon Electrification costs broken down by sector, sub-program, and cost category. The table below also provides a reference to tables in Attachment 3 to Appendix U of the Application as requested in BCOAPO IR 1.69.1.

Electrification Plan Expenditures ($ million)

Program Component / Sector / Program	Cost Category (with reference to Appendix U Attachment 3 Tables)		2022	2023	2024	2025	2026	F22-F26 Total
Low Carbon Electrification								
Residential Sector								
Low Income Program	Incentives (Table 6)		0.0	2.0	2.0	2.0	2.0	8.0
	Studies & Energy Management		0.0	0.3	0.3	0.3	0.3	1.0
Residential Heat Pump Program	Incentives (Table 2)		2.1	5.5	5.4	0.0	0.0	13.0
Public Awareness Initiative	Advertising (Table 17)		1.9	4.1	4.2	3.2	1.1	14.4
Standards & Policy Partnerships Initiative	Contractors (Table 18)		0.3	0.7	0.8	1.0	1.1	3.9
Supply Chain Initiative	Contractors (Table 19)		0.0	0.2	0.3	0.3	0.3	1.2
Program Costs	Labour		0.3	1.0	1.0	1.0	1.1	4.5
	Contractors		0.0	0.2	0.1	0.1	0.1	0.6
Total Residential Sector			4.7	13.9	14.2	7.9	5.9	46.6
Commercial Sector								
Commercial Custom & New Construction Program	Contractors		0.1	0.1	0.0	0.1	0.0	0.2
	Incentives (Table 5)		0.0	0.0	0.7	2.3	2.3	5.3
	Studies		0.1	0.2	0.3	0.3	0.3	1.3
Commercial Fleet & Mobile Diesel Electrification	Contractors		0.2	0.2	0.2	0.2	0.2	0.8
	Incentives (Table 9)		0.0	1.7	2.4	0.8	0.0	4.9
	Studies		0.5	0.5	0.5	0.5	0.5	2.6
Commercial Strategic Energy Management Program	Contractors	Table 4	0.0	0.1	0.2	0.2	0.2	0.6
	Energy Management		0.0	0.7	1.3	1.7	1.8	5.6
Standards & Policy Partnerships Initiative	Contractors (Table 18)		0.3	0.7	0.8	1.0	1.1	3.9
Program Costs	Labour		0.6	2.3	2.4	2.4	2.5	10.3
	Contractors		0.0	0.5	0.5	0.5	0.5	2.1
	Other Non-Labour		0.0	0.0	0.0	0.1	0.1	0.2
Total Commercial Sector			1.9	7.1	9.3	10.2	9.4	37.9
Industrial Sector								
Commercial Fleet & Mobile Diesel Electrification	Incentives (Table 9)		0.0	1.5	5.7	1.9	16.2	25.3
	Studies		0.2	0.2	0.2	0.2	0.2	1.0
Industrial & Large Custom Program	Incentives (Table 12)		0.4	13.0	15.8	25.9	8.2	63.3
	Studies		1.1	1.1	1.1	1.2	1.2	5.7
Industrial Strategic Energy Management Program	Energy Management	Table 11	0.2	0.4	0.4	0.4	0.4	1.8
Program Costs	Labour		0.6	1.7	1.8	1.9	1.8	7.7

	Contractors		0.1	1.0	1.0	1.0	1.0	4.1
	Other Non-Labour		0.0	0.0	0.1	0.1	0.1	0.3
Total Industrial Sector			2.6	18.9	26.0	32.6	29.2	109.3
Subtotal: Low Carbon Electrification			9.2	39.9	49.5	50.6	44.5	193.7
Load Attraction	Incentives	Table 13	0.0	2.5	2.5	2.5	19.5	27.0
	Studies		0.0	4.6	5.6	4.7	3.8	18.7
	Labour		0.0	0.9	0.9	1.0	1.0	3.8
	Advertising (Table 17)		0.0	0.5	0.4	0.4	0.4	1.7
	Contractors		0.0	0.2	0.2	0.2	0.2	0.8
Subtotal: Load Attraction			0.0	8.7	9.7	8.8	24.9	52.0
Connecting Customers (Operating costs)	Labour		0.0	0.5	0.7	0.8	0.8	2.9
	Contractors		0.0	0.4	1.1	1.6	1.6	4.6
EV Station Maintenance	Labour	Table 8	0.0	0.1	0.1	0.1	0.1	0.4
	Contractors		0.0	0.1	0.2	0.3	0.4	1.0
EV Station Capital	Capital costs (Table 8)		0.0	2.0	2.0	2.1	2.1	8.2
Total Electrification Plan			9.2	51.7	63.3	64.3	74.4	262.9

