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The Island Regulatory and Appeals Commission

July 31, 2025

Ms. Cheryl Bradley, CPA, CA
Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

2025 Capital Budget Application (UE20741)
Response to Additional Interrogatories from Commission Staff

Please find attached the Company's response to additional Interrogatories from Commission Staff with respect to the 2025 Capital Budget Application filed on August 2, 2024. An electronic copy will follow shortly.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice President, Finance &
Chief Financial Officer

MF40
Attachments

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ADDITIONAL INTERROGATORIES

Responses to Interrogatories of Commission Staff

2025 Capital Budget Application (UE20741)

Submitted July 31, 2025

In Order UE25-01, the Prince Edward Island Regulatory and Appeals Commission (the "Commission") approved Maritime Electric Company, Limited's ("MECL") 2025 Annual Capital Budget, with the exception of the following three capital projects:

- 6.1(d) – West Royalty Substation 13.8 kV Distribution Replacements
- 6.1(e) – Scotchfort Substation
- 6.2(c)(iii) – Y-119 Extension to Scotchfort

As stated in the Order, due to the combined capital costs of these projects, including interdependent projects, a further review of these specific capital items is required. The following additional interrogatories will assist the Commission with its review:

UPDATED FORECASTS

IR-25 Refer to MECL's 2020 Integrated System Plan (Docket UE21227). Please update Table 5 – Energy and System Peak Forecast 2020 – 2023 and Table 12 – Detailed Maritime Electric Load and Peak Forecast to include actuals up to (and including) 2024 and updated forecasts from 2025 to 2030. Please explain (a) any variance between forecast and actuals, and (b) any change to MECL's forecasts.

Response:

An updated version of Table 5 and Table 12 from the 2020 Integrated System Plan ("ISP") are provided in Table IR-25(i) and Table IR-25(ii), respectively. Some of the categories (i.e., rows) of Table IR-25(ii) were modified to reflect Maritime Electric's current load forecast methodology.

a. Actual energy sales and peak are dependent on winter temperatures, which can vary. However, in general, Maritime Electric's actual energy sales and peak in recent years were higher than forecast in the 2020 ISP. Two primary factors contributing to the Company's customer load growth are: PEI's rapid increase in population; and the transition from fossil fuel energy sources to electricity (i.e., electrification). Both factors have contributed to actual energy sales and peak being higher than the forecast provided in the 2020 ISP.

b. A notable change in Maritime Electric's load forecast is the way demand side management ("DSM") is incorporated. Previously, there was no controllable DSM, and non-controllable DSM, which is forecasted by the PEI Energy Corporation ("PEIEC"), was subtracted from the forecast as a separate line item.[1] In the current forecast, non-controllable DSM from PEIEC's Energy Efficiency and Conservation ("EE&C") Plan is included directly within each load category (e.g., residential or general service), rather than being shown as a separate line item. Controllable DSM, newly introduced in the recent EE&C Plan, is subtracted from the forecast system peak load as a separate line item.

   Another notable change was the shift in forecasting methodology to reflect that the system peak now occurs in January or February, rather than December. Historically, the December peak was driven by holiday lighting loads. However, with the widespread

[1] Controllable DSM programs aim to shift electricity usage from system peak periods to off-peak periods, while non-controllable DSM programs aim to improve energy efficiency. More information about controllable and non-controllable DSM are included in Section 5.3.2 of the Company's On-Island Capacity for Security of Supply Project application.

adoption of LED lighting and the electrification of space heating, lighting is no longer the dominant contributor. Today, space heating is the primary driver of peak demand, which typically aligns with the coldest days and hours of the year. This methodological change was a deliberate response to observed shifts in load patterns and resulted in a step increase in projected system peaks.

Aside from the changes described in the previous paragraphs, the methodology used to forecast energy sales and system peak load is the same as was used for the 2020 ISP. Inputs to the forecast, including housing starts, heat pump installations, electric vehicle adoption, PEI Gross Domestic Product, and other variables were updated to reflect the most recent data available when the latest forecast update was completed in February 2024.

TABLE IR-25(i)
Update to 2020 ISP TABLE 5
Energy and System Peak Forecast 2020 - 2030

	Actual					Forecast					
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MECL Energy (GWh)	1,392	1,431	1,498	1,586	1,658	1,724	1,770	1,806	1,841	1,878	1,912
Island Energy (GWh)	1,534	1,577	1,650	1,747	1,826	1,899	1,950	1,990	2,029	2,070	2,108
Island Winter Peak (MW)	286	271	323	395	342	381[2]	394	398	403	409	418
Island Summer Peak (MW)	221	238	238	247	251	274	280	286	291	298	304

2 2025 Island Winter Peak is based on actual peak experienced in January 2025.

TABLE IR-25(ii) Update to 2020 ISP TABLE 12 (with modifications) Detailed Maritime Electric Load and Peak Forecast											
	Actual					Forecast					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Heating Degree Days (below 12°C)[3]	2,667	2,443	2,521	2,534	2,408	2,740	2,740	2,740	2,740	2,740	2,740
Maritime Electric electricity sales growth (%)	0.5	2.6	4.9	6.4	3.0	5.4	2.7	2.0	2.0	2.0	1.8
Maritime Electric electricity sales (GWh)											
- Residential non space heating[4]	495	518	510	547	564	584	611	629	647	665	681
- General Service + Small Industrial[5]	469	482	491	510	524	526	526	527	529	531	533
Subtotal non-space heating[6]	964	1,000	1,000	1,057	1,088	1,110	1,137	1,157	1,176	1,196	1,214
- Residential space heating	177	172	227	254	272	326	342	356	370	384	397
- Large Industrial[7]	152	154	164	169	164	170	170	170	170	170	170
Total	**1,293**	**1,326**	**1,391**	**1,479**	**1,523**	**1,606**	**1,649**	**1,683**	**1,716**	**1,750**	**1,782**
Energy supply requirement (GWh)											
- Add Maritime Electric company use	2	2	2	2	2	2	2	2	2	2	2
- Add system losses (6.7%)[8]	97	103	105	105	110	116	119	121	123	126	128
Net Purchased & Produced Total	**1,392**	**1,431**	**1,498**	**1,586**	**1,635**	**1,724**	**1,770**	**1,806**	**1,841**	**1,878**	**1,912**
System Peak Load Factors											
- Non space heating loads	0.63	0.76	0.69	0.63	0.68	0.64	0.64	0.64	0.64	0.64	0.64
- Large Industrial	1.05	1.09	0.99	0.95	0.97	0.99	0.99	0.99	0.99	0.99	0.99

[3] The number of Heating Degree Days is calculated using a reference ambient temperature of 12°C, which is consistent with the 2020 Integrated System Plan and Maritime Electric's load forecasting methodology.
[4] Residential non space heating forecast sales include EV charging and are net of DSM.
[5] General service forecast sales are net of DSM.
[6] Subtotals and totals are rounded.
[7] Formerly "Maritime Electric Transmission Voltage."
[8] Forecast system losses have reduced to 6.7% instead of 6.8%.

Table IR-25(ii) continued …

	Actual					**Forecast**					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Maritime Electric Peak Load (MW)[9]											
- Non space heating loads[10]	171	142	161	181	177	187	199	203	207	210	214
- Residential space heating loads[11]	71	87	113	159	113	139	145	150	156	163	168
- Large Industrial	17	16	18	20	20	20	20	20	20	20	20
Subtotal	**259**	**245**	**293**	**359**	**310**	**346**	**363**	**373**	**383**	**393**	**402**
- Demand Response (controllable DSM)	-	-	-	-	-	-	(3)	(9)	(14)	(18)	(19)
Total	**259**	**245**	**293**	**259**	**310**	**346**	**360**	**364**	**369**	**375**	**383**
Peak Information[12]											
Date	Jan 17	Feb 12	Jan 11	Feb 4	Jan 19	Jan 30	-	-	-	-	-
Hour ending	18:00	9:00	18:00	18:00	8:00	19:00	-	-	-	-	-
Temperature at peak	(11.9)	(13.3)	(18.5)	(17.0)	(11.0)	(14.9)	-	-	-	-	-
Temperature 24h prior	(6.3)	(13.0)	(9.9)	(17.8)	(9.7)	(6.8)	-	-	-	-	-
Effective temperature[13]	(10.5)	(13.2)	(16.4)	(23.8)[14]	(10.7)	(12.9)	-	-	-	-	-

9 2025 peak loads represent actual peak experienced on January 30, 2025.
10 Non space heating loads forecast peaks are net of non-controllable DSM.
11 Residential space heating loads forecast peaks are net of non-controllable DSM.
12 Peak information was revised to reflect updated methodology due variability in peak timing.
13 The effective temperature is 75% of the temperature at the time of peak and 25% of the temperature 24-hours prior to the peak.
14 The 2023 peak occurred during a polar vortex weather event. The effective temperature listed is the average hourly temperature for the 24-hour period prior to the peak.

IR-26 There have been a number of recent regulatory approvals that are expected to impact MECL's load growth and peak load. These approvals include the EE&C Plan (Order UE24-02) and Advanced Metering Infrastructure (Order UE24-06). AMI technology, once implemented, will allow for innovative rate structures that can incent customers to shift load and reduce peak. Please explain the impact of these regulatory approvals on MECL's forecast future load growth and peak load.

Response:

Maritime Electric's load growth and peak load forecasts already incorporate the initiatives outlined in the PEIEC's EE&C Plan. The Company expects that AMI will support the EE&C Plan demand response initiatives.

The peak load reductions identified in the Commission-approved EE&C Plan fall into two categories: (1) reductions from energy efficiency and conservation measures (i.e., non-controllable DSM); and (2) reductions from demand response initiatives (i.e., controllable DSM).

For category (1), the energy and peak load reductions resulting from EE&C measures have been integrated into Maritime Electric's load forecast, as shown in Table IR-25(i) and Table IR-25(ii) of the response to IR-25.

For category (2), demand response-related peak load reductions are also reflected in Maritime Electric's peak forecasts in Table IR-25(i) and Table IR-25(ii), as well as in the forecasts submitted with the Company's On-Island Capacity for Security of Supply Project application ("Capacity Application") under Docket UE20742. Maritime Electric is awaiting further details from the PEIEC and efficiencyPEI regarding planned demand response programs. On February 11, 2025, efficiencyPEI issued a Request for Proposal ("RFP") for demand response pilot projects, which included suggested program categories such as: energy storage; interruptible rates and curtailment; dual fuel systems; and demand load control systems. While the RFP is currently limited to pilot projects, AMI is expected to play a key role in the successful implementation of these initiatives.

