CREATIVENERGY

18 December, 2024

Via E-filing

Mr. Patrick Wruck
Commission Secretary
BC Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: British Columbia Utilities Commission (BCUC, Commission)
Creative Energy Vancouver Platforms Inc. (Creative Energy)
2025 Revenue Requirements Application (RRA) for the Core Steam System (Application)

Creative Energy writes to file the enclosed Application and requests the approvals set out in section 1.5. A draft order is attached at Appendix A.

Creative Energy is requesting interim approval of 2025 rates effective January 1, 2025, as set out in the corresponding Tariff Pages included at Appendix B.

Attached to the Application electronically are:

- a working MS Excel model of the Revenue Requirement Schedules that support the Application.
- a working MS Excel model of the NEFC System Contribution Charge Forecast that supports the requested approval of the proposed NEFC System Contribution Charge.

Please contact the undersigned with any questions.

Sincerely,

Amr Ayad

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Creative Energy Vancouver Platforms Inc.

Core Thermal Energy System

2025 Revenue Requirements Application

December 18, 2024

Table of Contents

List of Tables

APPENDICES

ATTACHED ELECTORNICALLY

- 2025 Core and NEFC TES RRA Schedules.xlsx
- NEFC System Contribution Charge Forecast .xlsx

1 Application Summary

1.1 Executive Summary

Creative Energy Vancouver Platforms Inc. (**Creative Energy, CEVP**) owns and operates the steam production plant at 720 Beatty Street and associated steam distribution network, which began operating in 1968 and now serves over 208 customers in downtown Vancouver and which also serves customers connected to the hot water distribution networks in Northeast False Creek (**NEFC**) and the Butterfly Development (**Butterfly**)[1]. These systems together comprise the Creative Energy **Core Thermal Energy System** (or **Core TES**).

This 2025 Revenue Requirements Application (**2025 RRA, Application**) presents the consolidated cost of service of the Core TES together with corresponding proposed rates for service in 2025.

The BCUC approved the thermal energy rates for the Core TES for 2024 by Order G-272-24, pending the final decision on the Generic Cost of Capital (GCOC) Stage 2 proceeding. On December 6, 2024, Creative Energy submitted its final compliance filing following the conclusion of the GCOC Stage 2 proceeding requesting permanent approval of the 2024 RRA rates. The final 2024 RRA thermal rate stated in this compliance filing is $14.46/M#.

Pursuant to Order G-272-24, Creative Energy was also instructed to maintain the system contribution charge of $10.60 per MWh of thermal energy for customers connected to the NEFC system, pending the BCUC's decision on the GCOC Stage 2 proceeding. The Commission requested Creative Energy to conduct further analysis of the recovery of the System Contribution Charge and analysis of whether it is appropriate to continue to use the current charge. Further details on this matter are discussed in Chapter 3.

In this Application, Creative Energy seeks approval of a steam rate of $14.08/M#, which is a decrease in thermal energy rates of 2.6% below the amounts reflected in the 2024 Application Final compliance file with the BCUC on December 6, 2024, as shown in **Tables 1, 2** and **3** that follow below[2]:

- **Table 1** below presents a summary of the consolidated revenue requirements of the Core TES for the 2025 Test Year;

- **Table 2** highlights the key cost-drivers, which factors and cost variances are elaborated upon and explained in section 4 of this Application; and

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[1] There is an active proceeding for Approval of Butterfly Project Terms of Service and Interim Rates; found here: https://www.bcuc.com/OurWork/ViewProceeding?applicationid=1290

[2] The Core TES RRA Schedules are attached electronically as well as a file that computes the declining block charges set out in **Appendix B** for interim approval.

- **Table 3** presents a summary of the overall average rate impacts and underlying cost drivers in the full context of the cost of service including fuel costs.

As reviewed in **Tables 2** and **3** and further elaborated on in the sections below, the key drivers of the requested 2025 rate are increase in: the O&M costs, taxes and depreciation, offset by: lower amortization of deferral accounts, lower return on rate base, and slightly higher load forecast. The overall increase in customer bills is driven by an increase in FCAC partially offset by a decrease in the steam rate.

Table 1: Consolidated 2025 Core Revenue Requirements –Summary

Core Revenue Requirements Summary	2023	2024	2024	2025	Difference from
Cost or Rate Component	**Actual**	**Approved**	**Projected**	**Application**	**2024 Approved**
O&M - Total	7,526,902	8,030,693	8,434,404	9,218,914	1,188,221
Wages and Benefits (Steam, Distribution & Management)	4,075,092	4,801,509	5,219,325	5,402,086	600,577
Information Technology Services	349,143	502,276	433,557	573,522	71,246
Water and Electricity Expenses	1,068,261	1,096,816	1,173,105	1,196,076	99,260
Maintenance and related functional Operations	562,525	708,937	642,673	773,578	64,641
Special Services (Regulatory, Audit, Legal, Consultant)	710,329	342,173	464,643	616,409	274,236
Other General & Administration & Sales Expense	761,552	578,982	501,101	657,242	78,260
Municipal Access Fee	334,927	368,426	368,426	380,191	11,765
Property Taxes*	859,800	885,594	885,594	871,200	(14,394)
Income Taxes***	192,631	208,300	208,300	341,500	133,200
Depreciation	1,223,440	1,252,949	1,252,949	1,539,078	286,129
Interest Expense (deemed)	1,236,450	1,298,000	1,298,000	963,000	(335,000)
Return on Equity	713,447	1,790,000	1,790,000	1,962,000	172,000
Total Return on Rate Base	1,949,897	3,088,000	3,088,000	2,925,000	(163,000)
Subtotal	12,087,596	13,833,963	14,237,673	15,275,884	1,441,922
Approved amortization of deferral accounts in steam rate	98,334	1,746,248	1,746,248	424,483	(1,321,765)
Revenue**	12,185,930	15,580,211	15,983,921	15,700,367	120,156
Rate Summary					
Steam Load M#	1,144,000	1,077,614	1,077,614	1,115,063	37,449
Average Steam Rate $/M# (before amortization of deferral accounts)	10.57	12.84	13.21	13.70	0.86
Average Steam Rate $/M# (after amortization of deferral accounts)	10.65[3]	14.46	14.83	**14.08**	(0.38)
Average Steam Rate % increase (before amortization of deferral accounts)	n/a	0.0%	2.9%	6.7%	

[3] Approved rate for 2023 RRA was $11.21/M#

Core Revenue Requirements Summary	2023	2024	2024	2025	Difference from
Cost or Rate Component	**Actual**	**Approved**	**Projected**	**Application**	**2024 Approved**
Average Steam Rate % increase (after amortization of deferral accounts)	n/a	35.7%	2.6%	**-2.6%**	
Rate of Return Summary					
Rate Base	31,703,839	33,740,630	33,740,630	36,996,549	3,255,919
Debt	16,485,997	16,532,909	16,532,909	18,128,309	1,595,401
Equity	15,217,843	17,207,721	17,207,721	18,868,240	1,660,519
Debt %	52.0%	49.0%	49.0%	49.0%	0.0%
Equity %	48.0%	51.0%	51.0%	51.0%	0.0%
Weighted Average Cost of Debt (estimated)	7.5%	7.9%	7.9%	5.3%	-2.5%
ROE	4.7%	10.4%	10.4%	10.4%	0.0%
Total Return on Rate Base	6.15%	9.15%	9.15%	7.91%	-1.2%
* Projected and actual property taxes are adjusted to the approved balance due to there being a deferral account.					
** It's difficult to split actual income taxes between energy systems as such this is a deemed number based on a 27% tax rate.					

Table 2 below identifies the specific areas of the consolidated revenue requirement that are driving year-over-year variances.

Table 2: Consolidated Revenue Requirements- Summary of Component Rate Increase and Variance from 2024 RRA to 2025 Test Year

2025 Rate Increase Components		2025 Test Year to 2024 Application	
Cost Component	**Cost Control**	**Explanatory Variance of Overall Steam Rate Increase: 2024 to 2025**	
O&M		$ 1,188,221	8.6%
Wages and Benefits (Steam, Distribution & Management)	Internal	$ 523,403	3.8%
	External	$ 77,174	0.6%
Information Technology Services	Internal	$ -	0.0%
	External	$ 06,071	0.8%
Water and Electricity Expenses	Internal	$ -	0.0%
	External	$ 99,260	0.7%
Maintenance and related functional Operations	Internal	$ 64,641	0.5%
	External	$ -	0.0%
Special Services (Regulatory, Audit, Legal, Consultant)	Internal	$ 140,785	1.0%
	External	$ 133,451	1.0%
Other General & Administration & Sales Expense	Internal	$ (42,299)	-0.3%
	External	$ 85,736	0.6%
Municipal Access Fee	External	$ 11,765	0.1%
Property Taxes	External	$ (14,394)	-0.1%
Income Taxes	External	$ 133,200	1.0%

2025 Rate Increase Components		2025 Test Year to 2024 Application	
Cost Component	**Cost Control**	**Explanatory Variance of Overall Steam Rate Increase: 2024 to 2025**	
Depreciation	External	$ 286,129	2.1%
Interest Expense	External	$ (335,000)	-2.4%
Return on Equity	External	$ 172,000	1.2%
Summary		-	0.0%
Amortization of Deferrals	External	$ (1,321,765)	-9.6%
Revenue		$ 120,156	0.9%
RRA Internal control related	Internal	$ 686,529	5.0%
RRA External control related	External	$ (566,373)	-4.1%
Steam Load M#		37,449	0.3%
Total Core-related Steam Rate Increase (Decrease) 2025			**-2.6%**

1.2 Impact of BCUC Generic Cost of Capital Stage 2 and 3 Proceedings

The GCOC Stage 2 proceeding was concluded on November 29, 2024. As part of its directives and determination, and in recognition of the elevated risk faced by the Core TES, Creative Energy was directed to use an Equity Premium over the Benchmark Utility of 6.0%, increasing its equity component from 49% to 51% and decreasing its debt component from 51% to 49%. Creative Energy was also directed to continue to use a Return of Equity (ROE) of 10.40%, which is the same as what was used in the 2024 RRA. These updated assumptions were used to develop the Financial Schedules as part of this 2025 RRA Application.

In addition, Stage 3 of the GCOC proceeding commenced on November 29, 2024, and a Regulatory Timetable was provided according to Order G-322-24. The scope of Stage 3 is to examine three questions:

- Should the carrying costs that apply to deferral accounts/regulatory accounts (both referred to as regulatory accounts) be standardized for all rate-regulated public utilities?
- If yes, how should the carrying costs be standardized (universally applied to all rate-regulated public utilities, by groupings of specific utilities, by type of regulatory account, other)?
- If no, should the carrying cost be informed by any applicable BCUC guidelines or should the determination rest with future BCUC panels on a case-by-case basis?

Based on the scope and the timetable provided, this stage of the GCOC proceeding is expected to conclude sometime in April 2025. At present, Creative Energy cannot quantify or anticipate the impact of this further proceeding on this Application and whether Creative Energy will be required to file a compliance filing or an evidentiary update in compliance with the GCOC Stage 3 in relation to its impact on the 2025 RRA Application.

1.3 Average Core TES Customer Rate Impacts

Total average rates for thermal energy service are comprised of Core TES tariff rates (i.e., that recover the cost of service through the approved revenue requirements) and natural gas fuel cost charges (i.e., that recover the cost of natural gas service on a flow-through basis), which we express in **Table 3** below on an equivalent $/M# basis (not including other charges such as the System Contribution Charge to customers connected to the NEFC network as reviewed and approved in the 2024 application).

Table 3 below thus places the requested 2025 average rate decreases and resultant average tariff rate that is the subject of this 2025 RRA in the context of the total charges to Core TES customers for service inclusive of fuel cost charges. When assessing the combined impact of the rates for thermal energy and associated gas costs, the overall change in rates represents a projected increase in the customer rates of 3.9% over the 2024 RRA charges.