Note: table may not add due to rounding.

BCOAPO IR 1.69.1

With respect to Table U-3, please provide a breakdown of the annual Low Carbon Electrification expenditures as between the various LCE programs set out in Attachment 3 and provide references as to where in Attachment 3 the annual costs for each program can be found.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.119.3 where we provide the breakdown of Low Carbon Electrification expenditures by sector, program and cost category, and include references to Attachment 3 of Appendix U of the Application.

BCUC IR 1.122.4

Please provide a breakdown of the Electrification Plan costs into fixed costs that will not vary with participation, and variable costs that will.

RESPONSE:

BC Hydro designed the Electrification Plan to be scalable. For example, resources to support the plan as described in section 10.4.1 of the Application will be a combination of existing resources, contractors, temporary and regular FTEs to allow scalability based on program participation. Public awareness campaigns can be scaled or shifted depending on market conditions. Program incentives and rebates are only paid once the customer has made a commitment. Similarly, the majority of customer connection costs are only incurred after the customer has made a commitment to BC Hydro.

At the same time, BC Hydro recognizes that some program costs will occur ahead of customer commitments and therefore while these costs can still be scaled, they cannot be completely avoided. For simplicity, BC Hydro proposes the following classification of costs as fixed vs. variable based on the cost categories presented in BC Hydro's response to BCUC IR 1.119.3:

Variable costs:

- Incentives, studies & energy management costs for the Low Carbon Electrification Program and Load Attraction Program; and,
- Capital costs for Transmission and Distribution system improvements and interconnections, as shown in Table 10-8 of the Application.

Fixed costs:

- Labour, advertising and contractor costs for the Low Carbon Electrification Program and Load Attraction Program;
- Operating costs related to connecting customers;
- Operating costs for EV station maintenance; and,
- EV station incremental capital costs, since BC Hydro has previously committed to a deployment plan for EV charging stations.

While the fixed costs noted above do not vary directly with incremental load, BC Hydro's management has the ability to implement program revisions to scale a significant portion of these fixed costs (i.e. reduce/increase or re-assign labour resources, reduce/increase expenditures on advertising or contractor resources). It is further recognized that there will be a lag for BC Hydro to recognize and implement measures to adjust the scalable portion of fixed costs to fit actual load changes that differ from the forecast. As an example, in the scenario analysis requested in BCUC IR 1.136.2, BC Hydro has assumed that with a 25 per cent or 50 per cent reduction in load, variable costs are scaled back by 25 per cent or 50 per cent, and fixed costs are scaled back by 15 per cent or 30 per cent respectively

BCUC IR 1.136.2

Please reproduce Table U-8 based on a 25 percent and 50 percent reduction of the forecast annual Electricity Plan load, and provide any assumptions used in the calculations.

RESPONSE:

The tables below reproduce Table U-8 of Appendix U of the Application with scenarios based on the 25 per cent and 50 per cent reduction in electricity load.