Time of Use ("TOU") rates is an example of an innovative rate structure requiring AMI that can result in peak reduction by incentivizing customers to shift load from peak to off-peak periods. The Dunsky Energy Consulting's Prince Edward Island Efficiency Potential Study (Volume I) ("Dunsky Study") commissioned by efficiencyPEI found that "PEI's [electricity] system has a relatively flat load curve with an evening peak as well as a second peak in the morning," and, therefore, "[peak shifting] measures with significant bounce-back or pre-charge effects close to the peak will likely have limited potential to reduce the annual peak…".[15] Since the Dunsky Study was completed, Maritime Electric has observed growth in the morning peak due to the continued electrification of space heating (e.g., two of the last five annual peaks occurred during the morning). The growth of the morning peak has further limited the potential to reduce the annual peak with peak shifting measures. The Dunsky Study, at the time of publication in 2021, projected that TOU rates could achieve a PEI total peak reduction of 10.7 MW,[16] which represents only a 2.8 per cent reduction relative to the peak of 381 MW experienced in January 2025.

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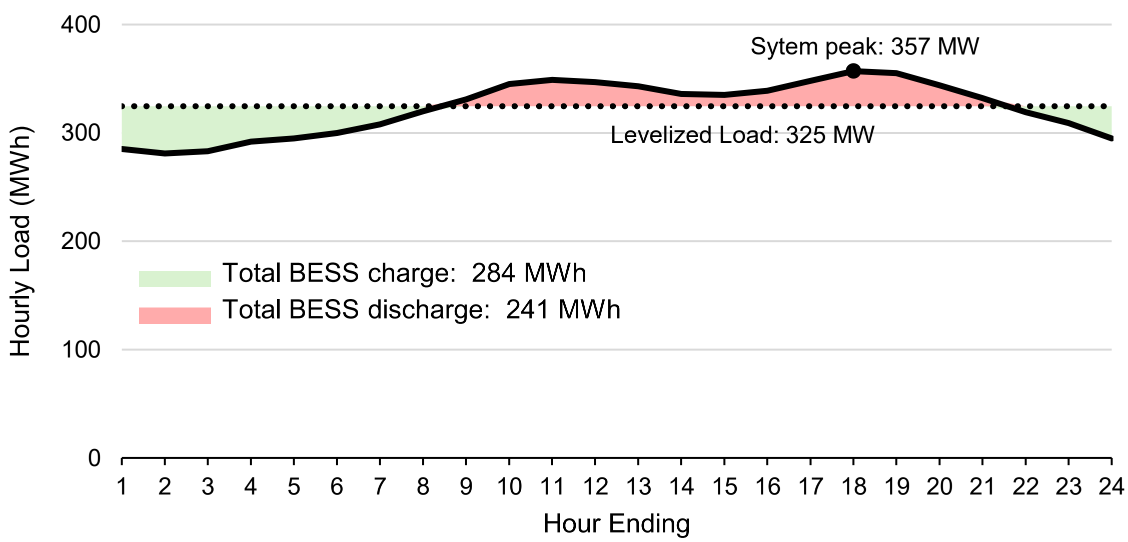
15 Dunsky Study page 56.
16 Dunsky Study Table 3-2.

Energy storage can also be used for peak shifting. Section 8.3 of the Capacity Application discussed the use of a 10 MW/40 MWh battery energy storage system ("BESS") for peak shifting. The example in Figure 29 of the Capacity Application, provided below as Figure IR-26, showed that "the maximum system peak reduction that could be achieved in this example is 32 MW (357 MW minus 325 MW, or a 9 per cent reduction), requiring a BESS with at least 262 MWh of energy storage."[17] A BESS of this size is currently not economical, but the 32 MW reference is an example of the limitation noted in the Dunsky Study, and represents the total theoretical peak reduction that could be achieved with peak shifting on the day that recorded the highest peak load in PEI history. Maritime Electric's proposed 10 MW/40 MWh BESS is expected to contribute to 10 MW of such peak reduction from peak shifting, which further reduces the potential peak reduction impacts of TOU rates.

Although the peak reduction impacts of TOU rates are limited, TOU rates may still be useful to reduce overall energy procurement costs throughout the year, if energy procurement becomes TOU based.

FIGURE IR-26
Generation Application Figure 29
System Peak Load Curve
February 4,2023



[17] Capacity Application page 113.

IR-27 Refer to MECL's 2023 General Rate Application (Docket UE20946). Please update Table 4-4 – Energy Sales to include actuals up to (and including) 2024 and updated forecasts from 2025 to 2030. Please explain (a) any variance between forecast and actuals, and (b) any change to MECL's forecasts.

Response:

An updated version of Table 4-4 from the 2023 General Rate Application ("GRA") is provided in Table IR-27.[18] Please refer to the response to IR-25 for information about variances between the 2023 GRA forecast, and actuals and changes to Maritime Electric's forecasts.

18 The 2023 GRA was approved by Commission Order UE23-04 under Docket UE20946.

TABLE IR-27
Update to 2023 GRA TABLE 4-4
Energy Sales

	Actual					Forecast					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Energy Sales (gigawatt hours or GWh)											
Residential											
Space heating load[19]	176.8	171.8	226.7	254.1	271.6	326.1	342.3	355.8	369.9	384.0	397.4
Non-space heating load	495.1	518.5	509.7	547.1	563.7	584.4	610.5	629.4	647.2	664.9	681.0
Subtotal[20]	**671.9**	**690.3**	**736.4**	**801.2**	**835.3**	**910.5**	**952.8**	**985.3**	**1,017.1**	**1,048.9**	**1,078.4**
General Service	370.5	381.6	392.8	412.0	423.5	425.4	425.7	426.3	427.5	429.1	431.6
Large Industrial	151.8	153.8	163.8	168.5	163.7	170.1	170.1	170.1	170.1	170.1	170.1
Small Industrial	91.6	93.4	91.0	91.0	94.1	93.9	94.0	94.1	94.4	94.7	95.3
Street Lighting/Unmetered	7.0	6.9	6.6	6.4	6.3	6.5	6.6	6.7	6.8	6.9	7.0
Total Energy Sales	**1,292.7**	**1,326.0**	**1,390.7**	**1,479.3**	**1,523.0**	**1,606.4**	**1,649.1**	**1,682.6**	**1,715.9**	**1,749.8**	**1,781.9**
Growth Rate (%)											
Residential											
Space heating load	(0.9)	(0.6)	32.0	12.1	6.9	20.1	5.0	3.9	4.0	3.8	3.5
Non-space heating load	7.0	4.7	(1.7)	7.3	3.0	3.7	4.5	3.1	2.8	2.7	2.4
Subtotal	**4.8**	**2.7**	**6.7**	**8.8**	**4.3**	**9.0**	**4.6**	**3.4**	**3.2**	**3.1**	**2.8**
General Service	(5.7)	3.0	2.9	4.9	2.8	0.4	0.1	0.2	0.3	0.4	0.5
Large Industrial	(1.5)	1.3	6.5	2.9	(2.8)	3.9	0.0	0.0	0.0	0.0	0.0
Small Industrial	(0.1)	2.0	(2.6)	0.0	3.4	(0.2)	0.1	0.1	0.3	0.3	0.5
Street Lighting/Unmetered	(5.4)	(1.4)	(4.3)	(3.0)	(1.6)	3.2	1.5	1.5	1.5	0.0	1.5
Overall Growth Rate	**0.5**	**2.6**	**4.9**	**6.4**	**3.0**	**5.5**	**2.7**	**2.0**	**2.0**	**2.0**	**1.8**

19 Space heating load refers to the use of electricity to heat a home or building, while non-space heating load refers to all other uses of electricity.
20 Subtotals and totals are rounded.

WEST ROYALTY SUBSTATION 13.8 kV DISTRIBUTION REPLACEMENTS

IR-28 MECL states that upgrades to the West Royalty Substation are justified, in part, due to load growth in the service area. Please provide the historic and forecast load growth for the West Royalty Substation from 2020 to 2030.

Response:

The majority of the Charlottetown area is served by the 13.8 kV distribution system from three substations: West Royalty; Charlottetown Plant; and UPEI.[21] Load is often transferred between circuits and substations to balance the overall 13.8 kV system within the Charlottetown area. For this reason, it is not appropriate to assess load within the West Royalty substation only. Table IR-28 shows the actual peak load from 2020 to 2024 and the forecast peak load from 2025 to 2030 for each of these substations.

TABLE IR-28
Historic and Forecast Peak Load for 13.8 kV Distribution System (MW)

	Actual					Forecast					
Substation	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
West Royalty	19.6	22.4	25.3	22.9	23.8	25.1	26.4	27.8	29.3	30.8	32.5
Charlottetown Plant	27.4	36.8	32.1	29.1	33.8	35.6	37.5	39.5	41.6	43.8	46.2
UPEI	14.9	16.9	12.6	16.2	15.9	16.7	17.6	18.6	19.6	20.6	21.7
Total Peak Load	**61.9**	**76.1**	**70.0**	**68.2**	**73.5**	**77.4**	**81.5**	**85.9**	**90.5**	**95.2**	**100.4**

[21] Surrounding areas are served by either 12.5 kV or 25 kV substations. As such, load transfer beyond the three 13.8 kV substations is not feasible.

IR-29 MECL states that the addition of two new 69 kV circuit breakers will decrease the probability of interruptions on the T-1, T-13 and T-15 transmission lines.

a. Please provide particulars of all unplanned interruptions on lines T-1, T-13 and T-15 from 2020 to present.
b. With respect to the interruptions referred to above, please provide details of any resulting customer outages, including the number of customers affected and the duration of each outage.

Response:

a. The addition of two new 69 kV circuit breakers will protect T-1, T-13 and T-15 from unplanned interruptions due to equipment failures that occur within the substation. As such, this response does not address unplanned interruptions on these lines due to causes that originated outside of the substation. On this basis, from 2020 to present, there was one unplanned interruption on T-1, and no unplanned interruptions on T-13 and T-15.

