

All our energy.  
All the time.



May 8, 2026



Ms. Cheryl Bradley  
Island Regulatory & Appeals Commission  
PO Box 577  
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

**UE20606 – ECAM Rate Adjustment Application  
Response to Interrogatories from Commission Staff**

Please find attached the Company's responses to interrogatories from Commission Staff with respect to the Company's Application for an Order to Approve an ECAM Rate Adjustment filed with the Commission on December 11, 2025.

An electronic copy will follow.

If you have any questions or concerns, do not hesitate to contact the undersigned at 902-629-3641.

Yours truly,

MARITIME ELECTRIC

A handwritten signature in blue ink that reads "Gloria Crockett".

Gloria Crockett, CPA, CA  
Director, Regulatory & Financial Planning

GCC18  
Enclosure



# **INTERROGATORIES**

**Responses to Interrogatories  
of  
Commission Staff**

**ECAM Rate Adjustment Application  
(UE20606)**

**Submitted May 8, 2026**

**IR-1 Background**

There are a number of tables and costs that have potential overlap of information. It was not always clear in the Application in which area certain costs were included. Provide a spreadsheet, broken down monthly, that details the units of measurement, unit costs, and total costs of each of the components included in the ECAM calculation for the 2023-2025 period.

***Response:***

The fundamental purpose of the Energy Cost Adjustment Mechanism (“ECAM”) is to capture prudently incurred energy supply costs over and above those costs that are recovered from customers through basic rates over the General Rate Application (“GRA”) period. The purpose of Table 5 is to provide the Commission with a breakdown of those costs deferred to ECAM from 2023 to 2025 by the underlying cost driver.

The amounts presented in Table 5 can be categorized in two primary ways. The first eleven items in Table 5 are amounts deferred to ECAM due to volume and/or price variances within the original forecast of energy needed to meet customer sales forecast as provided in the GRA. The last amount in Table 5 reflects the costs deferred to/from ECAM to meet customer sales over and above that which was forecast in the GRA.

A spreadsheet, broken down monthly, detailing the units of measurement, unit costs, and total costs of each of the components included in the ECAM calculation in Table 5 of the Application is provided for each of the years 2023, 2024 and 2025. These spreadsheets are attached in electronic format hereto as IR-1 CONFIDENTIAL Attachment 1 2023 Costs Deferred to ECAM, IR-1 CONFIDENTIAL Attachment 2 2024 Costs Deferred to ECAM and IR-1 CONFIDENTIAL Attachment 3 2025 Costs Deferred to ECAM.

**IR-2 Section 5.1 Introduction:**

Page 13, footnote 8 of the Application indicates the actual values were used for January to September 2025, and forecast values were used for October to December 2025.

- a. Provide a comparison of forecast versus actual results for October to December, including both:
  - i. The forecast values used in the Application; and
  - ii. The corresponding actual results.
- b. Quantify and explain any material variances between forecast and actual results.
- c. Confirm whether any variances would have a material impact on the ECAM balance.

**Response:**

- a. A reconciliation of the actual changes in the ECAM balance compared to the forecast provided in the application for each month (October, November and December 2025) is provided in IR-2 Attachment 1 to this response. Table 1 is a summary of this reconciliation.

<b>TABLE 1 Summary of ECAM Activity October 1 to December 31, 2025</b>		
ECAM Balance, September 30, 2025	A	\$ 26,257,657
GRA Forecast Energy Supply Costs Deferred	B	7,510,434
Variance to Actual Energy Costs Deferred	C	(270,392)
Subtotal – Actual Energy Costs Deferred to ECAM	D=B+C	7,240,042
GRA Forecast ECAM Collections from Customers	E	(1,787,046)
Variance to Actual ECAM Collections from Customers <sup>1</sup>	F	(402)
Subtotal - Actual ECAM Collections from Customers	G=E+F	(1,787,448)
<b>Actual ECAM Balance, December 31, 2025</b>	<b>H=A+D+G</b>	<b>\$ 31,710,251</b>

- b. As shown IR-2 Attachment 1, actual energy purchase costs were \$293,514 higher than forecast in the application. Table 2 is a summary of the variances by the type of energy purchased.

<sup>1</sup> Energy sales were 84,686 kWh higher than forecast resulting in collections from customers that were \$402 (84,686 kWh x \$0.00475/kWh) higher than forecast over the three-month period.

<b>TABLE 2</b>			
<b>Energy Costs</b>			
<b>October 1 to December 31, 2025</b>			
	<b>Forecast</b>	<b>Actual</b>	<b>Variance</b>
Point Lepreau Replacement Energy	\$ 5,910,960	\$ 6,294,750	\$ 383,790
Point Lepreau O&M	6,775,822	6,426,110	(349,712)
Wind Energy Costs	5,722,398	8,033,377	2,310,979
Net Metering	1,475,049	1,251,989	(223,060)
EPA Energy Purchase Costs	26,703,610	25,637,940	(1,065,670)
Capacity	154,965	-	(154,965)
Net Imbalance	(2,296,800)	(2,762,379)	(465,579)
Interconnection Costs	1,093,330	1,129,732	36,402
Generation Fuel	480,113	301,442	(178,671)
<b>TOTAL</b>	<b>\$ 46,019,447</b>	<b>\$ 46,312,961</b>	<b>\$ 293,514</b>

The increase in energy costs in Table 2 were incurred to procure 5,866,687 kilowatt hours (“kWh”) of additional energy to meet customer needs. From October to December 2025, an additional \$563,906 of energy costs were charged to the Company’s energy expenses in 2025 and recovered through customer rates.<sup>2</sup> Actual costs deferred to ECAM from October to December were \$270,392 (\$293,514 – \$563,906) lower than forecast in the Application as shown in Line B of Table 1.

Wind costs were \$2.3 million higher than forecast primarily due to production from the new Eastern Kings Wind Farm Phase II testing that was not forecast in the application. With more energy than expected being supplied by wind, less energy was purchased through the EPA resulting in the under-forecast variance of \$1.1 million in that category.

- c. The total variance of the actual ECAM balance compared to the forecast balance in the Application is \$(270,794). This variance is less than 1 per cent of the actual ECAM balance on December 31, 2025, and is not a material variance.

<sup>2</sup> 5,866,687 kWh of purchased and produced energy multiplied by the ECAM base rate of \$0.09612 per kWh = \$563,906 energy costs expensed by the Company in 2025.

**IR-3 Section 5.2 Point Lepreau Costs**

Provide a copy of the Point Lepreau Participation Agreement.

***Response:***

The Point Lepreau Participation Agreement is provided in IR-3 - CONFIDENTIAL Attachment 1.

**IR-4 Section 5.2 Point Lepreau Costs**

Provide details on the work that was completed at Point Lepreau during the 2023-2025 outages. If Maritime Electric has information on additional breakdown or explanation of capital and depreciation charges, please provide.

**Response:**

Table 3 provides details of the work that was completed during the 2023 – 2025 outages at the Point Lepreau Nuclear Generating Station (“Point Lepreau”).

<b>TABLE 3</b>	
<b>Details of Work Completed During Outages at Point Lepreau from 2023 - 2025</b>	
<b>Date</b>	<b>Description of Work Completed</b>
December 13, 2022 – January 18, 2023	Continuation of a 2022 unplanned outage. Point Lepreau tripped offline due to an electrical fault. During the shutdown, a small, heavy water leak was discovered and repaired. The unit was returned to service on January 18, 2023.
April 15, 2023 – May 25, 2023	Planned outage. For further details, see IR-4 Attachment 1 - Lepreau Outage 2023: Post-Outage Report.
November 15, 2023 – November 21, 2023	This unplanned outage was a proactive shutdown to replace a delayed neutron monitoring coil, following Point Lepreau’s Operational Decision Making Process. <sup>3</sup> The coil replacement required an outage due to system requirements and access restrictions.
April 6, 2024 – December 11, 2024	For details on this planned outage, see IR-4 Attachment 2 - Lepreau Outage 2024: Post-Outage Report.
March 17, 2025 – March 25, 2025	This unplanned outage occurred when a breaker for a concrete cooling fan tripped while the facility was operating at 100 per cent of rated power and the standby fan started, but the outlet damper did not open. This caused a loss of cooling to the east side of the reactor. The control room staff proactively took the unit offline until the issue was resolved, and the unit returned to service within a week.
July 14, 2025 – November 29, 2025	This was a planned outage (140 days) to facilitate a full generator stator rewind, which included the full replacement of all stator bars to address a manufacturing quality issue from the 2008 Point Lepreau Life Extension Project that was identified through complex troubleshooting during the 2024 planned outage. The final post outage report has not been finalized by NB Power. However, 90% of the potential scope of work was completed including: <ul style="list-style-type: none"> <li>- Generator stator bar replacement (full stator rewind);</li> <li>- Primary heat transport motor – two of four motor replacements completed;</li> <li>- Primary heat transport seal replacements;</li> <li>- Last two remaining rocky mountain fitting replacements;</li> <li>- Liquid zone controls pump replacement – third of three replaced;</li> </ul>

3 The Point Lepreau operational decision-making process is a highly regulated, safety-first framework overseen by NB Power and the Canadian Nuclear Safety Commission (CNSC). It integrates rigorous safety standards, Probabilistic Safety Assessments (PSA), and environmental monitoring to ensure safe base-load electricity production. Key decisions involve CANDU reactor operations, maintenance, emergency preparedness, and long-term fuel management.

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	<ul style="list-style-type: none"><li>- Shutdown safety system 2 maintenance;</li><li>- Main steam safety valve overhaul;</li><li>- Electrical class III maintenance and motor control centre replacement;</li><li>- Fire zone 34D upgrades; and,</li><li>- Other maintenance takes to improve overall equipment and plant reliability.</li></ul>
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The following explanations describe the accounting treatment of capital and depreciation of major planned outages at the Point Lepreau.

***Capital and Depreciation Charges***

**Plant assets**

Under International Financial Reporting Standards (“IFRS”), International Accounting Standard (“IAS”) 16 Property, Plant and Equipment, depreciation expense is recognized to systematically allocate the depreciable amount of property, plant and equipment over the periods in which economic benefits are consumed. For the majority of Point Lepreau’s generation plant assets, depreciation is based on an overall planned operating life to March 2041. Where specific plant components are expected to provide economic benefits over a shorter period than the underlying plant, those components are depreciated over their shorter estimated useful lives, consistent with the pattern of benefit consumption.

**Major planned outages**

Separately, costs associated with major planned outages are capitalized and depreciated over the period to the next relevant planned major outage. This treatment reflects that the benefits of outage activities are consumed through operation until the subsequent outage, rather than over the remaining life of the underlying plant and is consistent with IFRS guidance on accounting for major inspections and overhauls.

**IR-5 Section 5.2 Point Lepreau Costs**

How was the capacity that is normally provided by Point Lepreau procured during the 2023-2024 Point Lepreau outages? Is the cost of the capacity reflected in this Application, and if so, where?

***Response:***

Similar to Maritime Electric's own generation facilities, outages at Point Lepreau were scheduled during months when regional loads are lower and replacement capacity was not required to be purchased by the Company. No additional capacity charges were deferred to ECAM or included in this application because of outages at Point Lepreau.

**IR-6 Section 5.2 Point Lepreau Costs**

Provide summary details of correspondence, meetings, and meeting note summaries if available, on interactions between MECL and NB Power representatives regarding the outage details, schedules, and procurement of replacement energy for the 2023-2025 period.

**Response:**

NB Power and Maritime Electric maintain a critical, long-term supplier-customer relationship that has served electricity customers in Prince Edward Island and New Brunswick well. NB Power provides a significant portion of the Company’s electricity needs, a portion of which is supplied by the Company’s participation entitlement to generation from Point Lepreau.

Table 4 is a summary of virtual and in-person meetings on Point Lepreau outages.

<b>TABLE 4 Summary of PLNGS Outage Meetings</b>	
<b>Meeting Date</b>	<b>Meeting Summary</b>
June 26, 2024	Virtual meeting between Point Lepreau Operating Committee members from NB Power and Maritime Electric for an update on the status of the outage.
August 21, 2024	Virtual meeting between Point Lepreau Operating Committee members from NB Power and Maritime Electric for an update on the status of the outage.
April 7, 2025	Virtual meeting between Point Lepreau Operating Committee members from NB Power and Maritime Electric for information on the recent unplanned outage in March 2025 as well as status of planning for outage which was to begin in July 2025.
September 9, 2025	Virtual meeting between Point Lepreau Operating Committee members from NB Power and Maritime Electric for an update on the status of the outage.
October 3, 2025	Site visit to Point Lepreau by three employees of Maritime Electric, two of whom are Point Lepreau Operating Committee members, to tour the plant, discuss progress on the 2025 Planned Outage, meet the new Chief Nuclear Officer and Site Vice President (Steven Bagshaw), and address items including 2026 outage planning, status of insurance claim for required stator rewind, and update on NB Power’s small modular reactor program.
December 10, 2025	Virtual meeting between Point Lepreau Operating Committee members from NB Power and Maritime Electric for an update on the status of the outage.

Table 5 is a summary of email correspondence between NB Power and Maritime Electric regarding Point Lepreau outages from 2023 to 2025 including outage details, scheduling, and the procurement of replacement energy. In instances where multiple emails were exchanged on the same subject, only a single representative entry is included in the summary below.

<b>TABLE 5</b> <b>Summary of Email Correspondence with NB Power</b>		
<b>Date</b>	<b>Subject Matter</b>	<b>Summary</b>
January 3, 2023	Point Lepreau Details and Projected Return-to-Service	NB Energy Marketing provided indicative pricing for Point Lepreau replacement energy from January 6 through 21, 2023, as well as an update that Point Lepreau was expected to return-to-service by January 21, 2023.
November 15, 2023	Station Update	Provided an operational update on Point Lepreau, advising of a planned outage starting November 15, 2023, expected to last less than two weeks to replace delayed neutron monitoring equipment. Explained the operational rationale, outage controls, and indicated additional preparatory work for the upcoming spring 2024 outage.
May 29, 2024	2024-05-29 Outage Accountability Package	NB Power circulated the weekly Outage Accountability Package via SharePoint, providing outage progress and work management information for the 2024 outage.
May 30, 2024	2024-05-30 Outage Accountability Package	Another distribution of the Outage Accountability Package, continuing regular reporting on outage execution and status during the planned outage.
June 6, 2024	2024-06-06 Outage Accountability Package	NB Power shared the Outage Accountability Package link, supporting ongoing oversight of outage performance and maintenance progress.
June 14, 2024	2024-06-14 Outage Accountability Package	NB Power advised that the Outage Accountability Meeting was canceled, but the accountability package was distributed for information purposes.
June 17, 2024	Lepreau Capacity Table for May 2024 and YTD	Provided Point Lepreau generation, capacity factors, and Maritime Electric entitlement data through May 2024, noting the station remained offline and was tracking approximately 13 days beyond the original 70-day outage schedule at that time.
June 26, 2024	2024-06-19 Outage Accountability Package	Discussed outage restart challenges and scheduling, including adjusting a Teams meeting and requesting confirmation on delayed return-to-service timing.
July 17, 2024	2024-2028 Business Plan	Referenced planned maintenance outage durations from prior planning documents, including a 70-day planned outage for 2024.
November 18, 2024 (forecast update)	2024 Lepreau Replacement Energy Comparison	Provided a detailed forecast of replacement energy costs for the 2024 planned outage, including assumed replacement prices in the, netted against avoided O&M and fuel costs to determine the incremental revenue requirement impact.
November 18, 2024	Lepreau update on replacement energy	Sent a draft cost and replacement energy summary, reflecting the significant extension of the 2024 outage and revised replacement energy cost assumptions through year-end.
July 2, 2025	Replacement Energy for July 14 to December 1 outage	Discussed anticipated pricing for replacement energy during the outage period, noting that NB Power expected the replacement energy price to be higher than the EPA price due to prevailing market conditions.
July 15, 2025	Lepreau Contingency	Referenced follow-up discussions on addressing Lepreau Replacement Energy as part of a contingency plan, including

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from Commission Staff – April 2026**

**Maritime Electric**

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		potential third-party generation if the planned outage extended beyond December 1, 2025.
September 8, 2025	Lepreau Replacement Energy	Confirmed discussions with NB Energy Marketing indicating that if replacement energy is not fully locked-in, portions would settle at Final Hourly Marginal Cost (“FHMC”), exposing Maritime Electric customers to very high market prices during peak New England market conditions reinforcing the cost risk of floating replacement energy.
October 16, 2025	Lepreau Capacity Table for September 2025 and YTD	Transmitted the September 2025 capacity table, confirming Point Lepreau had been offline since July 14, 2025, with a planned return to service on December 1, 2025.
October 24, 2025	Nuclear support partnership between New Brunswick and Ontario	Circulated a Government of New Brunswick news release outlining a nuclear support partnership between New Brunswick Power and Ontario Power Generation, shared for executive-level awareness.
November 04, 2025	Lepreau - Updated Plant Life Forecasts	Provided an updated plant life forecast workbook, noting that long-term outage plans and end-of-life assumptions are still under development and may change outer-year projections.
November 13, 2025	Lepreau Capacity Table for October 2025 and YTD	Updated October 2025 capacity data and reiterated the ongoing 140-day outage with an expected December 1 return-to-service date.
November 21, 2025	Lepreau Outage Update	Summarized a meeting with NB Power on the 2025 outage, reporting positive progress on stator repairs, rotor inspections, and plans to replace retaining rings during the 2026 outage.
November 27, 2025	Point Lepreau Replacement Energy – 2023 Actuals	Summarized actual Point Lepreau replacement energy costs incurred in 2023, identifying \$4.77 million in replacement energy purchased to offset outages, with costs deferred to ECAM for recovery.
November 27, 2025	Point Lepreau Replacement Energy – 2024 Actuals	Detailed actual Point Lepreau replacement energy costs incurred during 2024, showing \$12.94 million in replacement energy purchased during outage periods, with costs tracked separately from EPA and deferred to ECAM.
November 28, 2025	RE: Lepreau Outage Update	Discussed short-term scheduling and tagging arrangements as Point Lepreau prepared to ramp up, noting flexibility depending on NB Power’s final direction.
December 2, 2025	Lepreau Outage Update	Exchanged status updates on generator disassembly and investigation of equipment issues, with expectations that more definitive information will be provided.
December 5, 2025	Re: Equipment failure thwarts N.B. power plant from resuming production	Confirmed interest in receiving further updates and coordinates a meeting time to discuss ongoing equipment issues.
December 10, 2025	Lepreau Update	Provided an executive briefing on the replacement of the #10 bearing, reactor status, and anticipated resynchronization to the grid within days.

**Maritime Electric**

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December 11, 2025	Lepreau Capacity Table for November 2025 and YTD	Reported November capacity data while confirming Point Lepreau remained offline and was expected to return to service imminently.
April 2, 2026	Lepreau Replacement Energy	Confirmed how outage days are split between EPA-priced energy and replacement-priced energy and discussed how extended outage duration affects the number of days priced as replacement energy.

In addition to the meetings and emails described in Tables 4 and 5 above, there were numerous phone calls between Maritime Electric and NB Power as needed on the status of outages and related matters. Although these phone calls are not documented, they provide continuous important updates during outages at Point Lepreau.

**IR-7 Section 5.2 Point Lepreau Costs**

Has Maritime Electric received a detailed outage and maintenance schedule for the 2026-2030 period or partial period there of? If yes, please provide a copy.

- a. Does Maritime Electric believe that Point Lepreau will remain an economic source of energy and capacity?
- b. Has Maritime Electric entertained other energy and capacity supplies to replace the Point Lepreau source?

***Response:***

Please see the “2026 Outage Planning Report”, provided herein as IR-7 Attachment 1, for the details on the planned outage that started on April 10, 2026. The 2026 outage is currently planned for 84 execution days, plus 34 days of contingency, for a total outage duration of 119 days.

In addition, the following outages are planned for 2027 to 2030:

2027	Planned Outage of 35 days;
2028	Planned Outage of 72 days;
2029	No outage is planned; and
2030	Planned Outage of 72 days.

Specific details are not available from NB Power for the outages planned from 2027 to 2030 at this time. Plans for Point Lepreau outages are developed on a continuous basis to address ongoing maintenance issues and stabilize the facility’s performance over its remaining life.

- a. Based on the planned outage periods described above, forecast annual energy production, and Maritime Electric’s projected costs for its participation share, the Company expects Point Lepreau to remain an economic source of both energy and capacity.

Maritime Electric forecasts that continued participation in Point Lepreau (i.e., purchase of energy and firm capacity) will be comparable on a total cost basis to the next lowest cost available alternative. Based on this assessment, the Company expects Point Lepreau to remain an economic source of energy and capacity over the period and beyond.

Although Point Lepreau has experienced higher-than-expected outage hours in recent years, the facility has been available during peak winter periods (e.g., January and February), providing Maritime Electric with critical firm capacity to meet peak demand. However, while above noted economic assessment assumed that replacement energy and capacity could be procured from New Brunswick Energy and Marketing (“NBEM”), the availability and pricing of additional firm capacity from NBEM remains uncertain.<sup>4</sup>

- b. Maritime Electric and NB Power are parties to a Point Lepreau Unit Participation Agreement dated June 26, 1990, in relation to Point Lepreau. This Agreement was extended by the parties on March 29, 1994, and further extended on September 29, 1995, until the end of the unit’s service life, which is currently estimated to extend to 2041.

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<sup>4</sup> NB Power has publicly indicated that it is expected to be capacity deficient by approximately 2028, forming the basis for the proposed RIGS project.

**Maritime Electric**

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Therefore, Maritime Electric has not considered a possible replacement source of supply for Point Lepreau beyond 2041.

The Agreement requires Maritime Electric to pay its proportionate share of Point Lepreau's operating and maintenance costs for the life of the Agreement.

Pursuant to ss.48.1(b) of the *Electric Power Act*, Maritime Electric is entitled to recover from ratepayers the annual operating and maintenance costs that it pays to NB Power pursuant to this Agreement.

As a result, Maritime Electric is contractually required to pay its proportionate share of Point Lepreau's operating and maintenance costs and statutorily entitled to recover these costs from ratepayers.

**IR-8 Section 5.3 – Wind Energy Costs and Section 5.5 EPA Ratchet Costs**

As per the Application, page 18, lines 19-22 state "As a result of the delays and maintenance issues, the Company was required to purchase additional energy through the EPA, often at a premium, to replace the energy the new wind farms were expected to supply."

- a. Provide a further breakdown of Table 8, separating the costs attributable to maintenance issues from the costs attributable to wind farm delays.
- b. Is there any provision in the energy purchase agreement with the PEI Energy Corporation that may allow Maritime Electric to recover some or all of these costs? If yes, please provide full details. If no, please explain why not.

**Response:**

The Company would like to clarify that amounts described as “Wind-Related Energy Costs” is better described as “Renewable Energy Costs” as the amounts described in Table 5, Section 5.3 also include variances attributed to the Slemon Park Microgrid Solar as detailed in the remainder of this response.

- a. The 2023 net variance of \$(556,885) in Table 8 of the application is broken down in Table 6.

<b>TABLE 6 2023 Renewable Energy Costs from Table 8 of the Application</b>		
<b>Renewable Resource</b>	<b>Annual Production Variance Below GRA Forecast</b>	<b>Allocation of Decrease from GRA (rounded)</b>
Hermanville	60%	\$ (332,000)
Slemon Park Microgrid Solar	17%	(97,000)
Other Commercial Renewables	23%	(128,000)
<b>TOTAL</b>	<b>100%</b>	<b>\$ (557,000)</b>

The Hermanville variance was primarily due to maintenance issues. A small portion was due to variances in forecasts associated with wind variability and differences between forecasts and actual results. The Company does not have sufficient data to provide a further breakdown of this variance.

When the GRA was filed, the Slemon Park Microgrid Solar was forecast to be in-service on January 1, 2023. However, the actual in-service date was January, 2025. This accounted for 17 per cent of the variance in renewable production below the GRA forecast in 2023.

The remaining commercial renewables variance was due to variances between the actual and GRA forecast production associated with wind variability and maintenance outages.

The 2024 net variance of \$1,687,736 in Table 8 of the application is broken down in Table 7.

TABLE 7 2024 Renewable Energy Costs from Table 8 of the Application		
Renewable Resource	Portion of Production Variance from GRA Forecast	Allocation of Increase from GRA (rounded)
Hermanville	14%	\$ 240,000
Easter Kings Phase II	74%	1,245,000
Other Commercial Renewables	12%	203,000
<b>TOTAL</b>	<b>100%</b>	<b>\$ 1,688,000</b>

The Hermanville variance was primarily due to maintenance issues. A portion was also due to variances in forecasts associated with wind variability and differences between forecasts and actual results. The Company does not have sufficient data to provide a further breakdown of this variance.

When the GRA was filed, the Eastern Kings Phase II wind farm was forecast to be in service on January 1, 2024. However, the actual in-service date was January 2026. This accounted for 74 per cent of the variance in renewable production below the GRA forecast in 2024.

The remaining commercial renewables variance was due to variances between the actual and GRA forecast production of the remaining commercial renewable resources due to variability of wind and solar forecasts and outages for maintenance.

The 2025 net variance of \$5,291,778 in Table 8 of the application is broken down in Table 8.

TABLE 8 2025 Renewable Energy Costs from Table 8 of the Application		
Renewable Resource	Portion of Production Variance from GRA Forecast	Allocation of Increase (Decrease) from GRA (rounded)
Hermanville	4%	\$ 233,000
Easter Kings Phase II	48%	2,537,000
New Wind Facility	50%	2,646,000
Other Commercial Renewables	-2%	(124,000)
<b>TOTAL</b>	<b>100%</b>	<b>\$ 5,292,000</b>

The Hermanville variance was primarily due to maintenance issues. A small portion was due to variances in forecasts associated with wind variability and differences between forecasts and actual results. The Company does not have sufficient data to provide a further breakdown of this variance.

When the GRA was filed, the Eastern Kings Phase II wind farm was forecast to be in service on January 1, 2024. However, the actual in-service date was January, 2026. This accounted for 48 per cent of the variance in renewable production below the GRA forecast in 2025.

When the GRA was filed, a second new wind farm was forecast to be in-service on January 1, 2025. However, this facility has not been constructed. This accounted for 50 per cent of the variance in renewable production below the GRA forecast in 2025.

The remaining other renewables variance is due to variances between the actual and GRA forecast production of the remaining commercial renewable resources due to variability of wind/solar forecasts and outages for maintenance. In 2025, this resulted in overall production that was higher than forecast in the GRA.

- b. There is a provision in the power purchase agreement (“PPA”) with the PEI Energy Corporation (“PEIEC”) for the Hermanville Wind Farm that addresses recovery of replacement energy costs. Specifically, if Maritime Electric must purchase replacement energy that is more expensive than wind energy, it may recover the incremental replacement energy costs. Conversely, if replacement energy is less expensive than wind energy, the cost difference is credited to PEIEC. These credits have no immediate monetary value but can be carried forward and used in future years if more expensive replacement energy is required. Hence, the savings from Hermanville in 2023 could be used to offset the increased costs in 2024 and 2025.

However, based on the wording of the PPA and the NB Power EPA, the impact of ratchet pricing is difficult to categorize as a "replacement energy cost", limiting Maritime Electric's ability to recover ratchet-related costs under this provision.

Additionally, the PPA includes a force majeure clause covering "weather conditions that are extreme for the local area," which relieves both parties from liability for performance under the agreement in cases where performance is affected by exceptional weather. Since at least some of the production issues at Hermanville were attributed to extreme high winds, this clause would protect the PEIEC from the costs incurred since 2023.<sup>5</sup>

Since the Eastern Kings Phase II wind farm was commissioned earlier this year, the PPA is still being negotiated and the Company is including in it as much protection for customers for production variances as possible. However, there is no legal grounds for the Company to recover the above noted costs incurred in 2024 and 2025 from the PEIEC or the Province as a PPA cannot be put in place until the facility is in service. This is also the case for the new wind facility that was expected to be in service in 2025.

The Company has been regularly advising the PEIEC of the impact of the delays in renewable in-service dates and lower production at existing facilities on the energy costs and customer electricity rates. It has been the PEIEC's position that these costs should be deferred to ECAM and recovered from customers as directed by the Commission.

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5 <https://www.princeedwardisland.ca/en/news/hermanville-wind-farm-repair-update>

**IR-9 Section 5.3 – Wind Energy Costs and Section 5.5 EPA Ratchet Costs**

Please confirm whether Maritime Electric has sought recovery of the additional energy purchase costs incurred under the EPA as a result of delays in generation expected from new wind farms from the Provincial Government or the PEI Energy Corporation. If so, provide full particulars, including any discussions, correspondence, or formal requests made. If not, please explain why not.

***Response:***

See the response to IR-8 b). above. The PEIEC represented the interests of the Province of PEI during the negotiated extension of the EPA between Maritime Electric and NBEM in 2020. The EPA extension was negotiated based on assumptions including the forecast growth in energy sales to customers, generation from existing wind farms, the expected in-service date of new proposed wind farms, and the addition of the Slemon Park solar farm. The energy production from the existing wind farms and the expected in-service dates for the two new proposed wind farms and the Slemon Park solar farm were provided by the PEIEC. Therefore, the Province of PEI and the PEIEC are fully aware of the commitments they made regarding the supply of renewable energy.

The Company has been advising the PEIEC of the impact of the delays in renewable in-service dates and lower production at existing facilities on the energy costs and customer electricity rates since the ratchet was first triggered in March 2022. It has been the PEIEC's position that these costs should be deferred to ECAM and recovered from customers as directed by the Commission.

**IR-10 Section 5.3 – Wind Energy Costs and Section 5.5 EPA Ratchet Costs**

As per the Application, page 22, lines 2-5 state “Such assumptions include the forecast growth in energy sales to customers, lower generation from existing wind farms, the expected in-service date of proposed new wind farms, and the addition of the Slemon Park solar micro grid.”

And per page 23, lines 1-4 state "In 2025 ... the majority of the wind replacement costs associated with the delayed 40MW wind farm, which was expected to be in-service in 2024, had to be purchased at a premium outside of the EPA. Therefore, the majority of the incremental energy purchases were excluded from the ratchet calculation."

- a. Break out, for the period 2023-2025, how the annual purchase costs of replacement wind and Slemon Park solar energy can be attributed to GRA Forecast, Ratchet, and Outside EPA purchases.
- i. Quantify the impact on energy purchase costs that differences between forecast and actual load impact had.

**Response:**

The purpose of Section 5.3 of the application is to describe and quantify the variance in the actual cost of renewable energy compared to the forecast in the GRA, which was deferred to ECAM. As discussed in the response to IR-8, actual energy from renewable sources was below what was forecast in the GRA. The related “replacement energy” was purchased from NBEM at the EPA purchase price in 2023. In 2024 and 2025, the Company was required to source a significant portion of the replacement energy from NBEM at a premium cost (i.e., purchased outside of the EPA) with a smaller portion of the replacement energy purchased at the EPA price in effect for the period. Table 9 provides a further breakdown of the GRA forecast of renewable energy costs compared to actual renewable energy costs and replacement energy costs for each year.

TABLE 9					
Year	GRA Forecast Wind Cost	Actual Renewable Energy Cost	Renewable Energy Replacement Purchased @ Premium	Renewable Energy Replacement Purchased @ EPA Prices	(Decrease) Increase over GRA
2023	\$ 24,760,131	\$ 17,005,155	\$ -	\$ 7,198,091	\$ (556,886)
2024	34,881,989	21,904,285	11,609,178	3,056,262	1,687,737
2025	47,866,428	22,707,765	24,754,611	5,695,830	5,291,779

The EPA ratchet costs, described in Section 5.5 and detailed in Table 10 of the application, is an EPA price variance applied to all energy purchased through the EPA when it is triggered, and is therefore not included in Table 9 above. The ratchet is triggered when the actual energy required from March 1 to February 28 of the prior year is more than 6 per cent lower or 8 per cent higher than the forecast energy requirement for that period in the EPA. The EPA was negotiated based on the Company’s forecast energy requirement prepared in July, 2020.

The GRA prepared in 2022 forecast that the ratchet would be triggered to varying degrees over the GRA period. The line from page 22 referenced in the question was a general description of

the factors that can contribute to the actual EPA ratchet varying from the EPA price assumed in the GRA.

Table 10 is a summary of the actual ratchet costs that can be attributed to delays in the in-service date of the Eastern Kings Phase II and to forecast variability and maintenance issues at existing wind farms. Energy forecasts for the 10 MW solar micro grid was not included in the Company’s EPA forecast and so delays in its in-service date did not contribute to the ratchet costs.

<b>TABLE 10 Allocation of Actual Ratchet Costs</b>			
	<b>2023</b>	<b>2024</b>	<b>2025</b>
Eastern Kings Phase II Delay	\$ 1,399,386	\$ 1,140,686	\$ 236,108
Other Existing Wind Facilities	794,333	1,053,623	239,014
<b>Total Actual Ratchet Costs Incurred</b>	<b>2,193,719</b>	<b>2,194,309</b>	<b>475,122</b>

Although there were variances in energy sales and other energy supply forecasts from the EPA forecast, those variances alone were not sufficient to trigger the ratchet clause in 2023, 2024 or 2025.

Detailed calculations of the renewable energy variances and the ratchet costs deferred to ECAM for each of 2023, 2024 and 2025 are provided in the IR-1 Attachments 1 through 3 to the response to IR-1.

- i The impact of the difference between forecast and actual energy sales on the overall energy purchase costs deferred to ECAM is discussed in Section 5.12 of the application and summarized therein in Table 18. As discussed in Section 5.12, increases in energy sales above forecast impact the ECAM in two ways. First, the Company must purchase or generate sufficient energy to meet the increase in customer sales. Second, the basic energy charge included in customer rates reflects a forecast of annual energy supply costs based on the Base Rate Cost, as defined in the ECAM and approved by the Commission as described in Section 5.1. For each additional kWh purchased to meet customer sales, the amount collected from customers in basic rates is offset to ECAM by multiplying the additional kWh purchased by the ECAM base rate approved by the Commission for the period. Table 11 is a summary of the variances related to customer sales by year deferred to ECAM.

<b>TABLE 11 Variances Related to Customer Sales</b>			
<b>Description</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>
Additional Energy Purchases to Meet Customer Sales	\$ 6,668,090	\$ 8,857,351	\$ 11,906,624
Additional Energy Recovered from Customers in Basic Rates	(8,036,641)	(10,953,004)	(15,153,739)
<b>ECAM Adjustments Related to Variances in Energy Sales</b>	<b>\$ (1,368,551)</b>	<b>\$ (2,095,654)</b>	<b>\$ (3,247,116)</b>

**IR-11 Section 5.4 – Net Metering Costs**

The Application indicates that net metering costs have increased significantly from 2023 to 2025.

- a. Provide a clear description of how the net metering program operates, including how participating customers are credited for energy exported to the grid.
- b. The Application indicates that net metering customers are credited at retail rates for energy exported to the grid, while Maritime Electric avoids only the cost of purchasing energy from other sources (i.e., the avoided cost). Please quantify the difference between the retail rate paid to net metering customers and the avoided cost of energy. Explain how this difference contributes to the net metering costs included in the ECAM balance.
- c. Explain how net metering costs are recovered, including which customers bear these costs.
- d. Explain whether customers who do not participate in net metering pay any portion of these costs. If so, please explain how and provide an estimate of the impact.
- e. Provide the number of net metering customers and total installed capacity for each of 2023, 2024, and 2025, and explain the primary drivers behind the increase in net metering costs over this period.

**Response:**

- a. The net metering program follows the requirements set out in the *Renewable Energy Act* (the “Act”). The Act requires Maritime Electric to enter into net-metering system agreements with customers who install behind-the-meter renewable generation equipment (e.g., rooftop photo-voltaic solar) at their premises. The Act refers to these customers as “small capacity renewable energy generators”.

As part of implementing net metering, the utility installs a second kWh meter at the customer’s premises. One meter (the consumption meter) measures electricity delivered to the customer by the utility. The second meter (the reverse flow meter) measures electricity delivered to the utility by the customer.

When a net metering customer generates electricity, the electricity is first used to supply some or all of the customer’s load in real time. To the extent that the customer’s generation is less than their load in real time, the shortfall is supplied by the utility and measured by the consumption meter. During periods when the customer generates more electricity than is used by their load in real time, the surplus electricity is exported to the Maritime Electric grid (i.e., reverse flow) and measured by the reverse flow meter.

In calculating the customer’s monthly bill, the reverse flow energy recorded during the month is applied as a credit, based on the retail price, up to the amount of energy recorded by the consumption meter. If the amount exported to the grid is greater than the amount consumed during the billing month, the difference, measured in kWh,<sup>6</sup> is recorded as unused credits and applied as a credit on a future bill. The customer may accumulate

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<sup>6</sup> On average, an estimated two thirds of the electricity generated by a residential roof-top solar installation is delivered to Maritime Electric’s electrical system in real time, while the other one third is used to supply the customer’s load directly.

these unused credits (e.g., during summer months when solar production is high and consumption is low) and the utility will apply them to the customer’s consumption in subsequent billing periods when the amount exported to the grid is less than the amount consumed (e.g., during winter months when solar production is low and consumption is high).

An example of a net metering bill for a Residential customer is shown in Table 12 below. The example is based on a consumption meter reading of 1,500 kWh for the monthly billing period, and a reverse flow meter reading of 1,800 kWh. In this example 1,500 from the reverse flow reading is applied as credit on the current bill, and 300 kWh is recorded as unused credits to be applied on a future bill.

TABLE 12 Residential Net Metering Bill Calculation		
Line	Charge	
1	Service charge: \$24.57/month	\$ 24.57
2	First block energy: 1,500 kWh x \$ 0.1723/kWh	258.45
3	Second block energy: 0 kWh x \$ 0.1375/kWh	<u>0.00</u>
4	Subtotal	283.02
5	HST: \$ 283.02 @ 15 %	42.45
6	PEI Gov’t rebate: \$ 258.45 @ 10 %	(25.85)
7	Net metering credit: 1,500 kWh x \$ 0.1723/kWh	<u>(258.45)</u>
<b>8</b>	<b>Total bill for current month</b>	<b>\$ 41.17</b>

The above example assumes that the customer is not a HST registrant (normally the case for a Residential customer), which is why the net metering credit does not include HST. This treatment follows a Canada Revenue Agency ruling and is consistent with the physical reality that the utility purchases reverse flow energy from the customer and uses it in real time to supply other customers.

- b. The retail rate for energy delivered to the customer of approximately 17¢/kWh, has two components of cost recovery:
- approximately 8¢/kWh recovers the cost to purchase the energy used by customers (i.e., variable costs); and
  - approximately 9¢/kWh recovers the cost to deliver the energy to customers (i.e., fixed costs), which is related to the operation and maintenance of the electrical system.

A net metering customer first avoids paying the 17¢/kWh because their solar installation generates energy for them. In addition, if their solar installation generates excess energy then the customer receives a credit valued at 17¢/kWh, thus avoiding any payment towards the operation and maintenance of the electrical system.

The difference between the avoided cost of energy at approximately 8¢/kWh and the retail rate for energy delivered to the customer at approximately 17¢/kWh represents a cost to Maritime Electric that is recovered from all other customers through rates (i.e., cross subsidization). These additional costs were forecast as part of the 2023 GRA and included

in customer rates; however, the actual costs were higher than forecast due to higher-than-forecast growth in the number of new net metering customers. The net metering costs included in the ECAM application represent the difference between the actual costs incurred and the GRA forecast costs.

- c. Refer to Response to IR-11(b).

Net metering costs are treated as energy supply costs, akin to wind energy purchases or energy purchases from NBEM. These costs are recovered from all customers through rates.

- d. Refer to Response to IR-11(b) and IR-11(c).

In general, non-net metering customers bear the costs associated with net metering. This issue is referred to as cross subsidization, where the cost to serve net metering customers is subsidized by non-net metering customers. Typically, these matters of cross subsidization are addressed and corrected through the rate design process, however, the provisions of the *Act* effectively legislate this cross subsidization within customer rates.

