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July 4, 2025

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
Vancouver Centre II
2900 – 733 Seymour Street
Vancouver, BC
V6B 0S6

Attention: David Craig

Dear David Craig:

Re: FortisBC Inc. (FBC)

2025 Cost of Service Allocation (COSA) and Revenue Rebalancing (Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 2

On February 14, 2025, FBC filed the Application referenced above. In accordance with the amended regulatory timetable established in BCUC Order G-127-25 for the review of the Application, FBC respectfully submits the attached response to CEC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

2025 COSA Study Methodology and Results

8. References: Exhibit B-5, BCUC IR 5.2, Page 14 and Exhibit B-5, BCUC IR 5.3, Pages 15-16

CEC Table 1 - Jurisdictional Review Summary, Exhibit B-5, BCUC IR 5.2

MSS Approach: Assignment of Costs to 'Customer'	FBC	BCH	ATCO	HQ	NS	NFP	NBP
Poles, Towers and Fixtures	86%	50%	65%-75%	20.2%	74%	37%	50%
Conductors & Devices	65%	50%	65%-75%	20.2%	54.3%	28%	50%
Line Transformers	43%	50%	52.4%	20.2%		28%	25%

A more simplified approach may save some time and cost, but there would be less confidence in the reasonableness of the results and there may be impacts to residential and other classes with relatively low average load factors. FBC notes that the MSS data only impacts Distribution Plant allocations; it does not impact Transmission or Power Supply allocations for rate classes that do not take distribution service. If a simplified approach is taken, such as allocating the Distribution Plant based on demand only, then the results would shift additional costs to rate classes with a larger difference between the average use and their maximum use or load factors. As such, rate classes such as the residential class, which have a relatively lower average of load factors but a large number of customers, would be most impacted by this type of change in methodology.

8.1 CEC Table 1 above summarizes FBC's response to BCUC IR 5.2.[1] To what does FBC/EES attribute the notable differences in the proportion of costs assigned to 'customer' among Hydro Quebec and Newfoundland Power on one hand, and the remaining jurisdictions on the other.

<u>Response:</u>

The following response has been provided by EES Consulting:

EES did not examine individual study inputs. However, the lower percentage of costs assigned to customers could result from Hydro Quebec and Newfoundland Power modelling a relatively smaller or less expensive minimum system. This could be due to these utilities excluding certain costs or equipment from their minimum system calculations, resulting in a higher allocation of the actual system to demand.

8.2 Please further explain and quantify how a potential change in methodology as contemplated in FBC's response to BCUC IR 5.3,[2] would affect FBC's residential class and commercial (RS 20, RS 21, RS 30, and RS 31) rate classes.

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[1] Exhibit B-5, Page 14.

[2] Exhibit B-5, Pages 15-16.

Response:

The following response has been provided by EES Consulting:

If a simplified approach were taken, the results could range from an allocation similar to the current MSS approach or a 100% allocation to Demand on non-coincident peak (NCP). The table below shows the R/C ratios for RS 1, RS 20, RS 21, RS 30, and RS 31 using the current MSS approach and using a 100% Demand approach for account 364.00 Poles, Towers, & Fixtures, account 365.00 Conductors & Devices, and account 368.00 Line Transformers.

	RS 01	RS 20	RS 21	RS 30	RS 31
R/C Ratio Min Sys	99.5%	107.5%	102.4%	100.7%	105.3%
R/C Ratio Demand	92.8%	102.8%	101.3%	100.1%	105.3%

Load, Average Customer Count and Load Analysis

9. References: Exhibit B-5, BCUC IR 9.1, Page 29; Exhibit B-5, BCUC IR 9.2 Series, Pages 30-32; and Exhibit B-8, CEC IR 3.1, Pages 7-8

Further on page 3 of the 2020 Compliance Filing, FBC stated:

> FBC has a number of customer classes with significant load spread over a relatively small number of customers. Specifically, Rate Schedule (RS) 31 – Large Commercial Transmission has five customers, and the Wholesale class (RS 40 and RS 41) has a combined six customers. This fact results in a situation where year-over-year variation in consumption in the class may result in swings in class load factor leading to R/C ratios that fluctuate in the short term, but that should not necessarily be the cause of rate rebalancing since a reversal may occur in subsequent years. Over the longer term, it is expected that R/C ratios would be relatively stable. In the 2020 COSA, FBC has addressed this tendency by using an average load factor for RS 31, RS 40, and RS 41 in the model that considers load factors from the test years of both the 2017 and 2020 COSA studies. [*Emphasis added*]

> The current COSA study does not use averaged load factors for any rate class. All classes are treated the same based on the loads in 2022. EES did not make adjustments to the 2025 COSA to average certain load factors across studies because the data overall was more complete due to the availability of AMI readings, and averaging a more complete data set with aspects of a less complete data set would tend to dilute the value of the higher quality data.