The interruption on T-1, which resulted in 5,596 customers being without power for six minutes, occurred on March 14, 2024, when power transformer X4 tripped off its side of the 69 kV bus due to a transformer oil heat alarm. It was determined that the alarm was triggered by a malfunctioning gauge. Had this event occurred under a higher load scenario, such as during a winter peak, the loss of the corresponding autotransformers would be likely to overload the remaining units and trigger a voltage collapse on the eastern 138 kV system. The resulting outages could affect more than 58,000 customers and would require significantly more time to restore. When there is an indication of a power transformer problem and there is no circuit breaker to isolate the unit, the lines cannot be re-energized until the transformer is repaired or manually disconnected.

While this customer outage was not long in duration, due to redundant feeds and system operator remote control capabilities, it could have been avoided completely with the addition of circuit breakers on the high-voltage side of the power transformers. The addition of circuit breakers on the high-voltage side of the power transformers eliminates the need to trip off half of the 69 kV bus if power transformer problems arise. This is Maritime Electric's standard engineering design for new substation construction and considered good utility practice, as it also allows for greater flexibility operating and maintaining the power transformer due to easier isolation.

b. Details of customer outages resulting from this event is provided in the response to IR-29a.

IR-30 Refer to MECL's response to IR-21 of Commission Staff. MECL states that a transformer consulting service provided a diagnosis on the two units serving the 13.8 kV load in West Royalty. Please provide a complete copy of the diagnosis.

Response:

Van Kooy Consulting Services Inc. ("Van Kooy"), a transformer consulting service provider, performed an analysis of the dissolved gases in the oil of the two 69 kV-to-13.8 kV power transformers in West Royalty substation in 2020. The results of this analysis provided an assessment of the transformers' condition based on the expected breakdown of their paper insulation. The reports provided by Van Kooy, which are included as IR-30 – Attachment 1, suggested that replacement of both transformers be considered within five years.

IR-31 Refer to MECL's response to IR-21 of Commission Staff. As justification for the proposed West Royalty Substation project, MECL states that the 13.8 kV underground cables and switchgear have recently experienced failures.

a. Please provide details of all failures experienced by the 13.8 kV underground cables and switchgear at the West Royalty substation from 2020 to present.
b. With respect to the failures referred to above, please provide details of any resulting customer outages, including the number of customers affected and the duration of each outage.

Response:

a. The cable termination and insulator arcing failure events as detailed in the December 2024 response to IR-21 have been the only failure events since 2020. The cable termination failure occurred in February 2023 and the arcing failure was identified in February 2024.

The cause of the termination failure was attributed to the condition and age of the cables, as a combination of weather conditions and cable degradation led to a flash over which caused significant damage. This failure resulted in customer outages of various durations as the electrical load of the approximately 800 customers on the Sherwood circuit was transferred to adjacent circuits for an extended period (i.e., several months) upon the determination that the damaged cable would require significant repair.

The cause of the insulator arcing failure was attributed to the deterioration of a cable insulation protective barrier. In this case, evidence of arcing was identified during a routine inspection and the underlying issue was repaired before a more significant arcing event occurred. Because the deficiency was identified during an inspection, the Company was able to plan the repair work and transfer load to adjacent circuits ahead of the outage. As a result, no customer outages occurred.

By 2027, the cables and switchgear will be 55 years old,[22] placing them near the end of their service life and presenting an increasing reliability risk. With two cable failures in the past three years, the likelihood of similar or more severe failures are expected to continue increasing until replacement occurs.

b. Details of customer outages resulting from these failures are provided in the response to IR-31a.

[22] Switchgear performs a similar function to a recloser. There are currently no reclosers in the electrical system over 50 years old.

IR-32 Refer to MECL's response to IR-21 of Commission Staff. MECL states that "*repairing the damaged insulation on the termination required specialized expertise that was not readily available and required several months to secure*".

a. Please provide details of all similar failures at the West Royalty Substation from 2020 to present.

b. With respect to the incident referred to in the IR response:

   i. Please explain why expertise was not available to repair MECL's equipment.

   ii. Please provide details of the resulting customer outages (if any), including the number of customers affected and the duration of each outage.

Response:

a. The cable termination failure events described in the responses to IR-21 and IR-31 were the only such events from 2020 to present. However, it is worth repeating from the response to IR-31, that as these cables will be 55 years old in 2027, they are near end of service life and pose an increasing reliability risk. With two cable failures in the last three years, it is reasonable to expect that the potential for similar and more significant failures in the future will continue to increase until they are replaced.

b. (i) The termination failure involved paper insulated lead sheath cable that has not been commonly utilized since the 1980's when alternative cable types became available. For this reason, in-service paper insulated lead sheath cable is now considered rare, and as a result, technicians with training and experience repairing this type of cable are not readily available.

(ii) The age of this cable and the type of failure that occurred indicates the equipment is nearing the end of its useful life. While the cable was repairable in this case, as the paper insulation continues to age and loading continues to grow, the probability of an unrepairable cable failure increases.

As provided in the response to IR-31b, approximately 800 customers experienced an outage due to the termination failure. The details of the customer outages are described in IR-31b. The duration of the outages (i.e., hours) was minimal as the customers were able to be transferred to an adjacent circuit. However, adding load to the adjacent circuits for an extended period can negatively impact reliability and power quality when demand is high, due to added stress on system components.

IR-33 Refer to MECL's response to IR-21 of Commission Staff. MECL states that the proposed upgrades to the West Royalty Substation will improve reliability.

a. Please provide all reliability and other performance metrics available for the West Royalty Substation from 2020 to present.
b. Assuming all of the proposed upgrades are approved, please quantify the forecast reliability improvements. Include all supporting data and assumptions.

Response:

a. Aside from recording breaker trip events, Maritime Electric does not track transmission outages or utilize reliability or performance metrics for substations and transmission lines.[23]

While reliability metrics such as System Average Interruption Duration Index ("SAIDI") can be useful for planning future distribution feeder and line projects, substation and transmission line projects tend to be planned based on a system's ability to survive single contingencies without customer outages. This is because substations and transmission lines must be highly reliable and resilient, with built-in redundancies and contingencies to avoid large customer outage events. Comparatively, distribution feeders and lines are less likely to withstand the loss of a single component without some customer outages. This substation and transmission planning approach ensures that these more critical system assets can withstand component failures without causing widespread supply disruptions and is aligned with industry standards.

Therefore, reliability metrics are not particularly helpful for assessing substation and transmission line projects. Maritime Electric proposed the West Royalty Substation 13.8 kV Distribution Replacements project based on the age of the equipment and capacity requirements due to load growth, which both indicate that this project is necessary.

b. The reference to reliability improvements resulting from this project is in comparison to not replacing the existing West Royalty substation 13.8 kV distribution equipment that is at end of life and increased risk of failure due to age. If the end-of-life equipment is replaced prior to failure, it is reasonably expected that substation reliability will be maintained.

[23] A breaker trip event refers to the automatic opening (or "tripping") of a circuit breaker in response to an abnormal condition on the electrical system, such as a fault, overload, or equipment failure. A breaker trip event always results in a line or component (i.e., transformer) outage.

IR-34 The 2020 ISP anticipates replacement of the X6 transformer with a 75 MVA 138/69 kV transformer in 2026 due to transformer condition and increasing load. Will approval of the West Royalty Substation upgrades in the 2025 Capital Budget impact the timing, cost or scope of the X6 replacement? Please explain.

Response:

For clarity, as shown in Figure IR-34, West Royalty substation is comprised of two sections: an upper yard which is primarily dedicated to the 138 kV transmission system; and a lower yard serving 69 kV transmission and the distribution system. The replacement of the X6 autotransformer will occur in the upper yard, while the 13.8 kV distribution replacements will occur in the lower yard. As such, there is no interdependence between the two projects.

FIGURE IR-34
West Royalty Substation Layout

The X6 replacement starting in 2026 (as indicated in Appendix B of the Application as "West Royalty Substation Upgrades") is required to ensure the capacity and reliability of the interconnection between the 69 kV and 138 kV transmission systems. The proposed West Royalty Substation 13.8 kV Distribution Replacements project starting in 2025 is required to replace end of life 13.8 kV distribution assets that serve a large number of customers in the Charlottetown area.

It is also worth noting that, unlike some other substation projects where both transmission and distribution upgrades are aligned to the same schedule for planning, construction and associated cost efficiencies, this was not required for these projects. This is because both projects will be completed within existing facilities and therefore will not involve land purchases or environmental impact assessments, and the nature of the work for each project is fundamentally different. The 13.8 kV distribution replacements require crews for civil work, underground cabling, structural steel erection, overhead line work and the installation of switches and breakers; whereas, the X6 replacement project is limited to removing and installing autotransformers, completing overhead line work, and installing switches and breakers, which can be mostly completed using internal labour resources including line crews and engineering technicians.

IR-35 The 2020 ISP indicated it intended to undertake a detailed system study for West Royalty, its surrounding areas, and the City of Charlottetown surrounding areas in the next several years.

a. Has MECL conducted a detailed system study as indicated in the 2020 ISP?
b. If so, please provide a copy of the report.

Response:

a. Studies for the greater Charlottetown area are included within the scope of work for the 2025 Integrated System Plan (“ISP”), which is currently underway.

b. A report, as such, will not be produced; however, study results will be reflected in the 2025 ISP.

IR-36 Appendix B to the 2025 Capital Budget Application includes West Royalty Substation Upgrades in 2027 ($3,210,000) and 2028 ($3,339,000). Please provide particulars of the proposed 2027 and 2028 upgrades.

Response:

As discussed in the response to IR-34, West Royalty substation is comprised of an upper yard that is primarily dedicated to the 138 kV transmission system and a lower yard serving 69 kV transmission and the distribution system. The West Royalty Substation Upgrades project referenced in Appendix B to the 2025 Capital Budget Application related to the replacement of autotransformer X6 and will occur in the upper yard of the substation. As such, the West Royalty Substation 13.8 kV Replacements project, which is planned for the lower yard of the substation, is a different and separate project.

The duration of the West Royalty Substation Upgrades project referenced in Appendix B of the 2025 Capital Budget Application has been increased by one year to allow for long-delivery components to be ordered in 2026, in time for the 2028 completion. As such, it will be included in the 2026 Capital Budget Application to be filed with the Commission later this year as the West Royalty X6 Autotransformer Replacement project, to be completed over three years from 2026 to 2028.