By way of further background, Creative Energy obtains its natural gas requirements from FortisBC Energy Inc. (**FEI**) for both commodity and delivery under FEI Rate 5, which is a firm rate. Creative Energy recovers its fuel costs from customers on a flow-through basis through a standard Fuel Cost Adjustment Charge (**FCAC**) based on annual forecast fuel costs divided by approved annual load. A FCAC or a FCAC Rate Rider may be approved from time to time if and as required to recover the balance in the Fuel Cost Stabilization Account (**FCSA**) if it exceeds a threshold balance.

The FCAC is approved by the Commission on a forecast basis for the Gas Year commencing November each year; that is, outside of Creative Energy revenue requirements applications and proceedings. A record of the last FCAC-related approvals is as follows:

- 2023/2024 Gas Year FCAC= $16.95/M#, effective November 1, 2023 – Order G-314-23; Permanent approval.
- 2024/2025 Gas Year FCAC = $18.55/M#, effective November 1, 2024 – Order G-316-24; Approved on an interim basis.

Table 3 below shows the Customer Rate Impact associated with 2025 Test Year.

Table 3: Summary of Average Rate Impacts

	2024 Approved	2025 Test Year	Incremental Cost, $/M#	Rate Increase (Decrease) %
Load, M#	1,077,614	1,115,063		
Revenue, $	15,580,211	15,700,367		
Steam Rate, $/M#	$14.46	$14.08	$(0.38)	-2.6%
FCAC, $/M#	$16.95	$18.55	$1.60	9.4%
Overall Customer Rate, $/M#	$31.41	$32.63	$1.22	3.9%

The analysis above does not account for the steam rate rider that has been proposed by Creative Energy, which was filed as part of a 2024 RRA compliance filing submitted on November 25, 2024. Pending the approval of the Commission, Creative Energy plans to include the impact of this steam rate rider in future analysis in the course of the 2025 RRA proceeding.

1.4 Application Assumptions

The 2025 RRA assumes that all requested approvals set out in the November 25, 2024 compliance filing for the 2024 RRA would be granted by the Commission, which altogether supports the filing of this 2025 RRA on a timely basis pursuant to a request for interim approval of rates effective January 1, 2025. As part of this approach, we contemplate that an evidentiary update may be needed to be filed in 2025 to update the underlying basis of the requested approvals for 2025 as need may arise subject to the determinations and directives of a Commission decision into the 2024 Application or other decision impacting this Application.

This application was prepared based on the following assumptions:

- Final rates requested in the 2024 RRA compliance filing after the conclusion of the GCOC Stage 2 proceeding are approved on a permanent basis;
- The assumed interest rate is 5.31 percent for the 2025 Test Year; and
- Assumed inflation rate is 2.18 percent throughout the 2025 Test Year, unless stated otherwise.

1.5 Summary of Requested Approvals

In this Application, Creative Energy is seeking Orders of the Commission granting the approvals described below pursuant to the noted sections of the legislation. A draft Commission Order for interim approval of 2025 rates is provided in **Appendix A** to this Application while **Appendix B** provides the corresponding Tariff Pages for interim approval.

Creative Energy requests the following approvals:

1. Interim approval, effective January 1, 2025 and pursuant to sections 58 to 60 and 90 of the *Utilities Commission Act* (**the Act**) and section 15 of the *Administrative Tribunals Act*, of the thermal energy rates and System Contribution Charge set forth in **Appendix B**; and
2. Approval of the load forecast methodology as set out in **Appendix G** of this Application and a 2025 thermal energy load forecast of 1,115,063 M# as discussed in this Application and **Appendix H** of it for the purpose of determining the average rate increase in the 2025 RRA Test Period and for other rate-making purposes as required.

1.6 Recommended Regulatory Review

Creative Energy proposes that this Application be reviewed through a written hearing process conducted by the Commission, commencing in January 2025. We respectfully request that the process be completed no later than early June 2025 to allow sufficient time ahead of filing our Low Carbon Rate Design Application, which we expect to be in Q4 2025, given the dependencies between the two applications. **Table 4** below illustrates the proposed regulatory timetable.

Table 4: Proposed Regulatory Timetable

Action	Date (2025)
Procedural Order, regulatory timetable and interim approval of the proposed rates	Monday, January 20
Public Notice of the Application	Monday, January 27
Intervener registration deadline	Friday, February 7
Creative Energy confirmation of compliance with Public Notice requirements	Monday, February 10
BCUC Information Request (IR) No. 1	Friday, February 21
Interveners IR No. 1	Monday, February 24
Creative Energy responses to IR No. 1	Monday, March 10
Letters of comment deadline	Monday, March 17
Creative Energy final argument	Tuesday, April 1
Intervener final argument	Monday, April 14
Creative Energy reply argument	Monday, April 28
Contingency for further process (if needed)	By early June

2 Load Forecast and Load Forecast Variance Account

2.1 Introduction

All costs will be recovered through the volume of thermal energy sold to Core TES customers. The thermal energy load forecast for the Core TES and for rate-setting purposes thus comprises:

1) Steam loads in M#, which are the essential billing determinants for the thermal energy consumption of customers connected to the steam distribution network, and

2) Hot water loads in MWh, which are the essential billing determinants for the thermal energy consumption of customers connected to hot water distribution.

For the purpose of determining the overall Core TES average rates and projected rate changes the forecast thermal energy consumption in MWh is converted to M# at a standardized conversion factor of 0.347 MWh/M# as reviewed and approved in the 2022 RRA application.

2.2 2024 RRA Load Forecast and Load Forecast Methodology

As part of the 2024 RRA proceeding, the Commission and interveners had the chance to evaluate Creative Energy's 2024 thermal energy load forecast for the Core TES, addressing several issues related to the methodology and the forecast itself. In the 2024 application, Creative Energy proposed a forecast of 1,077,614 M#, developed using a revised methodology that averages weather-normalized load data from 2022 and 2023. This approach replaced the previous method, which relied on a 10-year historical average, and which Creative Energy considered outdated due to changes in customer behavior, disconnections, and the impact of the COVID-19 pandemic.

Interveners raised concerns about the revised methodology. One of the interveners suggested retaining the current approach until Creative Energy's Long-Term Resource Plan (LTRP) is complete[4], while another intervener supported averaging recent data but recommended addressing declining load trends. The 2024 RRA Panel agreed that the old methodology used before the 2024 RRA results in persistent over-forecasting and accepted Creative Energy's revised approach as a temporary measure for 2024 rate-setting. As such, a 2024 load forecast of 1,077,614 M# was used for setting rates. However, the Panel denied using the new methodology beyond 2024, citing insufficient evidence and a need for further analysis.

The Panel directed Creative Energy to refine its methodology, incorporating broader customer data and more comprehensive analysis, and to provide this information in the 2025 RRA.

In response, Creative Energy has developed a robust new modelling methodology using comprehensive customer data. Accordingly, there is a new forecast for the 2025 RRA.

[4] The LTRP was filed with the Commission on November 25, 2024.

2.3 Load Forecasting Methodology

As part of the directives and determinations of the 2024 RRA Final Decision, the Panel directed Creative Energy to enhance its load forecasting methodology by providing more robust analysis and investigating load patterns more thoroughly.[5] The Panel suggested using a 10-year averaged data set, excluding disconnected customers, and incorporating data from more than the 25 customers that Creative Energy used as basis for the proposed load forecast methodology in the 2024 RRA application to better reflect the total load.

Creative Energy agrees with the Panel's assessment that a more refined modeling approach was necessary for several reasons. First, the previous methodology, which relied on adjusting historical consumption based on the effects of a smaller sample of 25 customers, did not fully capture the consumption patterns across the Core TES customer base. Second, excluding disconnected customers from historical data is essential to ensure load forecasts accurately reflect current system conditions. Third, a more robust statistical analysis incorporating longer-term weather patterns provides greater confidence in load projections by accounting for both typical and extreme weather scenarios. Recognizing these opportunities for improvement, Creative Energy began enhancing its load forecasting methodology in August 2024, even before the Panel's formal decision, demonstrating Creative Energy's commitment to continuous improvement and its alignment with the Commission's guidance for more accurate and reliable forecasting methodology.

Beginning in August 2024, before the Panel's decision was issued and based on the Information requests (IRs) received during the 2024 RRA proceeding, Creative Energy began to enhance its load forecasting methodology. Later, building upon the Panel's feedback, Creative Energy refined its load forecast approach for the 2025 RRA. To improve its weather-normalized load forecasting methodology and determine load forecast for the 2025 Test Period, Creative Energy followed these at **Appendix G.** This analysis explored how historical weather records from multiples sources related to steam consumption, establishing a relationship between Heating Degree Days (**HDD**) and steam consumption using the 2022/2023 period while validating against historical data (2019-2024). Key findings included:

1. The analysis yielded a statistically robust regression model using Vancouver Harbour HDD data that explains 98.33% of steam consumption variance. The model demonstrates:
    - Strong predictive capability across multiple years (2019-2024)
    - Predictions consistently within 95% confidence intervals
    - Statistical significance at a confidence level of 98%.

[5] Creative Energy Vancouver Platforms Inc., *2024 Revenue Requirements for the Core Thermal Energy System*, Order Number G-272-24, issued October 24, 2024, 5-6, https://docs.bcuc.com/documents/other/2024/doc_78936_g-272-24-creative-2024-rra-final.pdf.

- A univariate quadratic relationship, one where load increases disproportionality with falling air temperature, best explains the relationship between HDD and steam consumption, as compared to other relationships[6].

2. Using recent consumption data (2022/2023) results in accurate predictions.
3. HDD was confirmed as the primary driver of steam consumption, with consumption increasing at an accelerating rate as mean daily air temperatures drop. Cooling Degree Days and seasonal variations showed minimal impact on the predictive power.

Second, in December 2024, two refined statistical models were developed employing a quadratic relationship between Core thermal energy consumption and HDD, and between NEFC thermal energy consumption and HDD. This analysis is summarized in **Appendix H**. The resulting updated models continued to explain over 94% and 98% of energy consumption variability for NEFC and the Core respectively. These statistical models built upon the work completed in August 2024 and incorporate important updates, including the integration of NEFC thermal energy demand and cleaning of the historical consumption dataset to reflect current system conditions, specifically the removal of disconnected customers and accounting for those who are currently connected but inactive. The models incorporate all customers connected during 2022 and 2023 who were connected and active at the end of October 2024.[7] These weather-normalized statistical models account for the relationship between air temperature and thermal energy consumption across the current customer base, providing a robust framework for demand prediction.

Third, to establish a weather-normalized forecast, Creative Energy determined the median annual demand using this updated model by applying it to a 50-year heating year dataset (1973/1974 through 2022/2023). The methodology involved three key steps:

1. Reorganizing monthly HDD data from a traditional calendar year format into a July-to-June heating year format, which better aligns with seasonal heating patterns and captures complete heating seasons within single 12-month periods.

2. Using the Core and NEFC models to calculate monthly energy demand using monthly HDD data.

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[6] A univariate quadratic relationship is expressed in a formula which uses only one variable, in the case HDD, and combines it with itself, like the formula $x^2 + x + 1$.

[7] The regression model was developed using consumption data from 2022 and 2023 to establish the relationship between HDD and energy consumption. The three Butterfly buildings, while connected in 2024, were not included in the model development as they lack historical consumption data during the 2022 and 2023 period. As discussed later in this section, their projected consumption has instead been added to the load forecast as a separate adjustment to ensure the 2025 forecast captures their expected demand.

3. Aggregating monthly values into annual totals for each heating year and calculating percentiles and probabilities of exceedance using the 50-year dataset for the Core TES (Core and NEFC).

Compared with a calendar year analysis, using a heating year approach maintains the integrity of each heating season and provides more meaningful year-over-year benchmarking. The methodology utilizes the quadratic regression model to convert HDD data into predicted energy consumption values and then performs statistical analysis on these converted values. This sequence is important because it preserves the non-linear relationship between energy consumption and HDD ensuring that extreme weather events are properly weighted and accounted for in the analysis.

With the decision to use a statistical approach, Creative Energy chose to use a 50-year data set, rather than the 10-year time frame suggested by the Panel in the 2024 RRA Decision. Using a 50-year climate record provides better statistical confidence that might be missed in shorter periods (e.g. 10 years) by capturing rare events, variations, and natural cycles. Using a 50-year record balances the dampening of recent climate warming trends, which occur when using longer term data periods (e.g. 75 or 100 years), with the need for a dataset large enough to make probability analyses meaningful.