- **RS 30:** The Annual CP and NCP factors are between 56 percent and 106 percent, with a 50 percent spread across the three data sets and large increase in the most recent data. The high result in the most recent data was due to a low peak in December for the rate class compared to other months, resulting in the 106 percent CP load factor. Setting aside the coincident month result, other factors would only have a 23 percent spread across the studies. It is generally expected that when there are fewer and larger services, as is the case with RS 30, more variability will occur.
- **RS 31:** The Annual CP and NCP factors are between 59 percent and 80 percent. Similar to the discussion regarding RS 30, when there are fewer and larger services, more variability is expected.

9.1 Given the relatively small number of customers for RS 31, RS 40 and RS 41 rate schedules, please discuss the pros and cons of using average load factors in future COSA studies by calculating average load factors for all rate classes, based on the most recently available three years of actuals.

<u>**Response:**</u>

The following response has been provided by EES Consulting:

Generally, average load factors are used in COSA studies when there is a substantial amount of suspect or missing data, such that the average load factor can fill a gap or provide a larger sample. In the FBC COSA, the interval data set was largely complete for all meters and rate classes and there was no need to average load factors over a longer period.

The advantage of using average load factors is that it would smooth out changes in load factors over a range of points in time. Given the relatively small number of customers in RS 31, RS 40 and RS 41, this could provide a benefit to an individual customer whose load changes significantly in the test year, but at the expense of other rate classes.

The disadvantages of this approach include that it is contrary to the point-in-time nature of the COSA study and other inputs and factors. An embedded cost of service study does not attempt to analyze marginal cost of service trends, but rather evaluates rebalancing at a point in time. Using an average of longer-term data or a smoothing adjustment works against this general nature of the study and would be inconsistent with the point-in-time nature of the other inputs and factors used in the study. Given the relatively small number of customers in RS 31, RS 40 and RS 41, this could provide a significant benefit to an individual customer whose load changes significantly in the test year, but this benefit would be at the expense of other rate classes.

Given that other costs and inputs are not smoothed out over multiple years and the interval data set is largely complete for all meters and rate classes for the test year, the use of average load factors for these rate classes would result in a less fair cost allocation without significant multi-year adjustments elsewhere and to all other rate classes.

9.2 Please discuss the resourcing implications of using average load factors for all rate classes, including whether the availability of AMI readings could make this task more tenable for FBC on a forward basis, and please provide load for factors for FBC’s 2023 and 2024 AMI data applicable to RS 31, RS 40 and RS 41.

Response:

The following response has been provided by EES Consulting:

EES did not examine AMI data from 2023 and 2024. From a resource perspective, EES has helped FBC improve the internal production of COSA data over time, and it is feasible for FBC to provide rolling current year average load factor information from the AMI system using virtual meters and business intelligence dashboard reporting. Whether the cost of this effort would result in material changes to the results here is unclear. Generally, FBC has a balanced rate design and this has not diverged significantly over the course of the studies. However, a COSA study is a point in time study with point in time data. Taking a rolling current year or similar approach to factors can be complex (and potentially costly) and there is no certainty that such an approach would yield beneficial results unless there is a case for smoothing. As discussed in the response to CEC IR2 9.1, EES did not see a strong case for smoothing here and hence did not recommend a longer time horizon for average load factors. However, since AMI data for 2023 and 2024 was not compiled and processed for the 2025 COSA, FBC cannot provide RS 31, RS 40 and RS 41 load factors based on this data within the timeframe required for these IR responses.