In 2025, Maritime Electric credited approximately 37 million kWh of credits to net metering customers. By receiving credit on their bills at the retail price of approximately 17¢/kWh for this energy, delivery costs of approximately \$3.3 million have been shifted to non-net metering customers, representing an electricity rate impact of approximately 1.2 per cent for all other customers.<sup>7</sup>

- e. The number of net metering customers and total installed capacity for each of 2023, 2024 and 2025 is provided in Table 13.

<b>TABLE 13</b>				
<b>Solar Net Metering Data</b>				
	<b>Total</b>		<b>Year-Over-Year Increase</b>	
<b>Year End</b>	<b>Number of Customers</b>	<b>Capacity (MW)</b>	<b>Number of Customers</b>	<b>Capacity (MW)</b>
2023	3,269	32.8	1,290	13.7
2024	4,360	44.8	1,091	12.0
2025	4,913	51.6	553	6.8

The primary driver of the increase of net metering costs over the period is the increased popularity of net metering solar installations. In the five-year period from 2018 to 2022, the average increase in net metering capacity was 3.4 MW per year. During the three-year period that followed from 2023 to 2025, the average increase in net metering capacity was 10.8 MW per year.

The increase in popularity of solar installations was largely due to the Government of Canada’s Canada Greener Homes Grant program and the Government of PEI’s Solar Electric Rebate Program, which provided grants of up to \$5,000 and \$10,000 (that can be

<sup>7</sup> 37 million kWh x \$0.09 = \$3.3 million.

combined for a total of up to \$15,000), respectively, for solar installations. Applications for the former program closed in February 2024 and the latter program was paused as of September 2025.

**IR-12 Section 5.4 – Net Metering Costs**

MECL states at page 21, lines 13 to 17 of the Application, that it is appropriate to defer net metering program costs to the ECAM.

- a. Explain why this is appropriate.
- b. Explain how the deferral of net metering costs to the ECAM is consistent with MECL's approved General Rules and Regulations and Order UE21-05.

**Response:**

- a. Refer to Response to IR-11.

Net metering costs are treated as energy supply costs, akin to wind energy purchases or energy purchases from NBEM. It is a legislated source of energy supply with a price set above the ECAM Base Rate. When net metering customers export electricity to the grid, Maritime Electric must purchase that energy by issuing a credit to the customer at the retail value. As a result, Maritime Electric incurs a more expensive supply of energy than can be procured from other sources (i.e., avoided cost). All variances in energy supply cost, relative to forecast, are appropriately deferred to ECAM.

- b. Provisions regarding the function of the net metering program are outlined in the approved General Rules and Regulations. The provisions follow the requirements outlined in the *Renewable Energy Act*, as discussed in Response to IR-11(a).

In the Commission's Order UE21-05, the Commission found that "[Maritime Electric] shall continue to recover capacity costs and costs associated with volume fluctuations though the ECAM without change."<sup>8</sup> In this context, "volume fluctuations" refers to energy supply purchases. Due to higher-than-forecast growth in net metering, Maritime Electric experienced a higher volume of energy supplied by net metering customers than forecast. Deferring the costs associated with this higher volume of energy supplied to ECAM is consistent with Order UE21-05.

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<sup>8</sup> Refer to Order UE21-05, page 5.

**IR-13 Section 5.4 – Net Metering Costs**

MECL is not recovering its full costs of the Net Metering Program from net metering customers. This under-recovery is due, at least in part, to the provisions of the *Renewable Energy Act*. MECL is now seeking to recover its full costs of the Net Metering Program from all ratepayers through the ECAM.

- a. Please explain how this is consistent with the *Electric Power Act*, which requires that the “*rates, tolls and charges for electric power should be reasonable, publicly justifiable, and non-discriminatory*”.
- b. Please indicate whether MECL has engaged with the Province regarding the recovery of Net Metering Program costs arising from the Renewable Energy Act. If so, please describe the nature and timing of those discussions, and any outcomes or proposed policy solutions.

**Response:**

- a. Maritime Electric’s Response to IR-8(b) from Commission Staff in May 2023 as part of the Rate Design Application, which asked why Maritime Electric has not proposed to increase charges for net metering customers, provides some useful context:<sup>9</sup>

Article 12.(2) of the Renewable Energy Act (“REA”) states: “*Under a net-metering system agreement ... a public utility shall not charge the small capacity renewable energy generator any fee or charge that is not charged or imposed on, or that differs in amount from any such fee or charge that is imposed on, any other customer of the public utility who is in the same power rate class ...*”

Due to the statute obligations under the *Renewable Energy Act*, Maritime Electric is unable to impose fees or charges on net metering customers that differ from other customers of the same rate class. The Government of PEI’s stance on this issue was further underscored in February 2022 when the Minister of Energy stated that Government would “move to block” any additional charges imposed on net metering customers, if they were proposed by Maritime Electric.<sup>10</sup> The minister’s statement was made after Nova Scotia Power Incorporated had proposed a new solar net metering charge in Nova Scotia, which was subsequently withdrawn.

The ECAM application is consistent with the *Electric Power Act*, in that Section 24.2 states that “The Commission shall allow a public utility to recover, in addition to the return the public utility is entitled to earn annually under subsection (1), any expenditures that the Commission is satisfied were reasonably and prudently incurred by the public utility for the purposes of complying with requirements of the *Renewable Energy Act*.”

Maritime Electric’s ECAM application includes higher-than-forecast energy costs, which were prudently incurred due to higher-than-forecast growth in net metering and, therefore, it is appropriate for those costs to be recovered from all customers through ECAM.

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<sup>9</sup> Refer to Docket UE22503, Exhibit M-10.

<sup>10</sup> Thibodeau, W. (2022, February 3). *P.E.I. would block any plan to charge solar customers more, minister says*. Retrieved from CBC: <https://www.cbc.ca/news/canada/prince-edward-island/pei-solar-1.6337271>.

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- b. Maritime Electric has not engaged with the Government of PEI regarding the recovery of net metering program costs as these costs are recoverable through customer rates, per Section 24.2 of the *Electric Power Act*. However, Maritime Electric has engaged with the Government of PEI on numerous occasions to inform them of the cross-subsidization issue caused by the net metering program, with the goal of informing policy changes.

One example of this engagement is a letter providing input on the PEI Energy Blueprint Discussion Paper sent by Maritime Electric on September 18, 2023, to the Government of PEI's Department of Environment, Energy and Climate Action and the PEIEC. The letter provided the following input regarding net metering:

*Maritime Electric has cautioned Government that customers with behind-the-meter distributed generation (e.g., community energy, microgrid and net-metering installations) avoid contributing a portion of their system costs, and those costs ultimately have to be recovered from all remaining customers through increased electricity rates (i.e., cross subsidization). These distributed generation customers, however, continue to have full use of the utility's infrastructure without fully contributing to their cost of using the electrical system.*

*Concerning the matter of customer rate class cross subsidization, Maritime Electric's electricity rates are currently designed to recover both energy and demand costs from customers. The energy portion recovers all of the cost to purchase and/or generate the energy being consumed by the customer and the demand portion recovers some of the infrastructure costs. With respect to a distributed generation customer that generates some or all of the energy they consume while continuing to use the electrical system, that customer avoids paying demand or infrastructure costs because the energy they send to the grid is credited at the full retail rate, to be applied against future consumption. While the distributed generation customer benefits from avoided demand costs, the total system costs remain, as demand costs are directly related to existing infrastructure. Consequently, these costs must be recovered from all remaining customers.*

Input provided regarding the PEI Energy Blueprint Discussion Paper was intended to inform the updated PEI Energy Strategy, which was released in October 2025. Action 4.1 of the updated PEI Energy Strategy includes, among other things, a consideration to “[analyze] the true value of solar and storage to support updates to the NEM [net energy metering] program and make sure costs are distributed equitably between those who participate and those who do not.”

**IR-14 Section 5.4 – Net Metering Costs**

Provide a breakdown, by year, of how the figures in the 'Actual' column of Table 9 of a) 'Net Metering Costs', and b) 'Avoided Cost of Energy Required to be Purchased from Other Sources', were calculated.

***Response:***

- a. The breakdown by year, as well as by month, is provided in response to IR-1, in the IR-1 Attachments 1 through 3 under the tab labelled "Net Metering".
- b. The "Avoided Cost of Energy Required to be Purchased from Other Sources" was calculated by first comparing (1) the actual MWh purchased through net metering with (2) the forecast MWh of net-metering purchases in the GRA. Any actual net-metering purchases above the forecast were treated as incremental MWh. Those incremental MWh were then multiplied by the EPA purchase price forecast in the GRA to estimate the avoided cost, this energy would have been forecast to be purchased through the EPA in GRA.

**IR-15 Section 5.4 – Net Metering Costs**

Per the Application, Table 9 in the 2020 Maritime Electric Integrated System Plan assumes an avoided energy charge of 8 cents per kWh and a total residential cost of approximately 14 cents per kWh, suggesting the avoided energy charge of 8 cents per kWh was approximately 57 per cent of the per unit net metering cost. Table 9 in this Application provides a total avoided cost of energy in 2025 of \$1,843,588, compared to a total Net Metering Cost of \$7,293,056, suggesting that avoided energy costs were 25 per cent of total net metering costs.

- a. Explain how the Net Metering Cost in 2025 was calculated.
  - i. If there is a difference in the ratio between Avoided Cost of Energy the total net metering costs between the 2020 Integrated System Plan and Table 9, 2025 values, please explain.

**Response:**

- a. The net metering cost in 2025 (\$7,293,056) is the value of net metering credits refunded to net meter customers for energy generated and exported to the grid and applied to their account to offset their consumption in a later period. This energy is “purchased” by the Company at the retail price of energy approved by the Commission as required under the Renewable Energy Act.

In the GRA, it is assumed that the balance of energy purchases forecast to meet customer electricity sales less the forecast energy from all other sources of energy (i.e., Lepreau, commercial renewables, net metering, and generation) are purchased through the EPA.

To the extent that the actual energy purchased by the Company from net metering customers was more than forecast in the GRA, the difference is a reduction from what forecast in the GRA for EPA purchases (i.e., an avoided cost) to determine the net amount deferred to ECAM.

The 2025 avoided cost of \$1,843,588 in the “Actual” column represents the *incremental* avoided cost above the GRA forecast. The 2025 amounts of \$4,522,691 and \$1,843,588 shown in the “Increase (Decrease) Over GRA” column represent the *incremental* (i.e., variance) costs relative to the GRA.

- i. The amounts of \$1,843,588 and \$4,522,691 are used to calculate the ratio between the avoided cost of energy and the total net metering costs. The resulting ratio is 41 per cent. The smaller ratio, relative to the 2020 Integrated System Plan (“2020 ISP”), is due to customer rates (which impacts the net metering costs) increasing at a rate higher than the avoided cost of energy since the 2020 ISP.

**IR-16 Section 5.6 – Capacity Costs**

Provide a further breakdown of the capacity costs in Table 11 to differentiate the impact on incremental capacity due to: a) shortfalls in Actual capacity due to higher than expected load growth; b) replacement capacity for Point Lepreau when it was out of service, if applicable; and c) replacement capacity for the delayed wind facilities.

**Response:**

Table 14 represents capacity costs due to higher-than-forecast load growth only.

Replacement capacity for both Point Lepreau when it was out of service and the delayed wind facilities did not contribute to either the GRA forecast capacity cost or the actual capacity cost to meet capacity needs that exceeded forecasted levels.

In 2023, 2024, 2025 Maritime Electric did not purchase replacement capacity due to Point Lepreau outages because the outages were typically scheduled for summer months when capacity needs were lower.

Maritime Electric has never purchased replacement capacity due to delayed wind facilities because they are intermittent (i.e., non-dispatchable) facilities.

<b>TABLE 14 Capacity Costs</b>			
<b>Year</b>	<b>GRA Forecast</b>	<b>Actual</b>	<b>Increase over GRA Deferred to ECAM</b>
<b>2023</b>	\$ 11,687,880	\$ 11,687,880	\$ -
<b>2024</b>	13,050,000	13,500,000	<b>450,000</b>
<b>2025</b>	13,350,000	14,029,965	<b>679,965</b>

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**IR-17 Section 5.6 – Capacity Costs**

Did Maritime Electric procure replacement or incremental capacity at prices stipulated in the EPA?

***Response:***

Maritime Electric procured incremental capacity at prices stipulated in the EPA.

**IR-18 Section 5.7 – Non-Spinning Reserve Costs**

Detail the source of each of Maritime Electric’s ancillary services that was procured during the 2023 polar vortex event. Include a breakdown by asset if provided by Maritime Electric’s available assets.

**Response:**

Maritime Electric did not self-supply any ancillary services during February 2023.

The sources of ancillary services procured by Maritime Electric in February 2023 are provided in Table 15.

<b>TABLE 15 February 2023 Ancillary Services</b>				
<b>Ancillary Service</b>	<b>NBSO Balancing Area Requirement (MW)</b>	<b>Maritime Electric Requirement (MW)</b>	<b>Maritime Electric Procured (MW)</b>	<b>Source of Procured Supply</b>
Regulation	19	1.7	1.7	Mactaquac
Load Following	53	4.6	4.6	Mactaquac
Spinning Reserve	87.5	7.7	7.7	Interruptible Load Reserve
Supplemental Reserve - 10 minute	222.5	19.5	19.5	NBP-SO to supply
Supplemental Reserve - 30 minute	183.0	16.0	16.0	NBP-SO to supply

Regulation, load following and spinning reserve are purchased from NBEM through the EPA. Mactaquac is a large hydroelectric generation facility owned by NB Power. Interruptible Load Reserve is NB Power’s interruptible customers.

Maritime Electric can self-supply supplemental reserve, which is provided by the Borden Generating Station (“BGS”) (i.e., combustion turbines #1 and #2). Due to expected high loads in February 2023, the Company chose to purchase these ancillary services from the NB Power System Operator (“NBP-SO”) so the BGS could be used more economically as a source of generating capacity and therefore avoid more expensive capacity charges.

**IR-19 Section 5.7 – Non-Spinning Reserve Costs**

Explain why Maritime Electric spent \$460,552, per Table 12, on Non-Spinning Reserve for a three-day polar vortex event.

***Response:***

Ancillary services are purchased on a month-by-month basis. In 2023, non-spinning reserves were purchased from the NBP-SO for both January and February due to expected high load forecasts for those months. In the application, these costs were attributed to the February polar vortex due to the timing of the purchases being recorded in the Company’s accounting records.

By purchasing non-spinning reserve from the NBP-SO rather than self-supplying with the BGS, the Company was able to use the BGS more economically as source of capacity for these two months and therefore avoid more expensive capacity charges.

<b>TABLE 16</b>			
<b>2023 Non-Spinning Reserve Costs</b>			
<b>Ancillary Service</b>	<b>January</b>	<b>February</b>	<b>Total</b>
10 Minute Non-Spinning	\$ 122,696	\$ 131,750	<b>\$ 254,446</b>
30 Minute Non-Spinning	100,559	105,547	<b>206,106</b>
<b>TOTAL</b>	<b>\$ 223,255</b>	<b>\$ 237,297</b>	<b>\$ 460,552</b>

**IR-20 Section 5.8 – Imbalance Costs**

Provide a more detailed explanation of the three categories of imbalance costs, including practical examples of how each cost is incurred.

**Response:**

Maritime Electric must finalize its hourly transmission energy schedule with NBP-SO forty minutes prior to the hour in question. Imbalance charges occur when the actual transmission energy for that hour differs from the final hourly scheduled energy. Table 17 is an example of how imbalance energy is calculated for a one-hour period.

<b>TABLE 17 Example of Imbalance Energy Calculation</b>			
<b>Item</b>	<b>Scheduled (MWh) A</b>	<b>Actual (MWh) B</b>	<b>Required Imbalance Purchase (MWh) (C = B – A)</b>
Maritime Electric Total	200	195	(5)
Renewable Generation	(50)	(40)	10
<b>Total NB Power Purchases</b>	<b>150</b>	<b>155</b>	<b>5</b>

In Table 17, the actual energy required to serve customers (i.e., Maritime Electric Total) for the one-hour example period is 5 MWh lower than what was scheduled and Maritime Electric is responsible to pay for the energy that was scheduled under the EPA.

Also in Table 17, actual Renewable Generation was 10 MWh less than scheduled. This energy difference also needs to be purchased from NB Power as imbalance energy. However, the cost of this imbalance energy is charged to the renewable generation facility or facilities responsible for this imbalance. The cost is not passed on to Maritime Electric customers.

In Table 17, the total of 5 MWh of imbalance energy was purchased from NB Power to offset the 10 MWh of renewable generation that was below what was scheduled for this hour supply less the 5 MWh of energy scheduled above what was needed to serve customers.

**Application Table 13 - Difference in Hourly Energy Purchase Scheduled versus Actual Energy Consumed**

This is the additional cost of the scheduled energy versus actual energy at a hypothetical EPA price per MWh. For this example:

- If the EPA price was \$100/MWh and Maritime Electric purchased an additional 5 MWh from NB Power because the energy forecast to be purchased for that particular hour was 5 MWh higher than the actual energy required for that hour: 5 MWh x \$100/MWh = \$500.

**Application Table 13 - Imbalance Purchased/(Sold) at Final Hourly Marginal Cost (“FHMC”)<sup>11</sup>**

<sup>11</sup> The FHMC is the market price cost of electricity for a specific hour as determined by the NBP-SO.

**Maritime Electric**

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This is the actual cost/refund for the energy imbalances that are either purchased or sold at the FHMC. For this example:

- If the FHMC price was \$120/MWh and Maritime Electric had to purchase an additional 5 MWh from NB Power:  $5 \text{ MWh} \times \$120/\text{MWh} = \$600$ .

**Application Table 13 - Imbalance Charges/(Recoveries) from Commercial Wind/Solar Participants**

This is the actual cost/refund for only the renewable generation imbalances that are either purchased or sold at the difference between the FHMC and the cost under the EPA. This amount is recovered from the responsible generation facility. For this example:

- If the FHMC price was \$120/MWh and Maritime Electric had to purchase an additional 10 MWh from NB Power to offset the renewable generation:  $10 \text{ MWh} \times (\$120/\text{MWh} - \$100/\text{MWh}) = \$200$  is recovered from the responsible renewable generator.

**Maritime Electric**

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**IR-21 Section 5.9 – Energy Sales to Third Parties**

Maritime Electric states that third party sales are generally recovered from the purchasing party at cost plus a markup.

- a. Provide a detailed breakdown of the Energy Sales to Third Parties shown in Table 14 for each of 2023, 2024, 2025. Include the name of the purchasing party, the amount purchased, Maritime Electric’s generation costs, and the markup.

**Response:**

A breakdown of the energy sales to third parties is provided in Table 18.

TABLE 18 Energy Sales to Third Parties					
Year	Party Receiving the Energy Sales	MWh Generated	Maritime Electric Costs	Markup	Total Sales
2023		290	\$ 115,624	\$ 11,562	\$ 127,186
		141	62,036		62,036
	<b>TOTAL</b>	<b>431</b>	<b>\$ 117,660</b>	<b>\$ 11,562</b>	<b>\$ 189,222</b>
2024		127	46,109	4,610	50,719
		95	13,675		13,675
	<b>TOTAL</b>	<b>222</b>	<b>\$ 59,784</b>	<b>\$ 4,610</b>	<b>\$ 64,394</b>
2025		770	\$ 492,800	\$ 49,280	\$ 542,080
		1,043	461,805	46,180	507,985
		226	118,305		118,305
	<b>TOTAL</b>	<b>2,039</b>	<b>\$ 954,605</b>	<b>\$ 95,460</b>	<b>\$ 1,168,370</b>

Emergency energy transactions with [REDACTED] are governed by established Electricity Business Rules (“EBR”) and regional Emergency Energy Transaction Agreements designed to maintain grid reliability during contingency events. [REDACTED]

[REDACTED]<sup>13</sup> In the Emergency Energy Transaction Agreement with [REDACTED] sales between utilities are subject to a 10 per cent markup on cost to generate the energy.

Sales to [REDACTED] are a result of differences between the actual energy produced by the facility and the energy [REDACTED] scheduled to be produced. If actual [REDACTED] energy production is lower than scheduled and the [REDACTED] requires [REDACTED] to be held to the scheduled amount, Maritime Electric will run generation to offset [REDACTED] production deficiency and the associated generation costs are billed to [REDACTED] under their contract.

<sup>12</sup> [REDACTED] has a contract to purchase the energy from the [REDACTED] at the facility and is therefore responsible for the costs associated with the facility.

<sup>13</sup> [REDACTED]

**IR-22 Section 5.11 – Generating Costs**

Explain the term “Replacement Cost of Energy Generation Produced Below GRA Forecast” in Table 16.

- a. Is this not the same as additional energy procured through the EPA? If so, why has it been included here instead of in Table 18?

***Response:***

In the GRA, the 2022 to 2025 forecast generation costs were based on monthly testing requirements and generation to meet load requirements. In 2023 and 2024, the actual kWh of energy produced from Maritime Electric generation for testing requirements and to balance load was less than the GRA forecast. In the absence of a need to generate for testing or to meet load requirements, this energy is procured through the EPA as it is less expensive than running Company owned generation. The term “Replacement Cost of Energy Generation Produced Below GRA Forecast” in Table 16 in the application represents the cost of purchasing the energy shortfall from NBEM under the EPA instead.

**IR-23 Section 5.11 – Generating Costs**

Explain the term “Avoided Cost of Energy Generation Produced Above GRA Forecast”.

***Response:***

In the GRA, the 2022 to 2025 forecast generation costs were based on monthly testing requirements and generation to meet load requirements. In 2025, the actual kWh of energy produced from Company owned generation to balance load requirements during the winter months was more than the GRA forecast. The term “Avoided Cost of Energy Generation Produced Above GRA Forecast” in Table 16 in the application represents the avoided cost of purchasing fewer kWh of energy under the EPA than forecast in the GRA as a result of this additional generation.

**IR-24 Section 7 – Proposed ECAM Rate Adjustment**

The Application indicates that Maritime Electric is seeking to recover approximately \$32 million from customers over a 12-month period. MECL states that collecting these costs over this timeframe would help manage customer rate impacts.

- a. Please provide a detailed explanation supporting the proposed 12-month recovery period, including why this approach is reasonable and in the interests of ratepayers.
- b. Please provide a comparison of customer bill impacts if the balance were recovered over:
  - i. 24 months; and
  - ii. 36 months.

**Responses:**

- a. A one-year recovery period is in customers’ interest because it limits further cost shifting and compounding, reduces carrying/financing costs, and spreads recovery across the full seasonal load cycle.
- b. Table 19 illustrates the estimated annual cost, by component, for a benchmark rural residential customer using 1,000 kWh per month or 12,000 kWh per year for each of 12 months, 24 months, and 36 months recovery periods.

<b>TABLE 19 Annual Cost for Rural Residential Customer</b>				
	<b>Approved UE23-04 &amp; UE23- 09 March 1, 2025</b>	<b>01-Mar-26</b>		
		<b>12 Months</b>	<b>24 Months</b>	<b>36 Months</b>
Service Charge	\$ 323.04	\$ 323.04	\$ 323.04	\$ 323.04
Basic Energy Charge	1,995.60	1,995.60	1,995.60	1,995.60
<b>ECAM Charge</b>	<b>57.00</b>	<b>233.88</b>	<b>115.80</b>	<b>76.56</b>
Provincial Energy Efficiency and Conservation Plan	14.52	14.52	14.52	14.52
<b>Sub-Total</b>	<b>2,390.16</b>	<b>2,567.04</b>	<b>2,448.96</b>	<b>2,409.72</b>
HST	358.52	385.06	367.34	361.46
Provincial Clean Energy Rebate <sup>14</sup>	<b>(206.71)</b>	<b>(74.80)</b>	<b>(70.86)</b>	<b>(69.56)</b>
<b>Total Annual Cost</b>	<b>\$ 2,541.97</b>	<b>\$ 2,877.30</b>	<b>\$ 2,745.44</b>	<b>\$ 2,701.62</b>
<b>Percentage Annual Increase (%)</b>				
<b>Before Tax</b>		<b>7.4%</b>	<b>2.5%</b>	<b>0.8%</b>
<b>After Tax</b>		<b>13.2%</b>	<b>8.0%</b>	<b>6.3%</b>

Table 20 illustrates the estimated annual cost, by component, for a benchmark urban residential customer using 1,000 kWh per month or 12,000 kWh per year for each of 12 months, 24 months, and 36 months recover periods.

<sup>14</sup> The Province of PEI has announced that the rebate will be discontinued after June 2026.

TABLE 20 Annual Cost for Urban Residential Customer				
	Approved UE23-04 and UE23- 09 March 1, 2025	01-Mar-26		
		12 Months	24 Months	36 Months
Service Charge	\$ 294.84	\$ 294.84	\$ 294.84	\$ 294.84
Basic Energy Charge	1,995.60	1,995.60	1,995.60	1,995.60
<b>ECAM Charge</b>	<b>57.00</b>	<b>233.88</b>	<b>115.80</b>	<b>76.56</b>
Provincial Energy Efficiency and Conservation Plan	14.52	14.52	14.52	14.52
<b>Sub-total</b>	<b>2,361.96</b>	<b>2,538.84</b>	<b>2,420.76</b>	<b>2,381.52</b>
HST	354.29	380.83	363.11	357.23
Provincial Clean Energy Rebate <sup>15</sup>	(206.71)	(74.80)	(70.86)	(69.56)
<b>Total Annual Cost</b>	<b>\$ 2,509.54</b>	<b>\$ 2,844.87</b>	<b>\$ 2,713.01</b>	<b>\$ 2,669.19</b>
<b>Percentage Annual Increase (%)</b>				
<b>Before Tax</b>		<b>7.5%</b>	<b>2.5%</b>	<b>0.8%</b>
<b>After Tax</b>		<b>13.4%</b>	<b>8.1%</b>	<b>6.4%</b>

Table 21 illustrates the estimated annual cost, by component, for a general service customer using 10,000 kWh per month, or 600,000 kWh per year, and demand of 50 kW per month, or 600 KW per year.

TABLE 21 Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)				
	Approved UE23-04 and UE23- 09 March 1, 2025	01-Mar-26		
		12 Months	24 Months	36 Months
Service Charge	\$ 294.84	\$ 294.84	\$ 294.84	\$ 294.84
Demand Charge	4,834.80	4,834.80	4,834.80	4,834.80
Basic Energy Charge	20,292.00	20,292.00	20,292.00	20,292.00
<b>ECAM Charge</b>	<b>570.00</b>	<b>2,338.80</b>	<b>1,158.00</b>	<b>765.60</b>
Provincial Energy Efficiency and Conservation Plan	145.20	145.20	145.20	145.20
<b>Sub-total</b>	<b>26,136.84</b>	<b>27,905.64</b>	<b>26,724.84</b>	<b>26,332.44</b>
HST	3,920.53	4,185.85	4,008.73	3,949.87
<b>Total Annual Cost</b>	<b>\$ 30,057.37</b>	<b>\$ 32,091.49</b>	<b>\$ 30,733.57</b>	<b>\$ 30,282.31</b>
<b>Percentage Annual Increase (%)</b>				
<b>Before Tax</b>		<b>6.8%</b>	<b>2.2%</b>	<b>0.7%</b>
<b>After Tax</b>		<b>6.8%</b>	<b>2.2%</b>	<b>0.7%</b>

<sup>15</sup> The Province of PEI has announced that the rebate will be discontinued after June 2026.

**IR-25 Section 7 – Proposed ECAM Rate Adjustment**

In Order UE19-08, the Commission expressed concerns about the growing balance of the ECAM account, MECL's ability to earn a return on the ECAM balance, and the disincentive to minimize costs for ratepayers.

- a. What steps has MECL taken to minimize the cost of purchased and produced electricity, and the ECAM balance generally, for ratepayers?
- b. Calculate the return, in dollars, that MECL has earned on the balance of the ECAM account in 2023, 2024 and 2025, as well as the forecast return in 2026 and 2027.

**Response:**

- a. In conducting the Comprehensive Review of the ECAM filed with the Commission in June 2020, the Company reviewed each of the accounts included in ECAM to determine which accounts should be appropriately included in the ECAM and which accounts should be excluded. The assessment of which accounts should remain in ECAM was based on the following criteria:
  - The account and changes in the costs included therein are largely outside the control of the utility; and
  - The potential variance from forecast, individually or in aggregate, may have a significant or material impact on customer rates or the Company's earnings in a particular year.

Based on the Company's review, it was recommended that 27 energy supply accounts, with 2019 annual charges of approximately \$5.5 million, be removed from the ECAM calculation commencing with the next rate-setting period.

By association, the costs related to the accounts that remain in ECAM are largely outside of the control of the Company and little can be done to minimize these costs without compromising the Company's obligation to serve customers under the *Electric Power Act*. The results of the comprehensive review were accepted by the Commission and approved for implementation pursuant to Order UE-21-05.

The Company has taken other measures to mitigate rate impacts for customers. In particular, the Company chose not to file a general rate increase in 2026. By not doing so, the Company chose to operate within the rates approved for 2025 for the 2026 fiscal year despite the existence of real cost pressures and ongoing challenges to manage these costs. The primary driver of this decision was to mitigate customer rate adjustments in 2026 to deal with two large historical balances to be collected from customers, namely the Fiona restoration cost deferral account and the accumulated ECAM balance.

- b. The foundation of establishing customer electricity rates for a particular year in a GRA rate-setting period starts with a determination of the various components of the Company's revenue requirement, which includes the forecast energy generation and supply purchase costs for the year. Since the utility has an obligation to supply energy to its customers, it must also be provided the opportunity to recover those prudently incurred energy supply costs from customers within a reasonable time period. When those costs change from that

included in revenue requirement due to factors largely outside the Company's control, inclusion in the ECAM is appropriate. These incremental energy supply costs are a cost of providing electricity service to customers and are properly financed based on the Company's weighted average cost of capital which is comprised of both short and long term debt as well as shareholder equity that must be maintained at levels in accordance with the Electric Power Act. To the extent those costs are partially financed through equity, it is appropriate for the shareholder to be provided a reasonable opportunity to earn the regulator-approved return until such a time as the Company has an opportunity to recover those incremental costs.

The return, in dollars, that Maritime Electric has earned on the balance of the ECAM account in 2023, 2024 and 2025, as well as the forecast return in 2026 and 2027 is provided in Table 22.

<b>TABLE 22</b>						
<b>Actual and Forecast Earnings Associated with the ECAM Balance (000s except %)</b>						
		<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026F</b>	<b>2027F</b>
ECAM Balance, Beginning of Year	A	\$ 11,655	\$ 11,686	\$ 20,551	\$ 31,710	\$ 13,200
ECAM Balance, End of Year	B	11,686	20,551	31,710	13,200	-
Average ECAM Balance	$C=(A+B)/2$	\$ 11,671	\$ 16,119	\$ 26,131	\$ 22,455	\$ 6,600
Average Equity Component of Capital Structure	D	36.52%	36.47%	37.12%	37.12%	37.12%
Regulated ROE	E	9.49%	9.17%	9.69%	9.35%	9.35%
Earnings Associated with ECAM Balance	$F=C*D*E$	\$ 404	\$ 539	\$ 940	\$ 779	\$ 229

In accordance with Commission Order UE23-04, Maritime Electric's ROE used in the calculation of revenue requirement, which is used to set customer rates, has remained unchanged at 9.35 per cent on an average common equity of 40 per cent for 2023, 2024 and 2025 with an upper limit of 9.70 per cent to be used in the calculation of earnings for 2023, 2024 and 2025, or until otherwise varied by the Commission.

**IR-26 Section 7 – Proposed ECAM Rate Adjustment**

Is the Application consistent with MECL's approved General Rules and Regulations and previous Commission Orders including, but not limited to, Order UE21-05?

***Response:***

Yes, the Application is consistent with Maritime Electric's approved General Rules and Regulations and previous Commission Orders including, but not limited to, Order UE21-05.

As per Section N-0 of the approved GRR, the balance deferred to the ECAM account in Appendix A to the Application reflects the increases or decreases in purchased and produced electricity from the Base Cost calculated at the end of each month as follows:

1. Determining the total cost of purchasing and producing electricity in the month including any amounts amortized to ECAM as Ordered by the Commission.
2. Determining the net kilowatt hours of purchased and produced energy in the month.
3. Multiplying the quantity of net purchased and produced energy determined in (2) above by the forecast Base Rate Cost approved by the Commission in the month to determine the base cost of electricity:
  - For the period January 1, 2023 to April 30, 2023 of \$0.09244/kWh approved by the Commission in Order UE20-06
  - For the periods May 1, 2023 to February 28, 2024 of 0.09050/kWh, March 1, 2024 to February 28, 2025 of \$0.09440/kWh and March 1, 2025 to February 28, 2026 or until otherwise approved by the Commission of \$0.9612/kWh as approved by the Commission in Order UE23-04
4. Subtracting the base cost of electricity determined in (3) above from the total cost of purchasing and producing electricity determined in (1) above to calculate the excess or deficiency of the cost of purchased or produced electricity from the base cost.
5. Adding the excess (or deficiency) of the cost of purchased or produced energy calculated in (4) above to the corresponding excess (or deficiency) costs on the Balance Sheet.

The ECAM Rate Adjustment proposed in the Application to be applied to Customers' bills is calculated as shown in Table 20 of the Application. This rate adjustment was calculated as defined in Section N-0 of the GRR as follows:

6. Determining the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied. This is provided in Table 20 of the Application.
7. Determining the forecast total kilowatt hour sales for the twelve-month period commencing with the month in which the ECAM rate will be applied.
8. Dividing the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).

As discussed in Section 3.0 of the Application, the Company filed a Comprehensive Review of the ECAM [Docket UE20603] as ordered by the Commission in June 2020. The amounts deferred to ECAM and proposed to be recovered from customers in this Application comply with the Commission's Order UE21-05. This Order approved the continued operation of the ECAM with

revisions to the accounts included in ECAM and was ordered to be implemented in the next GRA effective May 1, 2023. Amounts deferred prior to May 1, 2023 reflected the Commission's previously approved operation of the ECAM which allowed virtually all energy supply costs to flow through ECAM as discussed in Section 3.0 of the aforementioned review.

**IR-27 Section 7 – Proposed ECAM Rate Adjustment**

The ECAM balance has accumulated over multiple years. Please explain why recovery over a shorter 12-month period is appropriate in this context, and why it is preferred over longer recovery periods, including consideration of rate stability and customer impacts.

***Response:***

Recovery of the ECAM balance over 12 months is generally appropriate because it aligns with the ECAM's stated objectives of providing timely cost recovery/refund, rate predictability, and administrative/regulatory efficiency.

A 12-month period recovers the balance across a full year of bills, which reduces month-to-month swings compared with shorter recovery periods, while still keeping recovery reasonably current.

The ECAM is intended to ensure customers “pay the related costs of the service they receive within a reasonable period,” so costs aren't transferred to future ratepayers beyond the next rate-setting period. A 12-month recovery is a practical “reasonable period.”

As stated in the response to IR-25, the Company chose not to file a general rate increase in 2026. By not doing so, the Company chose to operate within the rates approved for 2025 for the 2026 fiscal year despite the existence of real cost pressures and ongoing challenges to manage these costs.

The primary driver of this decision was to mitigate customer rate adjustments in 2026 to deal with two large historical balances to be collected from customers, namely the Fiona restoration cost deferral account and the ECAM balance, prior to what the Company anticipates will be a significant increase in energy supply costs in its next EPA with NBEM.

Customers and the Company have benefited from the long-term energy supply contract with NBEM that was signed in 2019 and will expire at the end of 2026. This long-term contract served to insulate energy supply costs from recent market pressures due to increased demand from electrification and a tightening energy supply as a result of the Clean Electricity Regulations. At this point, it is too early to predict with certainty what energy purchase costs will be in the next EPA but it is expected that prices will increase significantly, requiring further rate increases for customers in the next GRA. A regulatory decision that extends the proposed recovery period for ECAM beyond that proposed in the Application will only exacerbate future cost increases for customers.

**IR-28 Section 7 – Proposed ECAM Rate Adjustment**

The Application states that the forecast for energy sales is based on a methodology consistent with Maritime Electric's previous General Rate Application ("GRA") and was reviewed by Grant Thornton in 2020.

- a. Please confirm whether there have been any changes to the load forecasting methodology since the previous GRA. If so, please describe those changes.
- b. Please confirm whether the assumptions underlying the load forecast (including, but not limited to, customer growth, electrification, and demand patterns) have been updated since the previous GRA. If so, please describe those updates.
- c. Please explain whether the October 2025 load forecast incorporates the most recent available data and trends, including actual customer usage and recent system developments.

**Response:**

- a. The load forecast is based on a methodology consistent with the forecast provided in the previous GRA. While the methodology behind the forecast has not changed, the sales forecast is regularly updated to reflect known changes to the underlying data and assumptions, which are outlined in Response to IR-28(b).
- b. Maritime Electric regularly reviews and updates assumptions and inputs in the load forecast to reflect the most up-to-date information available. Below is a summary of the assumptions and inputs in the load forecast that are regularly updated:
  - The baseline for the load forecast is updated to reflect the most recent year with actual sales data;
  - Estimated annual usage per household for future housing starts is based on analysis of consumption from previous years' service orders for new housing starts;
  - The forecast number of housing starts is updated based on the most recent Conference Board of Canada ("CBOC") forecasts;
  - The estimated number of mini-split heat pump retrofit installations is updated based on current trends and available rebates;
  - The estimated number of electric vehicles is updated based on current trends and available rebates;
  - The estimated number of new rooftop solar installations (i.e., net metering customers) is updated based on current trends and available rebates;
  - The forecast PEI real gross domestic product ("GDP") is updated based on the most recent CBOC forecasts;
  - Demand side management impacts are updated using the PEIEC's most recent Energy Efficiency and Conservation Plan;
  - The forecast number of heating degree days is updated based on the number of heating degree days experienced in historical years;
  - Forecast large industrial load is updated to reflect current trends and any known expected usage growth; and
  - Forecast street lighting load is updated to reflect current trends.

These updates ensure that the current sales forecast reflects the best available information to the Company at a given time.

- c. Since October 2025, the load forecast was updated in February 2026. Assumptions and inputs were updated consistent with those listed in Response to IR-28(b).

Overall, the updated February 2026 load forecast has resulted in a small decrease in total sales compared to the October 2025 forecast.

<b>TABLE 23</b>			
<b>Comparison of Annual Load Forecasts (GWh)</b>			
	<b>2026</b>	<b>2027</b>	<b>2028</b>
October 2025 Forecast	1,631	1,663	1,694
February 2026 Forecast	1,626	1,644	1,669
Difference (%)	(0.3)%	(1.1)%	(1.5)%



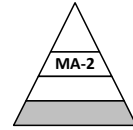
## **IR-2 – Attachment 1**

October to December ECAM Actual vs Forecast

	October		November		December		TOTAL		Variance
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	
ECAM Energy Costs	\$ 14,627,225	\$ 14,614,668	\$ 16,168,997	\$ 16,537,428	\$ 18,691,975	\$ 18,629,615	\$ 49,488,197	\$ 49,781,711	\$ 293,514
NPP	113,408,172	110,631,544	154,386,275	144,492,485	168,928,023	187,465,128	436,722,470	442,589,157	5,866,687
ECAM Basic Rate/kWh	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612
Base Energy Costs	10,900,794	10,633,904	14,839,609	13,888,618	16,237,362	18,019,148	41,977,764	42,541,670	563,906
Difference Between Actual & Base Energy Costs	\$ 3,726,432	\$ 3,980,764	\$ 1,329,388	\$ 2,648,810	\$ 2,454,614	\$ 610,467	\$ 7,510,434	\$ 7,240,041	\$ (270,392)
ECAM Opening Balance	\$ 26,257,657	\$ 26,257,657	\$ 29,477,011	\$ 29,734,473	\$ 30,231,911	\$ 31,795,080	\$ 26,257,657	\$ 26,257,657	\$ 0
Additions/(Reductions)	3,726,432	3,980,764	1,329,388	2,648,810	2,454,614	610,467	7,510,434	7,240,041	(270,392)
Rebated/(Collected) From Ratepayer	(507,077)	(503,948)	(574,489)	(588,203)	(705,480)	(695,296)	(1,787,046)	(1,787,448)	(402)
ECAM Closing Balance	\$ 29,477,011	\$ 29,734,473	\$ 30,231,911	\$ 31,795,080	\$ 31,981,044	\$ 31,710,250	\$ 31,981,044	\$ 31,710,250	\$ (270,794)
Rebated/(Collected) From Ratepayer									
Energy Sales - kWh	106,753,079	106,094,410	120,945,029	123,832,277	148,522,093	146,378,199	376,220,200	376,304,886	84,686
ECAM Adjustment Rate per kWh	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475	0.00475
Total Rebated (Collected) from Ratepayers	\$ 507,077	\$ 503,948	\$ 574,489	\$ 588,203	\$ 705,480	\$ 695,296	\$ 1,787,046	\$ 1,787,448	\$ 402



## **IR-4 – Attachment 1**



# POINT LEPREAU NUCLEAR GENERATING STATION

## Information Report

**2023 UNIT OUTAGE**  
**IR-00300-14**  
**Rev. 0**



**For Information**

## Document Approval

The document has been electronically approved through E-form # 1982474 on this date \_\_\_\_\_.  
 The following approvals are required prior to issue.