Lastly, the 2005/2006 heating year was selected as the representative median consumption year through a statistical analysis process. This particular year was chosen because its annual thermal energy consumption falls within 1.1% of the calculated 50% probability of exceedance value, making it the most statistically representative year for the median consumption patterns.

The weather-normalized analysis establishes a base load of 1,106,786 M# for the current Core TES configuration including the NEFC, which includes 205 connected customer buildings. A load of 8,277 M# has been added to this figure to account for projected partial-year consumption from three Butterfly buildings which are expected to be fully occupied over the course of 2025[8]. This results in a 2025 load forecast of 1,115,063 M#.

This methodology provides a statistically robust basis for the proposed Test Year demand forecast by incorporating two key elements: historical weather patterns spanning 50 years of data; and a robust statistical correlation between weather and historical consumption based on the current Core TES configuration. While Creative Energy acknowledges the limitations of this approach, such as the assumption of stable aggregate building usage patterns and the continued relevance of historical weather data, we believe the comprehensive nature of the dataset, strong statistical correlation, and selection of a representative median demand year provides an appropriate foundation for RRA planning purposes.

This weather-normalized methodology provides a more reliable foundation for future load forecasting by effectively accounting for historical weather variations and their corresponding impact on system-wide thermal energy consumption. Creative Energy remains committed to refining its forecasting methodologies to ensure accurate and reliable projections for revenue

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[8] Further details are in Section 2.4

calculation and rate setting purposes. This enhanced methodology aligns with the BCUC's directive to improve our load forecasting capabilities as outlined in Order 272-24 while providing a transparent and statistically sound basis for the 2025 RRA, presenting a significant improvement to the approach used in the 2024 RRA.

2.4 The Butterfly Development Project Load Forecast

When fully occupied, the forecasted annual loads outlined in the service agreements for the Butterfly Project are as set out in **Table 5** below.

Table 5: The Butterfly Development Project Load Forecast

Building	2025 Load (M#)
Residential Tower	10,075
Church and Podium	1,643
Rental Residential Building	1,596
Total	13,314

As of the date of this Application, both Church and Podium and the Rental Residential Building are fully occupied, and the lower third of the Residential Tower is beginning to be occupied. Creative Energy has been informed by the developer that the remaining floors are planned to be occupied in phases throughout 2025.

For the 2025 load forecast, Creative Energy has therefore included the full predicted load for the Church and Podium and the Rental Residential Building, along with 50% of the predicted load for the Residential Tower. Creative Energy considers this a reasonable approach for the 2025 forecast. If occupancy progresses as anticipated, Creative Energy plans to incorporate the full load of 13,314 M# into the 2026 RRA load forecast.

2.5 Core TES Thermal Energy Load Forecast

Creative Energy is applying to set rates for 2025 based on a load forecast of 1,115,063 M#.

Based on the expected approval of the Load Forecast Variance Account, any load variance between forecast and actual load would accrue to the Load Variance Account[9]. More details on this are in section 2.5 and section 6.2 of this Application. Please refer to **Table 6** below for the details of the load forecast.

[9] Please refer to section 3.2 in the 2023 RRA Application for details on the Load Variance Account

Table 6: Thermal Energy Load Forecast

M#	2024 Approved	2025 Test Year
	Weather Normalized	Weather Normalized
Core	1,007,305	1,040,428
NEFC	70,309	66,358
Butterfly	0	8,277
Total	1,077,614	1,115,063

2.6 Load Variance Observed in 2024

As expanded on in section 6.2, the variance in load, and the associated accruals to the Load Forecast Variance Account, are expected to be $434,079 as at October 31, 2024 (including interest but not amortization). This figure is the anticipated closing balance of the Load Variance Account for the first 10 months of 2024 based on the difference between actual loads and the forecasted load to the end of October 2024.

3 System Contribution Charge for the NEFC Hot Water Distribution Network

3.1 Introduction

As part of the determinations of the Final Decision of the 2024 RRA (G-272-24), the Panel directed Creative Energy to provide in its 2025 RRA an updated calculation and annual balance of the components recovered through the system contribution charge, including the NEFC system contribution charge itself.

The Panel also requested Creative Energy to conduct an analysis to assess whether the current charge is on track to fully recover the deferral account balance by the end of 2043 (as originally planned) and determine if any adjustments are needed to the charge or the long-term NEFC load forecast.

This section provides the information requested and discusses the analysis and its findings.

3.2 NEFC System Contribution Balance

As detailed in **Table 7** below, the balance of the NEFC system contribution charge as of the end of October 2024 is $2,473,338

Table 7: NEFC System Contribution Balances and Recovery[10]

NEFC System Contribution, $	Opening Balance	Billings (Recovery)	Interest	Closing Balance
2022	-	-	-	2,516,949
2023	2,516,949	(238,636)	207,494	2,485,807
End of October 2024	2,485,807	(198,028)	185,559	2,473,338

3.3 Analysis of the System Contribution Charge for the Remaining Asset Life

The current System Contribution Charge is $10.60 per MWh of thermal energy. Using this charge, along with a NEFC load forecast of 66,358 M# for the Test Year (equivalent to 23,026 MW, based on the approved conversion factor of 0.347, as discussed in Section 2), and assuming this load remains constant until the end of the asset's life in 2043, the projected closing balance for 2043 is $377,601. This indicates that maintaining the current System Contribution Charge will result in an under-collection of this amount.

[10] The Closing Balance in 2022 was after the termination of both the NEFC Revenue Deficiency Deferral Account and the NEFC Variance Deferral Account. For further details please refer to Decision and Order G-345-22A-
https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/521378/index.do?q=system+contribution+charge#_Toc120632847

Recalculating the analysis to target a zero closing balance in 2043 results in an updated System Contribution Charge of $10.99 per MWh of thermal energy. The full analysis, along with all assumptions, is detailed in the MS Excel workbook attached to this Application.

3.4 Requested Adjustments

Based on the analysis provided, Creative Energy requests approval to replace the current System Contribution Charge of $10.60/MWh with a revised charge of $10.99/MWh. We further request that this updated charge be approved on a permanent basis or until the Commission determines that a further update is necessary. This revision is also reflected in the Tariff Pages included with this Application.

4 Revenue Requirements

4.1 Revenue Requirements Drivers

Core Revenue Requirements drivers are split into five, as follows:

1. Operations and Maintenance;
2. Municipal Access Fee;
3. Property Taxes;
4. Income Taxes; and
5. Depreciation and Amortization Expenses.

The following sections discuss in detail each of the drivers.

4.2 Operations and Maintenance Budgeting

4.2.1 Introduction

Operations and Maintenance (O&M) budgets (and Capital budgets) are prepared by Creative Energy's management team and then approved by the CEVP Board. In general, and consistent with past practice as reviewed in the 2019-2020 through 2024 RRAs, prior year actuals and year-end projected amounts are used as benchmarks to identify the activities that need to be budgeted for given that most O&M activities are recurring in nature and that these costs typically change with inflation.

Budgets are prepared to align with Creative Energy's business functions and the established BCUC accounts for each function where possible. Where informative and predictive, some maintenance expenses are pooled by equipment type and analyzed on a combined and trended basis for budgeting purposes. Other cost categories such as water and electricity expenses are subject to rate increases set by a separate utility or governmental body and the amounts required vary by load and are estimated on those bases. Creative Energy develops an accurate operating budget reflecting anticipated inflation rates, supply cost increases, necessitated repairs, contractor services and a small built-in contingency budget. For some years, the actual budget will increase compared to the planned budget due to major repairs that were unplanned, while in other years the actual budget will decrease as operational costs are the largest component of the budget.

4.2.2 O&M - Summary by Cost Driver and Control

To assist with the underlying assessment of cost drivers, the following section and the individual O&M component review that follows illustrates O&M costs and variance explanations in relation to the following six categories of cost drivers.

1. Wages and Benefits (Steam, Distribution and Management);
2. Information Technology Services;
3. Special Services;
4. Water and Electricity Expenses;

5. Maintenance; and
6. Other General and Administrative plus Sales Expense.

This categorization is similar to the 2024 RRA. Consistent with prior RRAs, the intent of these groupings is both to offer clarity on the cost of service across the Core TES and to present the specific costs driving the requested rate increases in the 2024 test period.

Cost drivers[11] are also grouped according to a qualitative assessment of where management is generally able to exercise budgeting control and decision-making as follows:

1. **Internal Cost:** this is where operating costs are commonly understood to be within the scope of management control; and
2. **External Cost:** this is where determination is outside Creative Energy (e.g., rates applicable to Creative Energy's water, electricity, and natural gas consumption).

Although Creative Energy adds caution to the level of precision, we consider it to be the best approach overall for providing insight and understanding of the drivers for the 2025 Test Year cost of service. Please refer to **Table 8** below for an overall summary of costs in accordance with this approach.

Table 8: Total O&M by Cost Driver and Control

2025 Rate Increase Components		2024 Approved			2024 Projected			2025 Test Year		
Cost Component	Cost Control	$	% of O&M	% of Revenue	$	% of O&M	% of Revenue	$	% of O&M	% of Revenue
O&M		8,030,693	100 %	52%	8,434,404	100 %	53%	9,218,914	100 %	59%
Wages and Benefits (Steam, Distribution & Management)	Internal	4,648,821	58%	30%	5,055,622	60%	32%	5,172,224	56%	33%
	External	152,689	2%	1%	163,703	2%	1%	229,863	2%	1%
Information Technology Services	Internal	-	0%	0%	-	0%	0%	-	0%	0%
	External	502,276	6%	3%	433,557	5%	3%	608,346	7%	4%
Water and Electricity Expenses	Internal	-	0%	0%	-	0%	0%	-	0%	0%
	External	1,096,816	14%	7%	1,173,105	14%	7%	1,196,076	13%	8%
Maintenance and related functional Operations	Internal	708,937	9%	5%	642,673	8%	4%	773,578	8%	5%
	External	-	0%	0%	-	0%	0%	-	0%	0%
Special Services (Regulatory, Audit, Legal, Consulting)	Internal	110,584	1%	1%	334,283	4%	2%	251,369	3%	2%
	External	231,589	3%	1%	130,360	2%	1%	365,040	4%	2%

[11] For clarity, expanded definitions of the six categories of cost derivers are discussed in **Appendix C** of this Application.

2025 Rate Increase Components		2024 Approved			2024 Projected			2025 Test Year		
Cost Component	Cost Control	$	% of O&M	% of Revenue	$	% of O&M	% of Revenue	$	% of O&M	% of Revenue
Other General & Administration & Sales Expense	Internal	308,017	4%	2%	233,576	3%	1%	265,718	3%	2%
	External	270,965	3%	2%	267,525	3%	2%	356,700	4%	2%

The subsequent sections provide an explanation of the cost associated with each of the five categories summarized above. Total O&M cost is also assessed by business function, as shown in **Table D-1** in **Appendix D**.

4.2.3 Wages and Benefits

4.2.3.1 Approach and Summary

The Core TES system is supported by Plant and Distribution operations staff complemented by office and management staff, some of whom span business development and project engineering functions and allocate their time accordingly. Managing those functions to budget is the responsibility of the entire management team. Attracting and retaining talent is critical to the success of Creative Energy and accordingly serving customers. Creative Energy competes with other and typically much larger utilities in BC, other parts of Canada and in some cases North America for employees with specialized skillsets that are not widely available. In addition, there are specific risks associated with the size of Creative Energy. The loss of key employees can have a significant impact on the business given the small number of employees each having multiple skillsets and responsibilities.

Creative Energy's compensation strategy, therefore, continues to be to develop competitive market-based compensation packages that attract, motivate, and retain talent with the skills required for key roles, while also aligning the compensation of each management and office employee to their individual level of responsibility. Total compensation includes an incentive program designed to complement the compensation strategy.

Labour costs and year-over-year increases for unionized employees primarily working in steam production and distribution functions are set in accordance with a collective agreement. **Table 9** below provided a summary of Wages and Benefits.