10. Reference: Exhibit B-8, CEC IR 2.2, Page 4, Table 1

Table 1: Comparison between Forecast and Actual Loads Corresponding to the 2017, 2020, and 2025 COSA Studies

	2017 COSA				2020 COSA				2025 COSA (2024)			
	Load (GWh)		Difference		Load (GWh)		Difference		Load (GWh)		Difference	
Rate Class	Forecast	Actual	GWh	%	Forecast	Actual	GWh	%	Forecast	Actual	GWh	%
Residential	1,354	1,371	17	1.2%	1,326	1,334	8	0.6%	1,299	1,321	22	1.7%
Small Commercial	304	337	33	10.9%	312	328	16	5.1%	349	326	(23)	-6.7%
Commercial	575	579	4	0.7%	589	589	0	0.1%	624	634	10	1.6%
Large Commerical - Primary	311	272	(39)	-12.6%	263	251	(12)	-4.7%	268	226	(42)	-15.8%
Large Commerical - Transmission	96	96	0	0.4%	190	176	(14)	-7.5%	218	340	122	56.1%
Lighting	14	16	2	13.9%	11	11	0	0.4%	9	9	(0)	-5.4%
Irrigation	40	42	2	4.9%	35	37	2	6.2%	38	39	1	3.5%
Wholesale - Primary	505	505	(0)	-0.1%	485	478	(7)	-1.4%	507	501	(6)	-1.1%
Wholesale - Transmission	81	86	5	6.4%	82	82	0	0.0%	83	87	4	4.8%
Total	**3,280**	**3,304**	**24**	**0.7%**	**3,293**	**3,287**	**(6)**	**-0.2%**	**3,395**	**3,482**	**87**	**2.6%**

10.1 Please confirm that over forecasting of ‘Large Commercial – Primary’ load as part of FBC’s last three COSA study undertakings, has likely had the effect of over allocating costs to the RS 30 rate class, thus resulting in ‘understated’ R/C ratios for this rate class.

<u>Response:</u>

Not confirmed. FBC provided a detailed explanation of why a backward-looking re-examination of COSA results using actual load data in conjunction with the forecast cost of service from each COSA would be inappropriate in the response to CEC IR1 2.3.

Further, FBC notes that this question assumes the costs for allocation would remain unchanged while the loads used as part of the COSA studies would be reduced in accordance with the actual results. This assumption is incorrect. In cases where the actual loads were lower than forecast, the actual costs for allocation such as the power supply costs would also be lower. As such, the lower actual costs for allocation purposes would offset the reduced revenue from lower actual load, thereby mitigating the impact on the R/C ratios resulting from load forecasting variances.

10.2 Please provide an estimate of the understatement of RS 30 R/C ratios (in percent), for each of the 2017, 2020 and 2025 COSA studies.

<u>Response:</u>

Please refer to the response to CEC IR2 10.1.

10.3 Please provide the reasons (or developments) that lead to the significant over delivery (above that forecasted) of RS 31 load in the 2025 COSA study.

Response:

FBC clarifies that the Large Commercial – Transmission (RS 31) forecast load of 218 GWh used in the 2025 COSA study excluded an estimated amount of Large Commercial Interruptible Service (RS 38) load, as discussed in Section 5.1.2.1 of the Updated Application. However, since RS 38 was not effective until December 2024, the actual 2024 RS 31 load of 340 GWh shown in Table 1 of the response to CEC IR1 2.2 inadvertently included 105 GWh that would have been considered as RS 38 load for the purposes of the 2025 COSA study. For an equivalent comparison, the actual 2024 RS 31 load excluding the 105 GWh would be 235 GWh, which is approximately 17 GWh or 7.7 percent higher than the forecast of 218 GWh.

Please refer to the Revised Table 1 to CEC IR1 2.2 below with the RS 38 load removed from the actual RS 31 load for the purposes of the 2025 COSA study. FBC notes that once the RS 38 load is removed from both forecast and actual, the overall variance between forecast and actual load in the 2025 COSA study is small, at approximately -0.5 percent.