Energy Valued at Market (25% Load Reduction)	BC Hydro NPV (F22 $M)		NPV % of Total		B/C Ratio	
	F22-F31	F22-EML	F22-F31	F22-EML	F22-F31	F22-EML
Built Environment	$27	$60	9%	10%	1.3	1.4
Industry	$78	$200	25%	33%	1.4	1.4
Transportation	$52	$76	17%	12%	1.9	2.2
Load Attraction	$155	$276	50%	45%	1.5	1.3
Total	$312	$613	100%	100%	1.5	1.4
Non-Incentive Costs	-$83	-$83				
Total (incl. Non-Incentive Costs)	$229	$530			1.3	1.3

Low Energy LRMC in F31 (25% Load Reduction)	BC Hydro NPV (F22 $M)		NPV % of Total		B/C Ratio	
	F22-F31	F22-EML	F22-F31	F22-EML	F22-F31	F22-EML
Built Environment	$23	$34	9%	12%	1.3	1.2
Industry	$65	$85	24%	30%	1.3	1.1
Transportation	$50	$71	19%	25%	1.9	2.0
Load Attraction	$131	$92	48%	33%	1.4	1.1
Total	$270	$282	100%	100%	1.4	1.1
Non-Incentive Costs	-$83	-$83				
Total (incl. Non-Incentive Costs)	$187	$199			1.2	1.1

Energy Valued at Market (50% Load Reduction)	BC Hydro NPV (F22 $M)		NPV % of Total		B/C Ratio	
	F22-F31	F22-EML	F22-F31	F22-EML	F22-F31	F22-EML
Built Environment	$18	$40	9%	10%	1.3	1.4
Industry	$52	$133	25%	33%	1.4	1.4
Transportation	$35	$51	17%	12%	1.9	2.2
Load Attraction	$104	$184	50%	45%	1.5	1.3
Total	$208	$408	100%	100%	1.5	1.4
Non-Incentive Costs	-$64	-$64				
Total (incl. Non-Incentive Costs)	$144	$344			1.3	1.3

Low Energy LRMC in F31 (50% Load Reduction)	BC Hydro NPV (F22 $M)		NPV % of Total		B/C Ratio	
	F22-F31	F22-EML	F22-F31	F22-EML	F22-F31	F22-EML
Built Environment	$16	$22	9%	12%	1.3	1.2
Industry	$44	$57	24%	30%	1.3	1.1
Transportation	$34	$47	19%	25%	1.9	2.0
Load Attraction	$87	$61	48%	33%	1.4	1.1
Total	$180	$188	100%	100%	1.4	1.1
Non-Incentive Costs	-$64	-$64				
Total (incl. Non-Incentive Costs)	$116	$124			1.2	1.1

The assumptions that were used are:

- 25/50 per cent reduction in energy revenue;
- 25/50 per cent reduction in demand revenue;
- 25/50 per cent reduction in energy cost;
- 25/50 per cent reduction in capacity cost;
- 25/50 per cent reduction in incentive expenditure
- 25/50 per cent reduction in study expenditure; and,
- 15/30 per cent reduction in program costs.

MOVEUP IR 1.1.1

What is BC Hydro's understanding of the current status of the Roadmap in relation to the Authority's planning, operations and expenditures? At present, which elements that would have a material impact on BC Hydro does the Authority regard as mandatory in relation to itself, and to what extent? As persuasive? As aspirational? As where else on the spectrum?

RESPONSE:

As the CleanBC Roadmap to 2030 was only recently released, BC Hydro's assessment of its implications is preliminary and ongoing.

BC Hydro will assess the implications of the CleanBC Roadmap to 2030 on future electricity demand and supply. We will also be watching for corresponding legislation, regulation, programs, and funding to implement the Roadmap.

The following table provides the list of measures set out on page 68 of the CleanBC Roadmap to 2030 along with comments about the potential impact of each measure with regard to BC Hydro.

Clean Energy BC

Please also refer to BC Hydro's response to BCSEA IR 1.1.3 where we discuss whether the CleanBC Roadmap to 2030 is a policy document that BC Hydro is guided by.

Measure	Preliminary Comments on Potential Impact to BC Hydro
Evaluate additional reforestation and forest management activities.	**Not applicable.**
Support carbon sequestration, on-farm efficiencies, fuel switching and anaerobic digesters for biogas production	**Not applicable.**
Support investment in bioproduct development.	**Not applicable.**
Phase out utility gas equipment incentives.	**May encourage fuel switching to electricity.**

Table continues on the next page.