Table 9: Summary of Total Wages and Benefits

Total Wages and Benefits	2024 Approved	2024 Projected	2025 Test Year
500 Supervision and Labour	1,739,960	1,914,084	1,899,098
870 Supervision and Labour	919,892	1,028,803	998,824
920 Admin & General Salaries	1,921,704	2,048,517	2,251,779
926 Employee Benefits	219,954	227,921	252,385
Grand Total	4,801,509	5,219,325	5,402,086

4.2.3.2 Steam Production Supervision and Labour

Compared to the 2024 Approved RRA, steam production supervision and labour costs for the 2025 Test Year are planned to increase by 9.1 percent overall, details of which are shown below in **Table 10**. The variance between 2025 Test Year and 2024 RRA is shown in **Table D-2** in **Appendix D**.

Table 10: Steam Production Supervision and Labour – Account 500 – Summary

Account 500 Supervision and Labour	2024 Approved	2024 Projected	2025 Test Year
Wages	1,410,328	1,534,851	1,483,355
Overtime	104,446	115,722	110,000
Benefits	138,509	176,836	171,025
Pension Costs	86,676	86,676	134,718
Total	1,739,960	1,914,084	1,899,098

Plant wages are based on a full-time equivalent (FTE) of eleven engineers and an assistant chief engineer. The increase in the total expense from the 2024 application can be described by the following factors in **Table 11**.

Table 11: Factors Driving Increase in Cost of Steam Production Supervision and Labour

General salary increases of 2.8%	$39,489
Overtime	$5,554
Pension Costs	$48,042
Benefits	$32,516
Re-anchor budget based on 2024 actual increase	$33,537
Total	$159,138

There are no additions to the headcount planned for 2025 for the Core system. An additional headcount related to the Decarbonization Project is planned for 2025 but will not be capitalized until the project starts operating in 2026.

With respect to overtime expense, Creative Energy notes that it requires a minimum number of staff for every shift at the steam plant for operational and safety reasons, which leads to circumstances where overtime will be charged under short notice for rescheduling shifts when any staff member is absent. In addition, if a particular job in the steam plant or distribution network warrants a specific number of personnel for the safe completion of the work on that specific day, this work will in most circumstances have been preplanned and organized in advance, which may also lead to circumstances where the work cannot be rescheduled due to an unexpected staff absence. Overtime charges may also occur during steam plant safety training, which must occur in an overtime capacity due to the fact steam plant personnel must remain on shift when scheduled for shift coverage. By contrast, distribution and service safety training is typically scheduled during workdays as there is more flexibility in this regard. Creative Energy's overtime is a shared bucket of costs and hence overtime associated with the Core System is allocated based on the Massachusetts formula to the various systems. A small increase in overtime is planned for 2025, approximately the midpoint between the 2024 budget and full-year cost forecasts. Part of this increase is related to salary increases and part of the increase is to reflect the actual results from 2024.

Benefits are estimated based on projected rates for categories such as CPP, EI, WCB, employer health tax and extended health benefits. In reviewing these costs, Creative Energy notes that the 2024 budget for Extended Health Benefits was underestimated as actual costs have been substantially higher than the 2024 budget. The increase in this amount for the 2025 Test Year is to ensure that these costs are in line with the actual costs going forward. Creative Energy will review its actual costs early in 2025 and will adjust accordingly during the proceedings relating to this Application process to ensure this information is accurate going forward.

Pension costs are based on required contributions as prescribed by CEVP's actuarial consultant. The contribution rate used in 2025 is 6.9 percent based on the three-year cycle actuarial valuation prepared in 2023. The existing defined benefit plan with the above-mentioned contribution rate will continue for all unionized staff and legacy staff who are enrolled in the defined benefit plan. Variances in pension costs are captured in the approved Pension Expense Deferral Account. The contribution rate for the plan is the percentage that Creative Energy must contribute to the pension based on the total wages for each employee enrolled in the plan. The contribution rate does not refer to the percentage of employees enrolled in the plan. The increase in pension costs compared to 2024 relates to actuarial fees that were not included in the previous year's budget. They have been included in 2025 to ensure that the budget is in line with actual costs going forward.

The remaining variance relates to the fact that there is inherent uncertainty in prior year budgets. The actual wage increase came in higher than the 3.3 percent that was budgeted for in 2024, and actual salaries will change depending on the experience level of employees. The CBA includes provisions that result in changes in wages in periods of higher-than-average inflation. The 2025 budget has been updated for the most recent salary information and there is an increase to bridge the difference between the 2024 budget and 2024 actual results for the reasons described above.

4.2.3.3 Distribution Supervision and Labour

The Distribution team directly charges time to the energy systems it supports. The Distribution team supports the Core TES, the Main & Keefer TES, South Downtown Heating TES and Cooling TES, Kensington Gardens TES, Mount Pleasant DCS, Horseshoe Bay TES, Pendrell TES and Alberni TES. There are specific employees that are assigned to support the steam network and specific employees to support the hot water network. However, throughout the year employees that are assigned to one team may support the other when there is a pressing need. This provides flexibility and allows Creative Energy to avoid the step cost of hiring additional employees for both networks when one shared employee may be able to assist on both. At present, the combined team consists of two managers and 10 unionized service technicians. There is no change in the headcount from 2024. Two additional headcounts are planned in Q4 2025 to support the growth of other systems, but this will not impact Core costs. Compared to 2024, Distribution supervision and labour costs for the 2025 Test Year are budgeted to increase by 8.5 percent compared to the 2024 RRA and lower than the 2024 Projected cost. The components of these costs are illustrated in **Table 12**. The detailed variance table for this cost is in **Appendix D-Table D-3**.

Table 12: Distribution Supervision and Labour – Account 870 – Summary

Account 870- Supervision and Labour	2024 Approved	2024 Projected	2025 Test Year
Wages	757,571	839,078	784,760
Overtime	22,555	24,620	26,816
Benefits	84,354	107,054	107,636
Pension	55,411	58,050	79,611
Total	919,892	1,028,803	998,824

The increases in the total cost from the 2024 RRA are described by the following drivers in **Table 13** below.

Table 13: Factors Driving Increase in Cost of Distribution Supervision and Labour

General salary increases of 2.8%	$21,212
Overtime	$4,261
Benefits	$23,282
Pension Costs	$24,200
Other	$5,978
Total	$78,933 (8.5 percent)

Similar to Account 500 Supervision and Labour discussed in the previous section above, the 2024 RRA underestimated costs related to benefits and pension. The 2025 RRA more accurately reflects the expected actual costs going forward. The remaining areas driving the increase are relatively minor, and overall costs are lower than forecast actual costs for 2024.

4.2.3.4 Management Labour and Benefits

As shown in **Table 14** below, Administration and General Salaries (Management Labour) are planned to increase for the 2025 Test Year by 17.2 percent over the 2024 RRA. Employee Benefits are also planned to increase by 14.7 percent, with an overall increase of 16.9 percent. Details on those variances are laid out in **Table D-4** in **Appendix D**.

Table 14: Management Labour and Benefits – Accounts 920 and 926 - Summary

Account 920- Admin & General Salaries	2024 Approved	2024 Projected	2025 Test Year
Wages	1,921,704	2,048,517	2,251,779
Account 926- Employee Benefits			
Benefits	209,352	208,944	236,851
Pension	10,602	18,977	15,534
Subtotal Total	219,954	227,921	252,385
Total	2,141,658	2,276,438	2,504,164

This increase in 2025 Test Year from 2024 RRA is due to an increase in Wages (Account 920) and associated increase in Benefits (Account 926). The increase relates primarily to Creative Energy's continued focus on building the complement of staff that is necessary to maintain safe and reliable service, to maintain timely and effective regulatory compliance and to sustain and grow the customer base connected to the Core TES system. One new role has been added to the RRA in 2025 to support the development and execution of Creative Energy's Long-Term Resource Plan (LTRP). The role was hired in 2024 and was communicated as part of the 2024 RRA but was not included in 2024 rates. We note that the 2024 RRA decision also denied a full year of costs for certain roles that were ultimately only filled later in the year. Those roles have now been filled, and corresponding costs have been included for the full year in the 2025 RRA. In the 2024 RRA Decision, the Commission found that the prorating of the budgeted amount for new hires to be reasonable, because Creative Energy's plan to hire people to fill nine new roles was behind schedule.

The increase for 2025 also includes salary increases of 3.5 percent. This variance in Wages and Benefits is distributed as follows in **Table 15**.

Table 15: Summary of Management Labour and Benefits Variance by Allocation[12]

Salary Increases	67,260
New Role and Full Year of Roles Hired in 2024	399,009
Reallocation of Time from 2024	(103,763)
Total	362,506

Table 16 shows the costs by business unit for both 2024 RRA and 2025 Test Year as well as their respective variance. We note there has been a shift where some roles (e.g. Executive Leadership, Information Technology Services) are charging less time to the Core system in 2025 than 2024, while significant increase could be noticed in Engineering & Projects, the majority of which is due to the increase in the LTRP costs discussed above. The regulatory department is similarly anticipated to spend more time on the Core system in 2025 and is also impacted by the workload of the LTRP proceedings.

Table 16: Summary of Management Labour and Benefits and Variance by Business Unit

	2024 Approved	2025 Test Year	Variance
Business Development	306,247	303,266	(2,981)
Engineering & Projects	118,074	443,896	325,822
Executive Leadership	482,456	392,179	(90,277)
Finance and Customer Support	375,033	390,179	15,146
Human Resources	52,765	111,032	58,267
Information Technology Services	305,365	226,573	(78,792)
Operations Management	176,675	171,102	(5,573)
Regulatory	325,043	465,938	140,895
Total	2,141,658	2,504,164	362,506

Costs for Wages and benefits under Accounts 920 and 926 that are associated with the Core System are allocated based on the Massachusetts formula or by direct assignment. Further details on this allocation are in **Appendix F**.

[12] Reallocation of Time from 2024 means that there are some roles that were allocated less to the Core TES in 2025 and some that are being allocated more, on a net basis, the figure in the table represents a reduction in cost going to Core TES.

4.2.4 Information Technology Services

4.2.4.1 Introduction

Creative Energy's information technology services - including information technology, information systems, operational technology, and cybersecurity – are essential to the long-term resilience of the utility. As a result of ongoing development around the requirements for information technology services, as well as the historical underinvestment in critical infrastructure, Creative Energy applied for and received approval for an increase in these costs as part of the 2024 RRA. For the 2025 RRA, Creative Energy is requesting approval for expenditures related to information technology services that are in line with the approved costs from 2024.

Creative Energy's 2024 forecast IT infrastructure costs were accepted by the Commission in the final 2024 RRA decision. As a result of this decision, Creative Energy removed $182, 044 of Managed Security Operations Centre (MSOC) costs from the 2024 revenue requirements and established a deferral account to record the actual 2024 MSOC costs with interest at Creative Energy's weighted average cost of debt (WACD). This deferral will be added as part of an evidentiary update to the 2025 RRA when final audited MSOC costs are known. The 2025 RRA includes an adjusted value for MSOC for 2025 in line with current expectations. Creative Energy believes that this deferral will no longer be required for 2025 costs.

4.2.4.2 Cost Allocation and Summary

Creative Energy's 2025 budgetary allocations for Information Technology Services embody a holistic and foundational strategy aimed at enhancing operational efficiencies, bolstering proactive cybersecurity measures, and ensuring the delivery of safe and reliable services to customers. This comprehensive approach reflects a commitment to advancing technology initiatives that contribute to overall business excellence and customer satisfaction. The change in 2025 is relatively minor in comparison to increases that were approved in 2023 and 2024. **Table 17** below provides a high-level illustration of the cost components of Information Technology Services. Further details are available in **Appendix D- Table D-5**

Table 17: Summary of Information Technology Services

Information Technology Services	2024 Approved	2024 Projected Year	2025 Test Year
General IT: Data Backup and Recovery, System Maintenance, Software Licenses, Cloud Infrastructure, SaaS subscriptions, IT Consulting, IT contractor costs, Peripherals and Accessories, Managed Service Provider, Professional Development, Internet Service Provider	502,275	314,828	427,946
Cyber Security: Managed Security Operations Center, Security Tools, Security Audits	0	118,729	180,400
Total	502,275	433,557	608,346

It should be noted that the 2024 Approved value does not include the cost of the MSOC which will be added to a deferral account for recovery in 2025 instead of being included in rates during 2024. To compare 2024 and 2025, it is important to normalize for this amount. The value for MSOC in the 2025 budget is $70,000. When adding this value to 2024, the planned cost for 2025 is not as significant of an increase.