Role	Name
Author	[REDACTED]
Document Owner (Approved by)	[REDACTED]

## Revision Record

The following is the latest revision record for this document.

Rev. #	Date	Page	Section	Comments
0	2024-02-05			New issue.

## Classification Statement

**Available upon request usage**

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## 1.0 Purpose and Scope

### Purpose

This report provides a summary of the PLNGS 2023 Planned Maintenance Outage.

### Scope

This report will provide an Outage overview, summary of performance against outage targets, and identify strengths and areas for improvement both overall and in specific areas.

## 2.0 Outage Overview

### 2.1 Outage Summary

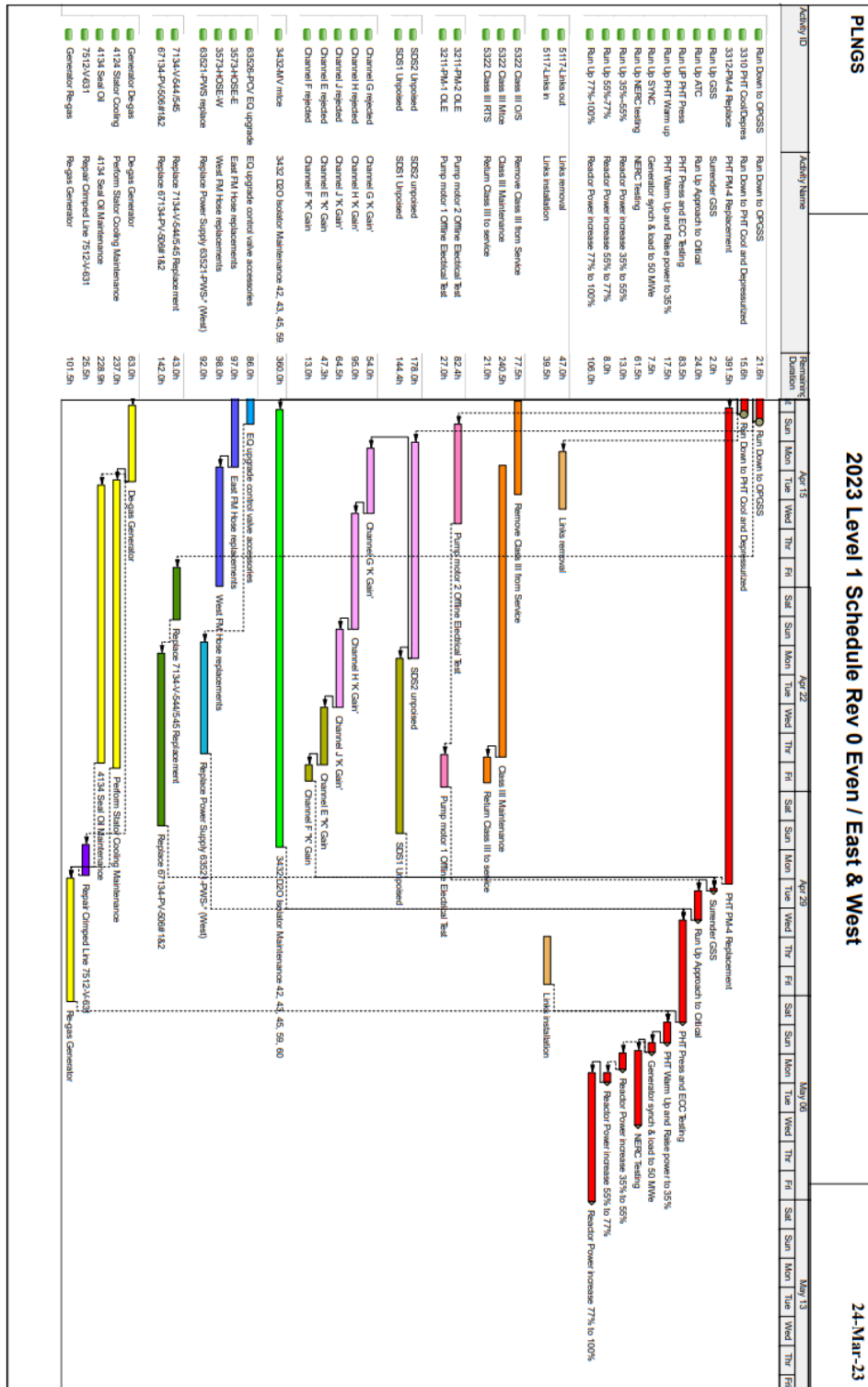
Rundown commenced on Saturday April 15<sup>th</sup> 2023 with SDS2 tripped at 10:55 hrs. and the unit breaker closed on May 25<sup>th</sup> @ 16:55. The Outage Duration from breaker to breaker was 40 days 6 hours.

The major outage work included.

<b>Class III Electrical Maintenance</b>	<b>East and West Fueling Machine Hose Replacements</b>
<b>Replace SOR WLU Power Supplies</b>	<b>East and West Fueling Machine Power Supply Replacements</b>
<b>PHT PM-4 Replacement</b>	<b>East and West Fueling Machine EQ Upgrades</b>
<b>ECC D2O Isolator Packing replacement</b>	<b>ECC HX Isolator Replacements</b>
<b>PHT PM-4 seal replacement</b>	

# 2.2 Level 1 Schedule

Final version of the Level 1 schedule was issued on 2023-03-24:



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### 3.0 Outage Management Summary

#### 3.1 Outage ACEMAN Targets

The 2023 Outage targets were aligned with the ACEMAN guidelines.

Area	Measure	Target	Actual
Accident Free	High Potential Incident that could have led to serious injury or death	0	2
	Medical Aid	0	1
Control Dose	Whole Body Dose (mSv)	≤ 88.50	80.38
	Personal Contamination Events	≤ 9	2
Event Free	<ul style="list-style-type: none"> <li>• <b>Category 1 or 2 PICAs:</b> <ul style="list-style-type: none"> <li>• Challenging Shutdown Safety</li> <li>• Inadequate Contractor Oversight</li> <li>• Radiation Protection Incident</li> <li>• Actual or Potential Impact to the Environment</li> </ul> </li> <li>• <b>Level 1 or Level 2 Work Protection Events</b></li> </ul>	0	0
		0	0
Meet Commitments	Planned Outage Duration (Breaker to Breaker)	≤ 22 days	40
Attend Training	Focus Work Schedule Delays due to Lack of Qualified Staff	0	0
No Rework	Delays to critical path as a result of rework	0	1
	Continuous Days of High-Power Operation after the Outage (No forced outages caused by Outage rework)	≥100 days	100

## 3.2 Accident Free

### **High Potential Incident (that could have led to disabling injury or death):**

The outage target was 0. The actual high potential incidents were 2. Further details are listed in appendix A

### **Medical Aids:**

The outage target was 0 Medical Aids. This target applies to PLNGS and Contract staff. The actuals were 1. Further details are listed in appendix A.

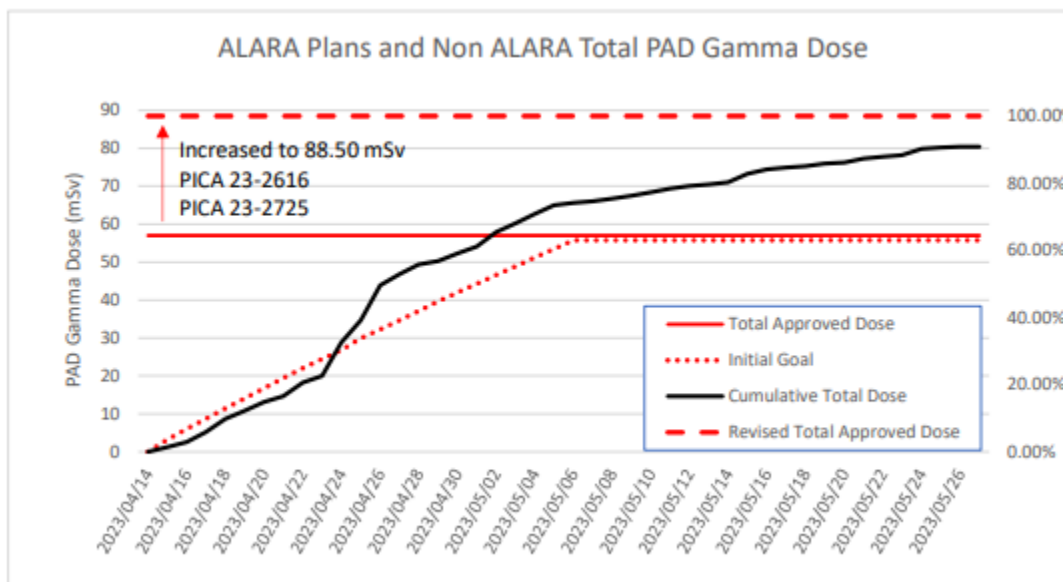
### **First Aids:**

There outage target for first aids for the O23 was <13. the 3 first aids are listed in Appendix A.

### 3.3 Control Dose

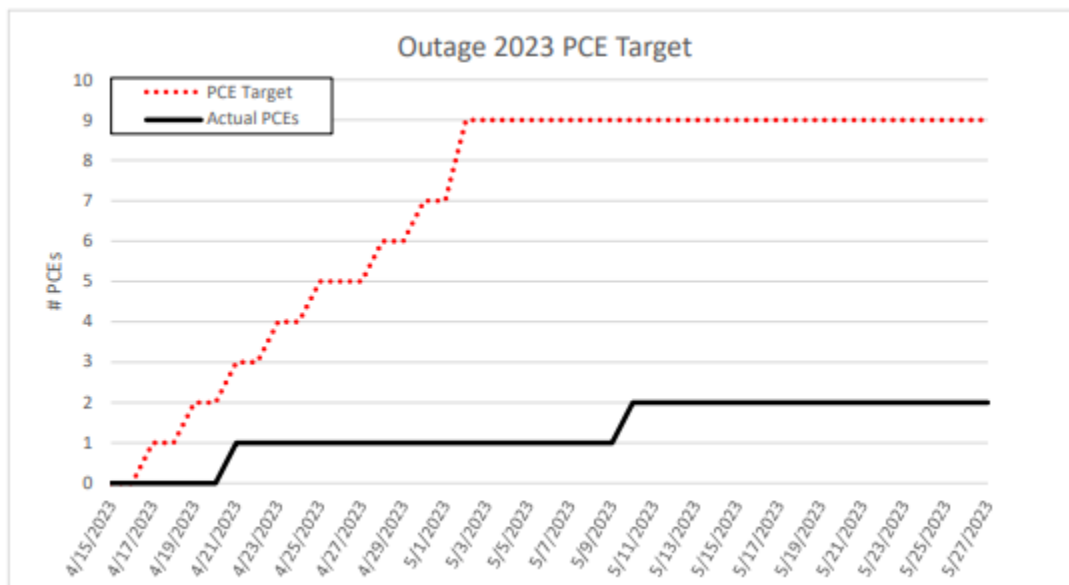
**Whole Body Dose:** The ALARA Committee set an outage target of  $\leq 88.50$  mSv, 8.50 mSv for ALARA plan dose and 80.0 mSv for non-ALARA plan dose. The actual dose was 80.38 mSv, 7.96 mSv for ALARA plan dose and 72.42 mSv for non-ALARA plan dose, which was below the target. A breakdown of actual dose measurements by major job and work center is available in *Appendix D, Dose and Personal Contamination Events*.

	Daily Total (mSv)	Daily Target (mSv)	Outage Total to Date (mSv)	Outage Goal (mSv)	% of Total Approved
ALARA Plan Dose	0.01	0.05	7.96	8.50	93.65%
Non-ALARA Plan Dose	0.18	2.10	72.42	80.00	90.53%
Outage ACEMAN Dose	0.19	2.15	80.38	88.50	90.82%



### 3.3 Control Dose, Continued

**Personal Contamination events (PCE):** The outage target was  $\leq 9$  PCE's, the actual was 2 which was below the target. A breakdown of actual PCE's is available in *Appendix D, Dose and Personal Contamination Events*.



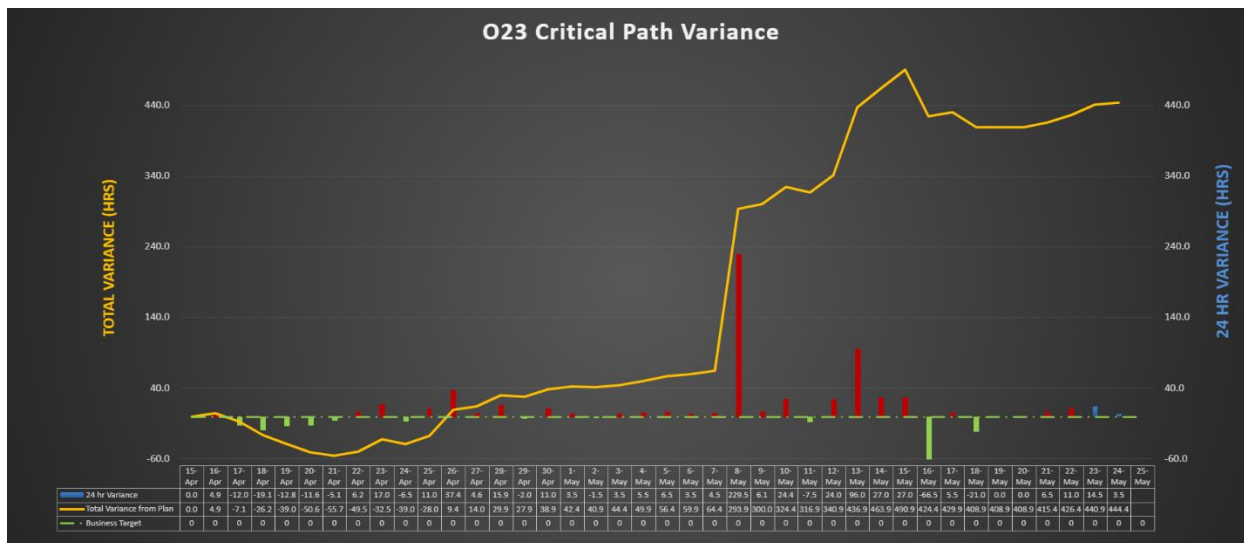
### 3.4 Event Free

**Category 1 or 2 PICA's:** The Outage target for category 1 or 2 PICA's for the following areas was 0. This target was achieved with 0 category 1 or 2 PICA's being recorded.

- Challenge Shutdown Safety
- Inadequate contractor oversight
- Radiation Protection Incident
- Actual or Potential impact on environment.

### 3.5 Meet Commitments

**Outage Duration:** The planned outage duration target was 22 days and the Business objective plan was 27 days (breaker to breaker). The actual duration was 40D 6H which did not meet either of our targets. Significant delay was encountered due to a Human Performance procedure issue on coupling up of the PHT PM-4 to the pump seal causing mechanical seal failure on start-up. The graph below shows the overall outage and additional details are documented in Appendix B.



### **3.6 Attend Training**

Delays in scheduled focus work due to untrained or unqualified staff.

There were zero delays due to lack of unqualified or untrained staff this did meet the target of zero.

### **3.7 No Rework**

Continuous days of high-power operation after the outage: The “no rework” target was  $\geq 100$  days of Continuous high-power operation after the outage. This target was met.

### **3.8 Lessons Learned PICA**

A comprehensive review of Lessons Learned for Outage 2023 (PICA 23-7003) was completed with 6 actions. All actions are being tracked to completion against either O23 Milestone 27 or O24 Milestone 33 Lessons Learned Incorporated into Outage Strategy. Due 2023-01-20/2024-01-12. See Appendix F for specifics on Outage Lessons Learned.

## 4.0 Nuclear Safety

### 4.1 Defense in Depth

The Pre-Outage Defense in Depth information report (0087-01430-2023-001-IR-A-00) for planned outage 2023 was formally issued on 2023-02-21. A revision was issued on 2023-04-18 to reflect changes made up to the start of the outage. This report addresses activities from the original rundown, through run up.

### 4.2 Probability Safety Analysis (PSA)

A PSA risk profile was created for the outage to represent the plant total risk created by the planned maintenance and unavailability of risk significant systems and components. The risk profile was employed as a tool for use in outage preparation to understand and minimize risk by risk-informed planning. There are two quantitative risk metrics which are considered in the risk profile, Severe Core Damage Frequency (SCDF) and Large Release Frequency (LRF).

The Risk Profile was updated daily to reflect the current configuration as the outage progressed.

## 4.2 Probability Safety Analysis (PSA), Continued

### Pre-Outage Risk Profile

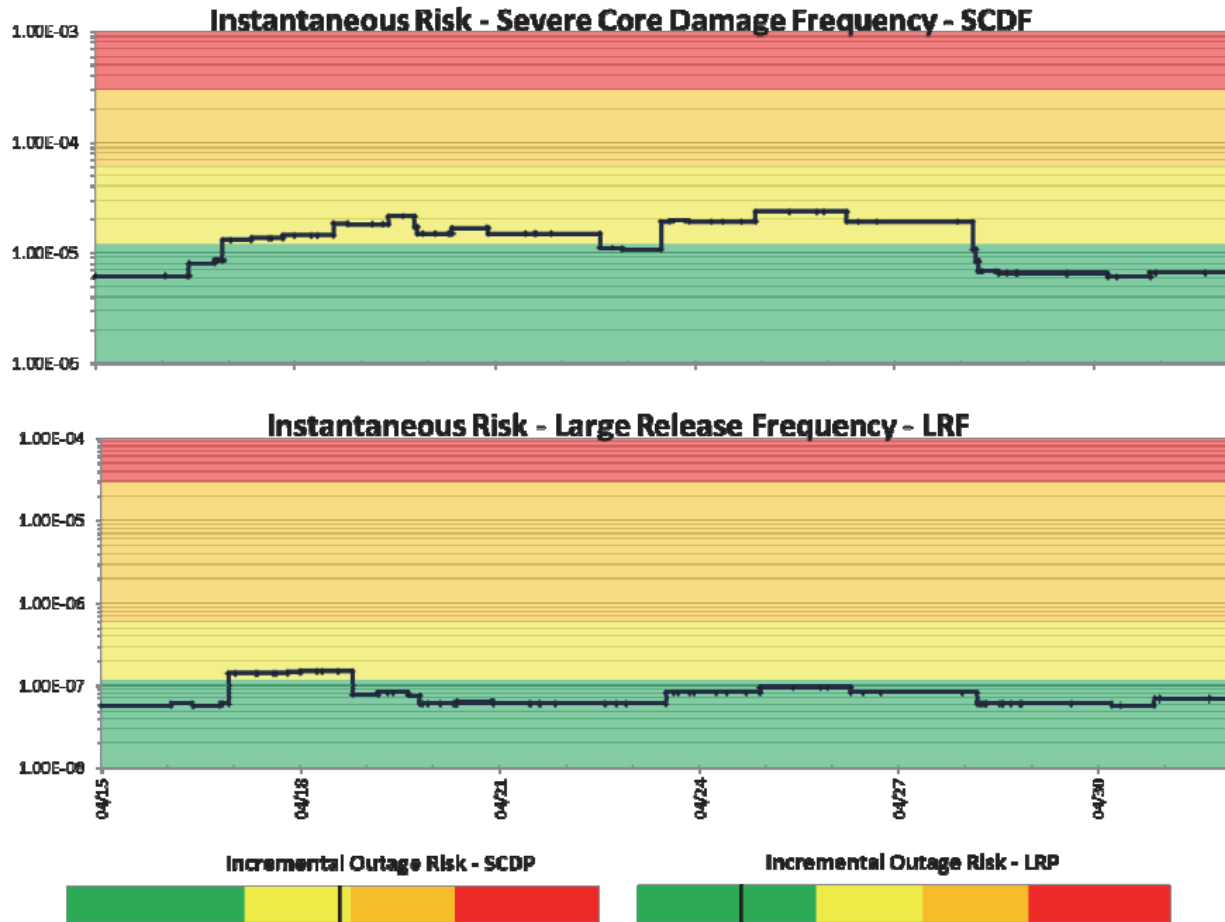
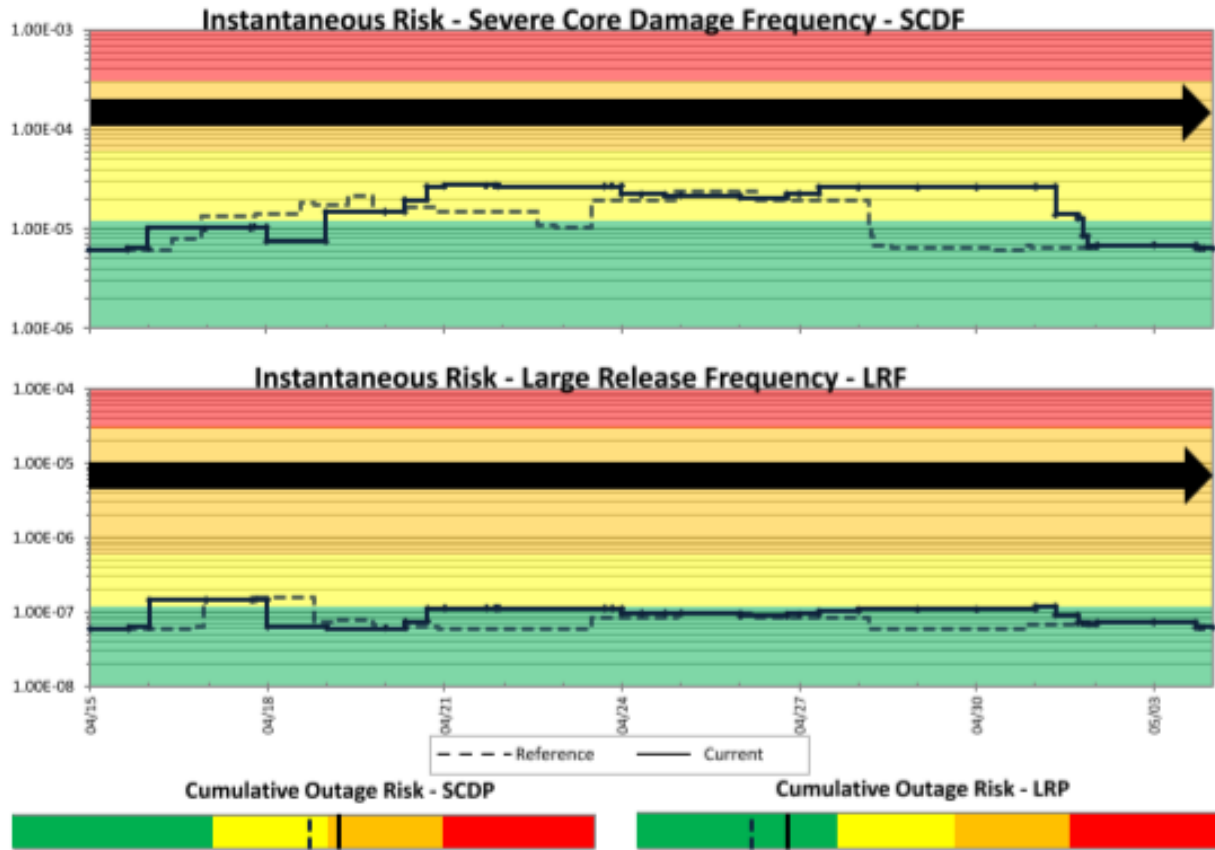


Figure 2: 2023 Outage Risk Profile (2023-03-30) (Colour)

## 4.2 Probability Safety Analysis (PSA), Continued

### Post Outage Risk Profile



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## 4.2 Probability Safety Analysis (PSA), Continued

### Pre Outage Risk Item Schedule

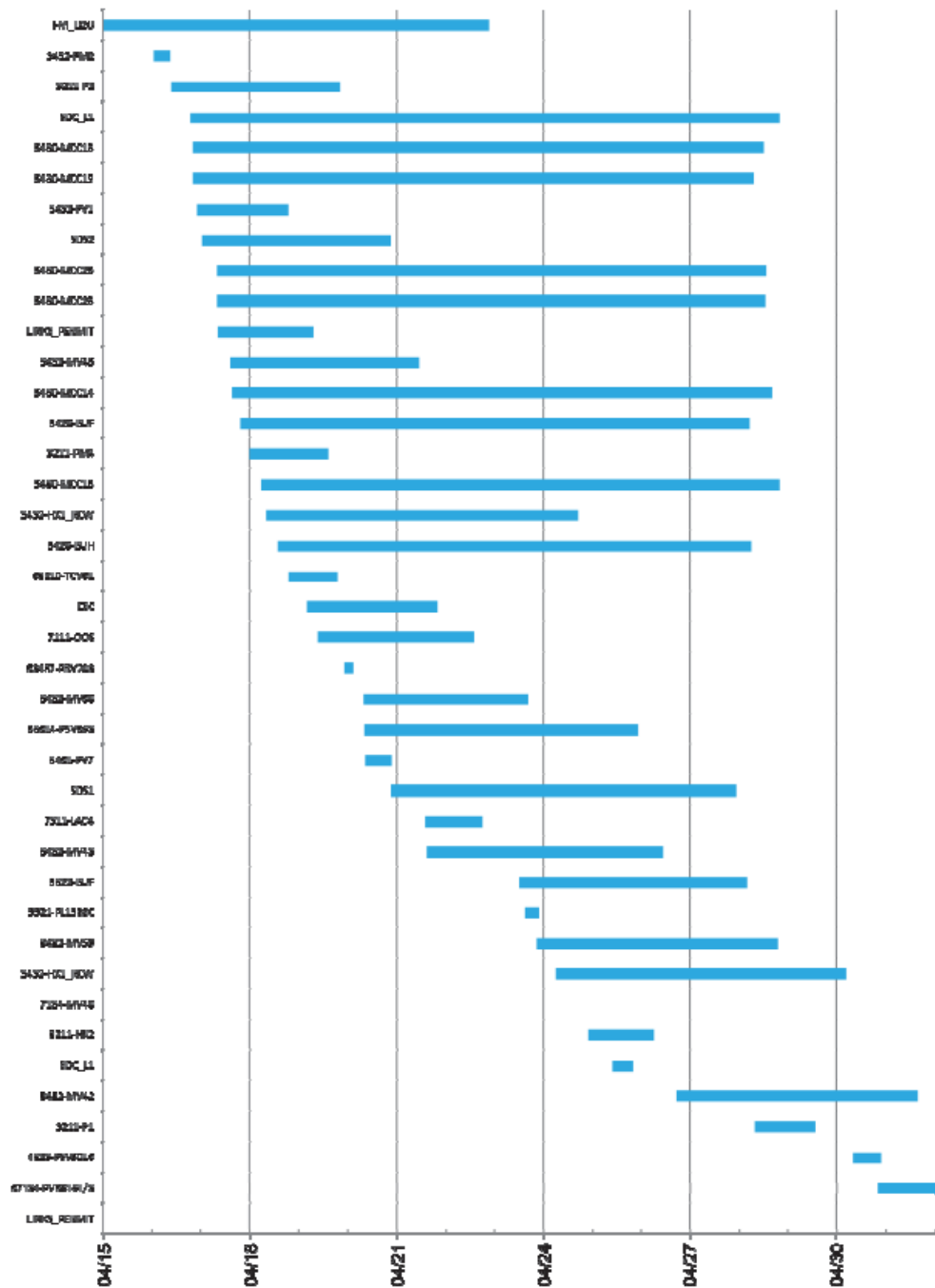


Figure 1: 2023 Outage Risk Profile Items (2023-03-30) (Colour)

## 4.2 Probability Safety Analysis (PSA), Continued

### Pre Outage Risk Item Schedule



## 5.0 Outage Performance Metrics

### 5.1 Outage Budget

The multi-year outage cost was \$28,953,498 versus a target of \$24,867,344.

Outage 2023			
Cost Element	FY23 Pre-Outage	FY24 Outage Execution	Total O23 Actuals
Labour - Regular	1,017,199	5,812,586	6,829,785
Labour - Terms & Casual	9,557	161,961	171,518
Labour - Staff Overtime	247,232	7,355,800	7,603,032
Labour - NMA	106,222	5,416,844	5,523,066
Materials	1,119,510	2,316,528	3,436,038
Hired & Professional Services	74,887	3,839,421	3,914,307
Overhead	201,699	1,174,890	1,376,589
Other	615	98,548	99,163
<b>Total</b>	<b>2,776,922</b>	<b>26,176,576</b>	<b>28,953,498</b>
<b>Budget</b>	<b>3,200,000</b>	<b>21,667,344</b>	<b>24,867,344</b>
<b>Variance</b>	<b>- 423,078</b>	<b>4,509,232</b>	<b>4,086,154</b>

Outage preparation actuals for FY23 was \$2,776,922 versus a budget of \$3,200,000. Outage execution actuals for FY24 was \$28,953,498 versus a budget of \$24,867,344. Variance was attributed to outage extension and cost associated with addressing emergent issues. See Appendix E for the day-by-day charges.

## 5.2 Outage Milestone Performance

Outage Milestones were established in accordance with station governance *SI-01365-P074*. With a total of 47 Preparation and 2 post outage milestones identified for Outage 2023, this was a decrease of 7 milestones based on lessons learned. There were 2 missed milestones in the preparation for O23. Summary of outage milestone achievement is as follows:

### Pre outage Milestones

#### O23 Milestones

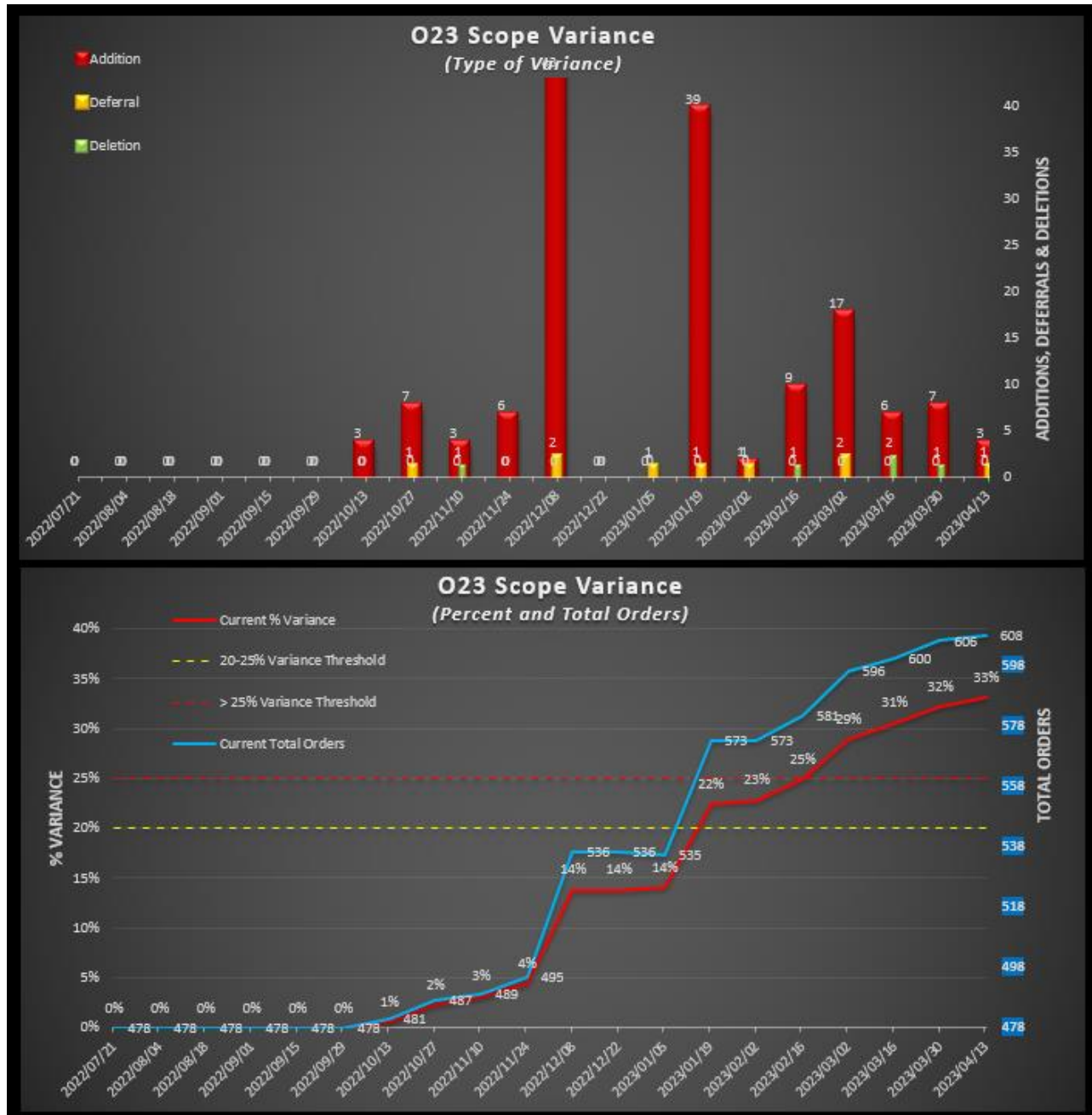
Milestone Number	ASSIGNED TO	STATUS	Milestone Name	START DATE	END DATE	Days to Milestone	DURATION days	Actual Completion	COMMENTS	STATUS
1	VP Nuclear	Complete	Outage Target Goals and Objectives	2022/02/01	2022/04/14	✓	134	2022/03/25		Not Started
2	Outage Manager	Complete	Major Work Scope Identified	2022/02/01	2022/06/14	✓	134	2022/03/25		In Progress
3	Engineering Director	Complete	Proposed Scope Identified by Engineering	2022/06/09	2022/06/24	✓	16	2022/06/24		Complete
4	Outage Manager	Complete	Detailed Scope Freeze	2022/06/04	2022/07/22	✓	29	2022/07/22	NSOC required for PHT Pump Screen Inspections.	Missed
5	Outage Manager	Complete	Preliminary Outage Budget Developed	2022/06/09	2022/09/02	✓	86	2022/09/02		At Risk
6	Work Management Manager	Complete	Level 1 Assessments Complete	2022/06/09	2022/09/16	✓	131	2022/09/16		Completed Late
7	Operations Manager	Complete	Operations Level 1 Review	2022/06/09	2022/09/16	✓	131	2022/09/16		
8	Outage Manager	Complete	Work Assigned to Reforming Organization	2022/07/22	2022/09/23	✓	64	2022/09/23		
9	Outage Manager	Complete	Pre-Outage Preparation Organization Identified	2022/07/22	2022/09/23	✓	64	2022/09/23		
10	Outage Manager	Complete	Schedule Rev A Issued	2022/07/22	2022/10/07	✓	78	2022/10/07		
11	Supply Manager	Complete	Long Lead Materials Identified	2022/07/22	2022/10/07	✓	78	2022/10/07		
12	Supply Manager	Complete	Long Lead Materials Ordered	2022/07/22	2022/11/25	✓	127	2022/11/25	Adjusted date as per PICA 22-5937	
13	Engineering Director	Missed	HENGs Cleared	2022/07/22	2022/10/14	✓	85	2023/01/12	Recovery date 2023/02/28	
14	Outage Manager	Complete	System Window Strategies Complete	2022/07/22	2022/10/14	✓	85	2022/10/14		
15	Training Manager	Complete	Training Needs Identified	2022/08/12	2022/11/17	✓	98	2022/11/17		
16	Work Management Manager	Complete	Assessments Complete	2022/07/22	2022/11/18	✓	120	2022/11/18		
17	Work Management Manager	Complete	Pre-Req Orders Scheduled	2022/07/22	2023/01/06	✓	169	2023/01/06	This aligns with E-14	
18	Work Management Manager	Complete	On-line Work for the Outage Identified	2022/07/22	2022/11/25	✓	120	2022/11/25	The aligns with E20	
19	Outage Manager	Complete	Outage Budget Finalized	2022/09/02	2022/12/22	✓	112	2022/12/22		
20	Regulatory Affairs Manager	Complete	Regulatory Approval Requests Submitted	2022/11/17	2023/01/26	✓	71	2023/01/24		
21	Operations Manager	Complete	Work Clearance Block-Sub-Block Preparation Complete	2022/07/29	2023/01/20	✓	174	2023/01/18		
22	Outage Manager	Complete	Schedule Rev B Issued	2022/10/09	2022/11/23	✓	76	2022/12/23		
23	Outage Manager	Complete	Outage Control Center Staffing Finalized	2022/10/28	2023/01/20	✓	85	2023/01/19		
24	Training Manager	Complete	Contractor In-Processing Plan Finalized	2022/10/09	2023/01/05	✓	89	2023/01/04		
25	Outage Manager	Complete	Contingency Plans Developed	2022/09/05	2023/01/05	✓	123	2023/01/06		
26	RF Manager	Complete	ALARA Plans Issued	2022/11/11	2023/01/20	✓	71	2023/01/19		
27	Outage Manager	Complete	Lessons Learned Incorporated into Outage Strategy	2022/10/03	2023/01/20	✓	110	2023/01/19		
28	Operations Manager	Complete	Configuration Orders Complete	2022/11/11	2023/01/20	✓	71	2023/01/19		
29	RF Manager	Complete	Eradication Exposure Permits Approved	2022/11/11	2023/01/20	✓	71	2023/01/19		
30	Outage Manager	Complete	Challenge Meetings Complete	2023/01/09	2023/02/17	✓	40	2023/02/17		
31	Supply Manager	Complete	Material On-Site or Dispositioned	2022/09/23	2023/02/10	✓	141	2023/02/10		
32	Operations Manager	Complete	Work Clearances Prepared	2022/08/07	2023/02/17	✓	195	2023/02/17		
33	Outage Manager	Complete	Schedule Rev C Issued	2022/12/11	2023/02/17	✓	69	2023/02/17		
34	Outage Manager	Complete	Horizontal Schedule Review Complete	2022/12/04	2023/02/02	✓	61	2023/02/02		
35	Outage Manager	Complete	Space Utilization Plan Finalized	2022/11/11	2023/02/02	✓	84	2023/02/02		
36	Operations Manager	Complete	Operational Procedures Revised	2022/11/11	2023/02/02	✓	84	2023/02/01		
37	Operations Manager	Complete	Water Management Plan Established	2022/11/11	2023/02/02	✓	84	2023/02/02		
38	Maintenance Manager	Complete	Crane Utilization Plan Established	2022/12/09	2023/02/17	✓	71	2023/02/17		
39	Outage Manager	Complete	Vertical Schedule Review Complete	2022/12/09	2023/03/03	✓	85	2023/03/03		
40	Reactor Safety Manager	Complete	Shutdown Safety Review Complete	2022/12/12	2023/02/17	✓	68	2023/02/17		
41	Outage Manager	Complete	ACEMAN/Outage Dose Targets Established	2022/10/28	2023/02/24	✓	120	2023/02/24		
42	Maintenance Manager	Missed	Walkdowns Complete	2022/11/07	2023/02/24	✓	110	2023/02/24	Placed at risk on 2023-01-25	
43	Outage Manager	Complete	Critical Path Challenge Meeting	2023/01/29	2023/03/17	✓	48	2023/03/17		
44	Outage Manager	Complete	Schedule Rev D Issued	2023/01/29	2023/03/24	✓	55	2023/03/24		
45	Training Manager	Complete	Outage Training Complete	2023/01/01	2023/04/07	✓	97	2023/04/07		
46	Maintenance Manager	Complete	Pre-Req Orders Complete	2022/11/07	2023/04/14	✓	129	2023/04/14		
47	Outage Manager	Complete	Outage Start	2023/04/15	2023/05/06	✓	22	2023/05/06		
48	Work Management Manager	Complete	Post-Req Orders Complete	2023/05/06	2023/09/15	✓	133	22/08/2023		
49	Outage Manager	Complete	Post Outage Order Clean-up	2023/05/06	2023/06/18	✓	106	22/08/2023		