Revised Table 1 to CEC IR1 2.2: Comparison between Forecast and Actual Loads Corresponding to the 2017, 2020, and 2025 COSA Studies

	2017 COSA				2020 COSA				2025 COSA (2024)			
	Load (GWh)		Difference		Load (GWh)		Difference		Load (GWh)		Difference	
Rate Class	Forecast	Actual	GWh	%	Forecast	Actual	GWh	%	Forecast	Actual	GWh	%
Residential	1,354	1,371	17	1.2%	1,326	1,334	8	0.6%	1,299	1,321	22	1.7%
Small Commercial	304	337	33	10.9%	312	328	16	5.1%	349	326	(23)	-6.7%
Commercial	575	579	4	0.7%	589	589	0	0.1%	624	634	10	1.6%
Large Commerical - Primary	311	272	(39)	-12.6%	263	251	(12)	-4.7%	268	226	(42)	-15.8%
Large Commerical - Transmission	96	96	0	0.4%	190	176	(14)	-7.5%	218	235	17	7.7%
Lighting	14	16	2	13.9%	11	11	0	0.4%	9	9	(0)	-5.4%
Irrigation	40	42	2	4.9%	35	37	2	6.2%	38	39	1	3.5%
Wholesale - Primary	505	505	(0)	-0.1%	485	478	(7)	-1.4%	507	501	(6)	-1.1%
Wholesale - Transmission	81	86	5	6.4%	82	82	0	0.0%	83	87	4	4.8%
Total	**3,280**	**3,304**	**24**	**0.7%**	**3,293**	**3,287**	**(6)**	**-0.2%**	**3,395**	**3,377**	**(18)**	**-0.5%**

For the remaining difference of 17 GWh, FBC is unable to identify the specific reasons with certainty; however, the difference is likely due to the specific economic circumstances and operational needs associated with the type of customers served under RS 31.

11. References: Exhibit B-7, ICG IR 4.1, Page 8 and Exhibit B-7, ICG IR 4.2, Page 8

> the year. Further, the 2 CP approach was selected rather than a 1 CP or 4 CP approach because FBC has a significant summer peak.

> RS 31 class load has a higher peak in the winter during the test year, but it is generally less seasonal than other classes. RS 31 is generally coincident with the system peak due to its load being close to its maximum most of the time and hence contributing to system peak in all seasons. If RS 31 load were not coincident, that would be a benefit to the system.

11.1 Please explain and quantify the extent to which ‘commercial’ rate classes (RS 20 + RS 21 together; RS 30 + RS 31 together; and all four rate schedules combined) exhibit 2 CP characteristics and contribute to FBC’s system summer peak and otherwise confirm and quantify the role that residential and (potentially) wholesale classes play as contributors to the system summer peak.

Response:

The following response has been provided by EES Consulting:

The following table provides the 2 CP summer only allocation percentages compared to the annual 1 CP.

	RS 20 & RS 21	RS 30 & RS 31	RS 20, 21, 30, 31	Residential	Wholesale	Other
Summer 2CP	27.1%	9.9%	37.0%	44.4%	16.6%	2.0%
Annual 1CP	21.8%	9.4%	31.2%	47.9%	20.5%	0.4%

As shown in the above table, the Commercial classes contribute more to the summer peak than the Residential and Wholesale classes due to Commercial summer cooling loads, whereas Residential and Wholesale annual peaks are more influenced by winter heating needs. Because both shapes contribute to annual needs, the 2 CP approach continues to be appropriate.

Revenue / Cost Rebalancing

12. References: Exhibit B-8, CEC IR 4.1, Pages 9-10 and Exhibit B-4, PDF Page 2

> As such, and as explained above, FBC generally aims to rebalance all rate schedules to within the RoR but not to unity.

> The context for Directive 15 is contained in the RDA Decision at page 29 and reads:
>
> While the deviation from unity does not, for the reasons outlined above, necessitate a more widespread rebalancing of rates than has been directed by the Panel, it is something that should be monitored. Accordingly, we direct FBC

12.1 Please provide the R/C ratios for each of the commercial rate classes from the 2017 and 2020 COSA studies.

Response:

The following is an excerpt from Appendix C of the Application which provided the R/C ratios for each customer class from the 2017 and 2020 COSA studies.

	2017 Revenue to Cost Ratio	2020 Revenue to Cost Ratio
Residential	98.4%	99.7%
Small Commercial	102.2%	101.5%
Commercial	104.7%	99.5%
Large Commercial Primary	104.0%	105.7%
Large Commercial Transmission	107.0%	110.4%
Lighting	92.2%	84.9%
Irrigation	97.2%	96.5%
Wholesale Primary	96.7%	96.7%
Wholesale Transmission	103.9%	95.8%
Total	100.0%	100.0%

12.2 Please explain the circumstances that could prompt FBC to consider gradually lowering the R/C ratios for those rate schedules that have historically been at the upper bound of the RoR, to bring them to fair, just, and reasonable.