Table 18 below details the allocation of this total cost of Information Technology Services for the 2025 Test Year.

Table 18: Allocation of Cost of Information Technology Services

Directly Charged	180,400
Allocated via Mass formula	427,946
Total	608,346

Within the overall expenditure for Information Technology Services in 2025 Test Year, an additional cost of $311,402, which is not discussed in the abovementioned tables, is allocated to Creative Energy's non-regulated entities. Note that consistent with the 2024 RRA application, Creative Energy charges 100 percent of cybersecurity related costs to regulated operations and 65 percent of all other IT costs to regulated operations.

4.2.5 Special Services

4.2.5.1 Introduction

Special Services include the following:

1. Audit Fees: The fee for the 2025 Test Year is based on the actual quote from Creative Energy's auditor.
2. Legal Fees: Legal fees in this category of costs do not include expenses relating to regulatory applications and proceedings. Legal fees are typically driven by emergent priorities. An average forecast of legal fees has been determined using the most recent three-year weighted average approach (20/40/40 adjusted for inflation).
3. External Services: External Services are historically related to consulting costs for government advisory services, reviewing customer and business development opportunities, recruiting costs and external costs for preparing tax returns. There are also other items such as enterprise risk assessments, consulting related to benefits and the pension plan and ESG consultants. To estimate the base level of these costs Creative Energy has used costs from previous years adjusted for inflation.
4. Regulatory: Consistent with the fact that the level of activity and absolute costs are difficult to forecast, Creative Energy will continue to apply differences between forecast and actual amounts to the Third-Party Regulatory Costs Deferral Account as approved.
5. Others: Other costs included under Special Services are Steam Distribution Network Study and the Opportunity Assessments and Third-Party Engineering.

4.2.5.2 Summary

Table 19 below provides an overall summary of the Special Services costs. Overall, the 2025 Test Year forecast cost is higher than the 2024 approved RRA. The increase is primarily driven by the increase in external services cost and regulatory cost. The increase in external services is approximately $135,000 when compared to the 2024 approved figure. This includes costs related to the Enterprise Risk Management Program and a Managed Payroll Service Provider. The increase in regulatory cost is approximately $100,000, relating to increased activity anticipated in 2025 primarily related to the Long-Term Resource Plan and the Low Carbon Rate and Rate redesign application. Regulatory costs are largely a placeholder with a deferral account as these costs typically are unknown in advance and are outside of Creative Energy's control. Variances are detailed in **Table D-6** of **Appendix D**.

Table 19: Special Services – Account 923 – Summary

923 Special Services	2024 Approved	2024 Projected	2025 Test Year
Audit Fees	80,680	83,918	115,040
Legal Fees	40,508	63,357	46,804
External Services	70,076	270,926	204,565
Regulatory	150,909	46,442	250,000
Steam Distribution Network Study	0	0	0
Opportunity Assessments and Third-Party Engineering	0	0	0

923 Special Services	2024 Approved	2024 Projected	2025 Test Year
Total	342,173	464,643	616,409

4.2.6 Water and Electricity Expenses

4.2.6.1 Introduction

The cost of water is one of the major expenses for the Core TES Steam plant. Creative Energy's primary water usage consists of:

1. Feed water as an input in steam production;
2. Water cooling applied to Distribution system condensate within the steam plant so that it can safely be discharged into the City of Vancouver's storm and sewer network; and
3. Electricity costs are included in this cost category to reflect the entirety of these costs and are broadly driven by factors and external rates outside of management control.

The methodology to forecast the water expense is based on a historic ratio of actual water expense and actual steam load multiplied by forecast steam load, given the direct relationship between the water input and steam produced.

4.2.6.2 Summary

Water and Electricity Related Expenses are shown in **Table 20** below. The budget for 2025 Test Year is 9 percent higher than 2024 RRA. The increase in water and electricity costs are primarily driven by the forecast increase in load and the change in water and electricity costs. The increase in water treatment is due to the work required to maintain water quality in anticipation of supplying the new electric boilers by 2026.

Details about the estimation methodology of each cost component are discussed in **Appendix C**. The variance for this cost category is in **Table D-7** in **Appendix D**.

Table 20: Water and Electricity Related Expenses – Account 502 Partial and Account 874 – Summary

Accounts 502 and 874	2024 Approved	2024 Projected	2025 Test Year
502 Steam Expenses - Partial			
Water	860,135	933,084	913,083
Electricity	109,049	84,131	106,712
Water Treatment	101,256	140,845	140,000
Subtotal	1,070,440	1,159,061	1,159,795
874 Mains and Services			
Electricity	287	258	281
Water Mains	26,089	13,785	36,000
NEFC Operating Costs	-		
Subtotal	26,376	14,044	36,281
Total	1,096,816	1,173,105	1,196,076

4.2.7 Maintenance

4.2.7.1 Introduction

Maintenance budgets are pooled across business functions overall and they may vary within the year based on priority or emergent need, as indicated by the variation in spend within and across the account category of expense. Maintenance cost includes multiple accounts as follows:

1. Steam Expenses – Maintenance & related Expenses;
2. Structures and Improvements;
3. Other Distribution Operation;
4. Transportation;
5. Mains and Services;
6. Meters & House Regulators; and
7. Maintenance of General Plant.

4.2.7.2 Summary

Forecast 2025 maintenance costs exceed 2024 amounts by 9.12% as shown in **Table 21**. Operational requirements for maintenance include costs relating to the procurement of replacement parts and their freight delivery, tool replacement, safety related costs, cost of service agreement for plant controls and consultants' fees. The budget is prepared by the plant and distribution management team based on expected spending needs in 2025. In 2025, it is anticipated that there will be general increases for inflation, safety training that was not included in the previous year's budgets, and cleaning costs. **Table D-8** in **Appendix D** gives further details on variances for this cost category.

Table 21: Maintenance and related functional operation – Multiple Accounts – Detailed Summary

	2024 Approved	2024 Projected	2025 Test Year
502 Steam Expenses – Maintenance & Related Expenses	380,720	345,992	411,000
506 Structures and Improvements	-	-	-
880 Other Distribution Operation	-	-	-
933 Transportation	12,288	1,753	12,911
887 Mains and Services	86,891	49,759	75,000
889 Meters & House Regulators	196,798	201,141	215,167
932 Maintenance of General Plant	32,240	44,028	59,500
Total	708,937	642,673	773,578

4.2.8 Sales Expenses

The 2025 Test Year expense is a bottom-up budget consisting of promotional costs supporting the Low Carbon project and future growth in the Core TES. The components of this cost are as follows:

1. Core TES - Advertising
2. Core TES - Promotion
3. Core TES - Commissions
4. Core TES - Selling Expense-Trade Shows
5. Business Development Expense
6. Core TES - Dues & Membership
7. Core TES - Courses & Conferences
8. Core TES - Bad Debt

As shown in **Table 22** below, there is a decrease of 55.7 percent in the cost of sales primarily driven by reduced business development expenses. The increase in 2024 was not anticipated to be a permanent increase and the decrease in 2025 is reflective of planned activities for 2025.

Table 22: Sales Expense - Summary & Variance

Account 910	2024 Approved	2024 Projected	2025 Test Year
Sales Expense	187,543	195,056	83,140

4.2.9 Other General & Administrative

4.2.9.1 Introduction

Other General and Administrative Cost comprise a relatively small percentage of Creative Energy's cost of service. This cost is comprised of the following:

1. Director Fees;
2. Office Supplies & Expenses;
3. Admin & General Expenses;
4. Insurance; and
5. Injuries & Damages – WCB.

Table 23 below illustrates the details of this cost. There is an increase of 46.7 percent for the 2025 Test Year over the 2024 RRA. This increase is primarily driven by increases in insurance costs. The variance table of the Other General & Administrative expenses is in **Table D-9** in **Appendix D**.

Table 23: Other General and Administrative- Summary[13]

	2024 Approved	2024 Projected	2025 Test Year
915 Directors Fees	$49,313	$31,916	$48,418
921 Office Supplies & Expenses	$71,471	$51,927	$91,593
922 Admin & General Expenses	$15,769	$(38,147)	$47,881
924 Insurance	$243,240	$247,909	$338,207
925 Injuries & Damages - WCB	$11,646	$12,440	$13,179
Total	$391,439	$306,045	$539,279

[13] Similar to what we did in the 2024 RRA, IT cost are not includes under this account but rather discussed in a separate section, Section 4.2.4.

One of the more substantial changes is insurance costs. Insurance increased in 2025 primarily related to Commercial General Liability (CGL) costs. When renewing for 2025, the market dictated that costs were increasing due to concerns regarding the aging nature of the distribution system and a recent claim for third party damage. The claim for third party damage is ongoing and Creative Energy believes that after resolution, the future rates for CGL beyond 2025 could decrease.

4.3 Property Taxes

4.3.1 Allocation to Non-Regulated Operations

Creative Energy has historically allocated a portion of the total property tax to its non-Core TES operations; thus, reducing the amount of its regulated revenue requirement and benefiting customers through lower rates.

Creative Energy's non-Core TES operations historically included leasing of surplus office space to tenants and parking rentals on land not used in utility operations. While this activity is now minimal, Creative Energy has still allocated a portion of the costs related to this space to the non-Core business. Creative Energy has also allocated out a portion of property taxes related to office staff that are not specifically working on the Core TES.

To calculate the appropriate amount to be allocated to non-Core TES operations, Creative Energy applies the levy rates to the total assessed value of the land and building and a portion is then allocated using building and land square footage.

In the 2021 RRA decision, Creative Energy was directed to address the allocation of property taxes and the treatment of land located at 720 Beatty Street and 701 Expo Boulevard related to the redevelopment. There is currently no change in use of the land planned for 2025. It is anticipated that the land will be fully utilized by the regulated operations and construction of the new regulated plant. As such, there will be no change in the methodology for allocation of property taxes in the 2025 RRA. It should be noted that Creative Energy has not been charging any property tax increases related to the valuation of the land changing since 2022. The rezoning occurred in 2023, and the component of property taxes related to the land valuation is fixed going forward. The same method was used in 2024 and is being used in the 2025 RRA. The only change in property tax included in the revenue requirement will be related to changes in the City of Vancouver rates. The impact on property taxes related to valuation of land is paid for by the developer.

4.3.2 Summary

Property taxes are paid to the City of Vancouver for the properties located at 720 Beatty Street and 701 Expo Boulevard. The total property tax expense is a function of the value of the property, as assessed annually by BC Assessment, multiplied by various levy rates, which are also set amounts and typically changed annually. Please refer to **Table 24** below and Schedule 16 for further details. There is a small increase in property tax of 3 percent mainly due to the increase in the value of the property at 720 Beatty Street.

Table 24: Property Taxes

Item	2024 Approved	2025 Test Year
Total for 720 Beatty Street	936,393	964,465
Reduction for Non-Core TES	-141,000	-145,000
Property Tax for 701 Expo Blvd.	49,239	51,701
Total Property Tax Allocated to Core System	844,632	871,165

Variances between forecast and actual property taxes are captured in the Property Tax Deferral Account approved on an ongoing basis as per Order G-310-21.

4.4 Municipal Access Fee

Creative Energy has a thirty-year Municipal Access Agreement (**MAA**) with the City of Vancouver (the **City**) effective September 1, 1999. The current MAA was approved by the BCUC under Order C-13-00. The MAA grants Creative Energy the right to continue to operate, construct and maintain its distribution system in City streets for the supply of steam-heat and hot water services. In exchange for the rights under the MAA, Creative Energy pays the City an annual fee. The details of how this annual fee is estimated are found in **Appendix C**. Also, **Table D-10** in **Appendix D** gives more details on the calculation for 2025 Test Year and **Table D-11** in the same appendix provides details on the calculation of the gas adjustment. This process is consistent with the 2023 and 2024 RRAs.