### Execution Milestones

Milestones	Owner	Baseline		Current		Variance to Baseline (h)	
		Start	Finish	Start	Finish	Start	Finish
1		2023/04/12 18:30		2023/04/12 18:30		0.0	0.0
2		2023/04/14 23:00	2023/04/16 10:36	2023/04/14 23:00	2023/04/16 14:31	0.0	3.9
3		2023/04/17 14:30	2023/05/01 16:00	2023/04/18 00:00	2023/04/26 00:00	9.5	-136.0
4		2023/04/18 19:36	2023/04/27 07:48	2023/04/19 00:00	2023/05/01 00:00	4.4	88.2
5		2023/04/18 22:30	2023/04/27 06:48	2023/04/17 17:30	2023/05/01 08:00	-29.0	97.2
6		2023/04/21 12:00	2023/04/27 01:48	2023/04/20 17:00	2023/04/30 20:00	-19.0	90.2
7		2023/04/17 05:30	2023/04/25 18:54	2023/04/20 08:00	2023/04/27 03:00	74.5	32.1
8		2023/04/15 22:06	2023/05/05 19:36	2023/04/16 00:00	2023/05/21 17:00	1.9	381.4
9		2023/04/18 10:00	2023/04/24 06:30	2023/04/17 19:00	2023/04/21 17:00	-15.0	-61.5
10							
11		2023/04/28 09:00	2023/04/29 09:00	2023/04/28 00:00	2023/04/30 00:00	-9.0	15.0
12		2023/04/13 19:00	2023/04/29 20:00	2023/04/13 19:00	2023/05/05 00:00	0.0	124.0
13		2023/05/02 05:06	2023/05/03 19:06	2023/05/03 17:00	2023/05/07 00:00	35.9	76.9
14		2023/05/07 01:06	2023/05/07 13:42	2023/05/25 10:00	2023/05/25 22:36	440.9	440.9
15		2023/05/08 12:36	2023/05/09 05:36	2023/05/27 09:06	2023/05/28 02:06	452.5	452.5

## 5.3 Outage Scope Change Summary

### Preparation

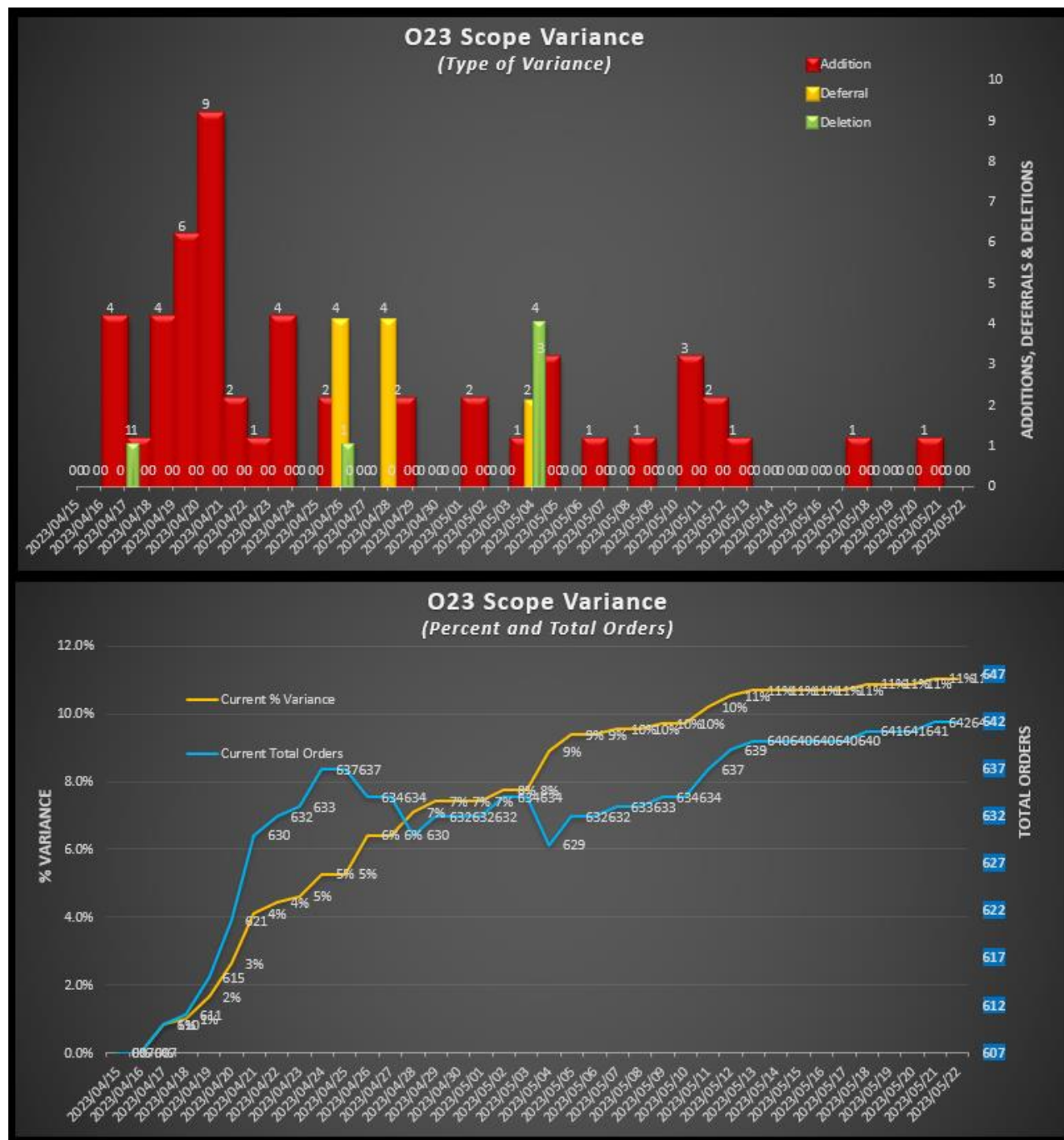


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### 5.3 Outage Scope Change Summary, continued

## Execution



## 5.4 Summary of Key Outage Metrics

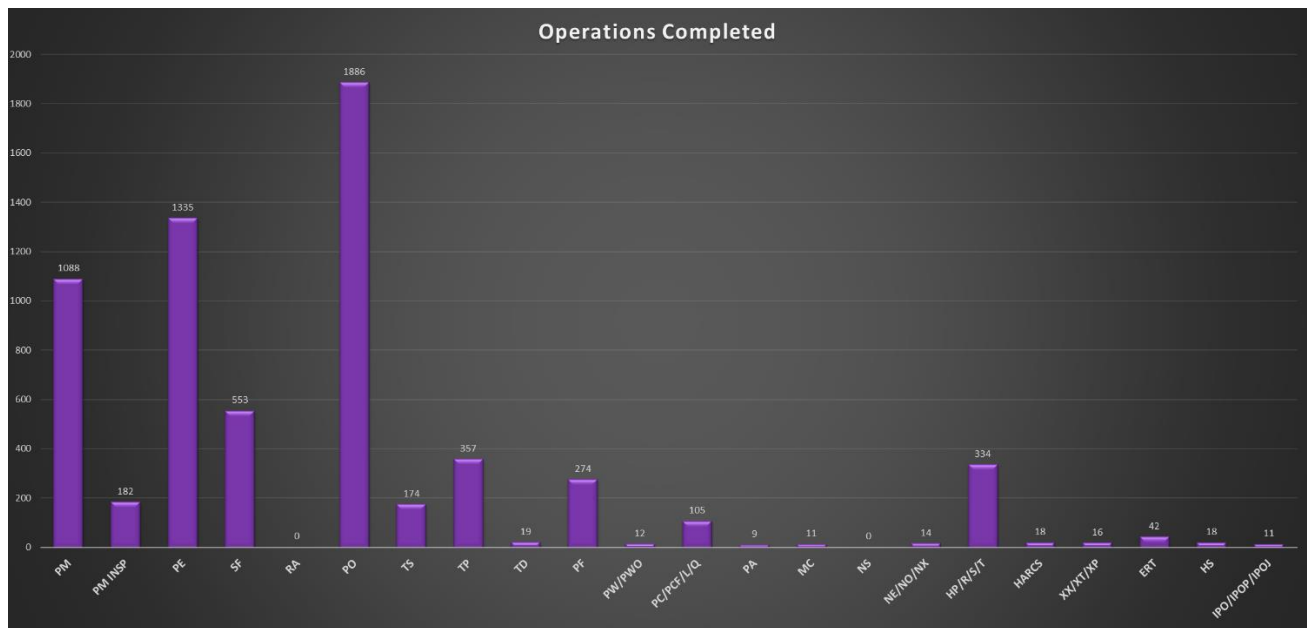
	<b>2023</b>
<b>Duration</b>	
Planned Duration (days)	27
Actual Duration (days)	40.25
Actual Maintenance Days	36
Variance (days)	13.25
Variance (% of original)	168%
<b>Scope</b>	
Initial Scope	478
Orders added (pre-outage)	144
Orders Removed (pre-outage)	14
Scope Variance (pre-outage)	33%
Orders added (outage)	51
Orders Removed (outage)	16
Scope Variance (outage)	11%
<b>Completion Rates</b>	
Total Orders	1199
Percent of Scope Complete (breaker open)	97.3%
Orders/Maintenance Day	9.42
Operations/Day	147
Total tasks (operations excluding PM04 and INFO)	5918
Tasks/Order	4.9
<b>Work Completed</b>	
Backlog (CC, CN, DC, DN) Completed	89
Leaks	16
Safety Orders	0
Operator Challenges	3

## 5.5 Work Center Activities Completed

### Work Orders Completed by Department



### Operations Completed by Department

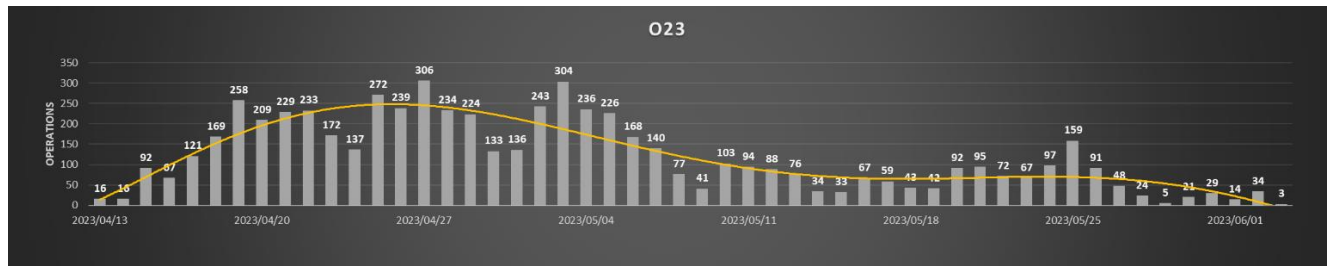


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## 5.5 Work Center Activities Completed, Continued

### Operations Completed per Day



## 6.0 NOS Outage Performance Assessment PICA-23-3533

Tracking PICA for the PLNGS Outage 2023 Performance Assessment NOS-2023-06.

During the O23 assessment window, over 100 observations were performed. In each observation, strengths and weaknesses were identified and grouped into the eight assessment evaluation criteria (six Recovery Plan gaps and two Nuclear Oversight (NOS) Escalations) as applicable. Based on the evidence collected during the performance assessment, some Recovery Plan gaps, and NOS Escalations are on track to being resolved; however, there remains areas requiring additional actions to ensure future resolution and success. A breakdown of insights from observations, Recovery Plan actions and recommendations for each evaluation criteria are included in the report. As the performance assessment scope was based on known gaps, the assessment findings are improvements for the Recovery Plan actions to support closure of the gaps.

Two category 4 findings resulted from this assessment. All findings were categorized in accordance with SDP-01368-CA04, Screening a PICA (Revision 40).

The category 4 findings represent areas for opportunities to improve. The first finding contains a summary of the recommendations for five of the six recovery plan gaps. There were no recommendations for additional actions on the Equipment Reliability (ER) gap, as the actions associated with ER behaviors are covered in section 1.1 and 1.6 of the recovery plan and the self-assessment to identify additional actions is in progress. The second finding is related to unclear Compliance vs Excellence thresholds, where unclear thresholds can lead to rationalization when interpreting expectations and can constrict improvements into compliance solutions, making gaps more significant. No findings were provided for the two NOS Escalations since the rubber area housekeeping showed improvement and the actions to improve forms and records were recently implemented and are in progress.

The following PICAs have been raised to document the findings associated with this performance assessment:

PICA 23-3534 Finding #1 (Recommendation): Additional Actions Required to Support Closure of Recovery Plan Gaps

PICA 23-3535 Finding #2 (Area of Interest): The Station Does Not Have a Clear Model for Achieving Compliance and Striving for Excellence

## Appendix A: Safety Statistics

2023 - Outage (22 days)				
Incident Outcome	Target	Total	Contractor	NBP
Medical Aid	0	1	0	1
First Aid	<13	3	1	2
High Potential	0	2	0	2
Work Protection				

E-Form #	Prepared on	Date	Work Group	Primary	Incident Outcome	Body Part	Incident Description
1903557	2023/04/17	2023/04/27	Supply	Employee	First Aid #1	Finger	went into the barn located outside in the cable yard to retrieve a crate. (It was dark and the only light source was from the light coming through the open door.) lifted a crate and it slipped and when i tried to grab it finger got caught between the lid and the crate which resulted in finger tip getting pinched. was wearing leather work gloves at the time which prevented more serious damage.
1905449	2023/04/20	2023/04/20	Health & Safety	Contractor	First Aid #2	Finger	While conducting a Work Site Inspection a Regulator attempted to operate the emergency eyewash & shower valve. The Regulator received a small cut on their left index finger. Regulator received minor first aid and continued Inspection.
1907562	2023/04/26	2023/04/26	Operations	Employee	First Aid #3	Knee	Employees vehicle made contact with Deer while driving on site, Employee's knee made contact with Dash when they applied brakes
1916602	2023/05/16	2023/05/16	Facilities	Employee	Medical Aid	Shoulder	The two individuals were stripping the floor and applied rip saw to the floor to help remove the wax .After waiting 10 mins One of the individuals got up and slipped on the floor causing her to hit her head and land on her left shoulder.
1913980	2023/05/09	2023/05/09	Projects	Contractor	Near Miss		Roofers installing a rubber membrane roof at Construction stores did not weigh down the insulation foam boards when they stopped for a break. The wind blew 2 - 1/2" thick polyiso foam sheets (4' x 8') and 2 - 1" thick styrofoam strips (8" x 8') off the main roof to a lower roof and down to the ground.
1919245	2023/05/23	2023/05/23	Operations	Employee	Near Miss		While in operation with and operator in attendance, the boiler gage glass failed immediately filling the boiler enclosure with steam. The operator immediately exited the enclosure and called supervision. Replacement Aux. Boiler was shut down as per procedure, gage glass was isolated, PICA 23-2898 filed.

## Appendix A: Safety Statistics, Continued

E-Form #	Prepared on	Date	Work Group	Primary	Incident Outcome	Body Part	Incident Description
1904717	2023/04/19	2023/04/18	Projects	Employee	Proactive Catch		While supplying nitrogen for an ice plug on a 24" RCW piping in S1-009, local oxygen monitor detected oxygen levels decreasing to 19.6%. The Operator monitoring the detector requested the nitrogen supply be isolated and initiated an evacuation of the work area. The evacuation was initiated prior to reaching the alarm set point for oxygen, set at 19.5%.
1907973	2023/04/23	2023/04/23	Operations	Employee	Proactive Catch		Work scope for stator cooling system had 6 work orders of scope of work, to replace 4124-V047, V003, V005, V006, replace LLS-3#3 and replace 4124-V030 (hot work). 1 work permit covered all 6 work orders. Work Clearance Application Instructions to Holder section referenced to check the components internal hydrogen LEL prior to commencing work and that hydrogen monitor is to be used for entire maintenance. The Generator degas was started 6 days prior to work commencing, isolations established for stator cooling on April 21st. Maintenance received a green light on permit for work to commence. When the flanges were cracked on 4124-V005 & V006, gas monitoring went into alarm and off scale on LEL readings.
1906118	2023/04/23	2023/04/22	Supply	Employee	Property Damage		I was driving pickup truck 31029 and backed into car 20109's front bumper causing minor damage. backing up slowly did not see the car
1911329	2023/05/03	2023/05/03	Strategic Engineering	Employee	Property Damage		Observer noticed that a heavily loaded Bookcase may need its weight redistributed as the pins holding the shelves in place were beginning to slip out of place. This was communicated to the individual using the bookcase so that they could address it promptly. Once they began reorganizing the bookcase, the side panel ripped off the bookcase and had all its shelves fall on to the ground. The individual was not struck by any of the shelves or material it was supporting.

## Appendix B: Critical Path Variance Detailed Listing

Day	Summary of Delay
1	
2	5hr loss due to tritium levels with a packing leak on GAD mixing tank agitator and blowing down fuel handling lines limited the time the scaffold crew could work in the RB to build for PHT PM-4.
3	(12 total gain) Gained 6 hours for removing electrical testing from PM-4 logic as it was not required and gained 6 hours on electrical disconnect of PM-4.
4	(19.1 total gain) Completed the coupling removal and shaft hold down device in 12 hours that was assessed for 24. (12-hour gain). Install Carriage assembly completed 4 hours completed off critical path (4 hour gain). Instrumentation and brake assembly coordinated for efficiency to gain 3 hours
5	(12.8 total gain) As found alignment checks was completed in 6 hours (Gain of 6). Good 10/30/60 between OPS/PEE/PMD for installing jacking oil permit, isolation walkdown (gain 1 hour). Coordination of disconnecting jacking oil PM and draining of oil scheduled for 14 hours completed in 12 (2-hour gain). Removing of brake drum not required as critical path activity. (4-hour gain).
6	(11.6 total gain) Efficiencies in repacking the D2O isolators. This is in part due to worker proficiency as well as the packing removal going better than expected with use of the packing blow out tool. The blow out of the packing going well is often by chance as sometimes it doesn't come out as a whole and requires use of picks and vacuum to remove it in pieces.
7	Coordinating PHT PM-4 scaffold build with seismic restraint install reduced the overall length of the string which removed the PHT PM-4 from critical path. The next closest job was the Class III work which only had 5 hours of float. The new critical path is class III.
8	6 hours lost due to modifications for 7512-CP-902 taking longer than assessed as part of 5420-BUH maintenance. PICA 23-2270
9	17 hours lost due to modifications for 7512-CP-902 as part of 5420-BUH maintenance. Originally on 2023-04-22#2 shift resources were being coordinated to come in on nights for walkdowns, QA checks and fire barrier maintenance. Individuals left site to come back when ready. It was identified late in the shift that an additional 12 hours would be required to complete the modifications because when it was walked down by the lead designer it was identified that the cables had to be pulled through a CT which was not identified in the package. It then took an additional 5 hours to remove grounds and STST permit. PICA 23-2315
10	(6.5 total gain) 7-hour loss due to shift supervisor not allowing maintenance on 5322-BUF to progress in parallel while the permit was being removed from 5420-BUH as the schedule showed. 3.5-hour gain with pulling the permit for 3211-PM-2 back to be installed in parallel as the permit is being removed for 5322-BUF 10 hour gain with paralleling testing BUF cables and potential transformers.
11	(11-hour loss) 5hrs to repair cable, which was longer than the original maintenance string, 6 hrs. due to retesting cables after repairs. PICA 23-2393
12	(37.4 total loss) All hours are attributed to the estimated time it will take to repair the cables feeding 5322-BUF transformer. Same PICA as previous day.
13	(4.6-hour loss) Time attributed to continued repair of the cables feeding 5322-BUF transformer. Same PICA as previous day.
14	(15.9 total loss) Took an additional 8 hours to complete repairs of cables and had to remove one of the stress cones and complete again as it was installed incorrectly. The assessment was completed to install the TA for bus bar extension and added 8 hours. The original reconnect was 4 hours and with the new bus bar it was 12 hours.

**Appendix B: Critical Path Variance Detailed Listing**, Continued

15	Gained 2 hours on the cable reconnects.
16	(11 hr. Loss) PHT PM took over critical path and lost 6 hours due to taking longer to complete the SOS and getting the permit off. The functional location tags were not transferred to the new motor which had to be completed before the SOS. It also took 11 hours to coordinate and complete a 4-hour uncoupled test run of the motor. We did leave critical path through the Class III work as that was a higher risk evolution and had a low float of 7 hours.
17	3.5 hour lost due to replace FE-150. The original critical path was through moderator PM-2 testing but the FE took over as they were parallel jobs. There were multiple reasons for the job extension: ANI holds took longer to get resolved due to fit up interpretation of the code, the welding took longer than assessed and the new FE was bigger than the original and required additional tubing modifications.
18	(1.5-hour total Gain) Lost 6 hours on the moderator electrical and mechanical inspections. The logic had the work being completed in parallel, but the permits did not allow them to be completed at same time due to electrical testing. The mechanical work had to be completed at the same time as the reconnect of the motor. Removed the 24-hour contingency time built into the schedule, when it was removed it revealed that the LOG N trip setpoint adjustment that was in parallel took up the majority of that time. After some investigation it revealed that the assessed hours for each channel was adjusted from 1 hour to 6 hours. This was changed after the LOG N trips were installed and it took more time than assessed.
19	3.5 hour lost due to a loose spanner nut on the moderator PM-1 breaker. When trying to torque the cable in the back of the cell the bottle was turning. Had to create a new order/permit to remove the grounding device, open the shutter and tighten the nut. This prevented getting into the test run.
20	(5.5 total loss) We missed a logic tie; we had approach to critical before we refilled and vented the spool piece which was a 4-hour activity. We also lost 1.5 hours at start of shift before we started the OPGSS removal permit.
21	Added 6.5 hours to start up as a contactor failed on one of the pressurizer heaters which delayed the warmup and pressurization of the pressurizer
22	Took longer than scheduled to finish heating up the pressurizer and parallel the PZR with main heat transport system.
23	ECC testing was assessed for 24 hours but it took 28.5 hours.
24	Initial estimate to replace the failed seal that occurred on Run up.
25	Added 6 hours into the schedule for measurements to be taken while removing the schedule
26	(30.4 total loss) 13 hours lost on the drain down partially due to 3341-MV-28 failing to open to drain the system and tried to troubleshoot but ended up manually opening the valve and had to wait to depressurize the PHT system of N2 before entering the pump bowl as the seal was passing. Added 4 hours into the schedule for testing after coupling removed, added 6 hours as an estimate to inspect the shaft. 1 hour added as a hold point to confirm EVAL is completed before motors are started.

**Appendix B: Critical Path Variance Detailed Listing**, Continued

27	The next 5 days are all attributed to the seal failure and the issues with getting the seal off the shaft as well as all the inspections, measurements and testing required.
28	
29	
30	
31	
32	Reduced the time to do ECC testing and tied GSS to after removal of drain down permit instead of non-rotation permit which is used for uncoupled run and coupling the motor back up.
33	Added additional measurements for the run out checks on the rotating element that was not identified in the original assessment, it was identified after the spool and coupling were removed. Mechanical had to re-install coupling/spool take measurements then remove again to install the seal.
34	Efficiencies in hand offs while installing seal, coupling motor and starting refill of PHT system pulled string ahead.
35	
36	
37	Took longer to get through ATC then pressurize and heat up the PHT system than planned.
38	Emergent issue on ECC CH "L" 980924 delayed ECC testing. 6Hr OMT-63432-01 was brought into the ECC testing window by the SS due to having the breakers open during the drain down window.
39	POT testing was not incorporated into run up and additional testing that was brought in as a result of outage extension attributed to extensions. PICA's 23-2896 & 2884 were raised.
40	3.5 hours lost due to an impairment's manual does not have a valid impairment value for power less than 60% PICA 23-2909

## Appendix C: Emergent Major Work Scope

Main WorkCtr	Function Location	Description
PMC	0781-4521-L-57	Replacement of Line 4521-L-57 (STD166)
PMD	0781-3312-PM-4	Change Out PHT Motor 3312-PM-4
TPM	0781-2300	Complete Forebay Cleaning
PEI	0781-63470-LI-45	CHALLENGE: 63470-LI-45 PB2 and 4 not working
PEI	0781-64115-PC-15	Replace 64115-PC-15
PMB	0781-64313-LCV-115C	Replace 64313-LCV-115C Packing
PMD	0781-3481-CPM-1	Replace Motor Bearings and Perform Re-al
TPTM	0781-4113-V-5012	Replace Valve 4113-V-5012
PMB	0781-4124-V-006	Passing isolation valve
PMD	0781-4124-V-005	4124-V5 is passing
PMB	0781-4124-V-047	Inspect/Replace Check Valve as required
PMD	0781-4124-V-048	Inspect/Replace Check Valve as required
PMD	0781-4124-V-003	Replace valve
PMB	0781-63614-PCV-16	Visible Steam leak on PCV16
PMB	0781-63614-PCV-18	Steam Leak on CSDV 18
PEI	0781-64321-LS-148	Replace Float
TPTM	0781-4113-V-5014	Replace Valve
TPTM	0781-4113-V-5014	Replace Valve
TPTM	0781-4113-V-5006	Replace Valve
TPTM	0781-4113-V-5006	Replace Valve
PMC	0781-4124-V-030	Pinhole Leak on Weld Upstream of V30
PMRV	0781-63614-PSV-6#3	Overhaul 63614-PSV-6#3 as it is leaking
PEEV	0781-4323-MV-070	4323-MV-070 is passing
PMB	0781-4521-DP-20	Drip pocket flange steam leak
PEEV	0781-3432-MV-71	Overhaul Actuator of 3432-MV-71
PEEV	0781-3432-MV-72	Overhaul Actuator of 3432-MV-72
PEE	0781-3432-PM-2	Electrical testing 3432-PM-2
PMB	0781-4134-P-102	Oil Leaking from Seal Oil Pump
PMRV	0781-4134-PRV-26	Erratic Operation -Overhaul/swap 4134-PR
PMC	0781-4100-V-37	FRF leaking weld
PMRV	0781-4323-PSV-5016	Bench Test 4323-PSV-5016
PMB	0781-7311-F-54	DE Fan Bearing Requires Replacement
PMP	0781-3432-EJ-1	Boroscope Inspection of 3432-EJ1 Liner
PMRV	0781-7134-PSV-987	Bench Test 7134-PSV-987
PMC	0781-7512-IAS-029V9	Repair Air leak at 7512-IAS-029V9
PMB	0781-7131-V-036	Replace Valve (Cannot Isolate RCW HX803)
PMB	0781-3335-MV-4	Swap actuator with spare
TSBB	0781-64100-PL-610	Perform OS Status Checks O23
PMRV	0781-7134-RV-204	Bench Test 7134-RV-204 (3335-HX-2)
PMC	0781-2280-DR-107	Weld Repair Required on 2280-DR-107
SFSB	0781-3431-VB-1	Access Port In 3431-VB-1 Not Sealed
PEI	0781-63410-TCV-15	TCV-15 will only stroke 55% open on full
PEI	0781-63210-PI-51	Low P1 outer seal pressure reading
PMC	0781-4124-TK-03	Repair / Mitigate Leak on TK-03
PMC	0781-4323-V-240	Replace Valve 0781-4323-V-240 (BYPASS VA
PMD	0781-7921-P-3	Overhaul Liquid Effluent Pump 3
PEI	0781-64324-PY-401#1	Lockout relay leaking excessive air @ PY
PMD	0781-3312-P-4	PHT P-4 Seal Activities (Prior to drain)
PMD	0781-3222-V-22	Overhaul valve/Install Repair Kit

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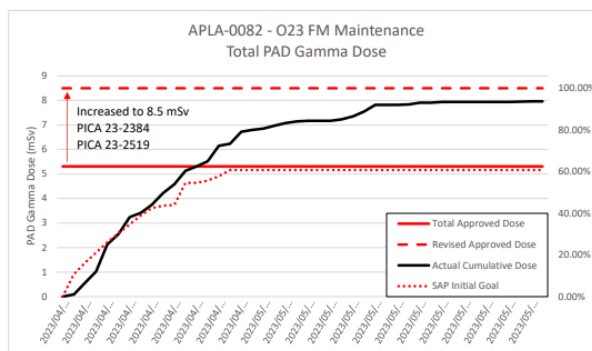
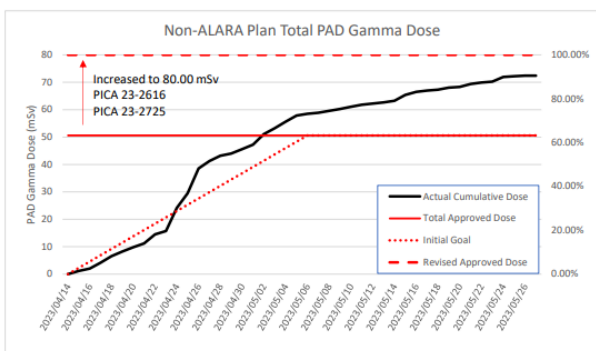
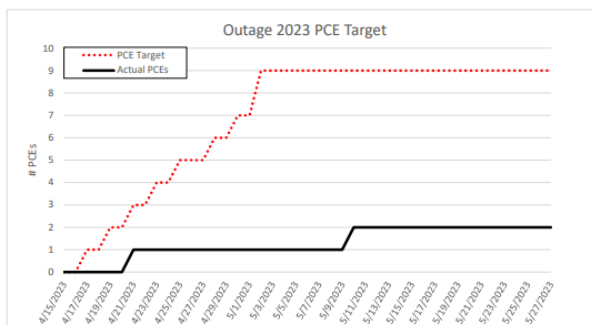
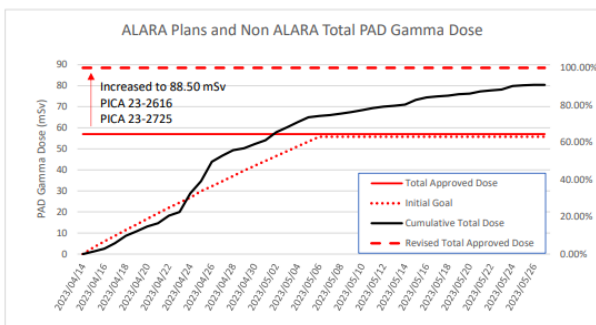
# Appendix D: Dose and Personal Contamination Events

ALARA PAD Gamma Dose Tracking and PCEs as of 2023/05/27 @17:30

	Daily Total (mSv)	Daily Target (mSv)	Outage Total to Date (mSv)	Outage Goal (mSv)	% of Total Approved
ALARA Plan Dose	0.01	0.05	7.96	8.50	93.65%
Non-ALARA Plan Dose	0.18	2.10	72.42	80.00	90.53%
Outage ACEMAN Dose	0.19	2.15	80.38	88.50	90.82%

	Daily Total	Cumulative Target	Outage Total	Outage Goal
PCEs	0	9	2	≤9
H3 Internal Dose (mSv)*	0.00	-	52.13	-

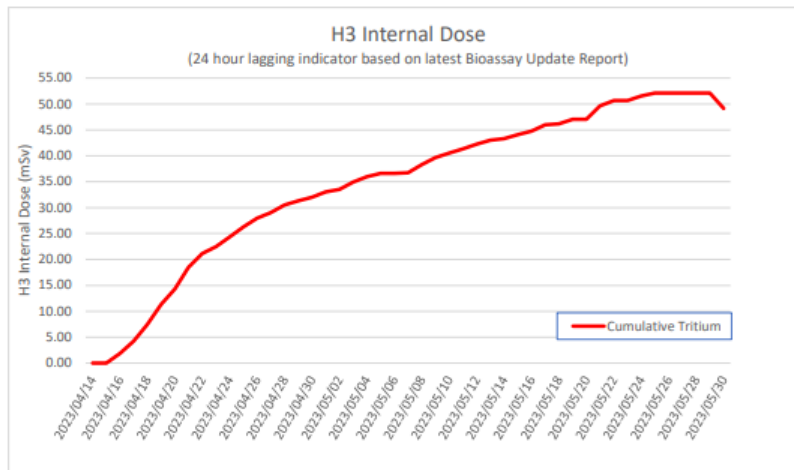
\*24 hour lagging indicator based on latest Bioassay Update Report



## Appendix D: Dose and Personal Contamination Events, Continued

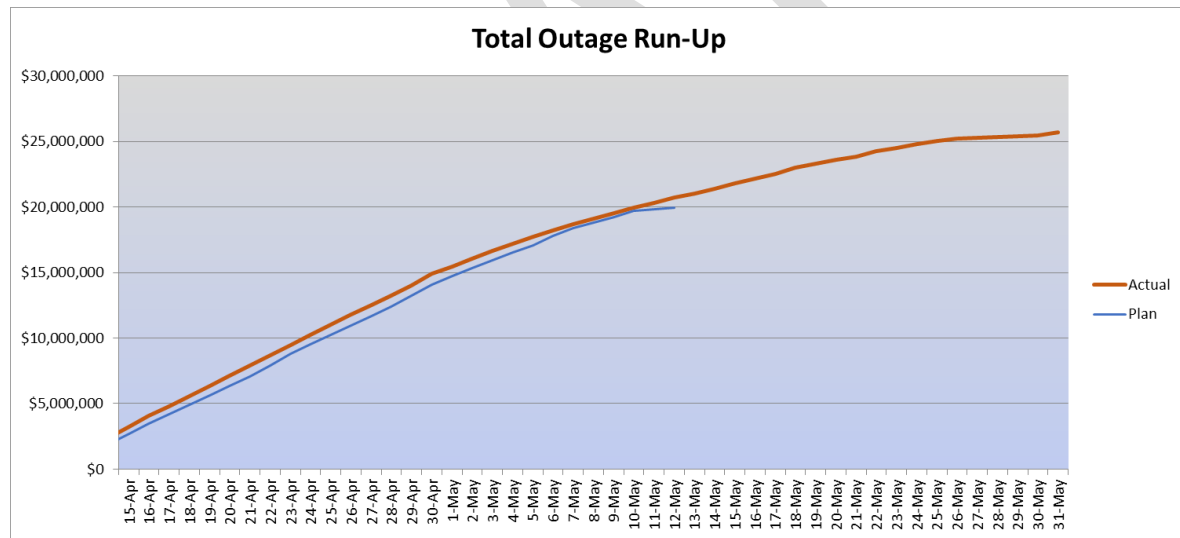
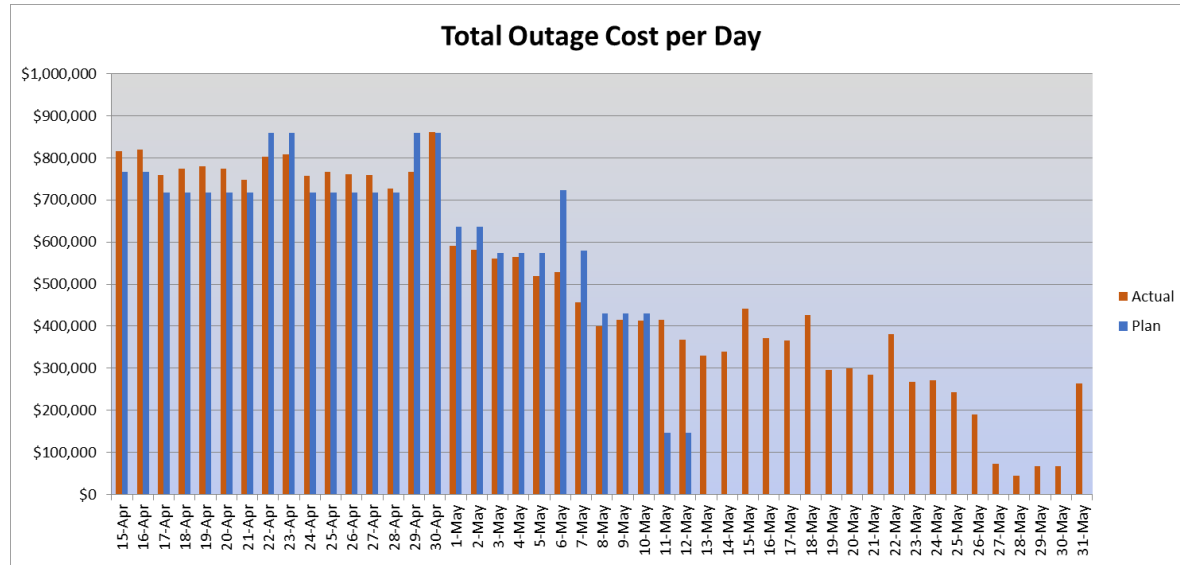
Outage 2023 ACEMAN  
ALARA PAD Gamma Dose Tracking and PCEs as of 2023/05/27 @17:30

Dose by Work Group	
Department	Total PAD Gamma Dose (mSv)
AD-ADMINISTRATION	0.02
CU-CHEMISTRY	0.98
EI-EI&C	6.77
EP-EMERGENCY PREPAREDNESS	2.04
FH-FUEL HANDLING	12.67
FM-FACILITIES MANAGEMENT	15.25
FN-FIX-IT-NOW GROUP	6.67
FS-FIRE SAFETY	1.48
HP-HEALTH PHYSICS	5.75
MM-MECHANICAL	7.33
NS-NUCLEAR SAFETY	0.07
OP-OPERATIONS	6.70
PA-PERFORMANCE ASSESSMENT	1.28
PN-PLANNING	0.05
RA-REGULATORY AFFAIRS	0.07
SE-SECURITY	0.00
SU-STORES	0.36
TC-TECH - EI&C	0.01
TE-ENG - ENGINEERING SERVICES	1.70
TP-TECHNICAL PROJECTS	8.36
TR-TRAINING	2.42
TS-ENG - SYSTEMS	0.57



PCE#	Date	PICA#	Contamination (cps)	Radionuclides	Comment	Work Location	Monitoring Location	WorkGroup	# of Workers	RP Qual	RP Oversight?	Body Part
1	2023/04/21	23-2278	25	Co-60	Contamination on Worker's boot	Various HRCD, path from T/B to	Zone 2:1 Boundary	HP-HEALTH PHYSICS	1	Orange	Yes	Foot
2	2023/05/09	23-2672	60-80	Co-60	on top of workers boot	R1-007	Zone 3:2 RB exit	EI-EI&C	1	Orange	Yes	Foot

### Appendix E: Budget & Resources



## Appendix F: Outage Lessons Learned

<b>2023 Lessons Learned to be incorporated into O24 planning PICA 23-7003</b>					
Action #	Action Description	Tracking Outage	Due date	Owner	Status
<b>J. Hatt</b>					
1	Incorporate into OCC training roles and responsibilities with regards to scope control to ensure alignment and understanding.	O24	2024/01/12	██████	Open
2	Update closure criteria for Milestone # 24 On line Work for the Outage Identified to provide more detail on what is expected as part of this milestone to ensure all work orders are created so they can be scheduled appropriately.	O24	2024/01/12	██████ ██████	Open
3	Provide additional breathing air by having a temporary breathing air skid installed for O24	O24	2024/01/12	██████	Open
<b>Marlene Dewar</b>					
4	Perform a review of how many rubber areas are in the outage and consider worst case scenario at how many can be installed at once and ensure we have adequate supplies to prevent delays to the outage.	O24	2024/01/12	██████	Open
<b>Pierre Michaud</b>					
5	Ensure SDP-01368-PSA3 is updated with a better definition of when the outage starts and ends. E-form # 1978454 has been submitted	O24	2023/11/30	██████	Open
<b>Halley Mawhinney</b>					
6	Develop a list of names and phone numbers ahead of the outage to ensure someone can be contacted at other NB Power locations where we can obtain parts from.	O24	2024/01/12	██████	Open



## IR-4 – Attachment 2



# POINT LEPREAU NUCLEAR GENERATING STATION

## Information Report

### 2024 UNIT OUTAGE IR-00300-0015 Rev. 0



## For Information

## Document Approval

The document has been electronically approved through E-form # 2075327 on this date 2026-03-26. The following approvals are required prior to issue.