Measure	Preliminary Comments on Potential Impact to BC Hydro
Implementation of BC Hydro Electrification Plan.	Confirms BC Hydro's existing actions to advance the Electrification Plan.
Local government climate action program.	May encourage fuel switching to electricity.
Enhanced CleanBC Program for Industry.	The CleanBC Program for Industry supports GHG reductions and competitiveness by investing carbon tax revenue in projects that reduce emissions and costs across B.C. These investments may enable fuel switching to electricity.
Develop province-wide Circular Economy Strategy.	Not applicable.
Establish energy intensity targets.	May facilitate greater adoption of electric vehicles.
Implement Clean Transportation Action Plan.	May facilitate greater use of electricity to reduce emissions in the transportation sector, including the use of electricity to produce hydrogen.
ZEV targets for medium- and heavy-duty vehicles in place.	Targets are still being determined but would increase sales of medium-duty and heavy-duty electric vehicles.
BC Hydro 100% Clean Electricity Delivery Standard.	Please refer to BC Hydro's response to BCSEA IR 1.2.1.
Establish requirement for net-zero 2050 plans for industry.	May facilitate greater use of electricity to reduce industry emissions.
Decision on industrial (including oil and gas) methane approach	Not applicable.
Advance provincial approach to CCUS.	May encourage fuel switching to electricity.
Establish emissions cap for natural gas utilities (GHG Reduction Standard) for 2030.	Not applicable.
Enhance LCFS including increasing stringency for 2030 and expanding to aviation/marine fuels.	May facilitate greater use of electricity to meet the requirements of the Low Carbon Fuel Standard.

Table continues below.

Measure	Preliminary Comments on Potential Impact to BC Hydro
Public sector new building and light-duty, ZEV-first requirements.	May facilitate greater use of light-duty zero-emission vehicles where available products meet our business use case requirements. New field buildings meet Building Code and are designed to reduce greenhouse gas emissions through the use of electric rather than natural gas-powered systems. Further specifications and standards changes may be required, as yet to be determined. Additional EV charging infrastructure may be required.
Revised carbon pricing system, including for Industry, that meets or exceeds federal benchmark and protects affordability.	May encourage incremental fuel switching to electricity.
Ensure broad geographic coverage of fast-charger sites.	BC Hydro continues to advance its Electric Vehicle Charging Infrastructure Program. For further information, refer to section 10.3.2.2 of Chapter 10 of the Application and to BC Hydro's response to BCSEA IR 1.19.5.
Introduce carbon pollution standards in the BC Building Code for new buildings.	May encourage incremental electricity use in new buildings. Page 40 of the CleanBC Roadmap to 2030 notes that the standard will be performance-based, allowing for a variety of options including electrification, low carbon fuels like renewable natural gas, and low carbon district energy.
Energy-efficiency standards for existing buildings in the BC Building Code.	Details are to be determined. Page 40 of the CleanBC Roadmap to 2030 notes that this will start in 2024.
Requirement for low-carbon and resiliency standards for existing public sector buildings.	Details are to be determined.
Implement energy intensity targets/policies for movement of goods.	May facilitate greater adoption of electric vehicles.
Develop accounting framework for NETs	Not applicable.
Evaluate opportunities to strengthen local government legislative framework.	Not Applicable. Page 47 of the CleanBC Roadmap to 2030 notes that this measure is focused on better land use.

Table continues below.