IR-37 Assume the West Royalty Substation 13.8 kV Distribution Replacements project is approved as proposed in the 2025 Capital Budget. Once in-service:

a. What is the rate impact of this project on customer rates? Please calculate as both a percentage and dollar figure.
b. What is the impact of this project on rate base?
c. What annual rate of return will MECL earn on these assets? Please calculate as both a percentage and dollar figure.

Response:

a. The estimated rate impact of the West Royalty Substation 13.8 kV Distribution Replacements project is estimated to be $5.54/year or 0.34 per cent increase over the 2025 forecast annual cost for a rural or urban Residential customer, or $85.20/year or 0.33 per cent increase over the 2025 forecast annual cost for a General Service customer as shown in Appendix F of IR-37 – Attachment 1. As the project is not projected to be finished and in service until 2027, rates would not be impacted by this project until that time.

b. The impact over the life of this project on rate base is estimated to be $12.9 million, or 2.33 per cent, as compared to the 2024 actual year end rate base as shown in Appendix D of IR-37 – Attachment 1.

c. The annual rate of return earned by the Company on assets is estimated to be $111,000 or 2.04 per cent, as shown in Appendix G of the IR-37 – Attachment 1.

SCOTCHFORT SUBSTATION

IR-38 The 2020 ISP indicates a 2027+ timeline for the Scotchfort Substation project. Please explain why MECL is proposing to move the project timeline up to 2025. In responding, please provide all supporting data and assumptions.

For example, if MECL's position is that the project should be moved up due to load growth in the service area, explain changes in load growth from the 2020 ISP to present, together with the reason for any variance.

If MECL's position is that the project will improve reliability, please provide all reliability or other performance metrics available for the Scotchfort Substation from 2020 to present, together with forecast reliability improvements.

Response:

The timeframes identified in the 2020 ISP for potential capital projects post-2025 are intended to forecast the "projected year of need," which means that the project would be completed and in-service by the year indicated. Therefore, the start date must be earlier to allow for activities including, but not limited to, land acquisition, engineering, regulatory approvals (including environmental impact assessment, if applicable), long delivery components, construction, and commissioning.

The 2025 Capital Budget Application proposed to complete the Scotchfort substation over three years, from 2025 to 2027. As such, with project completion expected by the end of 2027, the scheduled in-service date generally aligns with the 2020 ISP.

IR-39 In its 2024 Capital Budget Application, MECL stated (at pages 118-119) that a new Scotchfort Substation would be replaced in the near term, but that timing would depend on other more pressing system requirements. MECL is now seeking approval to begin work on the Scotchfort Substation in 2025. Does this mean that there are no other more pressing system requirements for MECL? Please explain.

Response:

Maritime Electric continuously evaluates its system requirements to ensure that the most critical needs are addressed in a timely manner. While there are always multiple pressing system requirements competing for resources, the advancement of a third west-to-east 138 kV transmission line requirement due to load growth has led to the conclusion that the Scotchfort Substation project, as proposed,[24] should be included in the 2025 Capital Budget Application. This conclusion is consistent with the List of Future Capital Projects, provided as Appendix F in the 2024 Capital Budget Application, which forecast that construction of a new Scotchfort substation would begin in 2025 and be completed in 2027.

Load growth also factors into the timing for replacing the existing Scotchfort substation. When the Y-106 Scotchfort to Lorne Valley transmission line rebuild project is completed in 2026, the existing Scotchfort substation will be retired.[25] At that time, and until the new Scotchfort substation is completed, Scotchfort area customers will have to be fed from various adjacent substations. This will increase the load served by these adjacent substations and increase the length and customer count of their feeders and lines. Maritime Electric originally planned for a period of one-to-two years where customers currently connected to the Scotchfort substation could reasonably be fed from adjacent facilities. However, due to continued load growth in the East Royalty, Scotchfort, and West St. Peters areas, the period during which the Scotchfort substation can be out of service is reducing.

[24] The new Scotchfort substation, as proposed, will replace the existing distribution substation and include a 138 kV transmission switching yard with a connection point for the Y-119 Extension to Scotchfort project.

[25] The existing Scotchfort substation has a high-side voltage of 69 kV which is currently fed radially from Lorne Valley via T-4. Once T-4 is converted to 138 kV (T-4 will be renamed Y-106 following the conversion) the existing 69 kV Scotchfort substation will no longer be compatible.

IR-40 Refer to the 2025 Capital Budget at section 6.1(e). MECL is proposing to combine the Scotchfort Substation and switching station into a single project due to "*construction and cost efficiencies*".

a. Please quantify the construction and cost efficiencies of combining the substation and switching station. Provide all supporting calculations and assumptions.
b. As recently as MECL's 2024 Capital Budget, MECL intended to proceed with the Scotchfort Substation project in 2025 and a separate Scotchfort switching station in 2026. Please explain why MECL is now proposing to combine these into a single project with a 2025 start date.
c. Please quantify the benefits to ratepayers arising from combining the projects with a 2025 start date.

Response:

a. It is difficult to quantify the efficiencies of combining the substation and switching station, but it is expected that they will be realized primarily by combining what would otherwise be duplicate activities and assets. Activities where duplication can be avoided include site selection, land acquisition, approvals and permitting, engineering, contractor mobilization/demobilization, etc. Assets where duplication can be avoided includes buildings, mechanical and electrical systems, security systems, backup generators, ground grids, fencing, etc.

   Another important consideration is the ability to avoid construction constraints associated with working in and around an energized and operational substation. If the distribution and transmission components are to be adjacent but constructed and operationalized separately, once the first section is commissioned, the remainder of the construction would have to be completed in close proximity to the energized section. This introduces several safety hazards, including increased exposure to live equipment and more complex worksite coordination. These hazards require careful planning and execution, may necessitate system outages that would otherwise be avoidable, and will slow the pace of work – ultimately leading to increase project costs. Therefore, combining the substation and switching station is a safer option and with less customer outages required.

b. The projects were originally planned to start just one year apart, but were combined to achieve the efficiencies discussed in the response to IR-40a. Therefore, by advancing the switching station by a single year, which is justified based on load growth, construction efficiencies can be realized along with a safer work plan and fewer customer outages.

c. With the efficiencies discussed in the response to IR-40a, it is reasonably expected that the total project cost of the combined project will be less than it would be for two separate projects. However, until detailed engineering is completed, it is difficult to quantify cost savings and other benefits.

IR-41 Refer to the 2025 Capital Budget at Section 6.1(e). MECL states that the proposed Scotchfort Substation is interdependent with several other projects, including the Scotchfort Substation transmission modifications project planned for 2027. If the new Scotchfort substation is approved in the 2025 Capital Budget, it will be completed in 2027. Please explain why MECL is proposing modifications to the substation in 2027, being the year of completion. Please include particulars of the anticipated modifications.

Response:

The proposed Scotchfort Substation Transmission Modifications project is necessary to reroute existing transmission lines Y-104 and Y-106 to enter and exit the new Scotchfort substation. These modifications are budgeted separately from the Scotchfort Substation project because they involve transmission line work that is primarily outside the substation fence. The same general approach has been used for other recent substation projects, whereby the transmission line work to connect a new or upgraded substation is budgeted separately from substation construction.

The proposed budget for the Y-119 Extension to Scotchfort project, which will also involve work that is primarily outside the substation fence, includes costs to route and connect Y-119 to the new Scotchfort substation.

IR-42 MECL states that the new Scotchfort substation will not be constructed at the site of the existing Scotchfort substation due to land size constraints.

a. What does MECL intend to do with the site of the existing Scotchfort substation once the existing substation is retired?

b. Please explain how the site of the existing Scotchfort substation will be used and useful once the substation is retired.

Response:

a. The intended use of the existing Scotchfort substation site will be evaluated in 2027, once the Y-106 Scotchfort to Lorne Valley transmission project is complete and the substation has been fully decommissioned. If it is determined at that time that there is no potential future benefit to owning the site, it will be sold, subject to Commission approval.

b. Potential future use for the site includes repurposing it as a storage yard and staging area for future central and eastern PEI projects. However, as indicated in the response to IR-42a, if the site is not required for these or other justifiable purposes, it will be sold.

IR-43 MECL states that the new Scotchfort substation is required as the existing substation is at the end of life.

a. Please provide evidence that the existing Scotchfort Substation is at the end of life.
b. What are the forecast decommissioning costs (if any) to retire the existing Scotchfort Substation? How will these costs be recovered?
c. Is the existing Scotchfort Substation fully depreciated? If not, what is the forecast net asset balance? How will this amount be recovered?

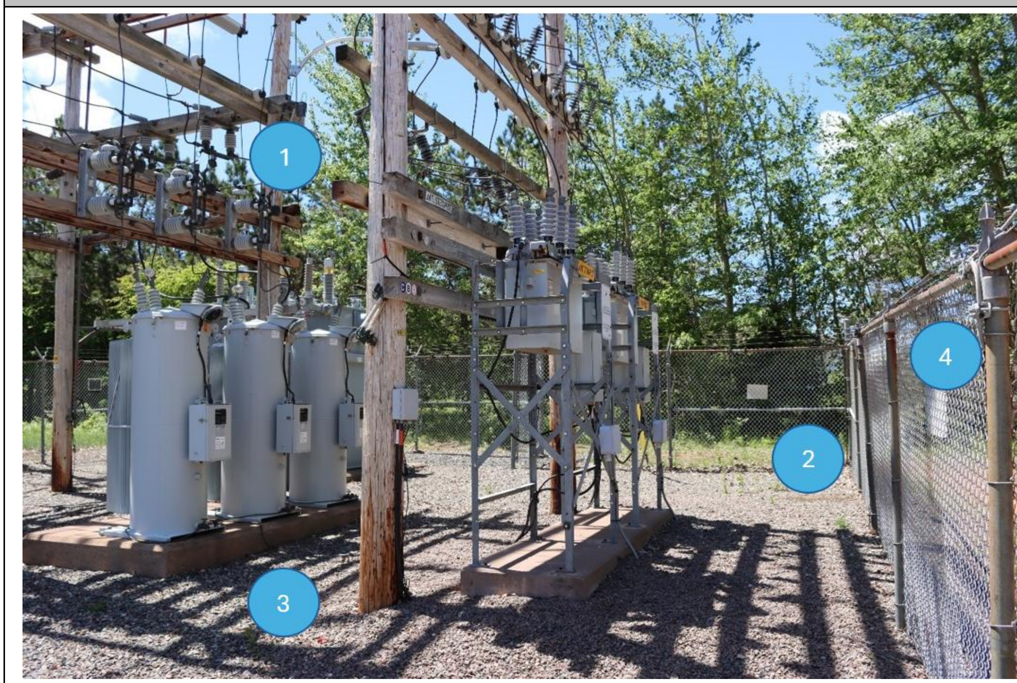
Response:

a. The existing Scotchfort substation was built in the late 1960s and, as such, will be approximately 50 years old upon retirement if the replacement project is approved by the Commission, as planned. With the age of the substation, the deficiencies requiring substation replacement are primarily associated with deteriorated components, inadequate safety clearances due to it being built to older and now out-of-date construction standards, and land constraints that limit modernization and expansion in the current location.