Response:

FBC does not agree with the inference in the question that rate schedules that have R/C ratios at the upper bound of the RoR are not fair, just, and reasonable. As noted in the referenced response to CEC IR1 4.1, the BCUC has previously stated that any R/C ratio that is within the RoR can be considered to be fully recovering its costs.

FBC provided the BCUC's most recent findings on rebalancing on page 24 of the Application which were included as part of the BCUC's Decision on the FortisBC Energy Inc. (FEI) 2023 COSA and Revenue Rebalancing Application. FBC provides the excerpt below for ease of reference and notes that the BCUC's statements were in response to similar submissions from the CEC in that proceeding:

> FEI's approach to assess the need for rebalancing a rate class is to rely on a range of reasonableness of 95 percent to 105 percent within which a rate schedule's revenue is considered to be recovering its costs. The CEC has raised no concern with this methodology in the current proceeding but has recommended the BCUC direct FEI in the next COSA proceeding to prepare rebalancing proposals that aim towards unity and ultimately do away with the range of reasonableness. The Panel disagrees. The evidence in this proceeding suggests that an R:C ratio calculation is derived from forecast revenues and costs for the test year and the COSA is reliant upon numerous assumptions and judgements. Thus, an R:C ratio has inherent uncertainty and it follows that R:C ratios are best interpreted as a range on either side of a theoretical mid-point of unity. Therefore, the Panel agrees with FEI's approach to use an R:C range within which a rate schedule's revenue is considered to be recovering its costs to assess the need to rebalance a rate class. Because of this, the Panel is not persuaded by the CEC that there is a need to achieve unity and rejects the CEC's recommendation to depart from the use of a range of reasonableness to assess the need for and the degree of rebalancing required, in this or the next COSA study.

As such, FBC does not foresee circumstances that would require adjusting cost recovery through rate rebalancing for an R/C ratio that is within the RoR.

12.3 If a rate class consistently has an R/C ratio of at or above 105% for three COSA studies in a row, then would a rebalancing to 104% be unfair, unjust and unreasonable from FBC's point of view?

Response:

No. It is the view of FBC, supported by determinations in previous COSA proceedings, that any R/C ratio that is within the defined RoR can be considered to be full cost recovery and is therefore fair, just and reasonable.

EES COSA Report – Net Metering

13. References: Exhibit B-8, CEC IR 6.1, Page 14; Exhibit B-8, CEC IR 6.3, Page 15; and Exhibit B-6, BCMEU IR 5.1, Page 10

EES maintained the net-metering data for consistency across historical COSA modeling, however, net metering is not part of the overall proposal and does not impact the COSA results. EES did not examine commercial net metering separately, nor does FBC propose any rebalancing related to net metering.

The table below shows net consumption for residential net metering across the three studies.

Residential Net Metering	2017 COSA	2020 COSA	2025 COSA
Net Consumption (kWh)	2,787,141	8,205,509	12,492,095
Average Monthly Customers	171	449	976

	Residential	Residential without Net Metering	Net Metering Only
Annual NCP Load Factor	41.2%	41.5%	23.8%
Annual CP Load Factor	41.2%	41.5%	24.2%

In addition, both summer and winter peaks continue to grow, although in more recent years, the summer peak is not growing as quickly as winter.

2009 - 2017	Summer	Winter
Growth (MW)	73	47
Growth %/yr	1.5%	0.8%
2017 - 2022		
Growth (MW)	104	127
Growth %/yr	2.2%	3.3%

13.1 Please confirm that the net metering figures provided in Appendix A to the Application[3] and in response to CEC IR 6.1 and CEC IR 6.3[4] are for residential net metering only, and please explain the meaning of the statement[5] 'EES did not examine commercial net metering separately' including clarifying the current state of commercial net metering applications in FBC's service territory.

Response:

The following response has been provided by EES Consulting:

[3] Exhibit B-1, Appendix A, Excel Spreadsheet Attachment: Appendix A – C_EES COSA Report Load Summary, Tab: COSA Factors Summary – Net Metering.

[4] Exhibit B-8.