Role	Name
Author	[REDACTED]
Document Owner (Approved by)	[REDACTED]

## Revision Record

The following is the latest revision record for this document.

Rev. #	Date	Page	Section	Comments
0	2026-03-26			New issue.

## Classification Statement

Available upon request usage

Available upon request. No restrictions.

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## 1.0 Purpose and Scope

### Purpose

This report provides a summary of the PLNGS 2024 Planned Maintenance Outage.

### Scope

This report will provide an Outage overview, summary of performance against outage targets, and identify strengths and areas for improvement both overall and in specific areas.

## 2.0 Outage Overview

### 2.1 Outage Summary

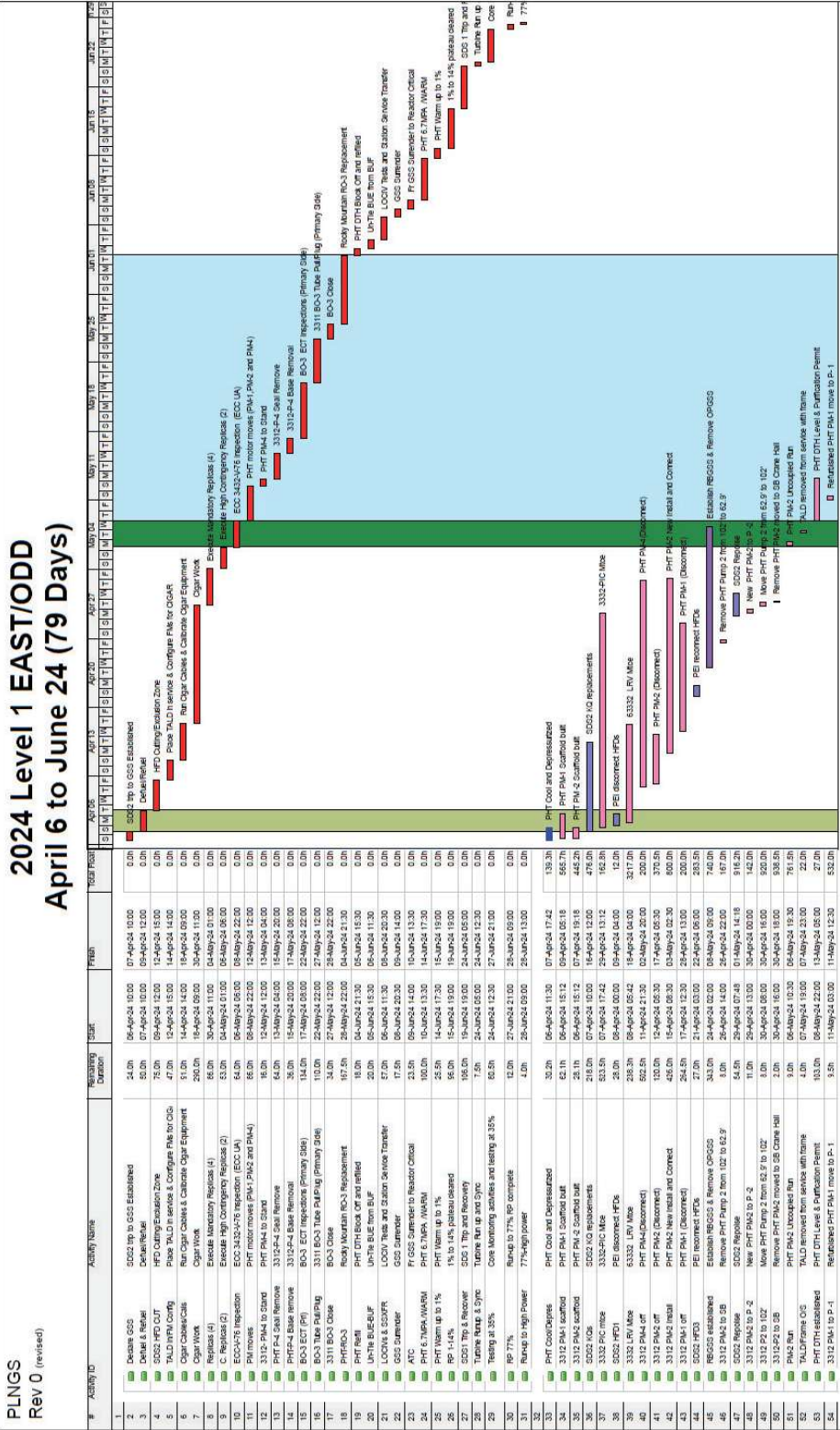
Rundown commenced on Saturday April 06<sup>th</sup> 2024 with SDS2 tripped at 11:08 hrs. and the unit breaker closed on Dec 11<sup>th</sup> @ 13:30. The Outage Duration from breaker to breaker was 249 days 2 hours.

The major outage work included.

<b>Generator Overhaul and Inspection</b>	<b>LP/HP Sectionalized Maintenance</b>
<b>Alternate Spent Fuel Bay Cooling Support</b>	<b>Turbine Valve Maintenance</b>
<b>SDS2 Horizontal Flux Detector Replacement</b>	<b>Condenser Inspections</b>
<b>Travelling Flux Detector Scanning</b>	<b>Replace EJ 4311-EJ-05, 06, 11, 12, 15, 16</b>
<b>Boiler Inspection/Waterlancing</b>	<b>PHT Pump Rotating Element</b>
<b>Feeder Thickness Inspection</b>	<b>Fuel Channel Inspections (CIGAR)</b>
<b>Balance of Plant Valve Replacement</b>	<b>Fueling Machine Bridge Maintenance</b>
	<b>MV39 Ice Plug</b>

# Level 1 Schedule

Final version of the Level 1 schedule was issued on 2024-03-22:



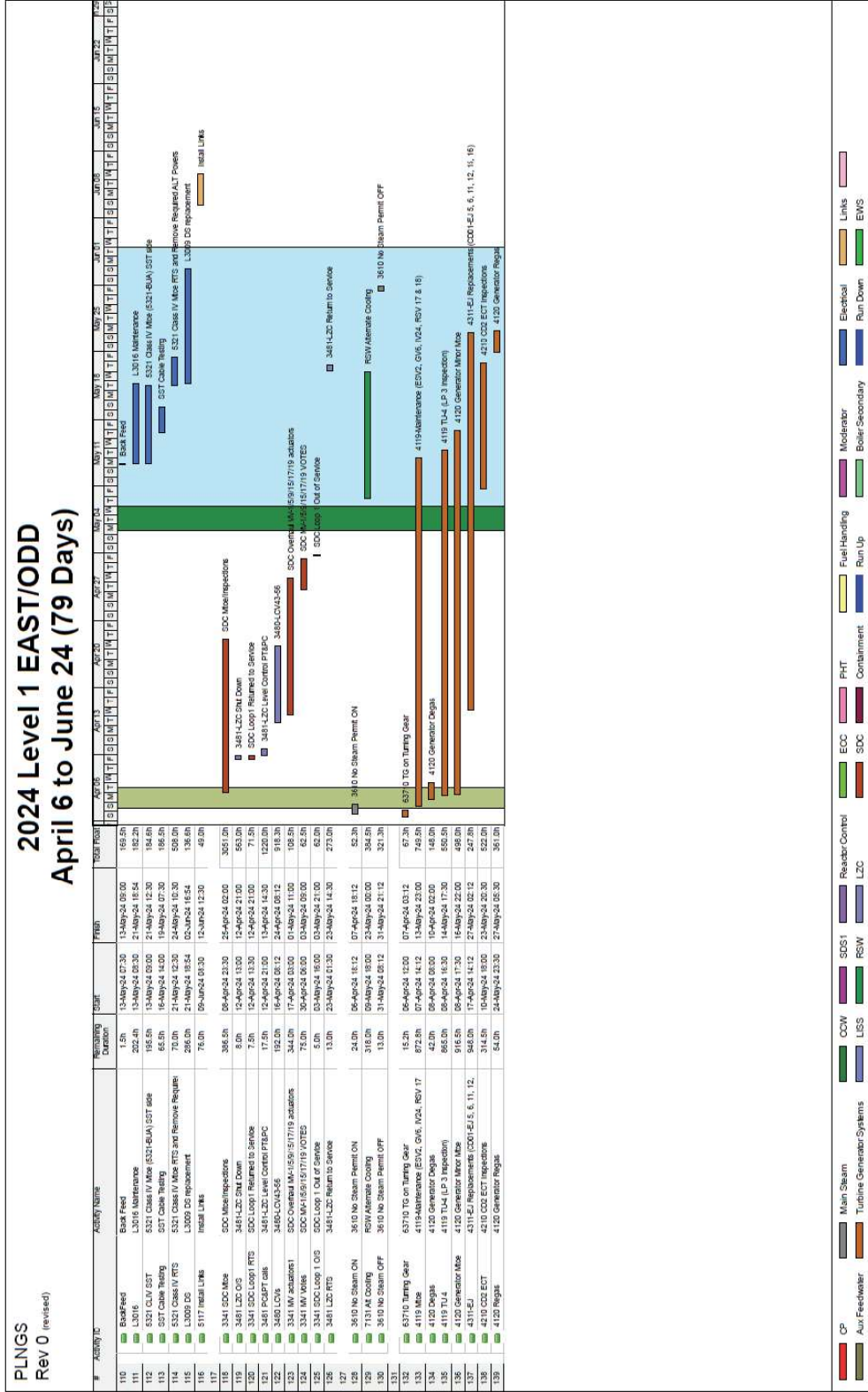
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Rev. 0

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## 2.2 Level 1 Schedule, Continued

Final version of the Level 1 schedule was issued on 2024-03-22:



### 3.0 Outage Management Summary

#### 3.1 Outage ACEMAN Targets

The 2024 Outage targets were aligned with the ACEMAN guidelines.

Area	Measure	Target	Actual
Accident Free	High Potential Incident that could have led to serious injury or death	0	5
	Medical Aid	0	3
Control Dose	Whole Body Dose	1285 mSv	1230.19 mSv
	Personal Contamination Events	≤ 35	36
Event Free	<ul style="list-style-type: none"> <li>• <b>Category 1 or 2 PICAs:</b></li> <li>• Challenging Shutdown Safety</li> <li>• Inadequate Contractor Oversight</li> <li>• Radiation Protection Incident</li> <li>• Actual or Potential Impact to the Environment</li> <li>• <b>Level 1 or Level 2 Work Protection Events</b></li> </ul>	0  0/0 L1/L2	0  0/0 L1/L2
Meet Commitments	Planned Outage Duration (Breaker to Breaker) As per schedule development this will be updated at Rev. 0	≤ 79 days	249
Attend Training	Critical path and near critical path Schedule Delays due to Lack of Qualified Staff	0	4
No Rework	Delays to critical path as a result of rework	0	0
	Continuous Days of High Power Operation after the Outage (No forced outages caused by Outage rework)	≥100 days	96

## 3.2 Accident Free

### **High Potential Incident (that could have led to disabling injury or death):**

The outage target was 0. The actual high potential incidents were 5; three involving NB Power employees, and two involving supplemental staff. The High Potential Incidents are further classified; 3 Tier 1 Events and 3 Tier 2 events. Further details are listed in *Appendix A*.

### **Medical Aids:**

The outage target was 0 Medical Aids. This target applies to PLNGS and Contract staff. The actuals were 3. Further details are listed in *Appendix A*.

### **First Aids:**

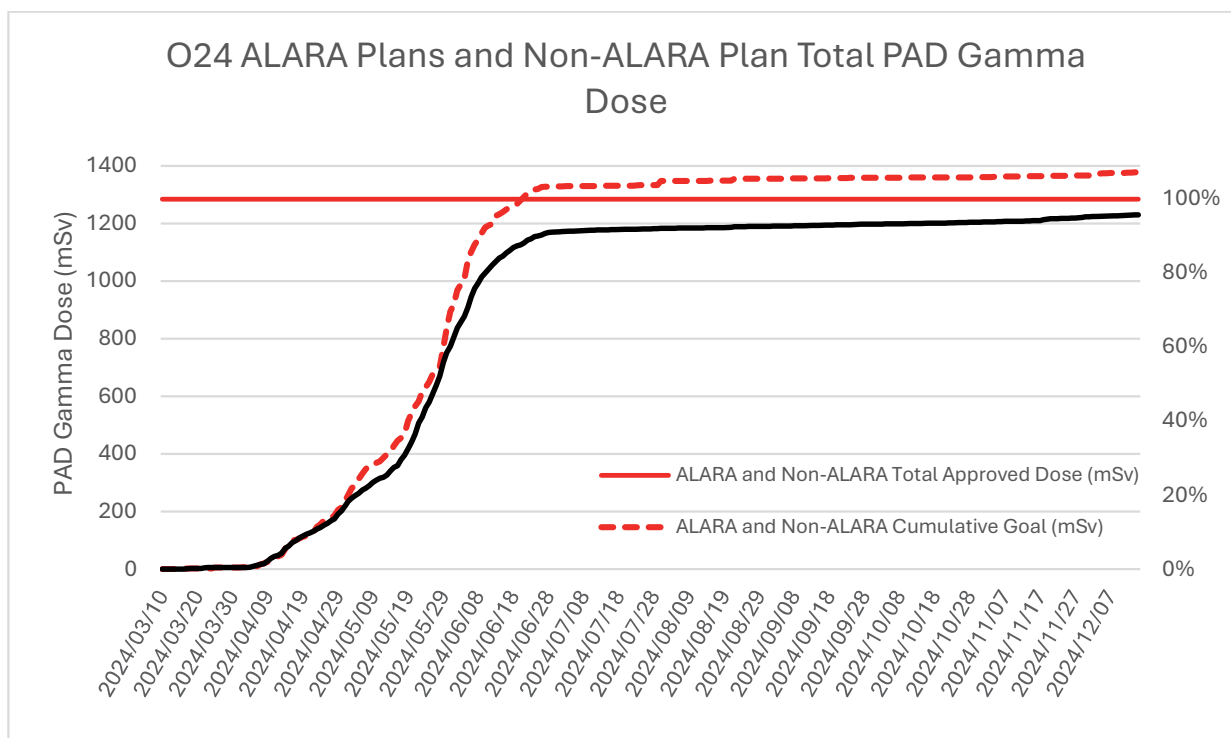
There were 56 first aids in O24. The 56 first aids are listed in *Appendix A*.

### 3.3 Control Dose

**Whole Body Dose:** The ALARA Committee set an outage target of  $\leq 1285$  mSv, 1110 mSv for ALARA plan dose and 175 mSv for non-ALARA plan dose. The actual dose was 1230.19 mSv, 982.54 mSv for ALARA plan dose and 247.65 mSv for non-ALARA plan dose. A breakdown of actual dose measurements by major job and work center is available in *Appendix D, Dose and Personal Contamination Events*.

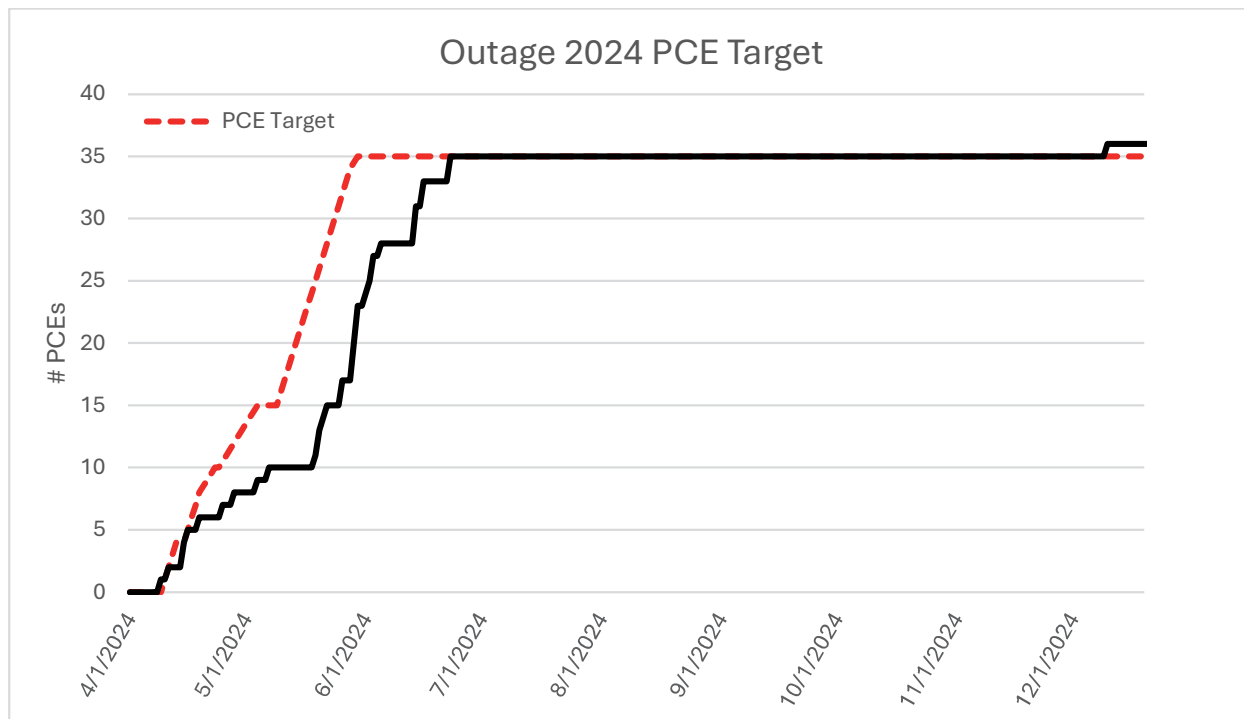
The non-ALARA Plan dose was not revisited by the ALARA committee when the Generator maintenance strategy was developed. The Non-ALARA plan doses reflects the initial 70-day duration.

	Outage Total to Date (mSv)	Outage Goal (mSv)	% of Total Approved Dose
<b>ALARA Plan Dose</b>	982.54	1110	88.55%
<b>Non-ALARA Plan Dose</b>	247.65	175	141.51%
<b>Outage ACEMAN Dose</b>	1230.19	1285	95.76%



### 3.3 Control Dose, Continued

**Personal Contamination events (PCE):** The outage target was  $\leq 35$  PCE's. O24 resulted in 35 PCEs over the first 79 days. An additional PCE occurred in the period following the outage extension, resulting in a total of 36 PCE over 254 days. A breakdown of actual PCE's is available in *Appendix D, Dose and Personal Contamination Events*.



### 3.4 Event Free

**Category 1 or 2 PICA's:** The Outage target for category 1 or 2 PICA's for the following areas was 0. This target was achieved with 0 category 1 or 2 PICA's being recorded:

- Challenge Shutdown Safety
- Inadequate contractor oversight
- Radiation Protection Incident
- Actual or Potential impact on environment.

### 3.5 Meet Commitments

**Outage Duration:** The planned outage duration target was 70 days and the Business objective plan was 70 days (breaker to breaker). The actual duration was 249D 2H, which did not meet either of our targets. Significant delay was encountered due to generator.

### 3.6 Attend Training

Delays in scheduled focus work due to untrained or unqualified staff.

There were 4 delays due to lack of unqualified or untrained staff this did meet the target of zero.

- PICA 24-3847 - DELAY to Critical Path moderator pump motor #2.
- PICA 24-4203 - Critical path delay to complete all testing to clear GSS plateau.
- PICA 24-2760 - Delay to critical path vendor resources.
- PICA 24-3614 - Critical path delay for coordination of PHT work and boiler work.

### 3.7 No Rework

Continuous days of high-power operation after the outage: The “no rework” target was  $\geq 100$  days of Continuous high-power operation after the outage. This target was met.

### 3.8 Lessons Learned PICA

A comprehensive review of Lessons Learned for Outage 2024 (PICA 24-5649) was completed with 16 actions. All actions are being tracked to completion under O25 Milestone 27. See *Appendix F* for specifics on Outage Lessons Learned.

## 4.0 Nuclear Safety

### 4.1 Defense in Depth

The Pre-Outage Defense in Depth information report (*0087-01430-2024-001-IR-A-00*) for planned outage 2024 was formally issued on 2024-02-27. A revision was issued on 2024-05-15 to reflect changes made up to the start of the outage. This report addresses activities from the original rundown, through run up.

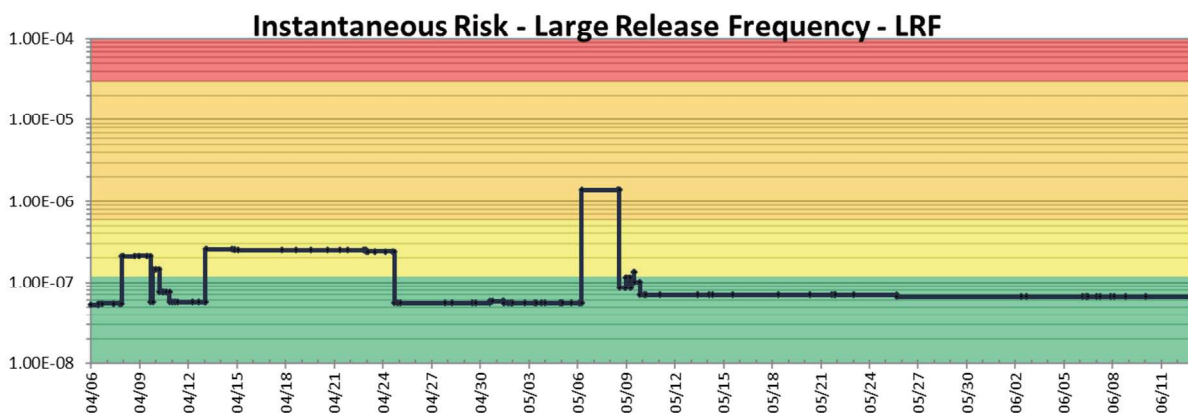
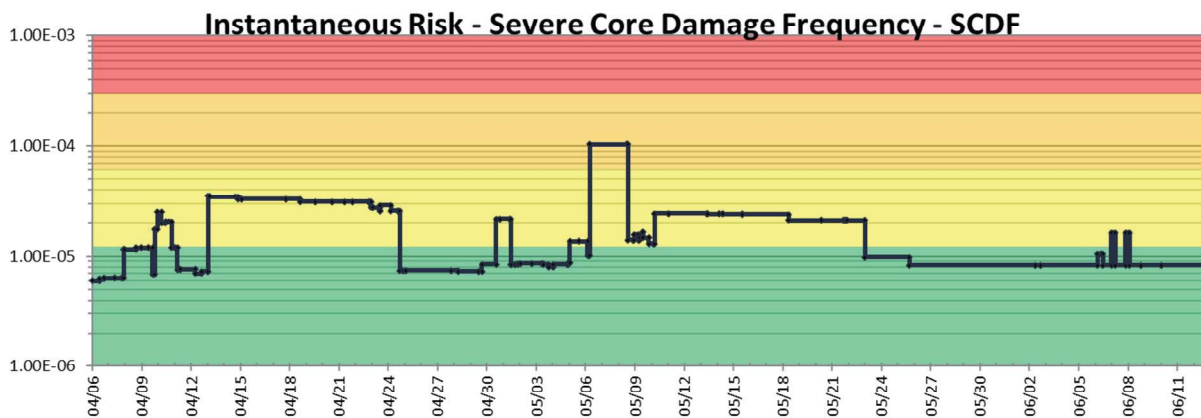
### 4.2 Probability Safety Analysis (PSA)

A PSA risk profile was created for the outage to represent the plant total risk created by the planned maintenance and unavailability of risk significant systems and components. The risk profile was employed as a tool for use in outage preparation to understand and minimize risk by risk-informed planning. There are two quantitative risk metrics which are considered in the risk profile, Severe Core Damage Frequency (SCDF) and Large Release Frequency (LRF).

The Risk Profile was updated daily from 2024-04-06 until 2024-07-12, when it was suspended per PICA 24-4513, to reflect the current configuration as the outage progressed.

## 4.2 Probability Safety Analysis (PSA), Continued

### Pre-Outage Risk Profile



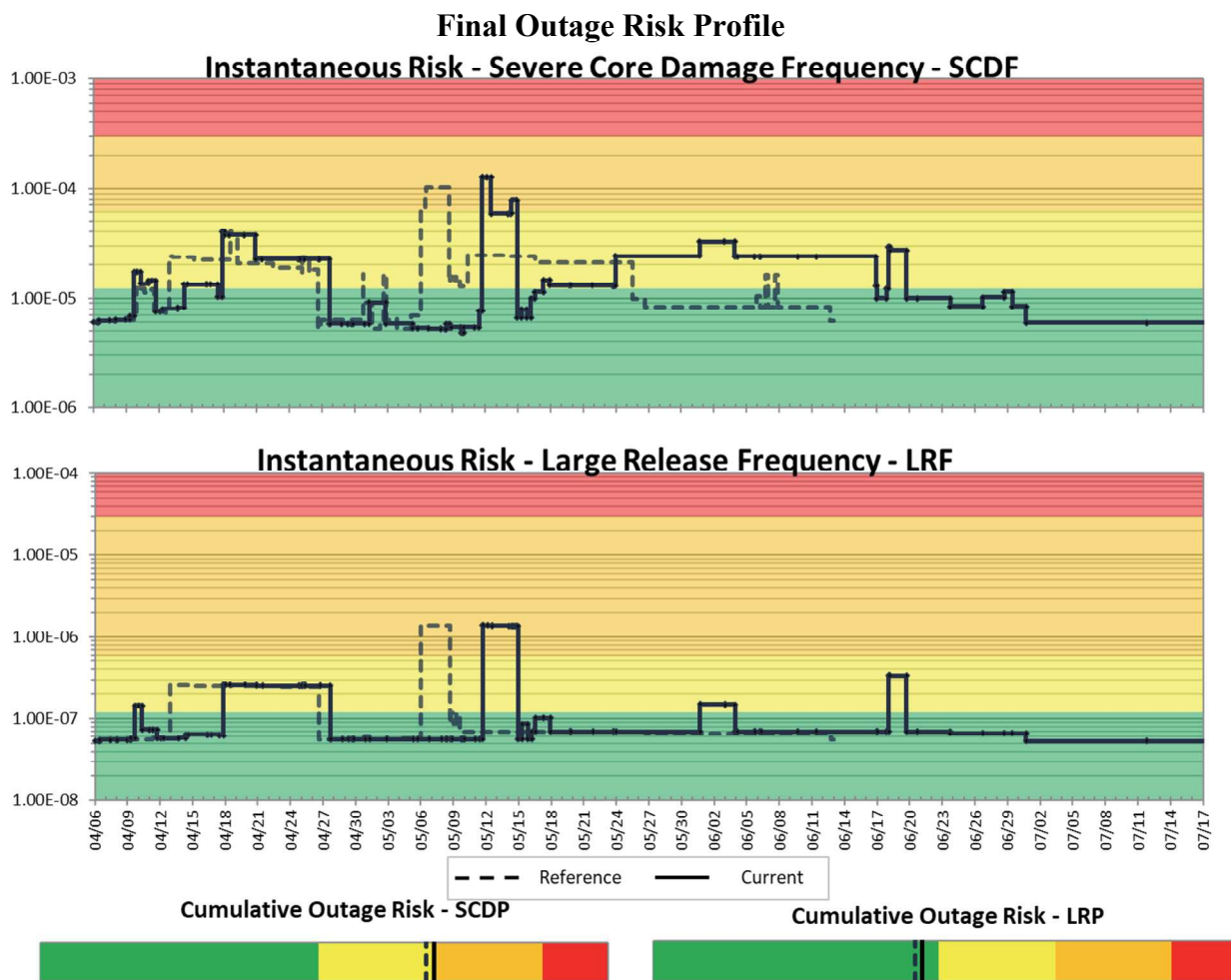
Cumulative Outage Risk - SCDP



Cumulative Outage Risk - LRP

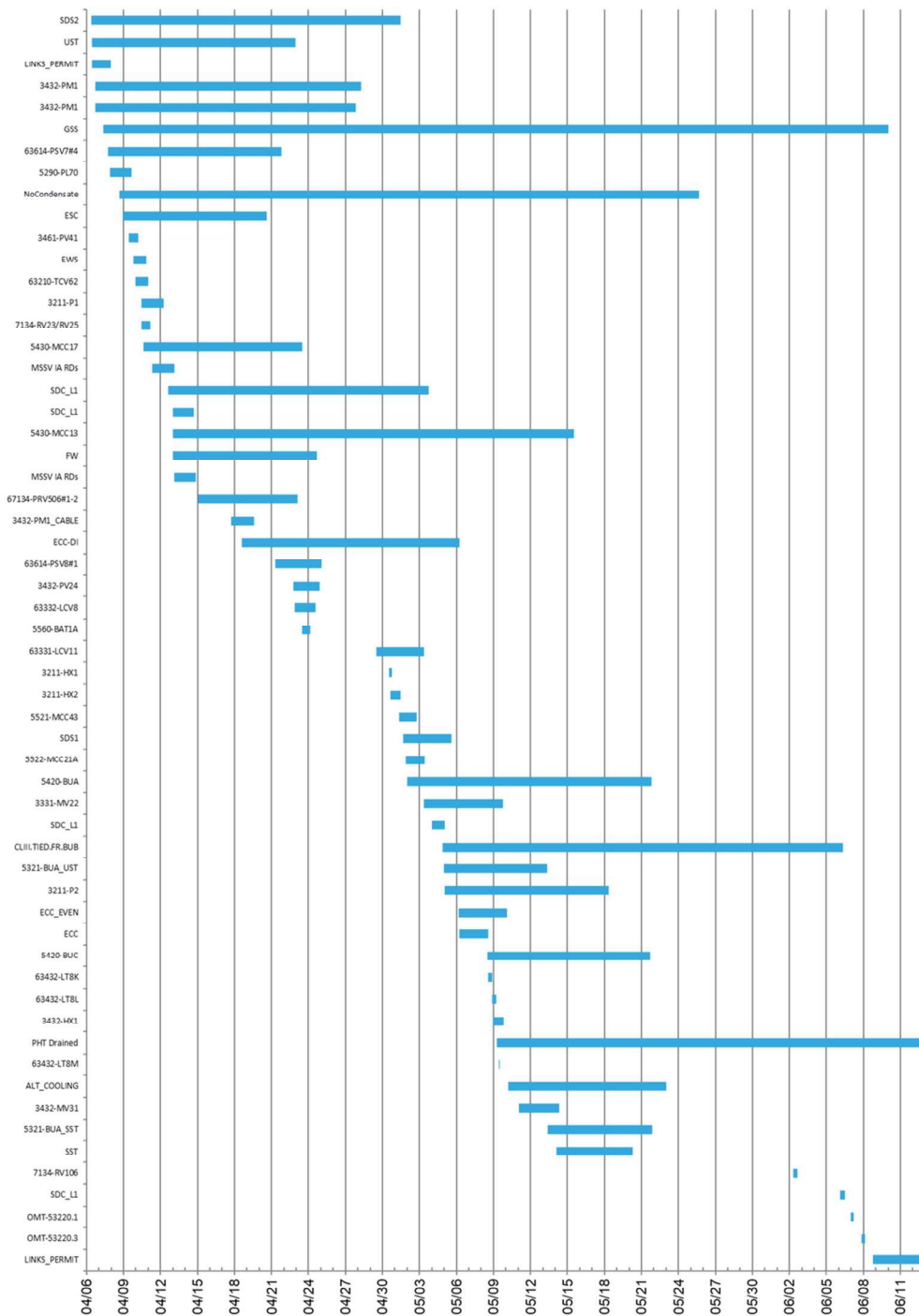


## 4.2 Probability Safety Analysis (PSA), Continued



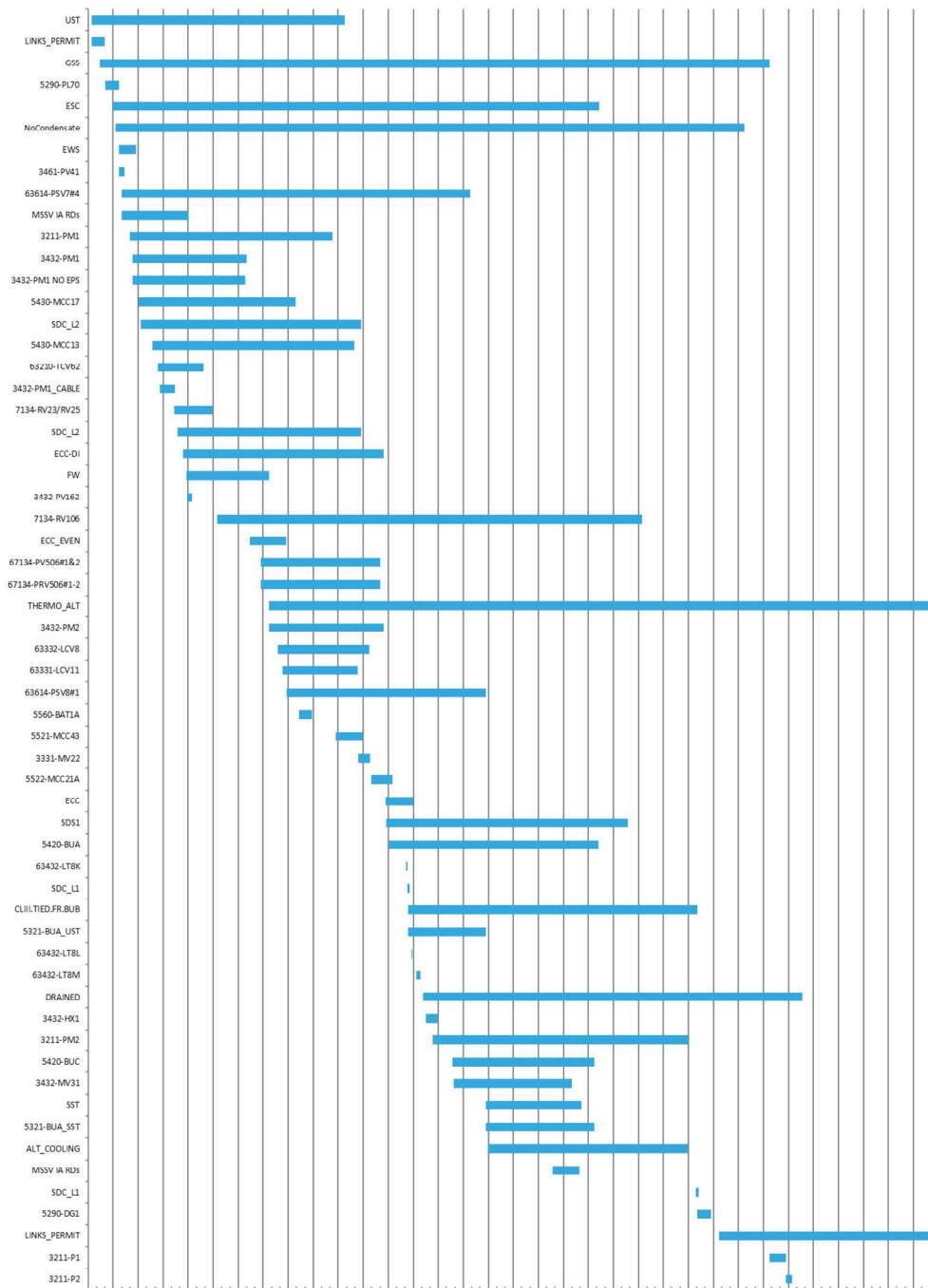
# 4.2 Probability Safety Analysis (PSA), Continued

## Pre Outage Risk Item Schedule



## 4.2 Probability Safety Analysis (PSA), Continued

### Final Outage Risk Item Schedule



## 5.0 Outage Performance Metrics

### 5.1 Outage Budget

The outage cost was \$161,534,326 versus a target of \$137,207,407.

Outage 2024			
Cost Element	FY24 Pre-Outage	FY25 Outage Execution	Total O24 Actuals
Labour - Regular	3,920,384	19,285,246	23,205,630
Labour - Terms & Casual	121,696	903,026	1,024,721
Labour - Staff Overtime	1,469,377	27,297,475	28,766,852
Labour - NMA	1,600,213	17,083,651	18,683,864
Materials	4,906,070	12,289,996	17,196,067
Hired & Professional Services	11,534,897	54,866,763	66,401,660
Overhead	631,030	4,164,703	4,795,733
Other	54,593	1,405,206	1,459,799
<b>Total</b>	<b>24,238,260</b>	<b>137,296,066</b>	<b>161,534,326</b>
<b>Budget</b>	<b>21,464,495</b>	<b>115,742,912</b>	<b>137,207,407</b>
<b>Variance</b>	<b>2,773,765</b>	<b>21,553,154</b>	<b>24,326,919</b>

Outage preparation actuals for FY24 were \$24,238,260 versus a budget of \$21,464,495. Outage execution actuals for FY25 were \$137,296,066 versus a budget of \$115,742,912. Variance was attributed to outage extension and cost associated with addressing emergent issues, unplanned external support for Ice Plugs and Project Oversight. See *Appendix E* for the day-by-day charges.