Municipal Access Fees are paid in April of each subsequent year once the figures have been audited. Costs are accrued throughout the year based on the formula described in the MAA agreement. Please refer to **Table 25** below for the Municipal Access Fees, which reflects an increase in the fee primarily due to the increase of revenue requirement between the two years. Please also refer to Schedule 17 for further details.

Table 25: Municipal Taxes – Consolidated Core and NEFC

	2024 Approved	2025 Test Year
Total Municipal Access Fee	368,426	380,191

4.5 Income Taxes

To calculate income tax expenses, Creative Energy uses a flow-through or current taxes method. Under this approach the equity portion of the return on rate base, adjusted for permanent and temporary tax differences, and future enacted tax rates (both Federal and Provincial) are used in calculating the total tax expense. More details on income tax calculation are discussed in **Appendix C**.

It is important to note that on an actual basis, revenues are known and subsequently used in arriving at the Net Utility Income figure[14]. With respect to the forecast, the fundamental purpose of the revenue requirement is to determine the amount of revenue required to deliver utility

[14] Utility Revenues less Utility Expenses equal Net Utility Income

services, cover all the expenses (including income tax), and provide for the allowed return on equity. Since the revenues are not "given", but the allowed equity return[15] is, we can use this percentage together with the rate base to calculate what the after-tax equity return would be. Working backwards and adjusting the after-tax equity return for tax differences, we can calculate the before tax income and consequently the income tax expense.

Forecast income tax expense for 2025 is reported in **Table 26** based on the income tax pertaining to regulated operations. The effective tax rate during the test period is 27 percent, which is the same as the 2024 RRA. Please also refer to Schedule 19 for further details.

Table 26: Income Taxes- Consolidated Core and NEFC

	2024 Approved	2025 Test Year
Allowed/Proposed Return on Rate Base (After Tax)	$3,088,000	$2,925,000
Add: Equity Portion of AFUDC		
Less: Financing Costs	$(1,384,543)	$(962,613.22)
Accounting Income After Tax	$1,790,000	$1,962,000.00
Total Additions (Depreciation Expense)	$1,307,900	$1,663,400.00
Total Deductions (Capital Cost Allowance)	$(2,389,500)	$(2,701,763.99)
Taxable Income/(Loss) for Tax Purposes (After Tax)	$708,400	$923,636.01
Tax Gross Up	$73.00%	$73.00%
Taxable Income/(Loss) for Tax Purposes (Before Tax)	$970,411	$1,265,254.81
Effective Income Tax Rate	$27.00%	$27.00%
Current Income Tax Expense	$262,011	$341,618.80

4.6 Depreciation and Amortization Expense

4.6.1 General

Depreciation expense is a function of undepreciated plant balances and applicable depreciation rates. Please refer to **Table 27** below and to Schedule 5 for further detail.

Table 27: Depreciation Expense- Consolidated Core and NEFC

	2024 Approved	2025 Test Year
Opening Accumulated Depreciation	-26,909,300	-28,217,205
Closing Accumulated Depreciation	-28,217,205	-29,880,640
Depreciation Expense	1,307,905	1,663,434
NEFC Reclass	-	-

For each asset class, annual capital additions are tracked separately, and depreciation begins in the year following their addition. Once a particular annual capital addition has reached the end of its useful life, depreciation is no longer applied, and such additions are then taken out of the depreciable asset pool for calculation purposes. The increase in depreciation expense primarily

[15] The equity return is after tax, and it is expressed as a percentage.

relates to investments in IT in recent years and the addition of the Butterfly system extension. Please refer to **Table D-12** in **Appendix D** for the Core Asset Classes and Depreciation Rates.

4.6.2 Depreciation of Contribution-in-Aid-of-Construction (CIAC)

Depreciation of CIAC reduces the overall depreciation expense and effectively lowers the rates. Creative Energy uses the same approach as discussed above when calculating CIAC depreciation. There is only one CIAC class and its depreciation rate is set at 2.5 percent. The depreciation percentage approximates the overall deprecation rate for distribution plant to which the CIAC pertains. In 2024, an addition was made to CIAC related to the Butterfly extension which is reflected in the rates. Please refer to **Table 28** below for a summary and to Schedule 6 for further details.

Table 28: Depreciation Expense of CIAC

	2024 Approved	2025 Test Year
Opening Accumulated Depreciation	(1,242,551)	(3,271,510)
Closing Accumulated Depreciation	(3,271,510)	(3,147,889)

5 Rate Base Return

5.1 Summary

The rate base return represents the return on capital invested to provide regulated utility services. It combines both debt and equity return based on the capital structure and approved rates. **Table 29** below summarizes the Rate Base Return as calculated for the 2025 Test Year.

Table 29: Summary of Rate Base Return- Consolidated Core and NEFC

	2024 Approved	2025 Test Year
Mid-year Rate Base	$32,699,025	$36,996,549
Cost of Capital		
Equity	10.40%	10.40%
Debt	7.85%	5.31%
Rate Base Return	9.10%	7.91%

Section 5.2 below provides further details on Return on Rate Base.

The forecast Rate Base Return for 2025 Test Year is $2,920,000, and it is calculated in accordance with the methodology and rates discussed below.

Interest rates have reduced from the 7.85 percent used in the 2024 RRA. The 5.3 percent rate projection for 2025 is based on forward-looking interest rates. Consistent with previous RRA decisions, rates are not set based on current interest rates, but future interest rates that factor in risk.

Creative Energy's borrowing rate under its senior secured credit facility is determined by the lower of the Canadian Overnight Repo Rate (CORRA) rate plus margin and Prime Rate plus margin.

The Prime rate in Canada is currently 5.45%. With a debt to total capitalization percentage between 50-60%, Creative Energy's interest rate would be 6.70% to 6.95% (Prime plus 1.25% - 1.50%).

For CORRA rates, three major Canadian banks have been used for the analysis of future rates. Each bank has forecast different rate changes for 2025, highlighting that there is variance and risk. The forecasted overnight rates are listed in **Table 30** below.

Table 30: Forecast Overnight Rates for the Major Canadian Banks

	Q1	Q2	Q3	Q4
TD	3.00%	2.75%	2.50%	2.25%
RBC	2.75%	2.25%	2.00%	2.00%
BMO	3.30%	2.75%	2.50%	2.50%
Average	3.02%	2.58%	2.33%	2.25%

The weighted average overnight rate forecast is 2.55%. After adding a margin of 2.50% to 2.75% based on Creative Energy's debt to cap ratio, the forecast rate would be 5.05% - 5.3%. Creative Energy also looked specifically at the TD bank rate noting that the rate curve is smoother and more conservative when compared to the other two banks' forecast. This resulted in an average rate of 5.31% for 2025, which is comparable to the average forecast rate. Overall, this results in a similar rate as the weighted average.

The Mid-year Rate Base comprises the following components:

- Net Mid-year Plant in Service (comprising of gross plant in service, accumulated depreciation and adjusted for the timing of major additions);
- Net Mid-year CIAC (comprising of gross CIAC and accumulated depreciation of CIAC);
- Mid-year Plant Allocated to non-Core TES activities (portion of the plant used to support such activities)
- Mid-Year Deferral Accounts (representing the Company's funding of activities where there is a timing difference between cost incurrence and its collection in rates)
- Mid-Year Working capital (representing Company's investment into non-capital assets used in support of regulated operations)

The Net Mid-year Plant in Service is the largest component of the Rate Base, and it represents the cumulative undepreciated investment in capital assets. It is Gross Plant in Service (**GPIS**) net of Accumulated Depreciation. GPIS comprises the prior year's closing balance carried over to the current period, plus capital additions, AFUDC, and capitalized overheads, less plant retirements. Each of these components and their balances are discussed in **Table 31** below.

Table 31: Rate Base Summary – Consolidated Core and NEFC

	2024 Approved	2025 Test Year
Gross Plant in Service		
Opening Balance	59,599,316	65,323,340
Closing Balance (estimated)	65,323,340	70,404,705
Average Balance (Mid-Year)	62,461,328	67,864,023
Accumulated Depreciation		
Opening Balance	-26,909,300	-28,217,205
Closing Balance (estimated)	-28,217,205	-29,880,640
Average Balance (Mid-Year)	-27,563,253	-29,048,922
Net Mid-year Plant in Service	34,898,076	38,815,100
Net Mid-year CIAC	-2,257,031	-3,209,700
Mid-year Net Plant Allocated to Non-Core TES	-23,461	-23,461
Mid-Year Rate Base Deferred Accounts	422,232	412,304
Mid-Year Working Capital	957,221	1,002,305
Mid-year Rate Base	$33,997,037	$36,996,549

In Order G-310-21 regarding the 2021 RRA Decision, Creative Energy was directed to address the allocation and accounting for land transferred to the developer in its 2022 RRA. Creative

Energy has continued to include the land in its rate base since there is no change in the use of the land anticipated for the 2025 Test Year.

5.2 Equity Thickness and Allowed Return on Equity

As has been covered in Section 1.2, the GCOC Stage 2 proceeding was concluded on November 29, 2024. As part of its determinations, and in recognition of the increased risk faced by the Core TES, Creative Energy was directed to apply an Equity Premium of 6.0% over the Benchmark Utility. This adjustment increased the equity component from 49% to 51% and reduced the debt component from 51% to 49%. Additionally, Creative Energy was directed to maintain a Return on Equity (ROE) of 10.40%, consistent with the rate used in the 2024 RRA. These updated assumptions have been incorporated into the Financial Schedules for this 2025 RRA Application.

5.3 Debt Financing

Creative Energy renewed its credit agreement with HSBC Bank Canada (now Royal Bank of Canada) and Toronto Dominion Bank in March 2023. By Order G-4-23, the Commission approved the revised terms of the debt financing. **Table 32** provides a summary of the key terms of Credit Facility.

Please note the terminology change from BA's to CORRA, . as a change occurred in June 2024 to this mechanism. BA's and CORRA lead to approximately the same interest rates to Creative Energy and has not impacted the interest rate forecast methodology.

Table 32: Credit Facility Summary

Tranche 1	Revolving Facility	6,000,000 (limit)	Prime + 1.25% or CORRA + 2.50% plus standby fee of 0.50% on the unused balance (based on a debt % less than 55%)
Tranche 2	Non-Amortizing Facility	10,000,000	Prime + 1.25% or CORRA + 2.50%
Tranche 3	Non-Amortizing Facility	11,587,000	Prime + 1.25% or CORRA + 2.50%

5.4 Capital Additions

The year-over-year increase to the Rate Base in 2025 is primarily driven by Capital Additions[16]. Projected Total Capital Additions are $5,081,365 million in 2025.

Capital additions in the 2025 Test Period are summarized in **Table 33**. Detailed capital expenditures and incremental additions are laid out in **Appendix E- Capital Additions**.

The breakdown of costs associated with each category is outlined as follows:

[16] Capital additions are based on the year that costs are transferred from Construction in Progress into Plant in Service. Costs may be spent in a previous year but not added to Rate Base until a subsequent year. Higher than average capital additions in one year could be directly related to lower-than-average capital additions in another year. Rate Base is adjusted each year based on actual capital additions.

- Steam Plant: Investments continue to be made to ensure safe and reliable service. An assessment of the existing plant condition has been completed, and the work is required in order to improve safety and reliability in the operation of the existing the steam plant in 2025 and beyond. The dollar values of 2025 capital additions are in line with this assessment. However, the details differ due to the conditions assessment being completed after Creative Energy's annual budget. Ultimately, capital additions are updated based on actuals. The memo that includes this assessment is attached at **Appendix I**[17]of this Application. Creative Energy intends to spend in 2025 based on the conditions assessment.
- Distribution System: Capital expenditures primarily related to manhole rebuild projects. Due to delays securing the required permits in 2024, more projects are anticipated to be completed in 2025 instead of 2024. Three manhole rebuilds are planned for 2025. Also included is a project related to the bonding work required at each customer connection as determined as part of a third-party study.
- Butterfly Project: This project was connected to the Core TES in August 2024[18]. Creative Energy has added the Butterfly Project as part of 2024 Projected additions. The first delivery of energy occurred in Q4 2024, and accordingly, the capital associated with this connection has now been included in the Application.
- Other: The drivers behind the increase in Capital Additions in the "Other" category are detailed in **Table 34**. Creative Energy plans to provide further details on Capital Additions in future evidentiary updates as part of the 2025 RRA proceedings.