Increased safety clearances within the new substation will meet modern safety standards, and upgrades to include a mobile transformer bay, an expanded transfer bus, transformer oil containment, and modern monitoring equipment with full telemetry, are planned.

Figures IR-43(i) and IR-43(ii) show specific deficiencies that provide supporting evidence of the existing Scotchfort substation being near the end of its service life.

FIGURE IR-43(i)
Scotchfort Substation Deficiencies 1 to 4



1. **12.5 kV bus clearance:** 12.5 kV live conductor below 8', which is an electrical clearance violation.

2. **Drainage gravel:** Too shallow drainage gravel creates electrical safety hazards.

3. **Oil containment:** No oil containment creates environmental and safety hazards.

4. **Fence condition:** Deteriorated fence conditions create security concerns and electrical safety hazards.

FIGURE IR-43(ii)
Scotchfort Substation Deficiencies 5 to 9

5. **Truck clearance:** Insufficient truck clearance creates operational inefficiencies and electrical safety hazards.

6. **Insulator condition:** End-of-life porcelain insulators increase the risk of electrical failures and electrical safety hazards.

7. **Pole condition:** Deteriorated and warped poles create structural weakness, increasing the risk of operational disruptions and electrical safety hazards.

8. **Bus layout:** Congested buses create maintenance challenges, reduce operational flexibility and present electrical safety hazards.

9. **Mobile transformer:** Not enough clearance to fit the new mobile transformer. This lack of flexibility in using both mobile transformers increases the risk of operational delays and logistical challenges, particularly during emergencies or maintenance activities.

b. The estimated decommissioning cost for the Scotchfort substation is approximately $16,000, which includes the internal labour and transportation needed to remove voltage regulators, reclosers, the power transformer, and the cost to clear the site. Per the audited financial statements submitted to the Commission on February 20, 2024, the Company has a regulatory liability provisional account for future site removal and restoration costs with a December 31, 2024 balance of $74.7 million. This liability amount is used to cover costs related to the removal and restoration of Company regulated assets. This account will therefore cover the actual costs of removal for the project and result in no additional cost to customers.

c. The forecast net asset balance is approximately $250,000. Included in this amount are 2011 additions which include a power transformer and related materials that will be removed from the site and, upon a favourable condition assessment, will be redeployed in a different location. Of the $250,000, approximately $234,000 relates to the 2011 assets that will be redeployed and therefore the remaining balance is relatively small.

This amount will be recovered through depreciation using the group depreciation methodology discussed in the 2020 Depreciation Study ("Study"). The Study was completed by Gannet Fleming and filed with the Commission July 29, 2021, and later approved to be adopted by the Commission in Order UE23-04.

As noted in the Study, page V-2 of the document explains that *"group depreciation for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life."*

This ensures that the costs remaining to be recovered for the current Scotchfort substation assets will be recouped over the average service life of the group of assets.

IR-44 As justification for the combined Scotchfort Substation and switching station, MECL states that the proposed Y-119 Extension needs to be connected to a switching station. Assume the Y-119 Extension is not approved as part of the 2025 Capital Budget. What impact will this have on the proposed Scotchfort Substation, including the scope, timing and cost of the project?

Response:

Under the assumption that the Y-119 Extension to Scotchfort project is not approved as part of the 2025 Capital Budget, the distribution section of the Scotchfort Substation project remains essential and must proceed for the reasons provided in the response to IR-43, as the existing substation is approaching 50 years old and is near the end of its service life.

Under the same assumption, the transmission switching section of the new Scotchfort substation would not be required. This would reduce substation construction costs by approximately 60 per cent, but the overall project timeline would not change, as the delivery time for long lead substation equipment is approximately three years. However, the avoided construction costs would only be temporary, as the third west-to-east 138 kV transmission line and the switching station in the Scotchfort area will be needed to avoid substantial operating costs due to line losses, and having to operate on-Island dispatchable generation for managing power quality and thermal loading on Y-109 and Y-111. More detail on these costs and the business case for the Y-119 Extension project are provided in the responses to IR-55 and IR-56.

It is also worth noting that adding the transmission switching section to a new distribution-only Scotchfort substation at a later date would be more costly, more complex to coordinate, and introduce greater risks to health, safety and system reliability, all which are consistent with the rationale provided in the response to IR-40a.

IR-45 Assume the Scotchfort switching station is not approved as part of the 2025 Capital Budget.

a. What impact will this have on the proposed Y-119 Extension?
b. What modifications are required to the West Royalty Substation to accommodate Y-119?
c. What is the forecast cost of the modifications referred to in (b) above?

Response:

a. If the Scotchfort switching station is not approved as part of the 2025 Capital Budget, the proposed Y-119 extension would have to be integrated into the transmission network at the West Royalty substation. This is less ideal than the proposed Scotchfort switching station.

As provided in Section 6.1e, page 125 of the Application, the drawbacks of the West Royalty substation as a connection point for the Y-119 extension include:

- The addition of a third line to the West Royalty substation is challenging due to physical constraints and would require significant substation modifications;
- The addition of a third line to the West Royalty substation would increase the reliance on this substation. The establishment of a new substation in Scotchfort will provide geographic supply diversity for central and eastern PEI, which represents approximately 70 per cent of Maritime Electric customers; and
- The addition of a third line to the West Royalty substation would not alleviate other system concerns, the most significant of which is the overloading of transmission line T-2 with the loss of line Y-102.

b. A significant bus expansion at the West Royalty substation would be required to accommodate the Y-119 Extension as the existing 138 kV bus is already congested. This would involve substantial challenges, including the need for additional substation space and working in an existing operational (i.e., energized) substation.

Working in an operational substation involves working on and around existing infrastructure, which can complicate construction activities and increase costs. Additionally, ensuring minimal disruption to regular substation operations (i.e., equipment and line outages) and maintaining safety standards during the expansion would be critical. These challenges would not exist at a greenfield and non-energized substation site. As such, the Scotchfort substation switching yard provides a more straightforward and efficient solution for integrating the Y-119 extension into the transmission network.

c. To determine the forecast cost of the modifications required to accommodate the Y-119 extension at the West Royalty substation, detailed engineering studies are necessary to scope the work, including the required bus expansion and associated infrastructure enhancements. These studies were not pursued because the West Royalty connection option was dismissed as a less preferable solution relative to Scotchfort.

IR-46 MECL states that the new Scotchfort switching station will serve existing lines Y-104, Y-106 and Y-114. What switching station currently serves these lines?

Response:

Currently, Y-104 runs from the Marshfield substation to the Church Road substation. After the Scotchfort switching station is complete, Y-104 will be split into two line sections, Y-104 and Y-114. One section will run between Marshfield and Scotchfort, and the other section will run between Scotchfort and Church Road.

When Y-106 is completed in 2026, it will connect into Y-104 via switches in the Scotchfort area. This configuration will connect the new transmission line and the Lorne Valley switching station into the 138 kV transmission system.

The full benefit of Y-106 will be realized once the Scotchfort switching station is complete. Once complete, all of these lines - Y-104, Y-114, Y-106, and Y-119 - will connect to the Scotchfort switching station which will serve as a central hub, enhancing the ability to manage and distribute electrical loads in central and eastern PEI.

IR-47 MECL states that the new Scotchfort Substation will reduce the potential for significant customer outages when unplanned transmission line outages occur.

a. Please confirm the specific transmission lines that MECL is referring to.
b. Please provide particulars of all unplanned outages on the lines referred to in (a) above from 2020 to present.
c. With respect to the outages referred to above, please provide details of any resulting customer outages, including the number of customers affected and the duration of each outage.
d. Please explain how the proposed new substation would reduce customer outages caused by unplanned transmission line outages.

Response:

a. The transmission lines include:

Y-102: (West Royalty to Marshfield)
Y-104: (Marshfield to Church Road)
Y-106: (Scotchfort area to Lorne Valley)
Y-109: (Borden to West Royalty)
Y-111: (Bedeque to West Royalty)

b. A listing of the unplanned outages that have occurred on these lines since 2020 is provided in Table IR-47.

Because Maritime Electric does not track transmission outages, the information in Table IR-47 was compiled from SCADA logs, relay events, Energy Control Centre reports and e-mail records. As such, it is possible that some events were missed due to the manual process of searching, sorting and reviewing data from a variety of sources, that was required to prepare this response.

TABLE IR-47(i) Unplanned Transmission Line Outages Since 2020					
Transmission Line	**Date (yy:mm:dd)**	**Start Time (hh:mm)**	**Duration (h:mm:ss)**	**Island Load (MW)**	**Cause**
Y-102	24 12 21	13:35	0:00:46	294	Wind related
Y-102	23 10 05	16:52	0:00:21	182	No record found
Y-104	25 02 10	21:00	1:04:00*	334	Protection trip
Y-104	24 10 14	22:20	0:00:01	168	Lightning
Y-104	24 03 08	14:28	4:25:00*	251	Motorized switch failure
Y-104	23 08 27	3:46	1:13:00*	128	Pole fire
Y-104	22 11 08	21:20	1:04:00*	193	Tree on the line
Y-104	22 10 12	10:31	1:52:07	168	No record found
Y-104	22 09 24	0:45	41:06:24	88	Hurricane Fiona
Y-104	22 07 03	14:43	0:00:02	175	No record found
Y-104	21 10 22	18:41	0:00:03	183	Lightning
Y-109	20 02 15	12:56	1:42:17	237	Enable repairs in Albany
Y-109	22 03 20	8:03	0:00:02	197	No record found
Y-109	22 09 24	4:48	35:49:51	5	Hurricane Fiona
Y-109	22 11 22	7:58	57:13:50	245	No record found
Y-109	23 12 18	18:48	0:00:25	235	No record found
Y-109	24 02 07	11:51	0:00:02	253	Insulators failure
Y-109	24 05 23	14:08	0:00:02	161	Lightning
Y-111	22 09 24	3:20	364:32:00	181	Hurricane Fiona
Y-111	23 01 15	18:21	23:44:00	263	No record found
Y-111	24 05 23	14:08	0:00:02	161	Lightning
Y-111	24 06 20	15:00	0:01:00	222	No record found
Y-111	24 09 13	21:15	1:30:14	183	No record found
Y-111	24 09 13	21:15	0:00:01	183	No record found
Y-111	24 12 31	10:32	0:32:49	220	Low gas in breaker
Y-111	25 05 08	14:55	2:25:36	162	Tree on the line

* The duration reflects the time to restore power to affected customers.

c. There were three customer outage events related to the line outages listed in Table IR-47(i). These were associated with unplanned interruptions on transmission line Y-104 and are listed in Table IR-47(ii).