Measure	Preliminary Comments on Potential Impact to BC Hydro
Public sector medium- and heavy-duty ZEV-first requirement.	**This is a medium-term measure (likely outside of the Test Period) that may facilitate greater use of medium and heavy duty zero-emission vehicles where available products meet our business use case requirements. Currently, there are limited viable products.** **Additional EV charging infrastructure may be required at our facilities.**
ZEV targets to 26 per cent for new light-duty vehicles.	**All other variables being equal, the new targets would have an upward impact on the reference EV load forecast.**
Public sector 100 per cent light-duty ZEV fleet acquisitions.	**This is a medium-term measure (likely outside of the Test Period) that may facilitate greater use of light duty zero-emission vehicles where available products meet our business use case requirements. Today, there are insufficient viable products.** **Additional EV charging infrastructure may be required at our facilities.**
Zero-carbon new public sector buildings.	**May encourage incremental electricity use in new public sector buildings.**
Near elimination of slash pile burning	**Not applicable.**
ZEV targets to 90 per cent for new light-duty vehicles.	**All other variables being equal, the new targets would have an upward impact on the reference EV load forecast.**
10,000 public EV charging stations.	**BC Hydro continues to advance its Electric Vehicle Charging Infrastructure Program. For further information, refer to section 10.3.2.2 of Chapter 10 of the Application and to BC Hydro's response to BCSEA IR 1.19.5.**
Highest efficiency standards for new space and water heating equipment and zero-carbon new construction	**May encourage incremental electricity use in buildings. Page 40 of the CleanBC Roadmap notes that the details are to be determined and that pilots will inform future province-wide requirements.**
Oil and gas sector achieves sectoral target and 75 per cent reduction in methane.	**Not applicable.**

Table continues below.

Measure	Preliminary Comments on Potential Impact to BC Hydro
Clean up 100 per cent of current orphan wells.	Not applicable.
Increase stringency of LCFS and double production of renewable fuels produced in B.C.	May facilitate greater use of electricity to meet the requirements of the Low Carbon Fuel Standard.
Phase out gas-fired facilities.	Page 29 of the CleanBC Roadmap to 2030 discusses the 100 per cent Clean Electricity Delivery Standard and states: "BC Hydro will meet the new standard by ensuring it has produced or acquired sufficient clean electricity to meet the needs of its domestic customers <u>and phasing out remaining gas-fired facilities on its integrated grid by 2030</u>." [emphasis added].
Embodied carbon targets for public sector buildings.	May encourage fuel switching to electricity.

BCSEA IR 1.1.2

Does BC Hydro see the CleanBC Roadmap to 2030 as confirming the direction taken by BC Hydro in the Five-Year Strategy and the Five-Year Electrification Plan? If so, why? If not, why not?

RESPONSE:

Yes, BC Hydro sees the CleanBC Roadmap to 2030 as confirming the direction taken by BC Hydro in the Five-year Strategy and the Electrification Plan. In particular, one of the measures in the CleanBC Roadmap to 2030 is "Advancing BC Hydro's Electrification Plan".

BCSEA IR 1.1.3

Is the CleanBC Roadmap to 2030 a policy document that BC Hydro is guided by?

RESPONSE:

The CleanBC Roadmap to 2030 sets out actions to achieve the 2030 greenhouse gas emissions reductions targets in the Clean Energy Act and to set a course to fulfill government's net-zero commitment by 2050.

Some of these actions include a role for BC Hydro. For example, the adoption of the 100 per cent Clean Electricity Delivery Standard or advancing our Electrification Plan. In these cases, BC Hydro is guided by the CleanBC Roadmap and is advancing these actions in response to the policy guidance it provides.

Some of these actions do not include a role for BC Hydro but will have an impact on BC Hydro. For example, all else equal, the accelerated light-duty Zero Emission Vehicle sales targets will increase BC Hydro's load. In these cases, the CleanBC Roadmap informs BC Hydro's actions in response to any anticipated impacts

BCUC IR 1.129.1

Please discuss the steps BC Hydro will take to engage with Indigenous Nations for interconnection opportunities.

RESPONSE:

BC Hydro engages potentially affected Indigenous Nations during the interconnection process. This engagement is project and site specific. For the implementation stage of interconnection projects, there may be procurement opportunities associated with our work to electrify specific projects.

As part of the implementation of the Load Attraction programs, we will be looking for additional ways to engage Indigenous Nations to identify opportunities.

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (Sections 10.3.1 & 10.4.1)