Table 33: Core System Capital Additions

	2024 Projected	2025 Test Year
Steam Plant	1,078,367	776,896
Distribution System	151,269	3,218,780
Customer Building Services	365,686	328,770
Customer Connections	984	0
Butterfly	3,256,708	0
Other	871,010	756,919
Total Capital Additions	5,724,024	5,081,365

[17]Please note that the figures in the Memo may differ from the Capital Additions figures presented in this Application, as the Memo was prepared after the budget used to develop the Application. We intend to reconcile these differences during the course of the 2025 RRA proceeding.
[18] Current proceeding could be found here: https://www.bcuc.com/OurWork/ViewProceeding?applicationid=1290

Table 34: Capital Additions under the Category: Other

Capital Additions (Other)	
Computer Hardware	190,000
Enterprise Resource Management System	270,000
Accounting, FP&A and Regulatory Tool	185,000
Integrated Platforms	133,000
Other Information Systems	155,000
Total Capital Additions	933,000
Allocated to non-regulated projects	(326,550)
Allocated to Core	606,450
Office and Other	50,000
Total	656,450

Appendix C provides elaborated definitions for the different categories of Capital Additions.

5.5 Allowance for Funds Used During Construction (AFUDC)

The AFUDC applies where an asset is not part of the rate base, but funds have been invested to finance its construction. The AFUDC recognizes that there are carrying costs arising from such an investment and provides for their future recovery. Capital additions in 2025 do not include AFUDC.

5.6 Accumulated Depreciation

Accumulated Depreciation is a contra asset account that reduces the carrying costs of the underlying asset (such as any plant asset) in recognition of its finite useful life and diminishing economic value with the passage of time. Annual Depreciation expense adds to the Accumulated Depreciation balance whereas plant retirements and net proceeds from disposition reduce it.

The change in Accumulated Depreciation is explained entirely by the change in annual Depreciation expense. **Table 34** provides details on the Accumulated Depreciation.

5.7 Contributions in Aid of Construction (CIAC)

A customer may be required to make a financial contribution to extend utility services, a Contribution in Aid of Construction, if the incremental cost of extending the service exceeds forecast incremental revenue over the planned or contracted period of service duration. When required, such contributions protect existing customers from subsidizing the costs of new customer connections.

CIAC reduces the rate base, and its net balance decreases over time recognizing the effect of depreciation. **Table 35** below details the balances of the Gross CIAC, Accumulated Depreciation and the Net CIAC.

Consistent with the proposed recovery of the System Contribution from NEFC customers over the remaining depreciable life of the NEFC assets, the contribution will be amortized over 22 years. Please refer also to Schedule 6 for further details on CIAC.

Table 35: Contributions in Aid of Construction – Consolidated Core and NEFC

	2024 Approved	2025 Test Year
Gross CIAC		
Opening Balance	-1,781,385	-3,864,595
Repayments	-	-
Additions	-2,083,210	-
NEFC Transfer	-	-
Closing Balance	-3,864,595	-3,864,595
Accumulated Depreciation		
Opening Balance	538,834	593,085
Depreciation	21,591	21,591
NEFC Contribution Depreciation	32,660	32,660
Closing Balance	593,085	716,706
Net CIAC		
Opening Balance	-1,242,551	-3,271,510
Closing Balance	-3,271,510	-3,147,889
Net Mid-Year CIAC	-2,257,031	-3,209,700

Allocation to Non-Regulated Operations

Creative Energy allocates a portion of building and land costs to non-Core TES operations and this allocation lowers the overall regulated rate base and the amount of revenue requirements to be collected through rates. Please refer to Schedule 8 for further details.

5.8 Working Capital

Working Capital[19] represents Creative Energy's investment in non-capital assets and accounts for the timing differences between payment of current period expenses (cash outlay) and their recovery in revenues. **Table 36** below provides a summary for the Working Capital Requirements. Please also refer to Schedules 9 and 10 for further details.

Working capital requirements are calculated as forecast expenses multiplied by the applicable Lead/Lag Days, as currently approved by the Commission, plus any pre-paid expenses such as fuel oil inventory. **Table D-13** in **Appendix D** provides more details on the Approved Net Lead Days for the Working Capital.

[19] Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility and are included as part of rate base for ratemaking purposes.

Table 36: Working Capital Requirements

Working Capital Requirements	2024 Approved	2025 Test Year
Natural Gas & Oil Purchases	-	-
Operation & Maintenance Expense	450,169	513,312
Insurance	121,620	169,104
Other	-	-
Municipal Taxes	-250,240	-258,231
Income Tax Expense	-81,558	-133,712
Property Taxes	332,098	326,700
Subtotal	572,089	617,173
Oil Inventory	399,407	399,407
Customer Deposits	-14,275	-14,275
Work in Process	-	-
Total	957,221	1,002,305

6 Deferral Accounts

6.1 Rate Base Deferral Accounts

6.1.1 After-Tax Regulatory Pension Asset Account

The After-Tax Regulatory Pension Asset Account is equal to the average of the opening balance of the pre-tax pension asset reported on the most recently audited financial statements (December 31, 2023) and an ending balance based on estimated employer contributions for 2025 less approved forecast pension expense for 2025. The average balance is then multiplied by the tax rate. Creative Energy is not currently required to make solvency payments into the pension plan above its current service cost. Creative Energy plans to provide further details on this account in future evidentiary updates as part of the 2025 RRA proceedings.

6.1.2 Revenue Variance Deferral Account (RVDA) for 2024

On November 25, 2024, Creative Energy submitted a compliance filing in accordance with Directive 9 of Order G-272-24. The filing included Revised Financial Schedules for the Core TES, updated to reflect the directives and determinations outlined in the Order and the accompanying decision.

As part of the same filing, Creative Energy enclosed a proposal detailing its proposed approach to collecting from customers the balance in the Revenue Variance Deferral Account (RVDA), as required under Directive 3 of the same order.

Creative Energy proposed amortizing the amount that is the difference between the interim approved rate by Order G-13-24 ($12.58/M#) and the final steam rate for 2024 RRA ($14.46/M#) over a two-year period (2025–2026). This proposal acknowledges the inherent inaccuracy of the calculation given the uncertainties associated with load forecasts, and customer additions or attritions during the amortization period. To recover the RVDA balance, Creative Energy plans to implement a steam rate rider, which will be billed monthly alongside the standard steam rate and fuel cost and collected over a two-year period, as discussed above. Once the Commission approves Creative Energy's proposal, Creative Energy will provide further details on these calculations, such as the balances of the RVDA and the exact amounts for the rate rider, in a submission as part of the 2025 RRA proceedings.

6.2 Non-Rate Base Deferral Accounts

6.2.1 Introduction

This section summarizes non-rate base deferral accounts in effect or proposed and the forecast balances reported to this point in time for proposed recovery in rates in 2024. Final balances in the non-rate base deferral accounts will be confirmed as part of future evidentiary updates as part of the proceedings of this Application.

There exist six deferral accounts that are non-rate base deferrals, as follows:

1. Pension Expense Deferral Account (PEDA);
2. Third Party Regulatory Costs Deferral Account (TPRCDA);
3. Water Cost Deferral Account (WCDA);
4. Property Tax Deferral Account (PTDA);
5. Load Forecast Variance Account (LFVA); and
6. Refinancing Cost Deferral Account (RCDA).

The following two sections discuss the Load Forecast Variance Account and the Third-Party Regulatory Costs Deferral Account in relation to Creative Energy's Long Term Resource Plan. Further details on the remaining accounts are laid out in **Appendix C**.

6.2.2 Load Forecast Variance Account (LFVA)

The LFVA effectively neutralizes the financial impacts of load forecast uncertainty and variance on an ongoing basis, whether related to weather or any other external factor that cannot be judged or controlled in advance with a reasonable degree of certainty. This account will thus convey to our customers the benefit of mitigating the impact of load forecast risk, while also easing the administrative and regulatory burden to develop and defend a specific, yet inherently uncertain, forecast level of load for year-to-year test period rate-setting. An extended definition of the LFVA can be found in **Appendix C**.

Table 37 below summarizes the expected load variance account balances for the year 2025. Schedule 12A provides further information on the Load Forecast Variance Account and other deferral accounts.

Table 37: Load Forecast Variance Account

Load Forecast Variance Account	Opening Balance	Additions/ (Deductions)	Interest/ AFUDC	Net Additions	Amortization	Ending Balance
2023 Actual	$(421,224.00)	$915,016	$2,721	$917,737	$452,816	$949,329
2024 Projected	$949,329	$345,977	$88,102	$434,079	$(1,194,621.00)	$188,787
2025 Test Year	$188,787	-	$10,025	$10,025	$(198,811.51)	$0

Creative Energy has amortized the balance of the LFVA in the current Application and will conclude a review of the observed changes in load before including these costs in rates. The balance may be amortized over a period extending beyond the current Application depending on the size of the balance after November and December 2024 results are known.

6.2.3 Third Party Regulatory Costs Deferral Account (TPRCDA)

This deferral captures variances from forecasted regulatory costs for items such as commission costs, intervenor costs and legal costs. It also captures third party costs related to the LTRP. **Table 38** below details the Opening and Ending balances for the TORCDA. Details of the actual addition for December 31, 2024, can be provided during the course of the 2025 RRA proceedings.

Table 38: TPRCDA Balances

TPRCDA Deferral Account	Opening Balance	Ending Balance
2023	$98,806	$ (97,212)
2024 Approved	$ (97,212)	$315,208
2025 Test Year	$315,208	$ -

6.2.4 Forecast Balances for Recovery in 2025 Rates

This section summarizes the forecast balances of the deferral accounts for rate recovery in the 2025 Test Year. **Table 39** below provides details on each of the accounts discusses above and their respective Opening and Ending balances expected for fiscal year 2025.

Table 39: Projected Deferral Account Balances

Deferral Account Name	2025 Opening Balance	Interest/ AFUDC	Net Additions	Amortization	Ending Balance
Pension Expense Deferral Account	$473,989	$25,169	$25,169	$(336,525)	$162,632
Third Party Regulatory Costs Deferral Account	$315,208	$16,738	$16,738	$(331,945)	-
Water Cost Deferral Account	$(100,792)	$(5,352)	$(5,352)	$106,144	-
Property Tax Deferral Account	$(71,688)	$(3,807)	$(3,807)	$75,495	-
Load Variance Account	$188,787	$10,025	$10,025	$(198,812)	-
Financing Fees Deferral Account 2023	$(247,991)	$ (13,168)	$(13,168)	$261,160	-
Total Deferred Accounts	$557,511	$29,604	$29,604	$(424,483)	$162,632

Appendix A

Draft Order for Interim Approval of 2025 Rates

Order Number

●

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Creative Energy Vancouver Platforms Inc.
2024 Revenue Requirements Application for the Core Thermal Energy System

ORDER

WHEREAS:

A. On December 18, 2024, Creative Energy Vancouver Platforms Inc. (**Creative Energy**) filed with the British Columbia Utilities Commission (**BCUC**) its 2025 Revenue Requirements Application (**RRA**) for the thermal energy system serving downtown Vancouver, Northeast False Creek (**NEFC**), and the Butterfly Development Project (together, **Core TES**) (Application). In the Application Creative Energy requests, among other things, interim approval of the thermal energy service rates for the Core TES which are equivalent to an average rate of $14.08 per thousand pounds of steam (M#), and a system contribution charge of $10.99 per megawatt hour of thermal energy (MWh) for customers connected to the NEFC system, as each set out in Appendix B to the Application, effective January 1, 2025; and
B. The BCUC has commenced review of the Application and determines that approving interim thermal energy service rates for Core TES customers and the system contribution charge for NEFC customers, as well as establishing a regulatory timetable, is warranted.

NOW THEREFORE, pursuant to sections 58 to 60 and 90 of the Utilities Commission Act and section 15 of the Administrative Tribunals Act, the BCUC orders as follows:

1. Creative Energy is approved to charge the thermal energy service rates to customers connected to the Core TES, and the system contribution charge to customers connected to the NEFC and the Butterfly systems, as set forth in Appendix B to the Application, on an interim and refundable/recoverable basis, effective January 1, 2025.