TABLE IR-47(ii) Customer Outages due to Unplanned Interruptions on Y-104 since 2020			
Transmission Line	**Date (yy:mm:dd)**	**Customers Impacted**	**Duration (h:mm:ss)**
Y-104	25 02 10	21,302	1:04:00
Y-104	24 04 08	1,355	4:25:00
Y-104	23 08 27	1,267	1:13:00
Y-104	22 11 08	1,204	1:04:00

All other unplanned transmission line outages in Table IR-47(i) did not result in customer outages,[26] due primarily to being components of “transmission loops”, meaning they are part of a network where two or more lines feed the same area.

During periods of light to moderate loading (e.g., total Island load below 300 MW), the loss of one of these lines is unlikely to result in customer outages due to the redundancy provided by the looped configuration. However, during periods of high loading (e.g., Island loads above 300 MW), an outage on any of these lines could lead to significant customer outages in central or eastern PEI until the new Scotchfort substation and its associated interdependent projects are completed. Such periods of high loading are increasing, for example, in 2022 there were 22 hours when Island load exceeded 300 MW. This increased to 69 hours in 2023 and 210 hours in 2024. So far in 2025 there have been 465 hours when the Island load exceeded 300 MW. As Island loads continue to grow, the number of hours above this threshold is expected to rise significantly year over year.

d. The proposed new Scotchfort substation would help to avoid customer outages caused by unplanned transmission line outages, by restoring the intended functionality of the looped transmission system in central and eastern PEI. Under current conditions, during periods of high system loading (i.e., total Island load above 300 MW), an unplanned outage on any of the transmission lines listed in the response to IR-47a could result in significant customer outages. This is because the remaining lines in the loop may not have sufficient capacity to carry the redistributed load, particularly as demand continues to grow.

The new substation will provide an additional switching point within the looped transmission system, enhancing the ability to isolate faults and reroute power without interrupting service to customers. As Island load continues to grow, the number of hours per year during which the system operates under high-load conditions is increasing significantly, as indicated in the response to IR-47c. During these periods, the redundancy typically offered by a looped system is compromised – as a single line outage can result in customer interruptions. Without the new substation, both the likelihood and scale of these outages will continue to increase in step with system load.

[26] Customer outages were recorded on September 24, 2022, as a result of Hurricane Fiona, which caused widespread disruptions across both transmission and distribution systems. Given the scale and severity of the event, it is not possible to definitively attribute individual customer outages to specific line failures. As such, these outages have been excluded from the scope of this response.

IR-48 MECL states that the new Scotchfort Substation will improve system reliability in central and eastern PEI.

a. Please provide all reliability or other performance metrics available for the existing Scotchfort Substation from 2020 to present.
b. Assuming the new combined substation and switching station is approved, please quantify the forecast reliability improvements. Include all supporting data and assumptions.

Response:

a. As explained in the response to IR-33a, aside from recording breaker trip events, Maritime Electric does not track transmission outages or utilize reliability or performance metrics for substations or transmission lines.

b. Once the new Scotchfort substation and related interdependent projects are completed, it is reasonable to expect that both the distribution system and the transmission system will be more reliable due to the infrastructure upgrades and network enhancements introduced by the project. In particular, the risk of system overloads and power quality issues, such as low voltage, will be reduced. However, while these improvements are anticipated, it is not possible to quantify the future reliability gains.

IR-49 In the 2020 ISP, MECL states that the Scotchfort transformer will be redeployed once the existing Scotchfort substation is retired. Please provide particulars of the redeployment, including any associated costs or costs savings.

Response:

The current plan is to redeploy the existing Scotchfort substation power transformer once the substation is retired. Prior to redeployment, a thorough assessment of the power transformer's condition will be conducted to confirm its suitability for continued service. This evaluation will consider factors such as age, performance history, and any signs of wear or damage. If deemed to be in good condition, the power transformer will be relocated to a new site where it can be effectively reintegrated into the distribution system. Associated costs or potential savings will be determined based on the specific requirements, logistics, and duration of the redeployment. Redeploying power transformers that are being replaced for reasons other than asset condition is a common Maritime Electric and industry practice.

Y-119 EXTENSION

IR-50 In the 2020 ISP, MECL identified a need for a third 138 kV transmission line from the Interconnection at loads above 353 MW. Is this referring to a base load or peak load of 353 MW?

Response:

The reference to requiring a third 138 kV transmission line from the Interconnection at total Island load above 353 MW is not specific to peak or baseload conditions. Rather, it highlights that whenever total Island load reaches or exceeds 353 MW the absence of a third 138 kV west-to-east transmission line creates a critical vulnerability, as the loss of Y-111 under these conditions would result in voltage collapse and overloading of Y-109.

The addition of a third 138 kV west-to-east transmission line mitigates this risk by ensuring that the system can withstand the loss of one line without triggering cascading outages. This added redundancy significantly increases system resilience, allowing it to operate reliably at load levels well beyond those currently forecast.

IR-51 In each year from 2020 to 2024, how many times and for what duration did MECL's system experience peak loads of 353 MW or higher? Please provide particulars of each instance.

Response:

As indicated in the response to IR-50, the 353 MW reference in the 2020 ISP was for total Island load. Table IR-51 shows actual data for when total Island load was above 353 MW since 2020.

TABLE IR-51
Number of Hours and MWhs Above PEI Load of 353 MW

Year	Daily Average Temperature[27] (°C)	Duration (hours)	Energy Above 353 MW (MWh)
2023 Feb 4	-21.6	14	364
2025 Jan 21	-14.4	5	46
2025 Jan 22	-15.2	6	47
2025 Jan 23	-10.2	3	20
2025 Jan 29	-10.8	3	5
2025 Jan 30	-12.1	8	112
2025 Jan 31	-10.8	5	57
2025 Feb 5	-13.3	4	48
2025 Feb 6	-9.3	2	7
2025 Feb 11	-12.3	1	2
2025 Feb 14	-6.2	2	3

Note: Customers were asked to conserve energy starting on January 22, 2025 and again on February 11, 2025 due to anticipated high loads, which may have reduced loads between January 22 to January 24, and February 11 to February 13, respectively.

From 2020 to 2024, total Island load exceeded 353 MW on only one occasion. This was during the February 2023 polar vortex weather event. However, to date in 2025, total Island load has exceeded 353 MW on ten occasions for a total 39 hours. As load growth continues to increase, the total Island load will exceed 353 MW more frequently and for longer durations.

[27] Source: Environment Canada (Charlottetown Airport).

IR-52 Between 2020 and present, how many times has MECL experienced an outage on Y-109 and/or Y-111 during peak loading?

a. Please provide complete details, including the cause and duration of any outage, the steps taken by MECL to ensure continuity of supply, and particulars of any customer outages resulting from the loss of Y-109 or Y-111.

Response:

Between 2020 and present, there were no outages experienced on Y-109 and Y-111 during periods of high loading (e.g., total Island load above 300 MW). However, until recently the number of hours per year when total Island load exceeded 300 MW were minimal. For example, in 2022 there were only 22 hours when Island load exceeded 300 MW. This increased to 69 hours in 2023 and 210 hours in 2024. So far in 2025 there have been 465 hours when the Island load exceeded 300 MW. As Island loads continue to grow, the number of hours above this threshold is expected to rise significantly year over year.

a. A listing of the outages on Y-109 and Y-111 that have occurred on these lines since 2020 is provided in Table IR-52.

Because Maritime Electric does not track transmission outages, the information in Table IR-52 was compiled from SCADA logs, relay events, Energy Control Centre reports and e-mail records. As such, it is possible that some events were missed due to the manual process of searching, sorting and reviewing data from a variety of sources, that was required to prepare this response.

TABLE IR-52
Y-109 and Y-111 Transmission Line Outages Since 2020

Transmission Line	Date (yy:mm:dd)	Start Time (hh:mm)	Duration (h:mm:ss)	Island Load (MW)	Cause
Y-109	20 02 15	12:56	1:42:17	237	Enable repairs in Albany
Y-109	21 04 15	8:59	367:24:44	200	Clyde River substation work
Y-109	22 03 20	8:03	0:00:02	197	No record found
Y-109	22 09 24	4:48	35:49:51	5	Hurricane Fiona
Y-109	22 11 22	7:58	57:13:50	245	No record found
Y-109	23 12 18	18:48	0:00:25	235	No record found
Y-109	24 02 07	11:51	0:00:02	253	Insulators failure
Y-109	24 05 23	14:08	0:00:02	161	Lightning
Y-111	21 11 15	8:49	30:22:00	187	Enable work on line
Y-111	22 09 24	3:20	364:32:00	181	Hurricane Fiona
Y-111	23 01 15	18:21	23:44:00	263	No record found
Y-111	24 05 23	14:08	0:00:02	161	Lightning
Y-111	24 06 20	15:00	0:01:00	222	No record found
Y-111	24 09 13	21:15	1:30:14	183	No record found
Y-111	24 09 13	21:15	0:00:01	183	No record found
Y-111	24 12 31	10:32	0:32:49	220	Low gas in breaker
Y-111	25 05 08	14:55	2:25:36	162	Tree on the line

There were no customer outages related to the loss of Y-109 and/or Y-111 between 2020 and present,[28] as these lines are “looped lines", which means that if one line experiences an outage, the other can supply the load, ensuring continuity of service.