## 5.2 Outage Milestone Performance

Outage Milestones were established in accordance with station governance *SI-01365-P074*. There was a total of 53 preparation and 2 post outage milestones identified for Outage 2024. Summary of outage milestone achievement is as follows:

### Pre outage Milestones

#### O24 Milestones

Milestone Number	ASSIGNED TO	STATUS	Milestone Name	START DATE	END DATE	Days to Milestone	DURATION in days	Actual Completion	COMMENTS
1	VP Nuclear	Complete	Outage Target Goals and Objectives	2021/11/22	2022/02/11	✓	82	2022/02/11	
2	Design Manager	Complete	Permanent Modifications Identified	2021/11/22	2022/02/25	✓	96	2022/02/25	
3	Outage Manager	Complete	Major Work Scope Identified	2021/11/22	2022/03/25	✓	124	2022/03/25	
4	Systems Manager	Complete	Proposed Scope Identified by Engineering	2022/01/10	2022/04/01	✓	82	2022/04/01	
5	Outage Manager	Missed	Detailed Scope Freeze	2022/02/25	2022/08/19	✗	176	2022/09/23	New recovery date 2022/09/23
6	Outage Manager	Complete	Preliminary Outage Budget Developed	2022/04/20	2022/09/16	✓	89	2022/09/16	
7	Outage Manager	Complete	Work Assigned to the Performing Organization	2022/08/22	2022/09/16	✓	26	2022/09/16	
8	Maintenance Manager	Complete	Level 1 Assessments Complete	2022/04/04	2022/12/23	✓	264	2022/12/23	
9	Operations Manager	Complete	Operations Level 1 Review	2022/08/22	2022/12/23	✓	124	2022/12/23	
10	Outage Manager	Complete	Pre-Outage Preparation Organization Identified	2022/08/29	2023/01/27	✓	152	2023/01/27	
11	Outage Manager	Complete	Schedule Rev A Issued	2022/02/21	2023/01/27	✓	341	2023/01/27	
12	Design Manager	Complete	Design Packages Issued	2022/02/21	2023/02/24	✓	369	2023/02/23	
13	Supply Manager	Complete	Long Lead Materials Identified	2022/04/04	2023/02/24	✓	327	2023/02/24	
14	Supply Manager	Missed	Long Lead Materials Ordered	2022/04/04	2023/05/12	✗	404	2024/02/27	PICA # 23-2807 Recovery Date 2024/01/05
15	Systems Manager	Missed	HENGs Cleared	2022/04/04	2023/05/12	✗	404	2023/04/30	PICA # 23-2747 Recovery Date 2023/06/30
16	Projects Services Manager	Complete	Installation Packages Issued	2022/02/21	2023/05/12	✓	446	2023/05/12	
17	Projects Services Manager	Complete	Commissioning Packages Issued	2022/02/21	2023/07/07	✓	502	2023/07/07	
18	Outage Manager	Missed	System Window Strategies Complete	2022/09/05	2023/07/14	✗	313	2023/09/29	PICA # 23-3944 Recovery Date 2023-09-29
19	Training Manager	Complete	Training Needs Identified	2023/02/13	2023/08/11	✓	180	2023/08/11	
20	Maintenance Manager	Missed	Assessments Complete	2022/08/22	2023/08/11	✗	355	2024/02/26	PICA # 23-5243 Recovery Date 2023/12/08
21	Projects Services Manager	Missed	Purchase Orders Issued for Major Contracts	2022/09/19	2023/11/24	✗	432	2023/12/22	PICA # 23-6164 Recovery Date 2023/12/28
22	Work Management Manager	Complete	Pre-Req Orders Scheduled	2023/05/08	2023/11/24	✓	201	2023/11/24	
23	Outage Manager	Complete	Outage Budget Finalized	2023/07/24	2023/11/24	✓	124	2023/11/24	
24	Regulatory Affairs Manager	Complete	Regulatory Approval Requests Submitted	2023/07/24	2023/11/24	✓	174	2023/11/24	
25	Operations Manager	Missed	Work Clearance Block/Sub-Block Preparation Complete	2023/06/05	2023/11/24	✗	123	2024/09/06	PICA # 23-5156 Recovery Date 2024/03/29
26	Work Management Manager	Complete	On-Line Work for the Outage Identified	2023/10/30	2023/12/01	✓	33	2023/12/01	
27	Outage Manager	Complete	Schedule Rev B Issued	2023/05/08	2023/12/15	✓	222	2023/12/15	
28	Outage Manager	Complete	Outage Control Center Staffing Finalized	2023/05/01	2023/12/22	✓	236	2023/12/22	
29	HR Business Partner	Complete	On-site Resources Plan Finalized	2023/08/07	2023/12/22	✓	138	2023/12/20	
30	Training Manager	Complete	Contractor In-Processing Plan Finalized	2023/10/09	2024/01/05	✓	89	2024/01/05	
31	Outage Manager	Complete	Contingency Plans Developed	2022/09/05	2024/01/05	✓	488	2024/01/05	
32	IP Manager	Complete	ALARA Plans Issued	2023/08/07	2024/01/12	✓	159	2024/01/12	
33	Outage Manager	Complete	Lessons Learned Incorporated into Outage Strategy	2022/07/25	2024/01/12	✓	537	2024/01/12	
34	Operations Manager	Complete	Configuration Orders Complete	2023/07/17	2024/01/12	✓	180	2023/11/24	
35	IP Manager	Complete	Radiation Exposure Permits Approved	2023/08/07	2024/01/19	✓	166	2023/01/19	
36	Outage Manager	Complete	Challenge Meetings Complete	2023/08/07	2024/01/19	✓	166	2023/01/19	
37	Supply Manager	Missed	Material On-Site or Dispositioned	2023/02/27	2024/01/19	✗	327	2024/08/23	PICA # 24-0102 Recovery Date 2024/04/05
38	Operations Manager	Missed	Work Clearances Prepared	2023/08/07	2024/01/26	✗	173	2024/09/06	PICA # 23-5158 Recovery Date 2024/03/29
39	Outage Manager	Complete	Schedule Rev C Issued	2023/12/11	2024/02/16	✓	68	2024/02/16	PICA # 23-7282 for date adjustment
40	Outage Manager	Complete	Horizontal Schedule Review Complete	2023/12/04	2024/02/02	✓	61	2024/02/02	
41	Outage Manager	Complete	Space Utilization Plan Finalized	2023/08/07	2024/02/02	✓	180	2024/02/02	
42	Operations Manager	Complete	Operational Procedures Revised	2023/08/07	2024/02/02	✓	180	2024/02/02	
43	Operations Manager	Complete	Water Management Plan Established	2023/08/07	2024/02/02	✓	180	2024/02/02	
44	Maintenance Manager	Complete	Crane Utilization Plan Established	2023/10/09	2024/02/16	✓	131	2024/02/16	
45	Outage Manager	Complete	Vertical Schedule Review Complete	2023/12/11	2024/03/01	✓	82	2024/03/01	
46	Reactor Safety Manager	Complete	Shutdown Safety Review Complete	2023/05/08	2024/02/16	✓	285	2024/02/16	
47	Outage Manager	Complete	ACEMAN/Outage Dose Targets Established	2023/08/07	2024/02/23	✓	201	2024/02/23	
48	Maintenance Manager	Missed	Walkdowns Complete	2023/08/07	2024/02/23	✗	201	2024/03/28	PICA # 24-1141 Recovery Date 2024/03/29
49	Outage Manager	Complete	Critical Path Challenge Meeting	2024/01/29	2024/03/15	✓	47	2024/03/15	
50	Outage Manager	Complete	Schedule Rev D Issued	2024/01/29	2024/03/22	✓	54	2024/03/22	
51	Training Manager	Complete	Outage Training Complete	2024/01/01	2024/04/05	✓	96	2024/04/05	
52	Maintenance Manager	Missed	Pre-Req Orders Complete	2023/10/09	2024/04/05	✗	180	2024/08/26	
53	Outage Manager	Complete	Outage Start	2024/04/06	2024/06/14	✓	70	2024/06/14	
54	Work Management Manager	Missed	Post-Req Orders Complete	2024/04/15	2024/10/25	✗	133		PICA 24-6559 Recovery Plan date 2025-05-23
55	Outage Manager	Missed	Post Outage Order Clean-up	2024/04/15	2024/09/27	✗	105	2025/05/05	PICA 24-6560 Recovery Plan date 2025-04-25

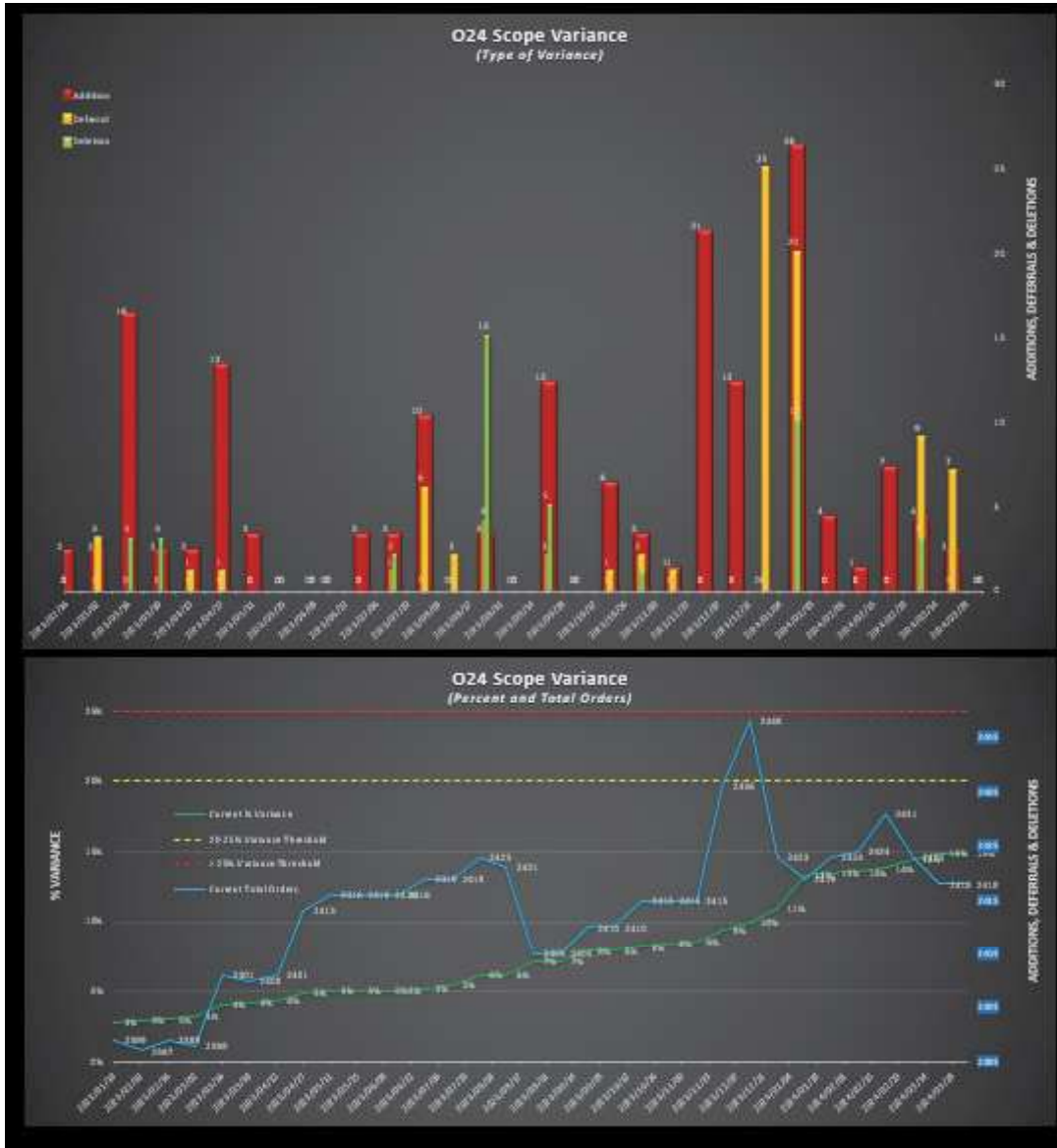
## 5.2 Outage Milestone Performance, Continued

### Execution Milestones

Milestones	Owner	Baseline		Current		Variance to Baseline (h)		Total Float
		Start	Finish	Start	Finish	Start	Finish	
1 Outage Control Center Activated	Josh Hatt	2024/04/05 18:30		2024/04/05 18:30		0.0	0.0	
2 OPGSS Established	Tom Demers	2024/04/06 10:18	2024/04/07 10:00	2024/04/06 10:18	2024/04/07 10:00	0.0	0.0	Complete
3 Defuel/Refuel	Jason Parker	2024/04/07 10:00	2024/04/09 10:00	2024/04/08 08:00	2024/04/09 03:00	22.0	-7.0	Complete
4 Horizontal Flux Detectors Replacements	Mike England	2024/04/09 12:00	2024/04/12 11:00	2024/04/09 06:00	2024/04/11 08:00	-6.0	-27.0	Complete
5 CIGAR	Jason Parker	2024/04/12 23:00	2024/04/28 22:00	2024/04/12 19:00	2024/04/28 10:00	-4.0	-12.0	Complete
6 Replicas	Jason Parker	2024/04/30 15:00	2024/05/06 03:00	2024/04/30 17:00	2024/05/11 10:00	2.0	127.0	Complete
7 Moderator Pump Motor 2 Replacement	Mike England	2024/05/06 11:30	2024/05/13 15:00	2024/05/05 20:00	2024/06/11 17:00	-15.5	698.0	Complete
9 PHT Pump Motor 1 Replacement	Mike England	2024/04/08 21:30	2024/06/05 11:30	2024/04/14 17:00	2024/06/19 17:00	139.5	341.5	Complete
10 PHT Pump Motor 2 Replacement	Mike England	2024/04/08 20:00	2024/05/06 02:30	2024/04/07 20:00	2024/05/14 23:00	-24.0	212.5	Complete
11 PHT Pump 4 Rotating Element Replacement	Mike England	2024/04/07 20:00	2024/05/28 22:06	2024/04/07 20:00	2024/06/09 17:00	0.0	282.9	Complete
12 Rocky Mtn fitting replacement	Jeff Gregory	2024/05/24 19:00	2024/06/04 18:30	2024/06/04 23:00	2024/06/13 08:00	268.0	205.5	Complete
15 Boiler 1&3 Eddy Current Testing	Jeff Gregory	2024/05/10 20:00	2024/05/28 14:00	2024/05/18 19:00	2024/06/05 01:00	191.0	179.0	Complete
16 Boilers 1/2/3/4 Water Lancing	Jeff Gregory	2024/04/13 22:00	2024/05/12 22:00	2024/04/17 08:00	2024/06/12 08:00	82.0	730.0	Complete
17 3432-V-076 inspection	Mike England	2024/05/06 03:00	2024/05/08 10:00	2024/05/11 23:00	2024/05/12 23:30	140.0	109.5	Complete
18 Turbine LP-3	Jeff Gregory	2024/04/08 08:30	2024/05/12 19:00	2024/04/09 03:00	2024/06/11 14:00	18.5	715.0	Complete
19 4311-Expansion Joint Replacement	Jeff Gregory	2024/04/09 08:12	2024/05/28 18:00	2024/04/17 08:00	2024/06/02 08:00	191.8	110.0	Complete
20 RSW Alternate Cooling	Jeff Gregory	2024/05/09 22:00	2024/05/25 02:30	2024/05/24 17:00	2024/06/12 17:00	355.0	446.5	Complete
21 Loss of Class IV Testing	Tom Demers	2024/06/06 08:30	2024/06/18 10:30	2024/06/18 08:00	2024/06/20 01:30	287.5	39.0	Complete
22 Surrender GSS and Approach to Critical	Tom Demers	2024/06/08 15:30	2024/06/09 18:00	2024/06/25 17:00	2024/06/26 17:00	409.5	407.0	Complete
23 Turbine Run-Up and Synchronization	Tom Demers	2024/06/24 05:00	2024/06/24 12:30	2024/12/10 17:00	2024/12/11 17:00	4068.0	4084.5	Complete

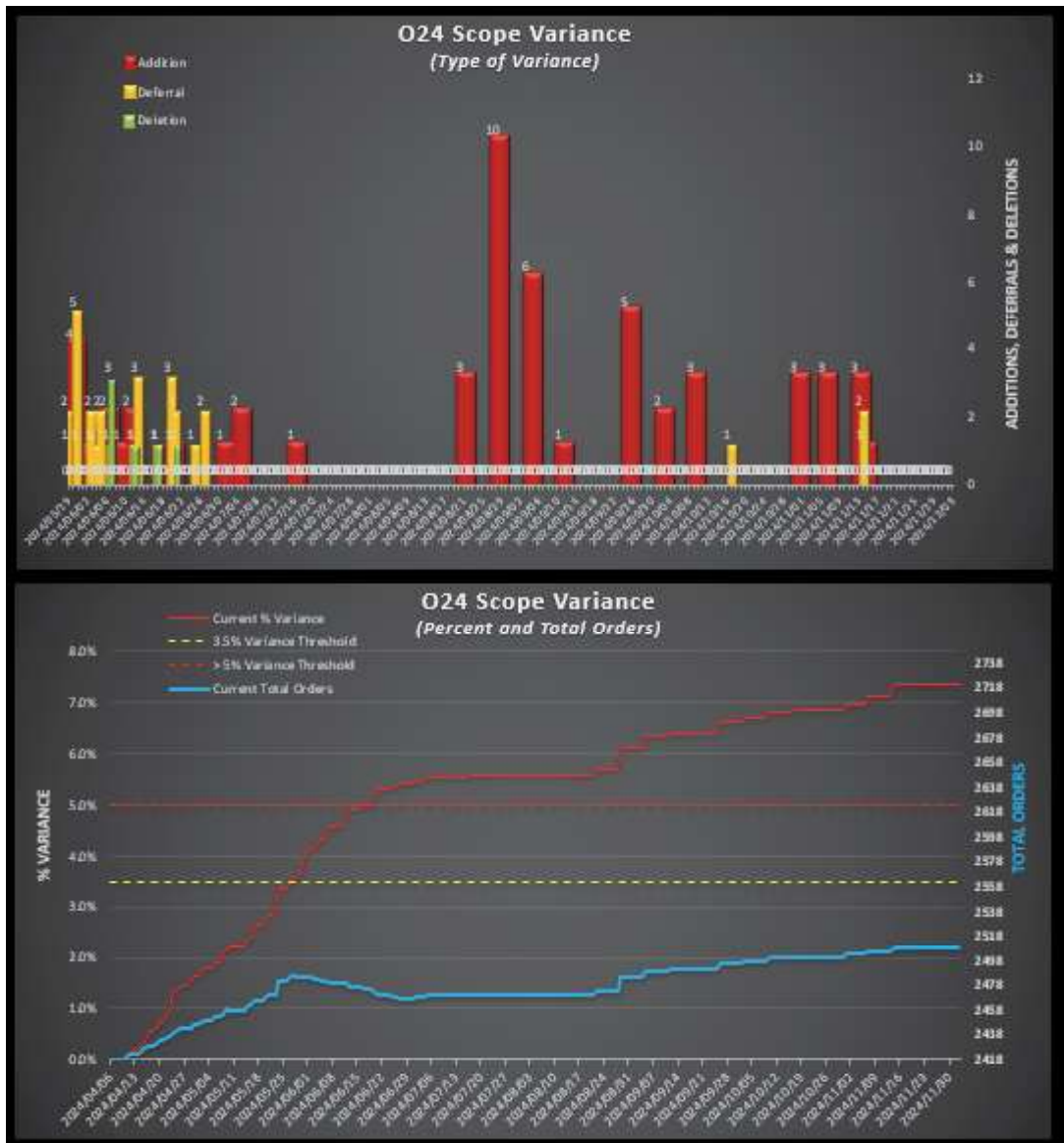
# 5.3 Outage Scope Change Summary

## Preparation



### 5.3 Outage Scope Change Summary, Continued

#### Execution

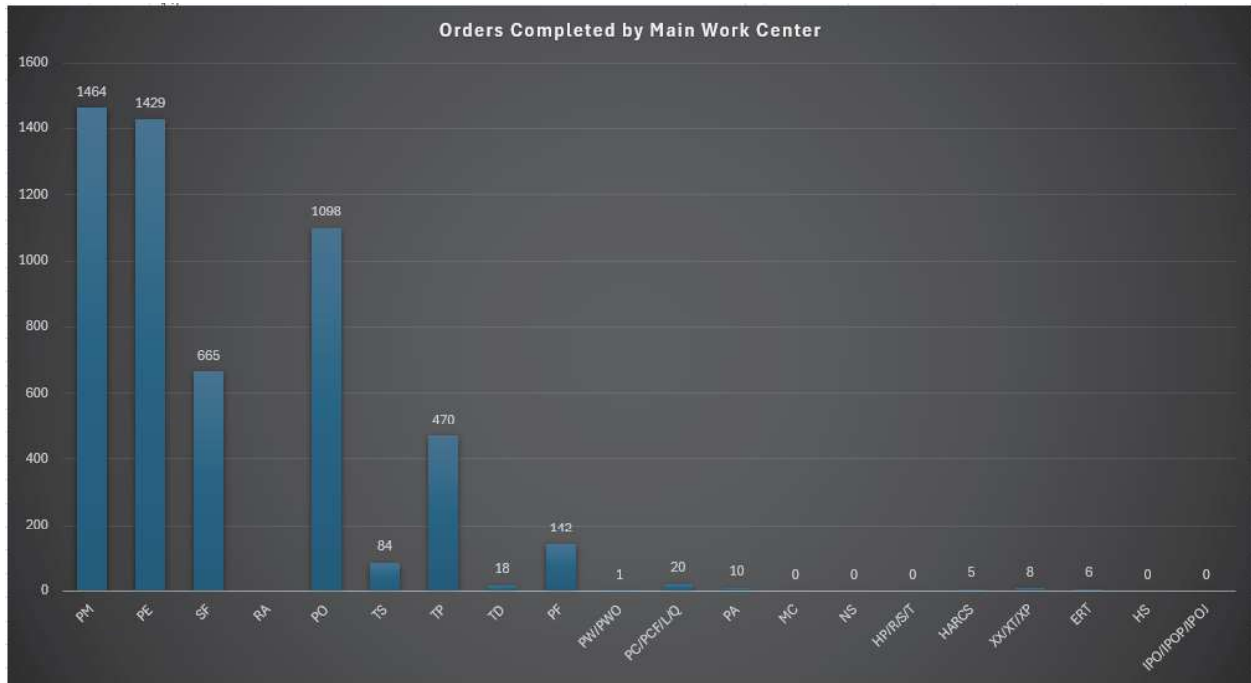


## 5.4 Summary of Key Outage Metrics

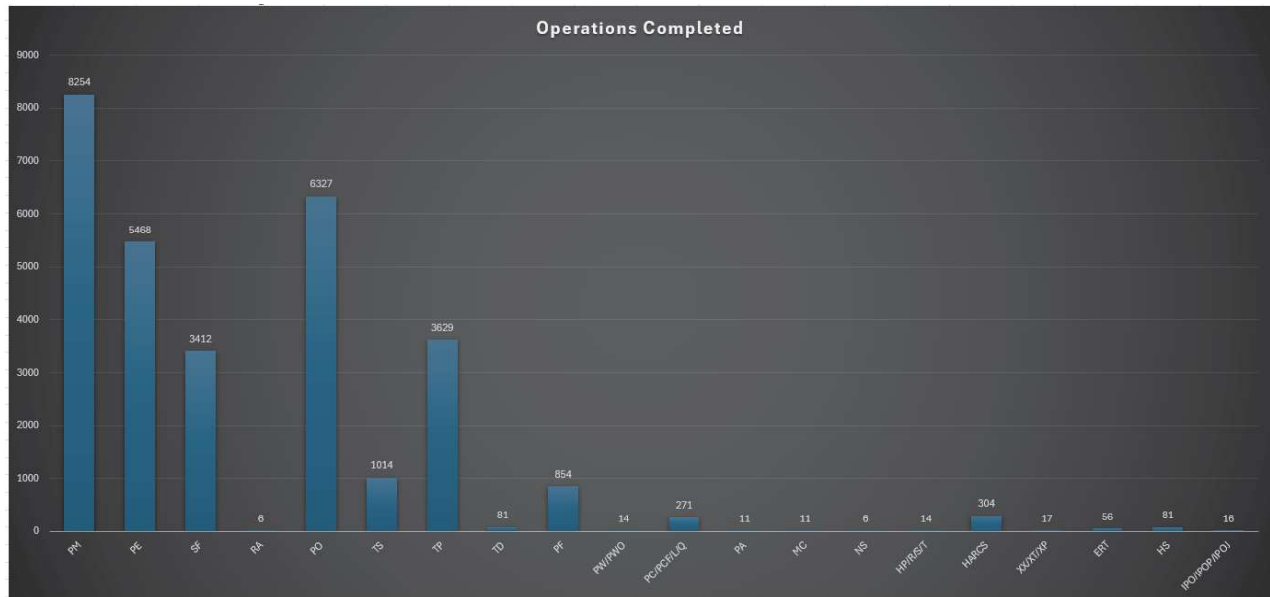
	<b>2024</b>
<b>Duration</b>	
Planned Duration (days)	70
Actual Duration (days)	249
<b>Scope</b>	
Scope Freeze	2387
Initial Scope	2418
Orders added (pre-outage)	212
Orders Removed (pre-outage)	164
Scope Variance (pre-outage)	16%
Orders added (outage)	134
Orders Removed (outage)	45
Scope Variance (outage)	7.4%
Percent of Scope Complete (breaker open)	98%
<b>Work Completed</b>	
Backlog (CC, CN, DC, DN) Completed	216
Leaks	69
Safety Orders	5
Operator Challenges	0

## 5.5 Work Center Activities Completed

### Work Orders Completed by Department



### Operations Completed by Department



## Appendix A: Safety Statistics

2024 - Outage (249 days)				
Incident Outcome	Target	Total	Contractor	NBP
Medical Aid	0	3	3	0
First Aid	<13	58	25	33
High Potential	0	6	2	4
Work Protection				

Request	Prepared on	Incident Date	Work Group	Primary Incident Type	Incident Outcome	Incident Description
2124620	2024/12/05 18:52	2024/12/05	Operations	Employee	First Aid	While walking through the LAC Catwalk, an operator made contact on their knee with a protruding valve stem. Immediate pain was felt while applying weight to the leg. Pain is felt when weight applied 8 hours after incident.
2121241	2024/11/27 08:42	2024/11/27	Facilities	Employee	First Aid	Was cleaning the door frame and the metal tag that identifies the door was sticking out caught employee's hand.
2120949	2024/11/26 13:06	2024/11/26	Projects	Contractor	First Aid	Employee, while investigating a cable pull location, while bending over employee's hard hat came off and while retrieving it, his head made contact with a piece of uni-strut. The employee received a minor cut on the top of their head. Employee went to the health unit where they received minor first aid treatment. Employee is going to rest till end of shift.
2118777	2024/11/20 08:30	2024/11/19	Facilities	Contractor	First Aid	A rag on roll of cleaning clothes fell and hit the hand she was carrying a knife in which jostled it and causing a cut on right hand between index and middle fingers.
2118416	2024/11/19 12:23	2024/11/19	Fuel Handling	Employee	First Aid	Upon exiting the STOIC building near HR, employees left foot struck raised concrete pad twisting left foot outward. Employee felt minor pain toward inside left knee.
2111254	2024/10/28 14:13	2024/10/28	Projects	Employee	First Aid	I cut myself with a piece a paper while folding it.
2109437	2024/10/23 12:36	2024/10/23	Facilities	Contractor	First Aid	Descending down the permanent ladder at the condenser 2B his foot slipped off the last rung of the ladder and fell backwards twisting left knee.
2107907	2024/10/18 11:18	2024/10/18	Security	Employee	First Aid	During the PIN testing for Security, an employee was doing the sit and reach portion of the test. In this test the employee will sit on the floor in front of a board that their feet rest up against. On this board there is a measuring tape and the goal is to reach down the tape as far as possible in order to calculate how far the individual can reach beyond their toes. During this reach the employee felt a "pull" in their quad muscle. The employee stopped at this point and did not retry the test. This also resulted in the employee not being able to complete the rest of the test at other stages. The damage to the quad does not seem to be severe and they can walk without problem.
2107847	2024/10/18 10:04	2024/10/18	Facilities	Employee	First Aid	lowering the ROV down into the clearwell while lowering individual was using left arm to brace there self against the wall and felt some discomfort in the left shoulder.
2106281	2024/10/13 00:18	2024/10/12	Projects	Contractor	First Aid	Contractor while working on bearing #9 (while kneeling ) lost balance on edge of plywood that the bearing is located. Contractor reached out with left hand to maintain balance and scraped his left pinky finger on the edge of bearing stop.
2104526	2024/10/07 16:42	2024/10/07	Projects	Contractor	First Aid	While milling a component for the generator the milling bits fetched up on the milled piece and snapped the 6", 1-1/4" endmill. The piece became a projectile and struck the worker in the head.
2099280	2024/09/19 19:06	2024/09/19	Emergency Response Team	Employee	First Aid	ERT member felt discomfort/ pain in right foot while walking across the yard after Fire pan extinguisher training, cause unknown.
2096737	2024/09/12 14:44	2024/09/12	Emergency Response Team	Employee	First Aid	While training on K12 rescue saw cutting metal, a spark flew up and went under safety glasses and made contact with eye. The spark remained there for a couple seconds and caused discomfort and itching to the eye. Proper PPE was worn as in helmet, gloves, safety glasses and helmet shield.
2096533	2024/09/12 10:30	2024/09/12	EI&C	Contractor	First Aid	While cutting open a plastic bag with a knife left index finger was cut. Knife cut through the employees glove. Employee went to health unit and site nurse bandaged cut and employee returned to work.
2095215	2024/09/09 13:59	2024/09/09	Emergency Preparedness	Employee	First Aid	After walking out of an office I tripped over a lobby table that is shin height and was against the wall right outside the office door. I fell to the floor. No immediate injury but work cell phone screen was cracked during the fall.

## Appendix A: Safety Statistics, Continued

2093189	2024/09/03 11:22	2024/09/03	Projects	Contractor	First Aid	The person involved was manipulating the Generator hydrogen seal end plate which weighs approximately 100 lbs and turned his torso at the hips. The person wrenched their back and suffered discomfort. The person immediately reported the incident to his supervisor who in turn reported the incident to his NBP sponsor
2091285	2024/08/27 11:54	2024/08/27	Security	Employee	First Aid	During a PLANSOC event on the firing range, an NRT member was carrying "rescue randy" 50m. During this carry the NRT member started to feel tingling in his right arm and hand and it would not go away. After sitting for 10 minutes with gear off the tingling started to go away.
2090019	2024/08/22 14:28	2024/08/22	Facilities	Contractor	First Aid	While placing a trunking can 6ft off the floor in a Sea can employee felt a pull in left shoulder.
2087864	2024/08/15 15:21	2024/08/15	Chemistry	Employee	First Aid	In the early afternoon it was noted by individuals working in the Chemistry Lab that a significant smell of diesel fumes were entering through the ventilation system. At least one person started to get a headache and went for lunch to take headache medication and get out of the fumes. Upon return from lunch, the fumes were worse and were also noticed by several other workers in the lab. Symptoms observed include headache and sore throat.
2082959	2024/07/30 18:43	2024/07/30	Training	Employee	First Aid	Security Training was conducting a Dynamic Learning Activity that was within the Training Course Plan. One Trainee's elbow came in contact with another Trainee's ribs. Impact was low and Trainer inquired to the individual if they were ok, and Trainee said yes. Trainee said it just felt like a bump/bruise.
2081346	2024/07/24 18:32	2024/07/24	SMR Project Technical	Contractor	First Aid	The individual involved in the incident was working with three other team members to clear deadfall and debris out of their archaeological testing area so the location could be delineated with flags to mark locations of test pits to excavate. The individual identified a dead tree (approx. 12 feet in height) in their work area that was in close proximity to a location in which a test pit would be marked. This was seen as a hazard and so the individual took it upon themselves to attempt to push over the dead tree by hand. During this action the tree fell over and while falling, the top portion of the tree broke off (approx. 2.5-3 foot length, weighing approx. 1.5-2 pounds) and hit the individual on the front right side of their head (with a hard hat on) before falling to the ground. The tree involved in this incident had significant decay and weathering causing it to be lighter compared to trees of a similar size.
2074071	2024/07/03 15:35	2024/07/03	Small Modular Reactor (SMR)	Contractor	First Aid	An individual was working outside and began noticing symptoms of heat stress; specifically they had a headache and felt nauseous.
2073592	2024/07/02 16:23	2024/07/02	Small Modular Reactor (SMR)	Contractor	First Aid	The individual was bitten/stung on their hand by an insect, which wasn't observed during the time of the bite/sting. The effected area swelled slightly.
2067874	2024/06/14 16:03	2024/06/14	Emergency Response Team	Employee	First Aid	Individual hurt ankle because it was wrapped in fire hose. Hose was being pulled into burn room which caused wrapped hose to hurt individuals ankle.
2064473	2024/06/07 08:24	2024/06/06	Facilities	Contractor	First Aid	Erecting scaffold in a congested area, his arm was cut on a valve that had insulation cladding on it.
2064360	2024/06/06 15:43	2024/06/06	Emergency Response Team	Employee	First Aid	Member was waiting for the 6 inch supply line between the hydrant and the Fire Engine to be charged with water which is high pressure. Member knew the risks and took a couple steps back while it was being charged but misgauged how far the supply line could move. The supply line moved and swiped the members feet from underneath him and fell to the ground.
2063884	2024/06/05 15:54	2024/06/05	Facilities	Contractor	Medical Aid	employees right arm came into contact with a sharp metal edge from insulation cladding while performing task
2063708	2024/06/05 11:06	2024/06/04	Mechanical Maintenance	Employee	First Aid	The employee was working on PHT Pump 4 equipment. This work involves being in a ventilated tent and dressed in a plastic suite. After exiting the congested work area, the employee notice their left leg becoming numb. It is believed that due to body positioning during the work , the employee pinched a nerve in their lower back.

## Appendix A: Safety Statistics, Continued

2063649	2024/06/05 09:30	2024/06/04	Design	Contractor	First Aid	While walking along side of the new access road (in the ditch due to paving) The contractor tripped over a rock and fell onto their hands.
2061874	2024/05/31 08:34	2024/05/31	IT	Employee	First Aid	The wind caught the woman's bathroom door (FC-201) causing the door to close on my finger.
2061689	2024/05/30 14:10	2024/05/30	Supply	Contractor	First Aid	while worker was performing cleaning duties on the mezzanine level of plant stores ( a low pipe hanging area), struck the right side of forehead on a low hanging beam. Worker was aware of where the beam was but underestimated the proximity.
2060937	2024/05/29 07:35	2024/05/29	Security	Employee	First Aid	On 24.05.29 at approximately 0600 Hrs. Nuclear Security Officer was on my way to began my regular shift 0630 - 1430 Hrs. Upon walking through the cafeteria I was entering the second set of double doors and the door was open due to the automatic door being pressed by someone else. As I began walking through the door I reached over with my right had to fix my left side jacket collar not noticing the steel door had begun to close as it struck directly with my right elbow (Funny Bone Area) causing sharp pain and tingling into my right elbow forearm and hand.
2059732	2024/05/25 17:57	2024/05/25	Projects	Contractor	Medical Aid	The task involved rotating the actuator on Valve 4323-V-102, 180 degrees to facilitate easier access to the valve handwheel for the operations team. To manage the actuator's position and reduce weight on the valve stem, a chain fall/sling combination was set up, choked around the top of the actuator. Three contractors were involved: one operated the chain falls, another worked the valve handwheel, and the third guided the actuator onto the yoke. They successfully rotated the actuator 180 degrees and were lowering it when it got caught on the spigot between the adapter plate and the actuator. The contractor operating the chain falls reached up to pull the actuator down to align it. Once aligned, the actuator dropped 1-2 inches, pinching the contractor's pinky and ring fingers between the adapter plate on the yoke and the actuator. The injured contractor was subsequently sent to the local hospital for treatment
2059350	2024/05/24 10:15	2024/05/24	Emergency Response Team	Employee	First Aid	During live fire training an ERT member exited the burn building feeling light headed and complained of his body tingling and a tight jaw. Member was sat down and hydrated. Initial vital signs BP-148/98, HR-124, O2 Sat of 98% Member was monitored and given fluids, ices packs were applied to the members neck and ampits. The members body temperature was lowered and he expressed feeling better. Last vitals showed BP 128/86, HR 86, O2 Sat 98%. Member was released from the firegrounds under supervision of another ERT Member, will not be exerting himself for the remainder of the training day.
2059234	2024/05/24 08:13	2024/05/23	Operations	Employee	First Aid	Individual was decending the staircase, both hands on railings, lost footing and slipped down the stairs falling backward. The individual caught themselves on the way down. The individual reported muscle pain in shoulders, arms and back.
2059169	2024/05/23 17:55	2024/05/23	Mechanical Maintenance	Employee	First Aid	Upon completion of a maintenance task in R1-501, an individual involved felt unwell and lightheaded. The condition passed after several minutes once work activities were stopped and respiratory protection removed.
2058830	2024/05/23 10:31	2024/05/23	Projects	Contractor	First Aid	While removing the weld from a dog (tool used to align steel) the individual released the trigger of the grinder and moved it away from the object he was grinding. While moving the still rotating tool back, the grinding wheel contacted the dog and jumped striking the individuals finger tip resulting in a small 1/4" long cut. Gloves were being used for this task.
2057661	2024/05/21 09:19	2024/05/19	Fuel Handling	Employee	First Aid	Individual was searching through FM Bridge maintenance tool box for an item and had to move a pail which contained a chain fall. Item was not lifted but slid to from its located within the box. The box was deep, and had to bend over to access. Preexisting back issue was aggravated when the pail was slid.
2057535	2024/05/21 01:10	2024/05/20	Health Physics & Radiation Con	Contractor	First Aid	The individual was checking a masslinn for contamination and when they stood up, they struck a pipe protruding from the wall. This resulted in a scrape on the persons lower back.
2056431	2024/05/16 02:08	2024/05/16	Mechanical Maintenance	Employee	First Aid	While performing PHT track movements, worker had track dolly underneath the jack, while lifting the track with the jack, the T-handle swung up and inadvertently moved and made contact with the workers nose.
2056188	2024/05/15 13:07	2024/05/15	Emergency Response Team	Employee	First Aid	During training evolution was removing tools and victim on scenario when fell over hay bale in limited visibility and twisted right knee. Continued scenario and exited the structure. Felt tightness in knee. No first aid required.
2055632	2024/05/14 12:22	2024/05/14	Emergency Response Team	Employee	First Aid	ERT member was completing a evaluated fire drill on their training week. During the drill the member twisted there arm while lifting equipment causing pain in there right elbow.
2052945	2024/05/08 00:34	2024/05/07	Facilities	Contractor	First Aid	While worker was descending stairs in Turbine Building Stairwell EI 58' down to EI 45' carrying (x1) Garbage bag of empty Gatorade Bottles, Worker felt discomfort in Right knee. Worker reported incident to supervisor and returned to work.

## Appendix A: Safety Statistics, Continued

2051579	2024/05/06 02:19	2024/05/06	Fuel Handling	Contractor	First Aid	After performing Rubber Area Work, the worker went to monitor at the WBC as per the RPP. When they bagged in and stepped in, the head sensor continued its downward motion onto the top of the employees helmet and did not stop. Their arms were still engaged in the hand sensors and the force generated was great enough to compress their upper body down and into the monitor. The employee had to step out of the monitor and bend out as the head sensor continued to travel down to the limit of its travel. Employee immediately reported to their supervisor.
2051496	2024/05/04 19:20	2024/05/04	Security	Employee	First Aid	While retrieving Work keys from left pocket, the employee made contact with their pocket knife that was slightly opened enough in the same pocket, causing them to cut palm of their left hand enough to cause it to bleed.
2051400	2024/05/03 16:21	2024/05/01	Facilities	Contractor	First Aid	While unloading wood pallets and an old desk into garbage bin the employee had to stretch to get the desk into the bin but did not feel any pain at this time. The next morning and all day had a sharp pain in lower right abdomen. Pain was still present the following day so went to site nurse.
2050753	2024/05/02 15:30	2024/05/02	Emergency Response Team	Employee	First Aid	Training fire brigade rescue techniques. After the exercise was complete, we were having a post-exercise debrief. during the debrief I felt my left hand go numb and pain begin the creep from my left shoulder, down to my left elbow.
2049907	2024/05/01 01:35	2024/05/01	Facilities	Contractor	First Aid	I was lowering gear down to coworkers with a rope and a bag. the space was very limited where the bag was being lowered. Roughly 15ft down there is a heat trace line that I had to avoid hitting with the gear bag. Once the bag reached the line I had to swing the bag outwards, which doing so cause a burning pain around the center of my back. after the task the burning continued
2049883	2024/04/30 23:19	2024/04/30	Health Physics & Radiation Con	Employee	First Aid	Individual was performing routine activities when he felt discomfort in his right shoulder.
2047832	2024/04/25 12:32	2024/04/24	Facilities	Contractor	First Aid	While modifying a scaffold worker was moving a 3m deck and felt pain in back
2047779	2024/04/25 12:08	2024/04/24	Performance Improvement/CA P	Employee	First Aid	The handicap parking spots were relocated to allow for a fire lane to be installed in front of the STOIC building. There are 4 replacement spaces and the spot furthest away is partially paved and the other part is dirt. As a result the boundary of the space is not clearly marked and people routinely infringe on that space. I went to get out of my vehicle and my foot landed on half pavement and half dirt, there is an elevation difference causing a falling hazard. I did not fall, but could have. There are also not enough spaces to accommodate the people who utilize these spaces. The 4th space should be completely paved or relocated to a place with even and like surface to mitigate a falling or tripping hazard by personnel with mobility limitations and more spaces should be allotted.
2045844	2024/04/19 23:32	2024/04/19	Health Physics & Radiation Con	Contractor	First Aid	Upon exiting a Alpha II Rubber Area in the East Maintenance Lock, the individual was opening a bagged instrument using a seat belt cutter. The seat belt cutter plastic body housing broke and struck the workers hand and sliced their palm below the thumb through their double nitrile gloves.
2045047	2024/04/18 04:45	2024/04/18	Facilities	Contractor	First Aid	While building scaffold at UT-C, employee was descending ladder for break. When he took the last step from ladder to ground he twisted his ankle.
2043129	2024/04/12 13:29	2024/04/11	Health Physics & Radiation Con	Employee	First Aid	While cleaning the vaults, I hit my ankle off a metal stand. No damage to equipment or PPE and only slight pain at time of incident. It was not until this morning (2024/04/12) that I noticed swelling and bruising and more pain due to the incident. Slight pain while walking but nothing other than that.