[5] Exhibit B-8, CEC IR 6.1, Page 14.

EES maintained separate treatment of residential net metering for consistency with past COSAs since this information was included in previous versions of the model. EES did not separate commercial net metering from other Commercial data in the same way as for Residential due to that information not being part of the existing model and since FBC is not proposing changes to its net metering program as part of this Application.

The following additional response has been provided by FBC:

At the current time, FBC does not have any pending commercial net metering applications.

13.2 Please explain and quantify the effect that lower annual NCP and CP load factors for the residential class (resulting from the impact of residential net metering which contributes significantly lower load factors than the rest of the residential class[6]) have on functionalized transmission and distribution costs allocated to RS 1.

Response:

The following response has been provided by EES Consulting:

NCP and CP load factors both drive $/kW demand or capacity unit costs. The impact of these factors for net metering can best be seen in the resulting unit costs between “residential net metering” and “residential without net metering”. The Unit Cost Comparison below shows that because “residential net metering” has a different load profile compared to the load profile of “residential without net metering”, the Demand or Capacity Cost and Customer or Fixed costs are higher.

	System Average (all rate classes)	Residential	Residential w/o Net Metering	Residential Net Metering
$/kW (demand or capacity costs)	**$16.52**	**$13.21**	**$13.19**	**$14.69**
$/kWh (energy only, 3-part rate)	**$0.0479**	**$0.0486**	**$0.0486**	**$0.0491**
$/kWh (energy with demand costs, 2-part rate)	**$0.1122**	**$0.1282**	**$0.1278**	**$0.1594**
$/Customer/Month (fixed costs)	**$38.58**	**$36.28**	**$36.24**	**$42.86**
Total Average Cost per kWh	**$0.1330**	**$0.1725**	**$0.1723**	**$0.1996**

6 Exhibit B-8, CEC IR 6.3, Page 15.

13.3 Please confirm that the rise in residential net metering could explain why FBC's system summer peak is not growing as quickly as the winter peak.[7] If not confirmed, please explain the factor(s) involved and provide their quantitative impact(s).

Response:

The following response has been provided by EES Consulting:

The rise in residential net metering could be a factor in reduced summer peak but is unlikely to be a driving factor overall since the capacity of residential net metering installations are not a significant portion of the overall load of FBC. The COSA uses information for forecast system peak provided by FBC but does not provide any qualitative or quantitative analysis on why the forecasts change over time, as these considerations are not part of the scope of the study.

[7] Exhibit B-6, BCMEU IR 5.1, Page 10.

EES COSA Report – Electric Vehicles (EVs)

14. References: Exhibit B-10, RCIA IR 1.3, Page 2 and Exhibit B-10, RCIA IR 1.4, Pages 2-3

> 1.3 What specific minimum household energy consumption level is assumed in the current COSA? Include the numerical value(s) used and the rationale behind this assumption.
>
> **Response:**
>
> **The following response has been provided by EES Consulting:**
>
> The minimum system equipment includes a 15 kVa transformer, a 40-foot pole, and No. 2 aluminum conductor steel reinforced (ACSR). The minimum household consumption is 1 kWh (or less) and the likely maximum would be less than 15 kVA peak demand. This configuration is appropriate because it is typical of the minimum sized equipment that would be installed for the smallest service.

> Generally, with respect to an actual physical system, time-of-use rates and demand side management can be approaches to limit the need for over-sized service installations above the minimum system. However, net metering and electric vehicle adoption typically require larger than minimum system equipment to provide adequate service. Typically, these are not factors that feed into a minimum system analysis as they are generally retail rate and after-the-system-is-built optimization considerations as opposed to the theoretical construction of a minimum system necessary to deliver one kWh to an end-point service. Please also refer to the response to RCIA IR1 1.2.

14.1 Please provide a comparison (including the cost difference) of minimum system requirements for residential customers with a) net metering; b) EV adoption; and c) net metering and EV adoption, versus the residential minimum system requirements provided in response to RCIA IR 1.3.[8]

Response:

The following response has been provided by EES Consulting:

There is no difference in the minimum system requirements under any of these scenarios. All of the scenarios listed could impact the maximum or as-built system requirements that the minimum system is a percentage of, but would not change the minimum system requirements portion.

[8] Exhibit B-10, Page 2.