Until recently, when total Island load rarely exceeded 300 MW, the capacity of Y-109 and Y-111 was adequate that either line could survive the loss of the other without power quality (i.e., low voltage) or thermal overload issues occurring. However, as system load increases, should one line experience an outage, the remaining line may not be able to adequately supply the load, potentially leading to power quality (i.e., low voltage) or thermal overload issues. Therefore, the addition of a third 138 kV transmission line is essential to maintain reliable service and ensure power quality under high load conditions.

[28] Does not include the Hurricane Fiona extreme weather event, which caused extensive transmission and distribution line outages across PEI.

IR-53 Please provide the SAIDI, SAIFI and any other performance metrics tracked by MECL for each of Y-109 and Y-111 from 2020 to present.

Response:

As explained in the response to IR-33a, aside from recording breaker trip events, Maritime Electric does not track transmission outages or utilize reliability or performance metrics for substations and transmission lines.

IR-54 The 2020 ISP states (at pages 56-57) that a third west to east line will be required if dispatchable generation is not added in the Charlottetown area. Similarly, in the 2025 Capital Budget, MECL states that on-Island generation would deliver power locally and prevent a widespread outage due to the loss of Y-109 or Y-111.

MECL has recently filed an application seeking approval to add 150 MW of on-Island capacity at a forecast cost of $427 million (Docket UE20742). If the additional on-Island capacity is approved, is a third 138 kV transmission line required to provide safe and reliable service? Please explain.

Response:

Technically, as indicated in the 2020 Integrated System Plan and the 2025 Capital Budget, the operation of on-Island dispatchable generation is an alternative solution to the proposed third 138 kV west-to-east transmission line. However, this approach is not the least cost option.

Maritime Electric is not currently obligated to comply with North American Electric Reliability Corporation ("NERC") requirements, but it strives to operate to NERC standards as good utility practice, considering reliability risk and cost when planning system requirements.

NERC standards for transmission planning include an expectation that the transmission system should be able to withstand the loss of a single transmission element (e.g., transmission line, generator, transformer, etc.) without overloads or power quality issues occurring in the system.

Currently, the transmission system must periodically operate when loads are above a recommended limit. During these periods, the system cannot remain operational if a single transmission system element is lost, which will result in customer loads being shed (i.e., potentially widespread and prolonged, or rotating, customer outages). As load growth is forecast to continue, it is imperative that either the Y-119 extension (and interrelated projects) or the on-Island generation capacity project is completed and operational by the end of 2028 (or sooner). Ideally, both should be completed within this timeframe as they each provide distinct reliability and security of supply benefits. To extend the present situation beyond 2028 will only put more customers at risk of load shedding, more often, when electricity is at its highest demand (i.e., during cold weather events), which is a risk to human life and property.

While on-Island dispatchable generation provides the ability to serve load in the absence of additional transmission, it is not the least cost solution for doing so. This is because generating a megawatt-hour ("MWh") of electricity with on-Island dispatchable generation is approximately eight times the cost of importing that same MWh.[29] As Island loads continue to increase, the amount of energy that would need to be generated to avoid the need for a third 138 kV west-to-east transmission line will become increasingly greater in quantity.

In contrast, the addition of a third line would reduce loading on the existing lines, thereby lowering system losses and improving maintenance flexibility. Transmission also offers other advantages. For example, outages on transmission lines are generally less frequent and easier to repair than

[29] The approximate 8:1 cost ratio for generating electricity on PEI versus importing from NB is based on the current average cost of Maritime Electric's three combustion turbines and the existing NB contract price. This ratio fluctuates with CT loading, ambient conditions, and diesel prices.

outages on generation equipment, which is more complex and contains more dynamic components. Additionally, imported electricity is significantly cleaner in terms of emissions compared to on-Island diesel generation.

Ultimately, both transmission and generation are essential. A balanced approach that includes both ensures security of supply while addressing the key pillars of affordability, reliability, and sustainability.

IR-55 In Appendix N to the 2025 Capital Budget, MECL states that it considered the operation of existing dispatchable on-Island generation rather than construction of a new transmission line. However "*fuel costs associated with the operation of on-Island generation during transmission outages is the primary reason why this option was not selected*".

a. Please quantify the fuel cost to run on-Island generation.
b. Please quantify the fuel costs that MECL has incurred from 2020 to present due to outages on Y-109 and/or Y-111 during peak loading.
c. MECL states that it has considered the operation of existing dispatchable on-Island generation. Has it considered the operation of future dispatchable on-Island generation as proposed in Docket UE20742?
d. Please quantify the cost to run on-Island generation if MECL's application to add 150 MW of on-Island capacity is approved.

Response:

The reference to "fuel costs associated with the operation of on-Island generation during transmission outages …" in Appendix N to the 2025 Capital Budget Application could have been worded differently to better reflect the text that preceded it. The preceding text indicated that the concern was around having to operate existing dispatchable on-Island generation preemptively during high system loads (i.e., above 300 MW), and not just during transmission outages.[30]

One reason for operating on-Island generation during high load periods is to prevent possible power quality or thermal overload issues should an outage occur. This practice of preemptive operation is considered good utility practice, and, in some jurisdictions, it is a regulatory requirement of NERC under the reliability standard "TPL-001-5.1 — Transmission System Planning Performance Requirements"

Analysis supporting this response, including all calculations and assumptions, is included in Excel spreadsheets provided as IR-55 - Confidential Attachment 1 and IR-55 – Confidential Attachment 2. For the analysis, the generation projects proposed in Docket UE20742 were assumed to be in service.

The analysis was completed for January and February 2030; therefore, amounts are presented in 2030 dollars.[31] Beyond 2030, fuel costs associated with preemptive generation are expected to rise each year due to increased reliance on on-Island generation, which is directly tied to forecasted annual load growth. Additionally, as system loads increase, system losses will also increase, further contributing to rising costs. For this reason, 2030 represents the most challenging year in which to financially justify the addition of a third 138 kV west-to-east transmission line, as the costs will only increase in subsequent years (i.e., each subsequent year strengthens the economic case for the project).

[30] The exact MW of load threshold where preemptive generation is required changes regularly based on system conditions, including localized load levels and renewable generation.
[31] 2030 was chosen as this is estimated to be the first winter season that additional on-Island generation is fully operational, based on the Company's On-Island Capacity for Security of Supply Project application.

For the analysis, the PEI-to-NB Interconnection ("Interconnection") transfer capability was input as 300 MW and 345 MW, as there is a reasonable possibility that the Interconnection transfer capability could be increased to approximately 345 MW by 2030.

a. The estimated incremental fuel cost to run on-Island generation related to the absence of the Y-119 extension (and interrelated projects) is approximately $2.8 million (with an Interconnection transfer capability of 345 MW) and $1.6 million (with an Interconnection transfer capability of 300 MW) in the winter of 2030.

Table IR-55(i) and Table IR-55(ii) are provided as examples to show how an increase in Interconnection transfer capability causes an increase in incremental fuel costs. Each example scenario is for the same ten-hour period.

In Table IR-55(i) the Interconnection limit was modeled as 300 MW. In this case, when load is above 300 MW fuel is required to offload the Interconnection; therefore, generation is operating to supply energy, but by operating, it is also providing voltage support and protecting against thermal overload on Y-109 and Y-111. This means that incremental fuel costs associated with preemptive operation of generation are not incurred because the generation must be operated to supply energy.

In Table IR-55(ii) the Interconnection limit was modeled as 345 MW. This causes incremental fuel costs to increase because up to a load of 345 MW, generation would not have to operate for energy supply if the Y-119 extension was in place; however, because it is not, generation must operate to produce energy at a higher cost than purchased energy.

TABLE IR-55(i)
Cost of Preemptive Generation with a 300 MW Interconnection Limit

Date (yy:mm:dd)	Time (hh:mm)	Cost of On-Island Generation to limit Interconnection Import (A)	Cost of Preemptive Generation to prevent Issues on Y-109 & Y-111 (B)	Incremental Cost of Preemptive Generation (C = B – A)
21 01 30	13:00	$ -	$ 6,230	$ 6,230
21 01 30	14:00	-	4,883	4,883
21 01 30	15:00	-	4,883	4,883
21 01 30	16:00	4,883	14,482	9,599
21 01 30	17:00	10,410	20,720	10,310
21 01 30	18:00	8,873	21,384	12,511
21 01 30	19:00	4,883	17,850	12,967
21 01 30	20:00	-	10,131	10,131
21 01 30	21:00	-	7,449	7,449
21 01 30	22:00	-	5,238	5,238
TOTAL		**$ 29,049**	**$ 113,250**	**$ 84,201**

TABLE IR-55(ii) Cost of Preemptive Generation with a 345 MW Interconnection Limit				
Date/Time	**Time (hh:mm)**	**Cost of On-Island Generation to limit Interconnection Import (A)**	**Cost of Preemptive Generation to prevent Issues on Y-109 & Y-111 (B)**	**Incremental Cost of Preemptive Generation (C = B – A)**
21 01 30	13:00	$ -	$ 6,230	$ 6,230
21 01 30	14:00	-	4,883	4,883
21 01 30	15:00	-	4,883	4,883
21 01 30	16:00	-	14,482	14,482
21 01 30	17:00	-	20,720	20,720
21 01 30	18:00	-	21,384	21,384
21 01 30	19:00	-	17,850	17,850
21 01 30	20:00	-	10,131	10,131
21 01 30	21:00	-	7,449	7,449
21 01 30	22:00	-	5,238	5,238
TOTAL		**$ 29,049**	**$ 113,250**	**$ 113,250**

b. As described in the response to IR-55a, fuel costs are incurred from preemptive generation to prevent power quality and thermal overload issues in the event of an outage, and this aligns with good utility practice and the NERC reliability standard "TPL-001-5.1 - Transmission System Planning Performance Requirements." To date, fuel costs related to preemptive generation have been negligible. However, Maritime Electric forecasts a significant increase in these costs over the next five years as a result of the exponential shape of the peaking section of the load duration curve. This trend is reflected in the increasing number of hours above the 300 MW threshold: 22 hours in 2022; 69 hours in 2023; 210 hours in 2024; and, 465 hours, to date, in 2025. As total Island load continues to grow, the number of hours requiring preemptive generation is expected to rise substantially each year.