## Appendix A: Safety Statistics, Continued

2042958	2024/04/12 10:52	2024/04/12	Operations	Employee	First Aid	Individual was performing Aux Steam Blowdowns as per Appendix 9 in SOS-73010-01. During the blowdown at 7214-V-122 the individual opened the valve till they saw condensate flowing then opened it a little more. They closed back in on it and the temporary drain hose blew off the threaded nipple on the valve. This lead to steam/condensate contacting their right forearm and bicep. The individual was wearing gloves and a long sleeve shirt. The steam burned the forearm and bicep. The individual contacted OFS and was in his office. When OFS got there he immediately called ERT and SS. The ERT came to the OFS office and said it did not require a medical alert. They helped the individual get to the health unit where they treated his injuries. They were driven to the Hospital by a co-worker.
2040666	2024/04/09 12:37	2024/04/09	Facilities	Contractor	First Aid	while pulling on the cladding trying to break firestop free, hand slips and caused a cut through the glove on his right pinky finger
2039413	2024/04/09 03:54	2024/04/09	Facilities	Employee	First Aid	Employee was performing a walkdown when they tripped over a transition hump on the floor, when the employee tripped their hand hit a piece of Unistrut causing a cut to their left hand.
2039378	2024/04/08 17:32	2024/04/08	Projects	Contractor	Medical Aid	On April 8, 2024 a contractor was prepping the ends of new replacement (metal) expansion joint as part of the Outage Work at Point Lepreau Nuclear Generating Station. These expansion joints are placed at a height similar in nature to piping, they will be working on inside condenser #1. During the preparation of one of the ends of the expansion joint, the worker was lying on their back, in an effort to prep the end of the joint on the bottom side. When the worker attempted to reposition themselves, they attempted to use the expansion joint to assist; by grabbing it with their hand. The edge that they were prepping, that cut through the welding Gauntlet glove and cause deep laceration to their thumb.
2039232	2024/04/08 12:46	2024/04/08	Mechanical Maintenance	Employee	First Aid	After cutting blue matting from the roll nearby for an FME Area Another employee and I were carrying it to CD-03 to lay. They were carrying one end and in the front while I was carrying the other end at the back and a pallet jack was in the path. This resulted in a trip and fall. We had done a walkdown of the area prior to starting work.
2038948	2024/04/08 05:41	2024/04/08	EI&C	Employee	First Aid	Employee was on their way to make adjustment on valve and struck hard hat on pipe and compressed neck.
2038885	2024/04/07 12:19	2024/04/07	Facilities	Contractor	First Aid	Worker was reaching into a scaffold bin to get material upon turning around to proceed to the build a scaffold tube was installed behind them and worker came into contact with this tube scraping legs, went to health unit for band aid and returned to work.

## Appendix B: Critical Path Variance Detailed Listing

Day	Summary of Variance
1	<p>24-2061 0.5 hours lost, 3 ½ hours of critical path gains were unable to be realized in fueling channel D13. There were undocumented schedule activities that needed to be completed, specifically replacement of the NFL stairs as well as an IPTE with fuel handling for the 12-bundle shift</p> <p>24-2066 1.5 hour lost due to fuelling machine accumulator issue</p> <p>Overall at the end of shift there was a 0.5 hour gain. The critical path scheudle did show a loss of 2 hours but it was issued before fuelling pulled ahead.</p> <p>24-2067: Delay to critical path – time requirement for IPTE not allocated in schedule.</p>
2	2.5 hour gain due to efficiencies in defuel/refuel string.
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4	10 hour gain due to HFD work pulled ahead
5	11.5 hour gain due to HFD work pulled ahead
6	
7	1 hour loss due to time getting the TALD in service taking longer than expected.
8	<p>PICA 24-2247</p> <p>4.5 hours delay waiting for scaffold for cable run. There was a scaffold frame required in the RB for CIGAR cables 961766 which was missed when we rearranged logic for CIGAR mobilization.</p> <p>4 hour delay as order under assessed 2hrs when actual work was 6 hrs. 961765 was only assesed at 2 hours</p>
9	17 hour gain which was attributed to work completed the previous day in the CIGAR string however unaccounted for until today. While delayed due to scaffold/cable run issues and under assessed activities, personnel leveraged the time to completed activities to power-up CIGAR. This gain was realized when the schedule was updated to reflect the activities being completed earlier.
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11	<p>24-2373 3 hours lost plant configuration checks being required following a change to the plant configuration order for CIGAR. There were also some confirmations required as PHT temperature was near the lower alarm limit. Following confirmations with Fuel Handling and Laurentis personnel, the PHT temperature was confirmed acceptably within range and permission was given to proceed with defueling activities. Further, extra time was required to prepare and execute the pre-job brief, ensuring all expectations were being met.</p> <p>24-2376 7 hours lost Difficulties encountered during installation of the modified closure plug.</p>
12	<p>24-2418 During the start of Q07 inspection execution the team encountered Scada software datum issues, this was resolved through adjustment of offset parameters.</p> <p>24-2419 The team is encountering channel conditions or flagging indications that require additional scans per the CIGAR acquisition process.</p>
13	
14	24-2493 2 hours lost Challenges in positioning carriage on 2024-04-19 #2 shift. Challenges resolved and carriage successfully installed for inspection of N04.
15	24-2485 3 hours lost CIGAR of channel N04 required more scanning due to channel conditions (CRUD)
16	24-2526 Refuel of O11 and Defuel of K08 took longer than average, stairs to NFL had to be reinstalled, temperature alarm on CIGAR control unit investigation and resolution.
17	Gain in time for efficiency on installation of the new inspection head
18	24-2603 At start CIGAR D18, vendor partner identified communication issues from 4 probes. Vendor led troubleshooting was initiated and material issues within the DAC were identified and resolved. Issue identified at 12:30, CIGAR inspection resumed at 20:00
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23	Initial estimate of duration of extra replicas
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## Appendix B: Critical Path Variance Detailed Listing, Continued

25	PICA 24-2737: Replica Head # 2 Test results did not meet pre-operational testing visual inspection. The contingency replica head was installed with the same results. Modifications to vendor partner dispensing tool in progress to reduce the volume of compound used. Replica Head # 1 passed the pre-operational test and will be the primary head used for this evolution.
26	24-2760: Resources of vendor partner were down to minimum complement. Note that the staff could not come in due to illness. 24-2770: During Modified Closure Plug (MCP) and Replica Head (RH) package installation on N04 it was observed that MCP latches had not fully engaged. The MCP passed the tug test. The FM was re-clamped on channel and FH & LEP developed and executed a troubleshooting plan, including installing the in-service RH on the alternate MCP at the Ancillary Port. When installed in N04 the alternate MCP latches were observed to be fully engaged. The original MCP was taken to the FH Shop for further analysis.
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32	24-2952 10.5 hours lost Carriage for CIGAR head tripping breaker when attempting to be moved.
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37	24-3078 6 hour delay Service Building Crane was out of service until 02:00 Delaying critical path work of installing Tracks for PHT pump Motor Movement PICA 24-3074 Covers crane unavailability for 12 hours due to Rail hold down stud failure
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39	24-3225 10 hour lost There was a missing tie in the drain to header sequence order 965940-0090 to break the loop seal it had to be tied after drain PHT purification 973103-0055. This added 10 hours to critical path. 24-3226 11 hour lost A permit needed to be modified to remove a red DNO tag from the shaft hold down device and move over to the grounding device. This was to allow coupling of the pump. The uncoupled pump motor run had been delayed which resulted in pushing the permit modification to be a critical path activity. This modification originally planned to happen while scaffold was being modified. 24-3228 7 hour delay due to the configuration of the shaft hold down device on PHT PM-2 was in the maintenance configuration (down) which would not allow drain to header to be progressed as the shaft hold down device needed to be in the up position to allow vending through the seal.
40	
41	24-3239 5 hour loss to CP While draining to header and venting the system water was observed in the pump 1 bowl while maintenance was working on the motor. The RB was evacuated and a troubleshooting team was established to understand the issue. Venting was stopped and a HIT team was established. There will be a separate PICA entered for the venting issue.
42	Delay due to number of drums required for PHT purification was insufficient.
43	Gained time on opening boiler doors and moved logic tie for boiler ECT to after stuffing box install on P-4 rather than after motor stand removal. This was agreed upon with OPS and was already part of the WCA comments.
44	24-3276 4 hour delay, There is a guide tube stored above PHT PM-4. It was required to be moved from the west side to the east so the cooler could be removed. This was not reflected in the schedule and added 2 hours to critical path. 24-3294 2 hour delay, After the cooler was removed from the PHT PM-4 oil drums also need to be removed from the work area before scaffold could be built up to the seismic restraints. This delayed critical path by 2 hours. This activity was not scheduled 24-3296 9.5 hour delay There was a missing logic tie that had a scaffold build in parallel while we were removing shaft hold down device. These two activities had to be tied in series which caused a 9.5 hour delay
45	24-3342 Took longer than anticipated to gather the scaffold gear required and get it into the boiler room for P-4 build, the original walkdown had thought there was adequate materials at the jobsite. 24-3324 Scaffold build for PHT P-4 hours estimated for "best case most likely" was 5 hours to erect scaffold as scheduled in P6, it took 12 hours to complete as it was assessed in SAP,
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## Appendix B: Critical Path Variance Detailed Listing, Continued

49	24-3402 Camera system was not functioning and required troubleshooting, it was working when it was originally setup but has not been checked for several days. Communication system was tested prior to entry but had issues in the field which was a documented back out limit. This was the first night for BWXT ECT staff on site and the first time for Boiler Makers to be in the primary side of the boilers.
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51	Efficiency in eddy current
52	24-3534 During an evolution of coordinating boiler entry with maintenance on PHT Pump 4 a failure of eddy current equipment on Boiler 1 required an entry into Boiler 1 bowl. No entry was allowed during the P4 movement.
53	Removed contingency time from boiler eddy current and placed in the back of the outage before sync. Originally it was 30 hours but removed 12 as it will be required for tent build around RO-3
54	Additional time required for boiler tube plugging, the time was built in the schedule, we removed 18 hours the previous day
55	then got the actual scheduled activities.
56	24-3601 Secondary side of 3311-BO1 was filled above the written assurance value specified in the WCA (-2.0m). Ops alerted permit holder, BO3 tube removal was safe stated with emergency plug installed, crews backed out and suspended work permit. WCA set to STST to allow boiler to be re-drained and written assurance reinstated.
57	24-3614 Decision was to stand down BO1 tube plugging at 1700 hrs, once the hot leg tube plug weld is complete which is required to allow the installation of 3312-P4 rotating element. Installing the rotating element on 3312-P4 is required this shift to prevent a 36-hour loss in this string of work due to planned days off in the PMO crew, qualification limitations on 2024-06-01 #1 shift and downstream work that would have been impacted by the delay in rotating element installation. This 36-hour delay would have made 3312-P4 work near critical path. Another contributor to this decision was that the boiler room crane is planned to be taken out of service to support scaffold build on the boiler room LAC PV75 repair, with the crane being taken out of service it would not allow the CAP for 3312-P4 to be executed which would result in no further window in this outage to execute PV75 maintenance. With the rotating element and motor stool in place the crane will not be required for the CAP.
58	
59	24-3687 Order to modify scaffold underassessed around restriction orifice 3
60	24-3717 Cleaning of Rubber / Rubber Change delayed crews from accessing the RMF work space to perform UT and mobilization pre-reqs (Approx. 2hr delay). This is due to a lack of Clean As You Go wrt RP Fundamentals. In addition, PTZ Camera installation was not previously identified by the vendor prior to mobilization of UT personnel, which further contributed to the delay (approx. 2hrs). Both delays combined resulted in a total push of 4 hrs to the critical path string. 24-3723 The cleaning of the rubber area post Boiler #3 work was extended due to the ALARA Plan not being followed and two layers of floor matting not being installed when the RA and Tent were established (ALPA-03400-0086) "A minimum of two layers of blue matting on SDC platform and RTD catwalk for ease of cleaning and/or removal if contamination cannot be reduced effectively.". This extended the cleaning time for the RTD catwalk and Bo-03 tent which delayed access for 3312-RO-03 work start. 24-3794 During removal of the Rocky Mountain Fitting spool piece (3312-RO-3) on 2024/06/06 #1 shift, the piping at west end of the removed spool sprang back approximately 1-1/8" and up 3/8".
61	
62	24-3793 RSW V-43 flange install, Comming into #1 shift. Weld prep was statted as 3 hours complete. At the start of shift, there was still several hours to remove the spool prior to the start of the weld prep.
63	
64	Gains in RSW V-43 flange install with a total overall loss over the last 3 days with a total 6.5 hours lost
65	24-3847 Termination of main motor leads delayed to not having proficient personnel to complete installation of terminations, this was identified at shift change and it was decidd to have an employeee return to work early 06:00 2024/06/09 Sunday #2 24-3848 Curent field conditions multipin cannon connector does not match new motors anphonol receptacle. and has caused a delay, current path forward is to obtain the receptacle from EMC off our old motor wiring still connected so we just have to install and connect the wiring to the terminals, Waiting on a response from EMC on wether we are getting the part we need or receiving the whole motor back and remove ourselves
66	24-3863 Operation to build tent for 3312-P3 could not be progressed as scheduled as the tent for PHT P1's shares some common area as P3. The tent and scaffold for P3 is currently being removed.
67	24-3887 an activity to disassemble and inspect the mechanical seal destined for 3312-P3 was statted as having 2.5 hrs remaining at the beginning of the shift before moving into the reassembly. At the 04:00 update meeting it was communcated that the maintainers were still in the inspection phase and it would take 6 hrs more into the next shift
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## Appendix B: Critical Path Variance Detailed Listing, Continued

69	24-3968 Jacking oil pump still required topping up of upper bearing reservoir at start of shift. after which a test run was made on the jacking oil pump motor it was found that it had the wrong rotation on 3312-PM-8 and needed to be corrected, required re-isolation and swapping of motor leads then de-isolation which caused final alignments to be pushed out to a later start <ul style="list-style-type: none"> <li>•4 hours needed to deliver an additional drum of oil for.</li> <li>•10 hours attributed to motor alignments were scheduled in parallel for PM1 &amp; 4 but the 2nd set of tooling was not usable</li> <li>•Additional logic changes were required for the additional 10 hours for break assembly.</li> </ul>
70	24-4010 10 hours Contingency order 997813 is needed to address pipe flange misalignment 24-4017 4 hours Permitry not ready to execute and delayed starting work to weld prep piping for RSW lines on pht pump motor 1 24-4102 8 hours contingency order required to finish planning and permit development to align RCW flanges on PHT PM-1
71	Efficiencies in welding. Total loss of RCW flange misalignment was 22 hours spread between the 3 previous PICA's
72	24-4036 PHT PM-1 Brake Element requires 9 helicoils to be installed during assembly
73	24-4051 PHT PM-1 Brake requires disassembly and reassembly in the correct orientation
74	24-4196 8 hours for a combination of permit install and maintenance to replace. This was identified on June 19th. This had to be repaired before scaffold could be removed and uncoupled test runs completed. 24-4197 The logic for coupling up of PHT motors 1 and 2 was shown in parallel and has to be done in series as there is only one set of tooling.
75	
76	24-4202 With a combination of testing feed and bleed valves and the dryout of the zones it took longer than originally assessed to return liquid zone to service.
77	24-4203 Testing that was required to be completed before clearing the GSS plateau delayed CP. One contributor was the loading for OPS and testing has been riding the schedule for multiple days and One of the contributors was that the previous night shift operations had 7 sick calls so a lot of testing that was scheduled was not progressed.
78	24-4180 During post maintenance testing Balance Header Feed PCV62A1 operating erratically causing balance header pressure to oscillate and cause AZL to oscillate. This required a calibration to be completed and functionality test
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## Appendix C: Emergent Major Work Scope

Work-Orders	Order-Description	Functional-Location	Functional-Location-Description
1004993	Open/Close Bearing Pedestal-3-and-5	0781-4111-BRG	BEARING
1004994	Remove/Install External Instrumentation	0781-4111-BRG	BEARING
1005016	Remove/Install Fire Piping-34C	0781-4111-BRG	BEARING
1004576	Internal Inspection of 4135-TK-01	0781-4135-TK-01	TANK--TURBINE-LUBE-OIL
1005238	Paint Aluminum Terminal Box Covers	0781-3312-PM-2	HEAT-TRANSPORT-PUMP-MOTOR-2
1013135	Repair Small oil leak	0781-5142-UST-1	1-51420-UST-1-UNIT-SERVICE-TRANSFORMER
1008712	Install ventilation on flask (for rotat)	0781-3312-P-4	HEAT-TRANSPORT-PUMP-4
1013345	New kW meters installed are not measurin	0781-65113-JQ	METER
960289	Partial Drain/Refill of 3431-TK-1-in-Q26	0781-3431-TK-1	DOUSING-TANK
1004112	pump-not-pumping	0781-4543-P-105	MONOSODIUM-PHOSPHATE-ADDITION-PUMP-T0
1004008	pump-not-pumping	0781-4543-P-106	MONOSODIUM-PHOSPHATE-ADDITION-PUMP-T0
1015166	Replace 64124-AE-1 with LDO Style Sensor	0781-64124-AE-1	DISSOLVED-OXYGEN-SENSOR
1004457	24-VDC +/- power supply required.	0781-3312-PM-2	HEAT-TRANSPORT-PUMP-MOTOR-2
1015252	Change alarm setpoint--DEM recommended	0781-64121	GENERATOR-ALTERNATOR-INSTR
1003750	FAC Inspection (UT) RHD267-6X4-RED	0781-4113-ISI-RHD267	RHD267-4-RED
1003751	FAC Inspection (UT) RHD268-4-90	0781-4113-ISI-RHD268	RHD268-4-90
1005040	Reseat H2 Seal Thermocouple	0781-64121-TE-950	SEAL FACE-TE
1014257	Install additional boiler to supplement	0781-7301-BO	BOILER
878953	PT cables in 5321-CB-801 Damaged	0781-5321-PT-801-1	POTENTIAL-TRANSFORMER
1008250	Repair patch#1 on HP Steamdrain Manifold	0781-4521-ISI-STD030	STD030-18-MANIFOLD (HP-STEAM-DRAINS)
831618	Repair Pipe Support 0781-3611-PGF-527	0781-3611-PGF-527	LINE-3-26" PIPE-GUIDE
1004527	Replace 3611-PH-11 Upper Turnbuckle Pin	0781-3611-PH-11	LINE-1-36" PIPE-HANGER
1004134	Replace 3611-PH-2 Turnbuckle Bolt	0781-3611-PH-2	LINE-4-26" PIPE-HANGER
1003549	CSDV-16 closed/limit not clearing	0781-63614-PCV-16	CONDENSER-STEAM-DISCHARGE-VALVE
1003419	Obtain Axial Displacement Measurements D	0781-3312-PM-1	HEAT-TRANSPORT-PUMP-MOTOR-1
918118	Replace gasket (Siemens)	0781-64100-JB-5536	JUNCTION-BOX-'C'-GENERATOR
948342	Swap Out 7134-RV-105 (3481-HX-1)	0781-7134-RV-105	RELIEF-VALVE-ON-OUTLET-OF-3481-HX-1
1012816	LUB: Grease Moderator PM-1 Bearings	0781-3211-PM-1	MODERATOR-PUMP-#-1-MOTOR
1012817	LUB: Grease Moderator PM-2 Bearings	0781-3211-PM-2	MODERATOR-PUMP-#-2-MOTOR
1004914	Maintenance and Load Testing---5290-RF1	0781-5290-RF-1	EPS-RECTIFIER-FOR-ODD-SUPPLY-TO-5290-BU
545913	Periodic maintenance on 5290-RF-2, EPS	0781-5290-RF-2	EPS-RECTIFIER-FOR-EVEN-SUPPLY-TO-5290-BU
1005411	Replace 7131-V-092	0781-7131-V-092	64135-TCV89-BYPASS
1007051	Replace LAC Fan Bearings	0781-7311-LAC-8	B/R-LOCAL-AIR-COOLER (SOUTH)
999774	Replace LAC Fan Bearings	0781-7311-LAC-6	B/R-LOCAL-AIR-COOLER (SOUTH)
1005542	67141-PL-4779 Ground Fault Loop-3	0781-67141-PL-4779	TURBINE-BUILDING-FIRE-PANEL-(NODE-160)
1005541	67141-PL-4779 intermittent loop-1-fault	0781-67141-PL-4779	TURBINE-BUILDING-FIRE-PANEL-(NODE-160)
1004822	7301-HX-003 Leaking	0781-7301-HX-003	HOT-WATER-SYSTEM-HEAT-EXCHANGER
1004434	Breaker Trip---Feeds MM Tool Crib	0781-5430-MCC-05-RM5	5623-PL-1536-POWER-SUPPLY
1003548	C-879 and related window annunciator	0781-68233-IS-4F	LRV-SV-CURRENT-MONITOR
1016605	Replace Resin in Polisher-4324-IX-1	0781-4324-IX-01	CONDENSATE-POLISHER-VESSEL
1016606	Replace Resin in Polisher-4324-IX-3	0781-4324-IX-03	CONDENSATE-POLISHER-VESSEL

## Appendix C: Emergent Major Work Scope, Continued

1016607	Support Polisher-Resin-Changes	0781-4324-IX	IDN-EXCHANGER
1003716	AIR-HOLD-TESTS-ON-FIVE-RHTR-01-BUNDLES	0781-4113-RHTR-01	REHEATER-01-(RIGHT)
1006511	Air-leak-on-0781-3631-PV-1-actuator	0781-3631-PV-1	ISOLATING-VALVE-ON-8D1-BLOWDOWN-LINE
846892	Calibrate-64115-Pi-3	0781-64115-Pi-3	HP-CYLINDER-GLAND-#2-PRESSURE
1011947	Calibrate-64115-Pi-7	0781-64115-Pi-7	LP2-CYLINDER-GLAND-#6-PRESSURE
1011948	Calibrate-64115-Pi-8	0781-64115-Pi-8	LP3-CYLINDER-GLAND-#7-PRESSURE
994844	Install-Online-Partial-Discharge-Sensors	0781-5711-CBL	Power-Cable
1007692	Perform-visual-inspection-of-feeder-spr	0781-33126-FDR-K6C	FEEDER-FROM-CHANNEL-K6(WEST)
1004985	R/B-Cooling-Auto-lubricator-New-Battery	0781-7311-LAC-9	F/M-VAULT-LOCAL-AIR-COOLER
1005441	South-East-Guide-Roller-on-East-Shieldin	0781-21652-DR-10B	F/M-SHIELDING-DOOR-EAST
1004537		0781-5141-FM	FAN-MOTOR
1005008	Clean-Tubes-Prior-to-ECT	0781-4210-CD-03A	CONDENSER-03A
1005013	Clean-Tubes-Prior-to-ECT	0781-4210-CD-03B	CONDENSER-03B
984791	Eddy-Current-Inspection-on-4210-CD-03A	0781-4210-CD-03A	CONDENSER-03A
984792	Eddy-Current-Inspection-on-4210-CD-03B	0781-4210-CD-03B	CONDENSER-03B
1003834	RAB-gauge-glass-LI-002-is-cloudy	0781-67301-LI-2	RAB-LOW-WATER-CUT-OFF-LEVEL-GAUGE
1005449	7512-V-1605-Leaking	0781-7512-V-1605	CHECK-VALVE-ON-MSSV-B#3-AIR-SUPPLY
1005450	7512-V-1612-leaking	0781-7512-V-1612	CHECK-VALVE-ON-MSSV-B#4-AIR-SUPPLY
1001105	Alt-Power-Scaffold-Support	0781-5430-MCC-06	MOTOR-CONTROL-CENTER--S/B-LOADS
1004137	isolation-valve-in-very-poor-condition	0781-4321-V-158	ISOLATING-VALVE-FOR-RCW-SYSTEM-MAKE-UP
918075	Replace-0781-3611-PH-39A-and-B	0781-3611-PH-39AB	LINE-8-26'-SPRING-HANGER
918042	Replace-0781-3611-PH-42A-and-B	0781-3611-PH-42AB	LINE-7-26'-SPRING-HANGER
1003417	Contingency-Replace-Fans-if-Required.	0781-5552-INV-2C	600VAC-INVERTER-2C-CLASS-II
1009376	Inspect-Steam-Drains-PV-016-for-passing	0781-64521-PV-16	TP10-BYPASS-WITH-HANDWHEEL-(SPEC-BB)
1009370	Inspect-Steam-Drains-TP-10-for-passing	0781-4521-TP-10	STEAM-TRAP-FOR-DPB-TO-REHEATER-#2
1009374	Inspect-Steam-Drains-Valve-053	0781-4521-V-053	STR10/TP10-ISOLATION-VALVE
1009375	Inspect-Steam-Drains-Valve-054	0781-4521-V-054	STR10/TP10-ISOLATION-VALVE
1004117	Loose-phase-"A"-bottle-in-5321-cell-B01	0781-5321-CB-B01	5321-BUB-POWER-SUPPLY
980094	Rebuild/Replace-Accessories-on-LCV-4A1	0781-63620-LCV-4A1	3311-BO-4-MAIN-LEVEL-CONTROL-VALVE
1004003	Drain-Valve-broken	0781-4313-V-256	3/4"-DRAIN-VALVE-BEFORE-LCV116A-B-C
1010277	Install/Remove-Spool-Piece-3632-SPL-1	0781-3632-SPL-1	FLANGED-SPOOL-PIECE-P1-SUCT-FROM-BOILER
1010276	Install/Remove-Spool-Piece-3632-SPL-2	0781-3632-SPL-2	FLANGED-SPOOL-PIECE-P1-DISCHARGE-TO
1010275	Operate-Boiler-Wet-Lay-Up-System	0781-3632	BOILER/STEAM-GENERATOR-WET
1007494	Replace-exciter-optocouplers,-base	0781-4122-EX-1	Static-Exciter
1006987	Document-Update	0781-3211-V-5	P1-(DISCH)-ISOL-GATE-V/V-WITH-OVERPRESS
1010795	Fabricate-new-Position-Indicator	0781-3211-V-5	P1-(DISCH)-ISOL-GATE-V/V-WITH-OVERPRESS
970343	Inspect-and-Clean-Fan-4135-F-100	0781-4135-F-100	MAIN-OIL-TANK-VAPOUR-EXTRACTION-FAN
959578	Install-new-position-indicator-assembly	0781-3211-V-6	P2-(DISCH)-ISOL-GATE-V/V-WITH-OVERPRESS
959577	Install-new-position-indicator-assembly	0781-3211-V-5	P1-(DISCH)-ISOL-GATE-V/V-WITH-OVERPRESS
999775	LAC-7-Bearing-Replacements	0781-7311-LAC-7	B/R-LOCAL-AIR-COOLER-(SOUTH)
1005455	O25-Contingency-ECT-&-tube-plug/staking	0781-4312-HTR-3A	CONDENSATE-HEATER
1005353	Remove-FM-from-FWH-in-O24	0781-4312-HTR-3A	CONDENSATE-HEATER
857649	Replace-Hoist/Trolley-7611-MR-19-dousing	0781-7611-MR-19	DOUSING-SYSTEM-CONTROL-VALVES-MONORAIL-2
1003755	4312-HTR-3A-level-increasing-shell-side	0781-4312-HTR-3A	CONDENSATE-HEATER
968313	calibrate-64333-PCVB#4	0781-64333-PCV-B#4	PEGGING-STEAM-PRESSURE-CONTROL-VALVE

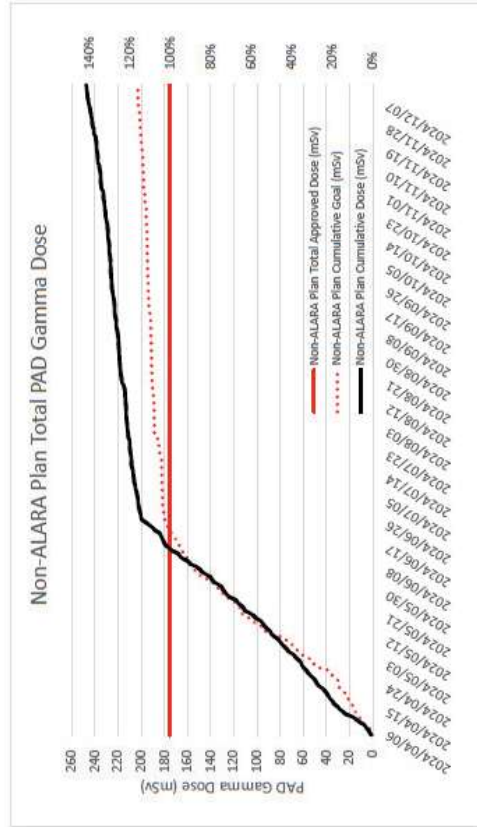
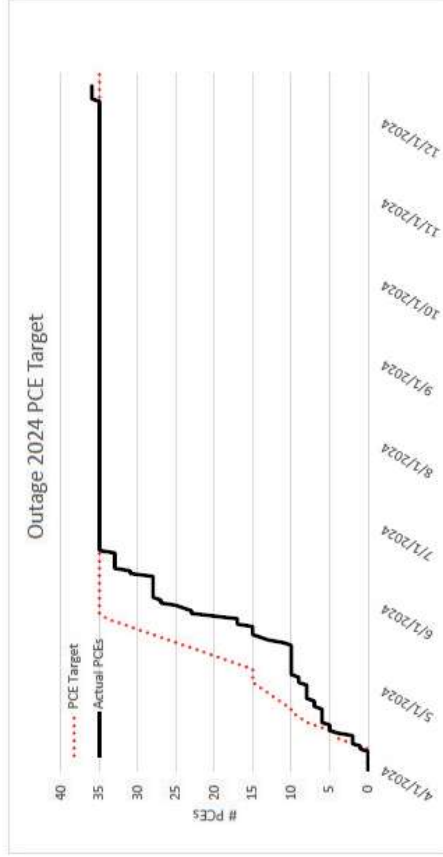
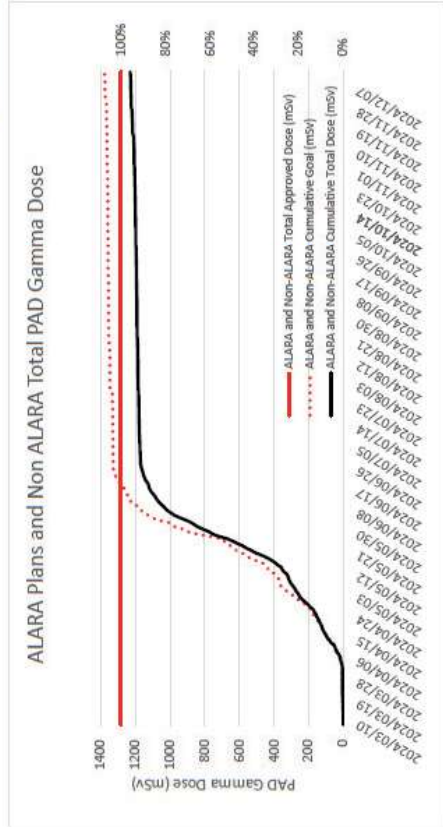
## Appendix C: Emergent Major Work Scope, Continued

1005239	Constant-Fuel-Oil-from-PI-Drain	0781-5224	SG-FUEL-SYSTEM
1004538	Noisy-Fan-on-Phase-A-UT	0781-5141-FM	FAN-MOTOR
1005582	Remove-Actuator-and-Remove-Packing	0781-64333-PCV-8#4	PEGGING-STEAM-PRESSURE-CONTROL-VALVE
999668	Replace-0781-65224-PI-39	0781-65224-PI-39	SG1-FUEL-SUPPLY-HEADER-PRESSURE
875906	SAFETY-Replace-3611-V-20-and-V-21-and-r	0781-3611-V-020	ISOLATOR-VALVE-TO-STEAM-SAMPLE-SYSTEM

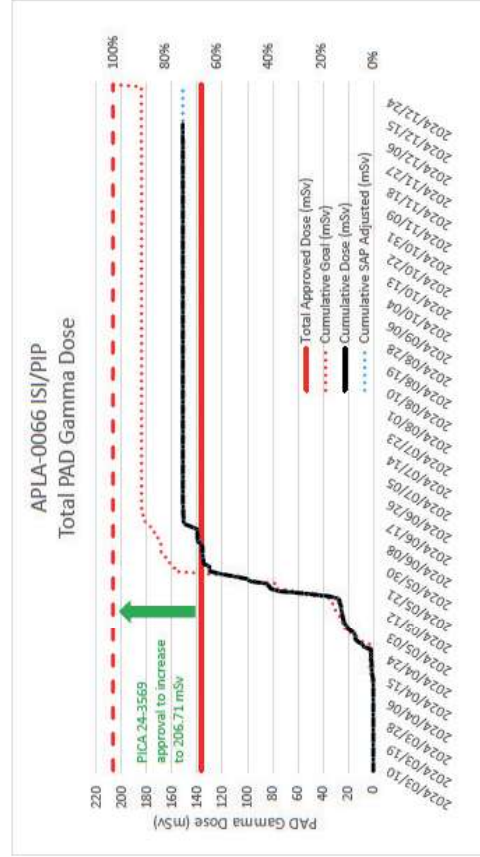
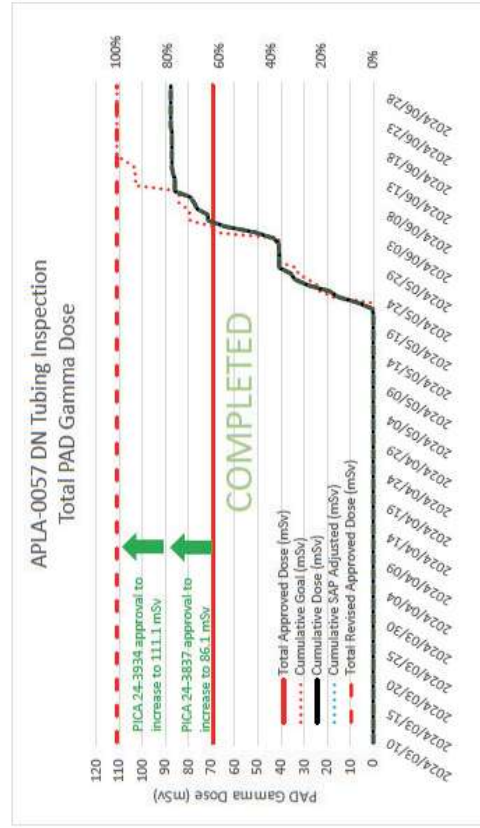
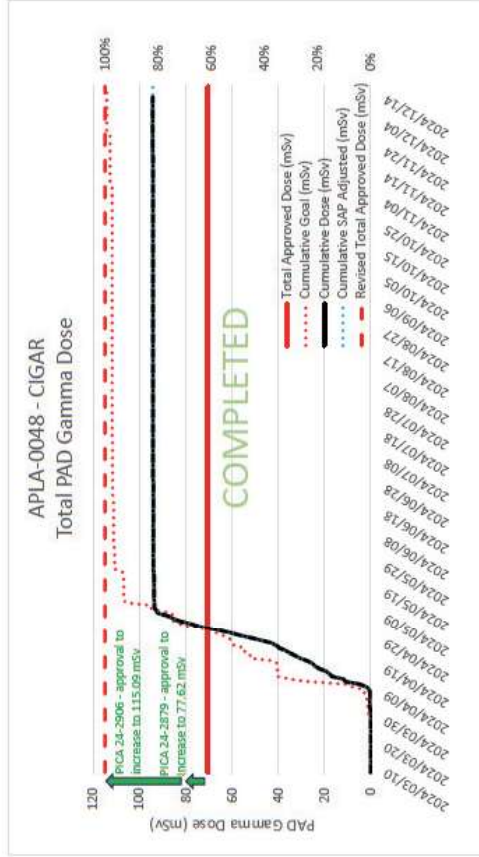
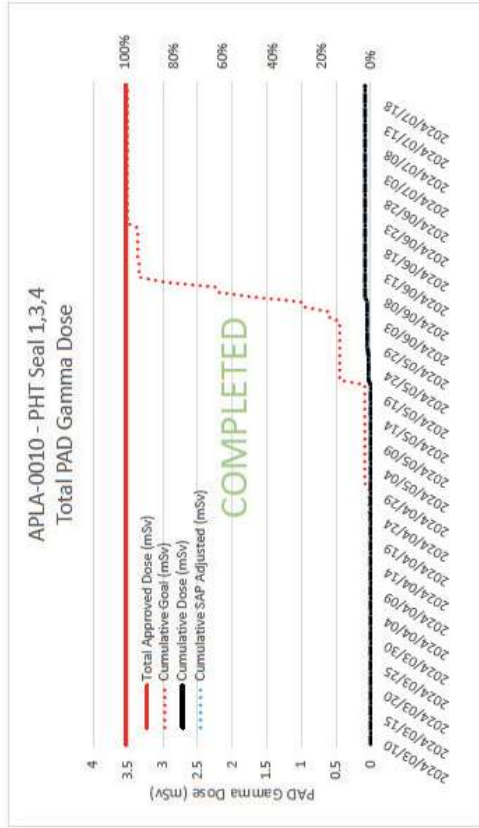
# Appendix D: Dose and Personnel Contamination Events

	Daily Total (mSv)	Outage Total to Date (mSv)	Outage Target to Date (mSv)	Outage Goal (mSv)	% of Total Approved Dose
ALARA Plan Dose	0.00	982.54	1175.31	1110	88.55%
Non-ALARA Plan Dose	0.46	247.65	203.08	175	141.51%
Outage ACEMAN Dose	0.46	1230.19	1378.39	1285	95.76%