Maritime Electric will attempt to mitigate fuels costs during the Y-119 extension construction period with a remedial action scheme ("RAS") which will automatically disconnect customers should a transmission outage occur. Maritime Electric considers this to be a temporary measure only, as it contradicts the Company's transmission planning standards.[32] However, due to the limited timeframe for the construction phase of the project, Maritime Electric considers a RAS to be a reasonable short-term solution to minimize costs.

[32] Maritime Electric planning standards state that no firm or network transmission service should be interrupted in the event of the loss of one section of a looped transmission line. The implementation of this RAS would result in an interruption to network service should a transmission line outage occur under high system loads. This contradicts planning standards and therefore should only be used as a temporary measure.

c. All analysis was completed, assuming that the generation projects proposed in Docket UE20742 are approved and in service. If they are not approved, the costs described in the response to IR-55a will increase due to the lack of additional synchronous condensers.

d. The incremental cost to run on-Island generation related to the lack of the Y-119 extension (and interrelated projects), assuming Docket UE20742 is approved, is described in the response to IR-55a. If Docket UE20742 is not approved, the costs described in the response to IR-55a will increase.

IR-56 Is constructing and maintaining a new 138 kV transmission line a lesser cost option than relying on on-Island generation? Please provide all supporting calculations and assumptions.

Response:

Yes, constructing and maintaining a new 138 kV transmission line is a more cost-effective option compared to operating on-Island generation. This is due to the high and recurring fuel costs associated with running generators, and increased system losses, in the absence of a new 138 kV transmission line.

In 2030 alone, savings are forecast to be in the range of $2 million, assuming that the Interconnection transfer capability is increased to 345 MW as shown in Table IR-56(i), with savings increasing in subsequent years.

Analysis presented in Table IR-56(i) and Table IR-56(ii) was completed for the year 2030. Excel spreadsheets including all supporting calculations and assumptions, are provided in the response to IR-55, as IR-55 – Confidential Attachment 1 and IR-55 – Confidential Attachment 2.

TABLE IR-56(i)	
Cost Analysis Summary for 300 MW Import Limit	
Cost of "Y-119 Extension to Scotchfort" project with all interdependent projects (A)	$ 39,774,000
Estimated cost of Scotchfort Distribution substation (B)	6,000,000
Portion of project directly related to transmission system improvements (C = A – B)	$ 33,774,000
Weighted average cost of capital (per cent)	6.6
Amortization period (years)	47
Annual carrying cost (D)	$ (2,347,808)
Estimated savings in 2030 related to reduced losses (E)	1,508,868
Estimated savings in 2030 related to reduced generation operations (F)	1,593,707
Project savings (G=D+E+F)	$ 754,767

TABLE IR-56(ii)	
Cost Analysis Summary for 345 MW Import Limit	
Cost of "Y-119 Extension to Scotchfort" project with all interdependent projects (A)	$ 39,774,000
Estimated cost of Scotchfort Distribution substation (B)	6,000,000
Portion of project directly related to transmission system improvements (C)	$ 3,774,000
Weighted average cost of capital (per cent)	6.6
Amortization period (years)	47
Annual carrying cost (D)	$ (2,347,808)
Estimated savings in 2030 related to reduced losses (E)	1,508,868
Estimated savings in 2030 related to reduced generation operations (F)	2,843,634
Project savings (G=D+E+F)	$ 2,004,693

IR-57 Assume the Scotchfort Substation and Y-119 Extension are approved as proposed in the 2025 Capital Budget. Once in-service:

a. What is the rate impact of these two projects on customer rates? Please calculate as both a percentage and dollar figure.
b. What is the impact of these two projects on rate base?
c. What annual rate of return will MECL earn on these assets? Please calculate as both a percentage and dollar figure.
d. What is the impact of all four interdependent projects on customer rates? Please calculate as both a percentage and dollar figure.
e. What is the impact of all four interdependent projects on rate base?
f. What annual rate of return will MECL earn on these assets? Please calculate as both a percentage and dollar figure.

Response:

a. The rate impact of the capital additions associated with the Scotchfort Substation and the Y-119 Extension projects is estimated to be $13.10 per year, which is an increase of 0.80 per cent and 0.81 per cent over the 2025 forecast annual cost for a rural and urban Residential customer, respectively, and $201.60 per year, which is an increase of 0.78 per cent over the 2025 forecast annual cost for a General Service customer, as shown in Appendix F of IR-57 – Attachment 1. Rates will not be increased by these projects until they are in service, which is projected to be in 2028. Operational savings, as described in the response to IR-56 will offset at least a portion of this expense initially and will completely offset these additional costs by 2030.

b. The impact over the life of this project on rate base is estimated to be $30.5 million, or 5.53 per cent, as compared to the 2024 actual year-end rate base as Appendix D of IR-57 – Attachment 1.

c. The annual rate of return earned by the Company on assets is estimated to be $274,000 or 2.12 per cent as shown in Appendix G of IR-57 – Attachment 1.

d. The rate impact of the capital additions associated with the Scotchfort Substation, Y-119 Extension to Scotchfort, Y-109 Rebuild, and Scotchfort Substation Transmission Modifications project is estimated to be $17.78 per year, which is an increase of 1.08 per cent, and 1.10 per cent over the 2025 forecast annual cost for a rural and urban Residential customer, respectively, and $273.60 per year, which is a 1.06 per cent increase over the 2025 forecast annual cost for a General Service customer, as shown in Appendix G of IR-57 – Attachment 2. Rates will not be increased by these projects until they are in service which is projected to be in 2028. Also, as described above in the response to IR-57a, operational savings will offset at least a portion of this increase.

e. The impact over the life of this project on rate base is estimated to be $41.4 million, or 7.51 per cent, as compared to the 2024 actual year end rate base as shown in Appendix D of IR-57 – Attachment 2.

f. The annual rate of return earned by the Company on these assets is estimated to be $369,000 or 2.10 per cent, as shown in Appendix G of IR-57 – Attachment 1.

ADDITIONAL INTERROGATORIES

IR-30 – Attachment 1

van Kooy Transformer Consulting Services Inc.

West Royalty X1	31	Moloney	261328	1972

Results from oil samples taken - Dissolved Gases in Oil Analysis (DGA) in ppm

DATE	Hydrogen	Methane	Ethylene	Ethane	Acetylene	Carbon Monoxide	Carbon Dioxide	Oxygen	Nitrogen
	H_2	CH_4	C_2H_4	C_2H_6	C_2H_2	CO	CO_2	O	N
18 Sep 15	14	3	22	0	0	290	2390	34497	87744
06 Oct 16	4	3	23	2	0	223	2268	28928	65443
22 Sep 17	4	3	21	2	0	202	1871	31229	68350
25 Oct 18	4	4	21	1	0	234	2026	29004	63641
16 Oct 19	4	3	19	1	0	214	2023	29633	65472
Thresholds									
IEEE	100	120	50	65	2	350	2500	na	na
vKTCS Inc.*	100	120	50	65	3	850	3750	na	na

*based on experience with transformers of similar size, voltage class, age and application

Results from oil samples taken – General Oil Quality (GOQ)

Date	Dielectric Strength	% Power Factor @ 25 C	Acid Number	Interfacial Tension	Water Content	Color
18 Sep 15	24	0.050	0.030	29	2	1.5
06 Oct 16	27	0.074	0.033	30	6	2.5
22 Sep 17	26	0.067	0.040	31	6	2.0
25 Oct 18	49	0.046	0.034	31	7	2.0
16 Oct 19	45	0.048	0.029	30	5	2.0
Good	30	1.0	0.1	30	30	<=1.5
Fair	**25**	**1.5**	**0.15**	**22**	**35**	**>1.5-2.5**
Poor	**22**	**2.0**	**0.33**	**14**	**45**	**>2.5**

Overview

This 48 year old transformer has aged well and presently there are no indications of impending doom. Notwithstanding, the long term service has certainly taken its toll on the internal insulation structures. It is always better to remove a piece of equipment from service in a planned and controlled way versus responding to an emergency outage.

I recommend that this transformer be sampled on a 6 month cycle for DGA and GOQ to monitor the trends.

I suggest you consider replacing this transformer within 5 years.

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van Kooy Transformer Consulting Services Inc.

West Royalty X4	42	Westinghouse	153705	1976

Results from oil samples taken - Dissolved Gases in Oil Analysis (DGA) in ppm

DATE	Hydrogen	Methane	Ethylene	Ethane	Acetylene	Carbon Monoxide	Carbon Dioxide	Oxygen	Nitrogen
	H_2	CH_4	C_2H_4	C_2H_6	C_2H_2	CO	CO_2	O	N
18 Sep 15	27	9	6	1	0	553	3601	21044	86902
06 Oct 16	16	4	5	1	0	330	2624	21637	61809
15 Sep 17	17	4	4	1	0	346	2386	22373	67289
30 Oct 18	21	4	4	1	0	379	2474	21923	68711
16 Oct 19	23	3	3	1	0	356	2497	22378	66791
Thresholds									
IEEE	100	120	50	65	2	350	2500	na	na
vKTCS Inc.*	100	120	50	65	3	850	3750	na	na

*based on experience with transformers of similar size, voltage class, age and application

Results from oil samples taken – General Oil Quality (GOQ)

Date	Dielectric Strength	% Power Factor @ 25 C	Acid Number	Interfacial Tension	Water Content	Color
18 Sep 15	40	0.060	0.051	27	9	1.5
06 Oct 16	32	0.078	0.060	24	6	3.0
15 Sep 17	27	0.069	0.061	25	9	3.0
30 Oct 18	59	0.078	0.059	25	9	3.0
16 Oct 19	70	0.074	0.070	25	11	3.0
Good	30	1.0	0.1	30	30	<=1.5
Fair	25	1.5	0.15	22	35	>1.5-2.5
Poor	22	2.0	0.33	14	45	>2.5

Overview

From the oil test data, this 44 year old transformer has seen some heavier loading in the past. The 2015 DGA shows the levels of Carbon gases approaching the Threshold but subsequent years these levels decrease. The GOQ Color at 3.0 is indicates a darkened oil indicative of overheating and insulation degradation.

I recommend that this transformer be sampled on a 6 month cycle for DGA and GOQ to monitor the trends.

I suggest you consider replacing this transformer within 5 years. Please note that the PCB level is > 2 so special disposal is required.