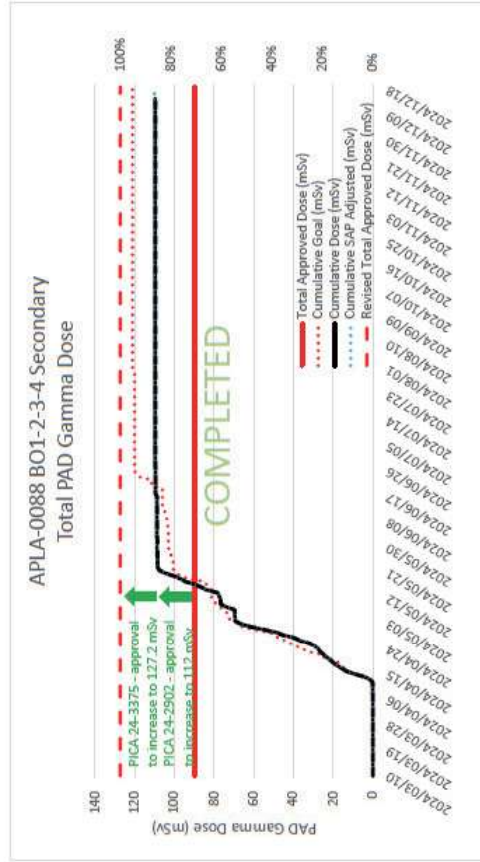
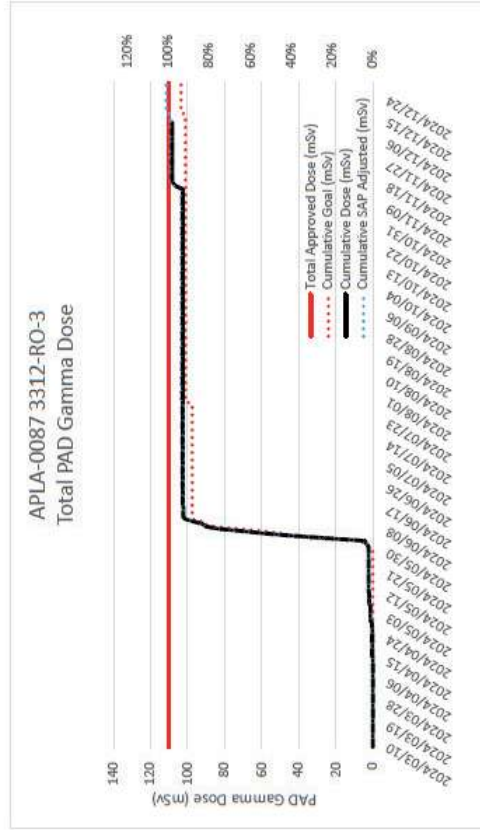
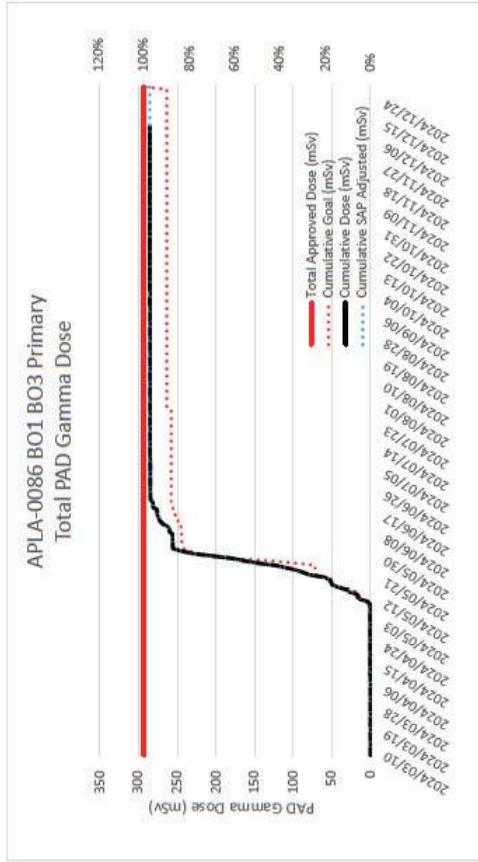
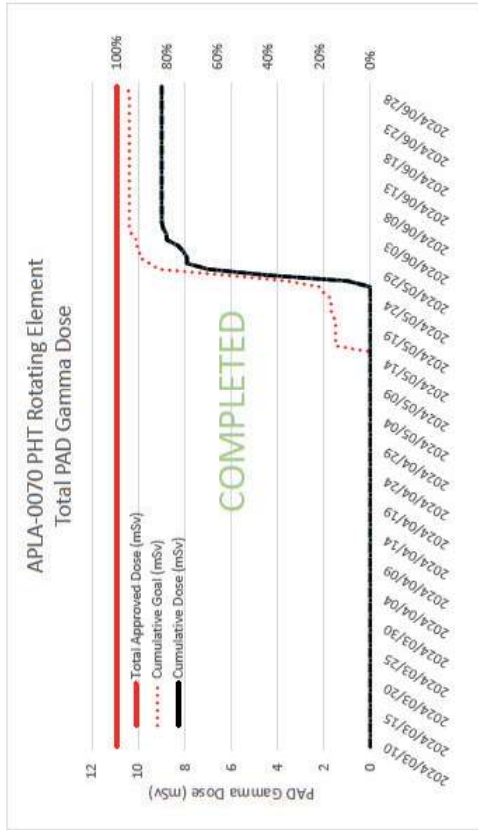
	Daily Total	Cumulative Target	Outage Total	Outage Goal
PCEs	0	0	36	£35



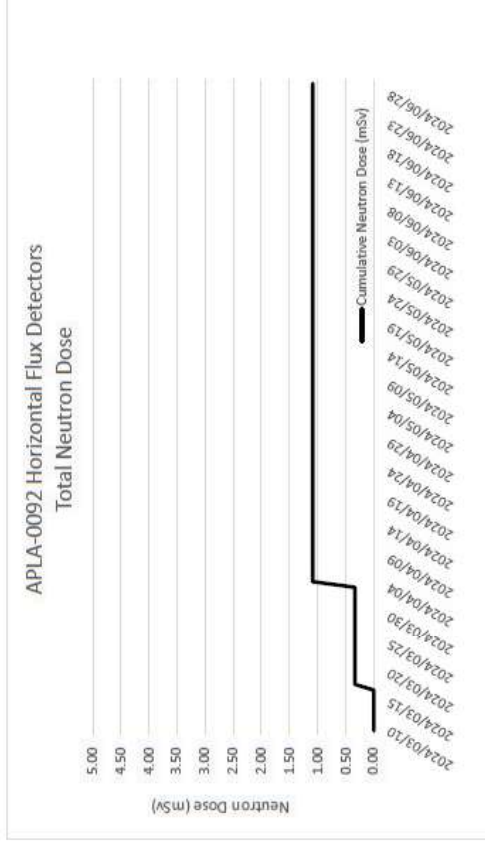
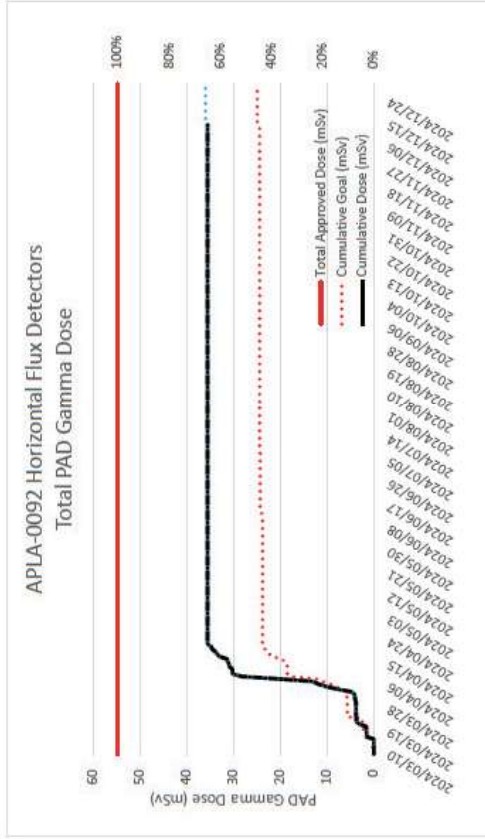
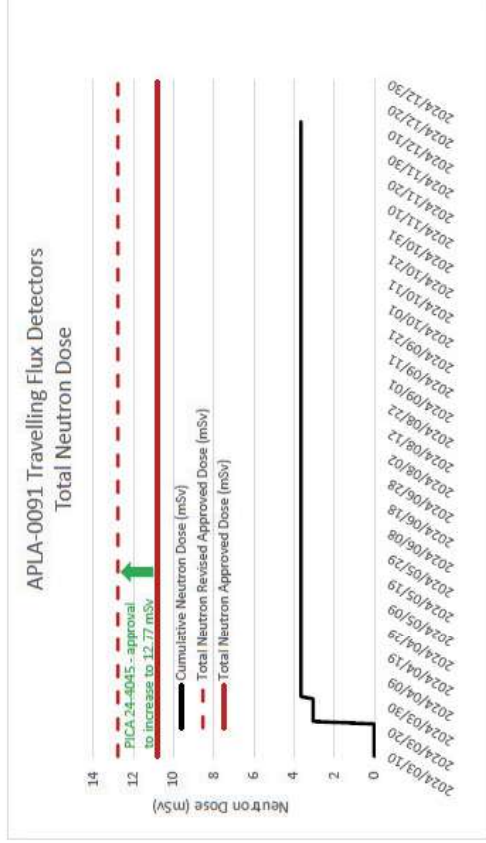
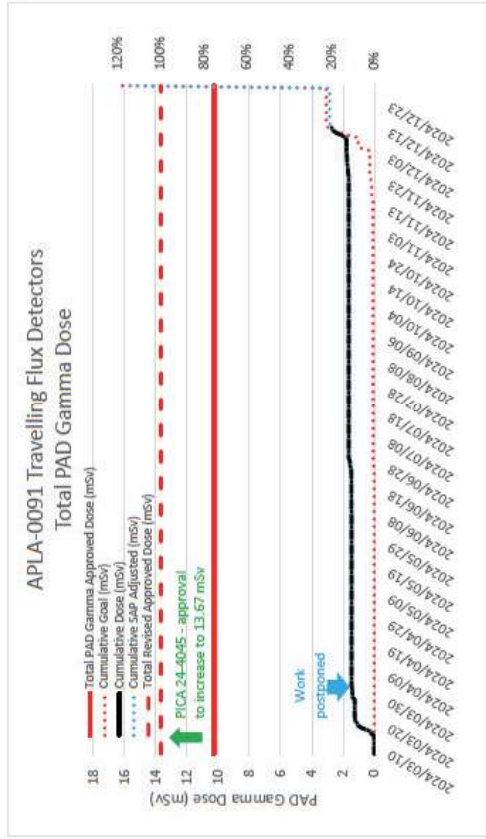
# Appendix D: Dose and Personnel Contamination Events, Continued



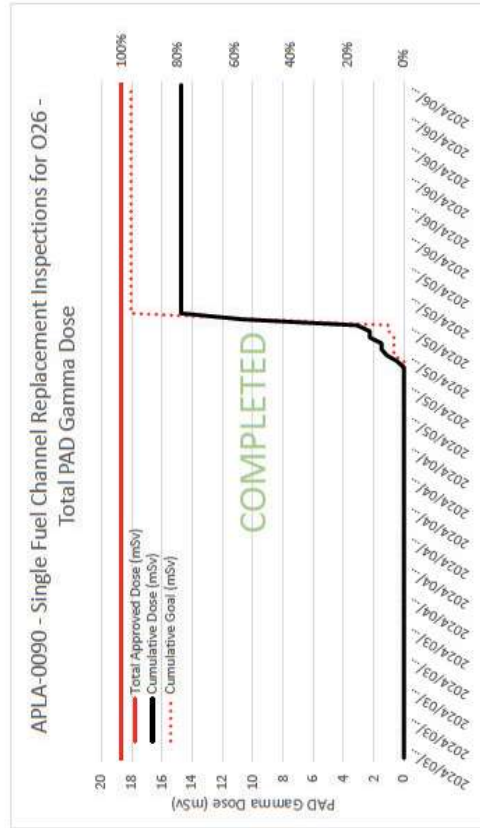
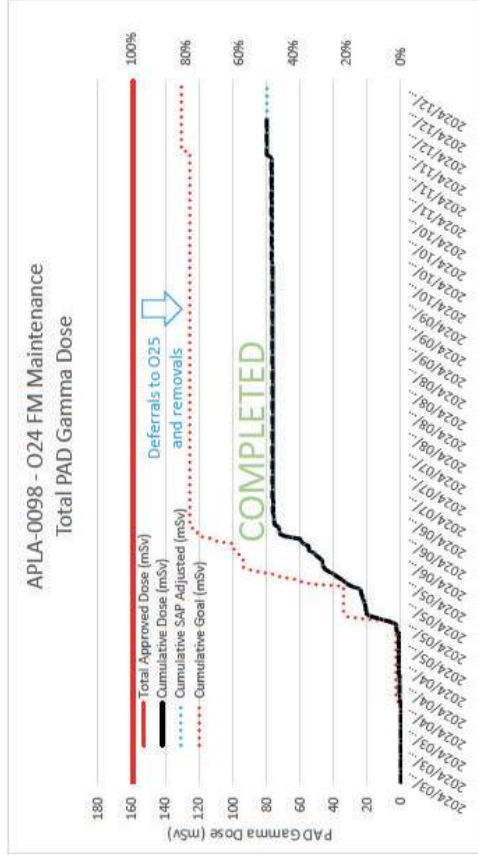
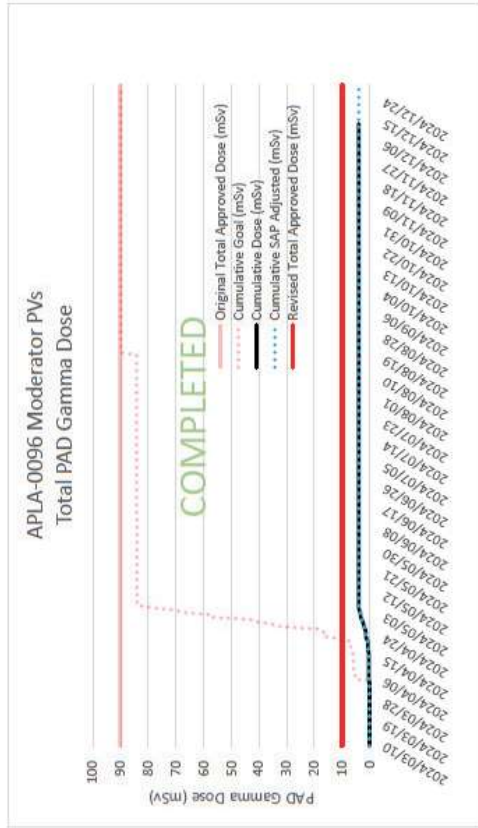
# Appendix D: Dose and Personnel Contamination Events, Continued



# Appendix D: Dose and Personnel Contamination Events, Continued



# Appendix D: Dose and Personnel Contamination Events, Continued



## Appendix D: Dose and Personnel Contamination Events, Continued

Dose by Work Group		Total PAD Gamma Dose (mSv)
2024-04-06 at 10:00:00 to 2024-12-15 at 23:38:00		
Department		Total PAD Gamma Dose (mSv)
AD-ADMINISTRATION		0.47
AS-ADMINISTRATION SERVICES		2.09
CU-CHEMISTRY		4.12
EI-EI&C		43.16
EP-EMERGENCY PREPAREDNESS		6.38
FH-FUEL HANDLING		161.29
FM-FACILITIES MANAGEMENT		219.93
FN-FIX-IT-NOW GROUP		32.45
FS-FIRE SAFETY		10.64
HP-HEALTH PHYSICS		215.94
MM-MECHANICAL		160.04
NR-NON RESIDENT STAFF		0.09
NS-NUCLEAR SAFETY		0.08
OP-OPERATIONS		31.73
PA-PERFORMANCE ASSESSMENT		2.57
PN-PLANNING		0.21
RA-REGULATORY AFFAIRS		0.50
SE-SECURITY		0.25
SU-STORES		0.09
TC-TECH - EI&C		0.00
TE-ENG - ENGINEERING SERVICES		23.85
TP-TECHNICAL PROJECTS		285.06
TR-TRAINING		19.95
TS-ENG - SYSTEMS		0.49
WM-WORK MANAGEMENT		0.08

ALARA Plan	Description	Cumulative PAD Gamma Dose (mSv)	Total Approved Dose (mSv)	%Total Approved Dose
APLA-03400-0010	Mechanical Seal Replacement PHT Pumps 3312-P1, P3 & P4	0.08	3.54	2.3%
APLA-03400-0048	Fuel Handling CIGAR Inspections	94.45	115.09	82.1%
APLA-03400-0057	DN Tubing Inspection and Maintenance	87.78	111.10	79.0%
APLA-03400-0066	ISI/PIP Inspections	151.29	206.71	73.2%
APLA-03400-0070	PHT Rotating Element Replacement	9.01	10.95	82.3%
APLA-03400-0086	Boiler Primary Side Inspections 3311-BO1 & BO3	285.61	293.37	97.4%
APLA-03400-0087	East Feeder Cabinet Restriction 3312-RO-3	108.25	110.10	98.3%
APLA-03400-0088	Boiler 3311-BO1-2-3-4 Secondary Water Lancing	109.63	127.20	86.2%
APLA-03400-0090	Single Fuel Channel Replacement Inspections for O26	14.72	18.69	78.8%
APLA-03400-0091	Travelling Flux Detectors	2.72	21.12	12.9%
APLA-03400-0092	Horizontal Flux Detector Replacement	35.48	54.70	64.9%
APLA-03400-0096	Moderator PV Replacement	3.96	90.19	4.4%
APLA-03400-0098	Outage 2024 FM Bridge Maintenance	79.56	159.25	50.0%

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## Appendix D: Dose and Personnel Contamination Events, Continued

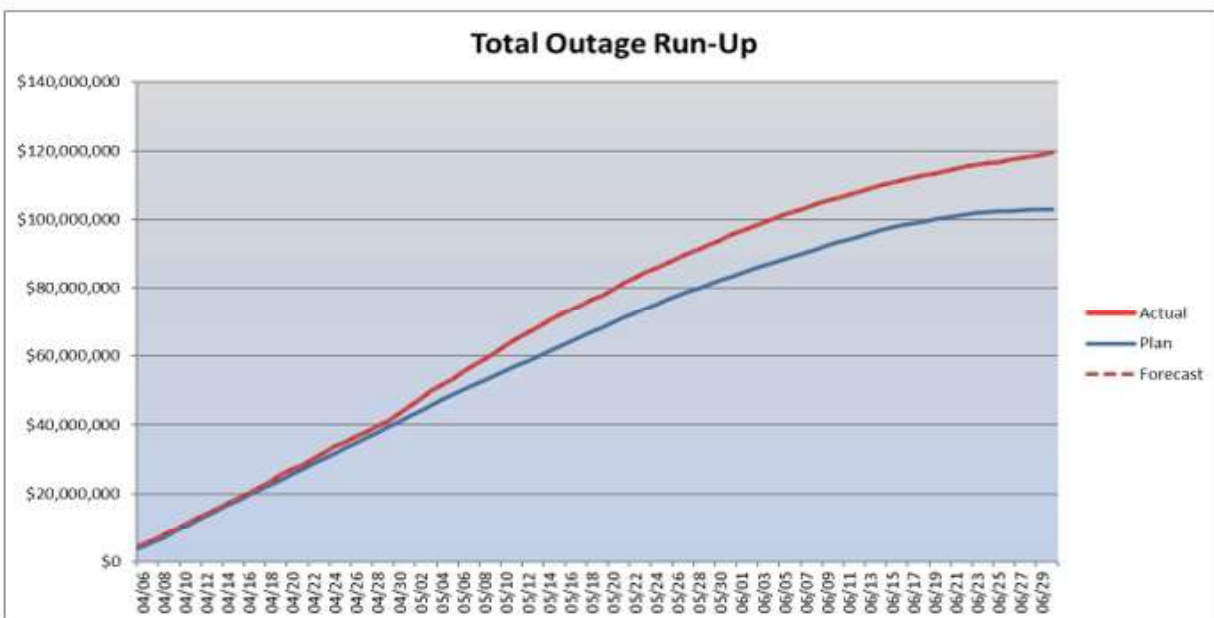
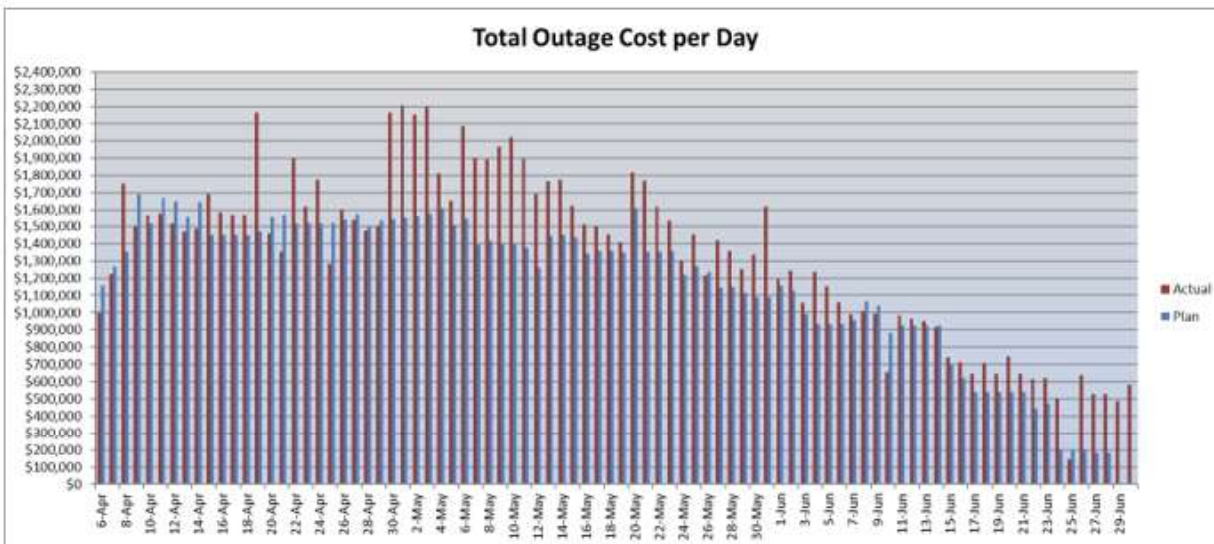
### O24 Personnel Contamination Events

<u>Date</u>	<u>Location</u>	<u>Work Group</u>	<u># of Workers</u>	<u>RP Qual</u>	<u>PICA</u>
2024/04/09	Zone 3:2 at EAL - 8 cps on scrub pants after working in R1-406	TP	1	Orange	24-2147
2024/04/11	HRCO - Rubber Area exit at South End of the Vaults	HRCO	1	Green	24-2209
2024/04/15	Zone 3:2 at EAL FH - 30 cps on sleeve after working in NFL	FH	1	Green	24-2303
2024/04/15	Zone 3:2 at EAL FH - 30 cps on sleeve after working in NFL	FH	1	Green	24-2305
2024/04/16	Zone 3:2 at EAL Projects - 60 cps on leg	TP	1	Orange	24-2332
2024/04/19	Zone 3:2 at SB el. 25' elevator - 1-2 cps on each boot (4kBq mixed gamma)	MM	1	Orange	24-2459
2024/04/25	Zone 3:2 at EAL - Rad Instruments (8 cps on hand) at SUI Rubber Area	EI	1	Yellow	24-2632
2024/04/28	Zone 3:2 at EAL - AIM worker from Maint. Lock Rubber Area (50 cps on arm)	FH	1	Orange	24-2741
2024/05/04	Zone 3:2 at EAL - Operations staff (100 cps on back) (Strap on gamma meter contaminated)	OP	1	Yellow	24-2856
2024/05/07	Zone 3:2 at Crane Hall - Facilities staff (100 cps on torso) processing waste	FM	1	Yellow	24-2950
2024/05/19	Zone 2:1 boundary after working in R1-007 in street clothes (50 cps)	EI	1	Yellow	24-3279
2024/05/20	Zone 3:2 at EAL - Tech Engineering staff (140 cps on torso)	TE	1	Green	24-3307
2024/05/20	Zone 3:2 at EAL - Maintenance staff (180 cps on torso)	MM	1	Orange	24-3308
2024/05/21	Zone 3:2 at Decontamination Centre (80 cps on pants)	RP	1	Yellow	24-3359
2024/05/22	Zone 2:1 boundary after being in MRM laydown area EAL S1-221 EL 62'9" (30 cps torso)	MM	1	Orange	24-3401
2024/05/26	Zone 3:2 at EAL - RP Staff (60 cps on torso)	RP	1	Green	24-3456
2024/05/26	Rubber Area exit at East Vault (100 cps) on bottom of boot	FM	1	Yellow	24-3477
2024/05/29	Rubber Area at SDC East (30 cps)	TP	1	Orange	24-3559
2024/05/29	Rubber Area at SDC East (60 cps)	TP	1	Orange	34-3561
2024/05/29	Rubber Area at SDC East (150 cps)	TP	1	Orange	24-3563
2024/05/30	Zone 2:1 boundary after being in Zone 2 hallway (60 cps shoe)	Visitor	1	Red	24-3576
2024/05/30	Zone 3:2 at EAL - TP Staff (60 cps on boot)	TP	1	Orange	24-3599

## Appendix D: Dose and Personnel Contamination Events, Continued

2024/05/30	Zone 3:2 at EAL - TP Staff working in Boiler Equipment Tent on el. 25' SB (50 cps on torso)	TP	1	Orange	24-3602
2024/06/01	Zone 2:1 boundary after being in Plastics Laundry (150 cps shoe)	FM	1	Green	24-3626
2024/06/02	Zone 3:2 at EAL - TP Staff (20 cps on left leg)	TP	1	Orange	24-3701
2024/06/03	Zone 3:2 at EAL - MIM Staff (30 cps on left leg)	MIM	1	Orange	24-3684
2024/06/03	Zone 3:2 at EAL - TP Staff (35 cps on left leg)	TP	1	Green	24-3582
2024/06/05	Zone 3:2 at EAL - TP Staff (75 cps on left leg)	TP	1	Orange	24-3740
2024/06/14	Zone 3:2 at EAL - FM Staff (15 cps on arm)	FM	1	Orange	24-3993
2024/06/14	Zone 3:2 at EAL - FM Staff (20 cps on hand)	FM	1	Orange	24-3994
2024/06/14	Zone 2:1 boundary after being in East SDC Platform (70 cps shoe)	FM	1	Orange	24-3996
2024/06/16	Zone 3:2 at EAL - FM Staff (100 cps on arm)	RP	1	Green	24-4028
2024/06/17	Zone 3:2 at EAL - FM Staff (20 cps on hand)	FM	1	Orange	24-4035
2024/06/22	Zone 3:2 at EAL - MIM Staff (650 cps on foot)	MM	1	Green	24-4167
2024/06/22	Zone 3:2 at EAL - FM Staff (40 cps on foot)	FM	1	Orange	24-4168
2024/12/10	TBC, likely Zone 2 valve shop S1-164 (15 cps on Torso)	PN	1	Yellow	24-6814

## Appendix E: Budget & Resources



\*Graphs reflect \$119.4m as at June 30<sup>th</sup> upon the completion of Daily Reporting. The remaining \$18.0m occurred during outage extension resulting in total outage dollars spent of \$137.3m as reflected in section 5.1 above.

## Appendix F: Outage Lessons Learned

Action PICA 24-5649	Owner	Status	PICA Action
Track closure of improvement actions under PICA 24-4470 in outage preparation package.	OWM – [REDACTED]	Completed	2
HR to establish a cross functional task team to revise staff shift schedules for outages.	HR – [REDACTED]	Completed	7
Outage work management staff (coordinators) to be quorum for Supply Chain’s weekly MSPT meetings to provide guidance on priority and submitting timely scope deferrals as required.	Supply – [REDACTED]	Completed	18
Maintenance to document Fix-It-Now mandate within forced and planned outages in governance documents.	Maintenance – [REDACTED]	Completed	21
Outage WM leadership and frontline team to implement scheduling improvement techniques and document in a roles and expectation guide. Train to any noted gaps.	OWM – [REDACTED]	Completed	23
Outage WM to assign an accountable staff for overall schedule control. Document on Outage WM staff roles and expectations document.	OWM – [REDACTED]	Completed	25
Outage WM to improve contingency plans to industry best practices for revisions required. Focus on planning and parts purchases and risk mitigation plans commiserate with risk scoring.	OWM – [REDACTED]	Completed	26
Outage WM to implement best practices for OCC/WAR/PIT/SWC roles and responsibility and document.	OWM – [REDACTED]	Completed	36
Outage WM to document OCC Major Issues Criteria in OCC desktop Guide	OWM – [REDACTED]	Completed	44
Outage WM to document RB coordinator responsibilities to include housekeeping walkdowns of Crane Hall and Service Building Elevation 25 and assign owners for cleanup.	OWM – [REDACTED]	Completed	45
Supply to work with Maintenance and Engineering to develop safety stock strategy for replacement cable, termination kits and EQ splice kits.	Supply – [REDACTED]	Completed	49
Radiation Protection and Supply to invest in rubber area supplies to meet demands	RP – [REDACTED]	Completed	53
Engineering, Maintenance and Operations to establish RAB health improvements before and during outage execution considering O24 Opex.	Eng – [REDACTED]	Completed	55
Radiation Protection and Supply to ensure sufficient amount of plastic suits are available on site and cleaning resourced appropriately. Ensure Contingency Action Plan requirements are considered in stocking.	Supply – [REDACTED]	Completed	61
Maintenance to ensure plastic suits laundry health, dehumidification of the room and staffing for suit cleaning to support outage scope.	Maintenance – [REDACTED]	Not accepted	62
HR to work with departments to identify and develop succession plans for SPV Staff as there is a risk to future outages.	HR – [REDACTED]	Not accepted	63
Maintenance to ensure adequate tooling available to enable 2 PHT motor coupling	Maintenance – [REDACTED]	Completed	64
Outage Work Management to perform a gap assessment on current milestones to industry. Adjust as required milestone order, closure criteria, oversight and challenges. Consideration of O24 Lessons Learned teams’ recommendations for noted milestone additions.	OWM – [REDACTED]	Completed	65



# IR-7 – Attachment 1



**Énergie NB Power**

# Point Lepreau Nuclear Generating Station

## Outage 2026

DATE: August 25, 2025

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## Executive Summary

The purpose of Point Lepreau Nuclear Generating Station (PLNGS) planned outages is to maintain the station life cycle and long-range plans to support safe, reliable operation of PLNGS. The 2026 Outage is to improve plant reliability by addressing plant deficiencies and completing preventive maintenance to support predictable plant operation.

The 2026 Outage scope includes corrective orders, preventative maintenance activities, system or component health improvements, regulatory commitments, and other significant work that cannot be performed during unit operation.

The process of Managing Planned Outages at PLNGS is based on Industry best practices having the following key elements: long range planning, outage scoping, outage planning, outage scheduling, readiness reviews, outage execution and close out. When implemented appropriately, these key elements ensure the outage schedule can be implemented efficiently with shutdown safety maintained.

### **Timeline:**

The 2026 Outage is planned for 84 execution days, plus 34 days contingency, for a total of 119 days.

## Current State and Outage Drivers

A planned maintenance outage is an important function that has a direct impact on the safe and reliable operation of PLNGS. Key benefits associated with outages are:

- The maintenance program during planned outages directly impacts the physical condition of systems, components and structures to ensure equipment is available to perform its intended design function. Maintenance activities and frequency are commensurate with safety importance, design function and required performance.
- Management of planned outages is a regulatory requirement as identified in the PLNGS License Condition Handbook (LCH-PR-17.00/2022-R000), issued by the Canadian Nuclear Safety Commission (“CNSC”), which states *“The licensee maintenance program shall include provisions for the management of planned outages. Planned outages represent a key activity which has a high regulatory significance. Therefore, the licensee is expected to ensure proper scoping of safety-related commitments, planning and execution (e.g., for heat sinks, dose control, etc.). Specific requirements related to heat sinks and dose control can be found in LCH Sections 3 and 7. The licensee shall implement and maintain a program for the management of outages”*.
- The scope of work undertaken during planned outages directly affects operating reliability and the number of forced outages expected over the station life cycle.
- Bundling and coordination of work activities and projects supports equipment alignment strategies help to lower the overall cost of maintenance and limit the duration of outages (e.g. Odd vs Even electrical bus maintenance strategies).
- Planned outages are scheduled during less expensive energy replacement periods, unlike a forced outage.

## Implementation Strategy and Milestone Schedule

### Outage scope

Overall outage scope includes preparation and execution activities. The majority of costs associated with preparation will be incurred in FY25/26 and execution costs in FY26/27.

#### Preparation

Successful outages require effective preparation and planning of outage execution activities. A series of milestones have been developed to track preparation activities. The milestones used at PLNGS are consistent with industry best practices used in the nuclear industry. Preparation activities include:

- outage work scoping to ensure the correct scope is identified to support reliable station operation
- detailed planning and assessing which includes ensuring the required parts are identified
- procurement of parts and material to support execution of outage scope (in some cases costs associated with parts and material are incurred during the preparation phase as they are withdrawn from stores as part of preparation and pre-requisite work)
- development of the required perimetry and work protection
- scheduling of outage activities to optimize outage duration and costs
- engineering for design modifications in outage scope as well as engineering support for corrective and preventive maintenance planning
- pre-requisite work such as installation of scaffolding, preparation and staging of tooling, parts and material
- pre-outage mobilization, orientation and training for contract staff brought to site to support outage execution activities
- pre-outage training for station staff to ensure readiness to execute the specific outage work scope.

## Work Scope

The Outage work scope includes corrective orders, preventative maintenance activities, system or component health improvements, regulatory commitments, major component inspections, modifications, and other significant work that cannot be performed during unit operation.

In accordance with the Outage 2026 milestones, detailed outage work scope was finalized on July 26, 2025. Outage scope is subject to changes as equipment issues and challenges arise and any changes to scope after it was initially established are reviewed and approved by station Outage Scope Control Board.

A summary of the major scope identified for Outage 2026 is as follows:

### Major Work Scope

The following projects have been identified as Major Scope for Outage 2026

#### Primary Heat Transport System

The primary purpose of the Primary Heat Transport System (PHT) is transporting heat from the fuel in the reactor core to the Steam Generators (boilers). This is done in two separate loops using two very large pumps per loop. The work will include the replacement of one PHT motor, and the replacement of a rotating element.

#### Reactor Building Leak Rate Test (RBLRT)

The primary focus of the Reactor Building leak Rate Test is to verify the condition of the structure. The test will identify if there are any issues with the liner of the building that provides the nuclear envelope of the facility. The test will require the use of multiple compressors to pressurize the structure and perform a “hold” of the pressure and identify any leakage.

#### Class III Electrical System

The class III electrical system provides power to key systems in the station that ensure proper control and cooldown of the station. Class III is backed up by three standby generators. The maintenance will include inspection, testing and cleaning of the buses, transformers and breakers.

### Boiler Mechanical Clean

The boilers (4) are the primary heat sink for the primary heat transport (PHT) system. The PHT tubes that travel through the boilers are subject to magnetite build up which affects thermal conductivity. The mechanical cleaning process will dislodge and collect the magnetite which will allow for an increased thermal transfer efficiency.

### Turbine LP/HP Sectionalized Maintenance

The turbine, which includes one High Pressure (HP) and three Low Pressure (LP) sections, will undergo focused work on one LP section during this outage. The casing and insulation will be removed to allow inspection of the blades, where signs of wear, aging, or deposits will be assessed and documented. Once complete, the turbine will be restored by reassembling the casing and insulation.

### Turbine Valve Maintenance

This outage will include sectionalized maintenance on one of the four hydraulically operated Emergency Stop Valves (ESVs), which are designed to shut off steam to the turbine if a trip signal occurs. The selected ESV will be removed, refurbished, and tested to confirm reliable hydraulic operation. In addition, two Main Steam Safety Valves (MSSVs), which provide overpressure protection for the main steam system, will be overhauled, reassembled with calibrated set points, and tested to ensure proper performance.

### Balance of Plant Valve Replacements

As part of an ongoing reliability campaign, this outage will include the replacement of 37 secondary side system valves across systems such as reheat, recirculating cooling water, condensate, and raw service water. Work will involve isolating and draining the affected systems, removing the existing valves and hardware, installing new valves, and completing appropriate testing. Once verified, the systems will be refilled, vented, and functionally checked to confirm performance.

### Generator Inspections

The Main Generator, which converts mechanical energy from the HP and LP turbines into electrical energy, will receive a medium-scope inspection during this outage. Work will include removing covers and access panels, inspecting stator and rotor components, assessing the condition of windings and key internals, and performing electrical and mechanical checks to confirm integrity. Inspection results will be documented for trending, and the generator will be reassembled and verified for operational readiness.

### Condenser Inspections

The condensers, which convert steam from the low-pressure turbines back into condensate for return to the boilers, will undergo inspections during this outage. Cooling is provided by salt water through the condenser cooling water system, making tube integrity critical to prevent leakage into the condensate system. Work will include opening the access to the tube bundles, completing eddy current inspections to assess tube health, documenting any signs of wear or degradation, plugging tubes as required, and cleaning internal surfaces. Once complete, the condensers will be restored to service and checked for proper operation.

### Replace Variable Frequency Inverter

Remove and disconnect the existing Variable Frequency Inverter (VFI), install the new unit, complete electrical terminations, perform configuration and start-up checks, and verify functional operation before returning the system to service.

### Summary of Remaining Work Scope:

The remainder of the outage work scope, although important, does not have the same outage cost and duration impact. A summary of this work is included below:

- Preventive and corrective maintenance of electrical systems including station transformers and switchyard equipment
- Preventive and corrective maintenance, calibration and testing of station instrumentation
- Preventive and corrective maintenance of motorized and pneumatic valves and actuators on conventional (non-nuclear) systems
- Preventive and corrective maintenance of motorized and pneumatic valves and actuators on nuclear systems
- Strainer, cooler, and heat exchanger inspections and cleaning
- Preventive and corrective maintenance of pumps, pump seals, motors and fans
- Testing of relief and pressure safety valves
- Calibration of motorized and pneumatic valves on conventional and nuclear systems
- Installation of approved engineered modifications to address deficiencies and improve equipment reliability.

# Financial Estimates

The initial financial estimates are based on the costs of past outages as well as estimated costs for scope of work. The table below provides a summary of the current forecast costs for the 2026 pre-outage preparation and outage execution windows.

**Table 1: Outage 2026 Cost Summary (values are in Millions \$)**

Activity	2025/26E (pre-outage)	2026/27B (execution)	Total Cost
<b>Major Work Scope</b>			
Generator Inspections	\$1.5	\$3.7	\$5.2
Boiler Mechanical Clean	\$8.5	\$17.0	\$25.5
Turbine LP/HP Sectionalized Maintenance	\$0.5	\$3.0	\$3.5
Turbine Valve Maintenance	\$0.2	\$4.1	\$4.3
Balance of Plant Valve Replacements	\$0.5	\$1.0	\$1.5
CCW expansion joint and valve replacements	\$0.5	\$2.0	\$2.5
Replace Variable Frequency Inverter	\$0.9	\$0.4	\$1.3
Condenser Inspections	\$0.1	\$0.5	\$0.6
RBLRT	\$0.5	\$2.4	\$2.9
PHT Pump Rotating Element	\$0.5	\$1.5	\$2.0
<b>Total Projects</b>	<b>\$13.7</b>	<b>\$35.6</b>	<b>\$49.3</b>
<b>Balance of Outage Scope</b>			
Regular Labour	\$3.4	\$12.2	\$15.6
Overtime Labour	\$1.7	\$15.6	\$17.3
Hired and Consulting Services	\$2.6	\$43.6	\$46.2
Material	\$1.1	\$9.1	\$10.2
Overhead	\$1.1	\$3.5	\$4.6
Contingency	\$0.0	\$24.3	\$24.3
<b>Total Outage Scope</b>	<b>\$9.9</b>	<b>\$108.3</b>	<b>\$118.2</b>
<b>Total</b>	<b>\$23.6</b>	<b>\$143.9</b>	<b>\$167.5</b>

## Benefits Expected

The primary benefit of the completion of the 2026 Outage is the improved reliability of the operation of PLNGS through risk reduction and sustained efficiency. Completion of the outage also supports maintaining regulatory confidence and license compliance by ensuring that regulatory requirements and commitments are completed in the timelines required by the federal nuclear regulator (CNSC).

## Risk Analysis

### Risks of not doing the outage:

- The risk of not doing the outage at the time allotted would be critical-major. The asset requires inspections and maintenance activities to be completed on a pre-determined frequency to ensure the reliability of the equipment is able to support the demand.

### Risks of delaying the outage:

- The 2026 Outage includes some preventive maintenance activities to address deficiencies that if not corrected could result in equipment reliability concerns. Lengthening the time between planned outages would increase the chance of a forced outage as maintenance could extend past required dates and plant deficiencies could degrade further.

### Risks of doing the outage:

- The main risks in executing the outage are discovery work and lack of proper preparation for executing outage scope. These could cause outage extension and cost escalation. This risk is mitigated by detailed and thorough planning of the outage scope and execution work.

# Operational Impacts

## Related projects and processes

PLNGS outages are coordinated with outages in other NB Power generating stations, transmission system requirements, and NB Energy Marketing for replacement energy.

## Impacts once the outage is complete

The following table shows the impact the 2026 Outage will have on NB Power operations once it is complete:

Impact	Yes/No	Explain
More/Less personnel required?	No	
Additional future OM&A costs/savings (i.e. labour, maintenance, hired services, software licensing)?	Yes	Reduced risk of incurring the costs associated with a forced outage
Requirement for training?	No	
Regulatory	No	
Other capital investments	No	
Existing contracts	No	
Write-off of existing assets	No	
Net earnings (1 <sup>st</sup> year impact)	Yes	Reduced risk of incurring the costs and lost revenue associated with a forced outage
Other	No	