2. Any variance between the interim and permanent thermal energy service rates and the system contribution charge for customers connected to the NEFC or the Butterfly systems, as determined by the BCUC following its final determination of the Application, is subject to refund or recovery from ratepayers, with interest at Creative Energy's weighted average cost of debt.
3. A regulatory timetable for the review of the Application is established as set out in Appendix ____ to this order.
4. The scope of Information Request No. 1 is limited to the specific topics outlined in Appendix ____ to this order.
5. On or before ________, 2025 Creative Energy is directed to provide a copy of this order and the Public Notice attached as Appendix ____ to this order, electronically where possible, to all customers of the Core TES and registered interveners in the 2024 RRA proceeding.

DATED at the City of Vancouver, in the Province of British Columbia, this ____ day of January 2025.

Appendix B

2025 Interim Tariff Page for Approval

CREATIVE ENERGY VANCOUVER PLATFORMS INC.

15. RATE SCHEDULE

Applicability: The Core steam distribution network, including the Butterfly and NEFC hot

water distribution networks served by the CoreTES Utility.

Class of Service: Thermal Energy Service.

Thermal Energy Service Rates:

For customers connected to the Core steam distribution network

$ 18.95 per thousand pounds (M#) of steam for the first 50 M# of steam per month
$ 16.04 per M# of steam for the next 150 M# of steam per month
$ 14.20 per M# of steam for the next 800 M# of steam per month
$ 11.26 per M# of steam for the remainder per month

For customers connected to the NEFC and the Butterfly hot water distribution networks, applying a 0.347 MWh/M# conversion factor:

$ 54.61 per MWh of thermal energy for the first 17 MWh of thermal energy per month
$ 46.23 per MWh of thermal energy for the first 52 MWh of thermal energy per month
$ 40.92 per MWh of thermal energy for the first 278 MWh of thermal energy per month
$ 32.45 per MWh of thermal energy for the remainder per month

Effective January 1, 2025, the above rates include an interim rate decrease approved by **Order G-xx-xx**.

Fuel Cost Adjustment Charge (FCAC):

For customers connected to the Core steam distribution network

FCAC	$18.55 per M# of steam
Rate Rider - Stabilization Account Amortization	$0.00 per M# of steam
Total	$18.55 per M# of steam

FCAC charge effective November 1, 2024, as approved on an interim basis by BCUC **Order G-316-24**

For customers connected to the NEFC and the Butterfly hot water distribution networks, applying a 0.347 MWh/M# conversion factor to the approved charges above.

FCAC	$53.46 per MWh of thermal energy
Rate Rider - Stabilization Account Amortization	$0.00 per MWh of thermal
energy Total energy	$53.46 per MWh of thermal

System Contribution Charge:

For customers connected to the NEFC hot water distribution network:

System Contribution Charge	$10.99 per MWh of thermal energy

Effective January 1, 2025, the above charge approved by **Order G-xx-xx**.

For the Residential Tower owned by Nelson Burrard Holdings Inc. connected to the Butterfly hot water distribution network:

Fixed Monthly Charge for a 30 year-term	$9,516.00 per month

Effective November 1, 2024, the above charge approved on an interim and refundable/recoverable basis by **Order G-343-24**.

Air Conditioning:

A 15% discount will be given to metered thermal energy used for air conditioning through the months of May, June, July, and August based on the average price, as calculated pursuant to the rates set out above, per unit of thermal energy per month used by the Customer concerned. The 15% discount only applies to Thermal Energy Service Rates and not the FCAC.

Issued by:	**Accepted for Filing:**
Steve Molnar	
Vice President, Legal & General Counsel	Commission Secretary British Columbia Utilities Commission
Creative Energy Vancouver Platforms Inc. Suite 1, 720 Beatty Street Vancouver, B. C. V6B 2M1	Effective Date: January 1, 2025 for Core TES and NEFC

Appendix C

Definitions

Table of Contents

(i) Capital Additions

- **Steam Plant:** production of steam; NEFC steam to hot water plant, boiler work, Beatty steam plant electrical, instrumentation or mechanical equipment used in the plant.
- **Distribution System:** Any piping, manhole or auxiliary equipment used in the steam network and NEFC hot water network.
- **Customer Building Services:** Meter replacements, upgrades or pressure reducing station improvement; for example, the installation of a primary and secondary pressure reducing station where previously only a primary station was installed, or installation of an access platform (safety) to a pressure reducing station.
- **Customer Connections:** Costs directly associated with adding new customers, including the pipe section from existing mains to building mechanical room, pressure regulating station, Energy Transfer Station, meter station, equipment insulation, mechanical and electrical install, commissioning, permits, fees, and management.

(ii) Financial Calculations and Considerations

- **Depreciation Methodology:** As per its existing depreciation methodology, Creative Energy uses a "pooled" or asset class depreciation approach, as opposed to depreciating individual assets. Under the asset class approach, all the capital additions to Utility plant are categorized and assigned to a specific asset class with its own specific depreciation rate. This depreciation rate is then applied to the asset class balance to arrive at the total annual depreciation expense for the class. Creative Energy uses a "straight-line" depreciation method for recognizing and recording the annual depreciation expense for each asset class. The depreciation rates are based on an estimated useful life for a "typical asset" in each class. Thus, the rates can either be expressed on a percentage or number-of-years basis. The asset classes and applicable rates are listed in the table below;
- **Electricity Expenses:** Creative Energy takes electricity service from BC Hydro under Large General Service Rate Schedule 1611. Electricity costs for the Test Year use the BC Hydro rates in effect at the time that forecast costs are determined and adjust for inflation. Electricity usage and peak demand are not consistent over time and may not predictably vary with load as other factors also drive electricity costs, such as the use of electric pumps in the summer months. Considering that this balance is not as material as an item such as water costs, for example, we consider that this simplified approach is appropriate and does not sacrifice accuracy to a material amount;
- **Income Tax Calculation:** Income taxes are a function of the return on equity (net income) and the timing difference between accounting depreciation and the tax capital cost allowance (CCA). The incremental income tax expense impact is created by adding the NEFC assets into rate base, which increases the return on equity. In turn, Creative Energy updated the CCA tables used for calculating Core rates to include the undepreciated capital cost (UCC) for the NEFC system and the accounting depreciation for NEFC in the tax calculation;
- **Load Forecast Variance Account:** calculated as the difference between Test-Year Actual Load and Test-year Forecast Load multiplied by the approved average rate for thermal energy service during the test-period in question. This difference constitutes the Revenue Deferral in the LFVA. Revenue Deferral, whether an increase or decrease overall, is applied to the subsequent years revenue requirements in the normal course of administration of such deferral accounts in Creative Energy RRAs, subject to evaluating on a case-by-case basis the overall balance and the proposed timing for recovery in relation to

whether any smoothening of the rate impact of the recovery of the deferral is warranted. As such, the Revenue Variance from the previous year is reported as past of the revenue requirements for this Test Year RRA.

- **Municipal Access Fee:** equals to 1.25 percent of Tariff Revenues plus a flat fee that the City escalates at 2 percent for 2024 plus an historical adjustment of $0.41 per MMBTU multiplied by 1.25 percent to compensate the City for the component of the rate that at one time included gas costs; and
- **Wages and Benefits:** The only external cost categorization under 'Wages and Benefits' are pension-related costs are the only external cost categorization under 'Wages and Benefits', while wages, overtime and benefits are categorized as generally controllable, although subject to external factors such as labour market trends and inflation, for example;
- **Water Expenses:** Water costs are estimated based on the projection model which takes the historical actual load and compares it to water usage per actual historical bills. The projected load for the current year is applied to the model and an estimate of water usage for next year. This usage is multiplied by an estimated rate for next year. As actual water usage is based on load and City of Vancouver water rates are unknown at the time of submitting the RRA, Creative Energy has an approved deferral account in place to capture the difference between actual and approved water costs. The City of Vancouver charges Creative Energy water and sewer fees together as part of its quarterly water billing. These costs are externally and outside of Creative Energy's control and correlate very closely with steam load;
- **Water Treatment Expenses:** Water treatment costs also vary with load, but the relationship is not as direct as in the case of water costs. Historical actual costs compared to load do not provide evidence of a relationship between load and costs. The estimate is based on a bottom-up budget prepared by the operations team but could be influenced by the balance of inventory remaining at the end of the current year.

(iii) Information Technology Services

- **Information Technology (IT):** Hardware, software, and networking components used to manage and store data, primarily focused on managing the technology infrastructure that supports an organization's business processes and decision-making activities;
- **Information Systems (IS):** Combination of people, processes, and technology used to organize, analyze, and disseminate information in organizations. It encompasses a broader range of topics, including business strategy, management, and the use of technology to meet organizational goals;
- **Cybersecurity (CS):** Protecting technology infrastructure from unauthorized access, theft, and damage. Involves the implementation of measures such as firewalls, encryption, and access controls to prevent cyberattacks and ensure the confidentiality, integrity, and availability of information; and
- **Operational Technology (OT):** Hardware and software components used to manage and control the physical processes and operations of an organization. Includes systems such as industrial control systems (ICS), supervisory control and data acquisition (SCADA) systems, and other technology that is used to monitor and control industrial processes.

(iv) Operations and Maintenance Cost Drivers and Controls

- **Information Technology Services:** includes Information Technology, Information Systems, Cybersecurity and Operational Technology;
- **Special Services (Regulatory, Audit, third-party consultants):** Special services in relation to regulatory costs and audit fees are categorized as external, while outside legal fees and consultants are considered as generally controllable (although the latter might at times depend on the specific driver of work need and any related decisions to manage peak work requirements externally versus internally);
- **Water and Electricity Expenses:** Water fees, water treatment costs and electricity costs are all externally set and vary with load;
- **Maintenance (including parts, supplies, safety and vehicles):** They are considered overall as within management control even though a specific driver of required maintenance may at times be an external event and requirements are influenced by external factors such as technical safety regulations; and
- **Other General & Administration plus Sales Expenses (e.g. insurance, office expenses):** They are categorized as generally controllable in relation to office-related expenses, such as supplies, phones and information technology, as well as directors' fees, sales expense and WCB-related costs, while externally driven amounts relate to insurance, permits and bank charges.

(v) Non-Rate Base Deferral Accounts:

- **Pension Expense Deferral Account (PEDA):** The PEDA is approved by Order G-98-15 on an ongoing basis. The PEDA captures the annual variance between forecast Pension expenses recovered in rates and the pension expense reported in financial statements, with the balance to be amortized over one year at a carrying cost equal to Creative Energy's short-term debt rate. Recorded variances include expenses related to revaluation gains and losses;
- **Third Party Regulatory Costs Deferral Account (TPRCDA):** The TPRCDA is approved by Order G-310-21 on an ongoing basis. The TPRCDA captures the annual variance between forecast and actual third-party costs relating to regulatory filings and proceedings required under the Act, with the balance to be amortized over one year. Recorded variances include quarterly Commission fees, Commissioner and Commission Contractor costs charged to individual proceedings, Intervenor Participant Assistant Cost Awards as well as the costs of external legal services that support Creative Energy's regulatory submissions and proceedings;
- **Water Cost Deferral Account (WCDA):** The WCDA was approved by Order G-345-22 on an ongoing basis. The WCDA captures the annual variance between forecast water costs recovered in rates and actual water costs reported in the financial statements, with the balance amortized over one year at a carrying cost equal to Creative Energy's short-term debt rate;
- **Property Tax Deferral Account (PTDA):** The PTDA was approved by Order G-310-21 on an ongoing basis. The PTDA captures the annual variance between forecast property tax costs recovered in rates and actual property tax costs reported in the financial statements, with the balance to be amortized over one year and attract a carrying cost equal to Creative Energy's approved debt rate;
- **Water Cost Deferral Account (WCDA):** The WCDA was approved by Order G-345-22 on an ongoing basis. The WCDA captures the annual variance between forecast water costs

recovered in rates and actual water costs reported in the financial statements, with the balance amortized over one year at a carrying cost equal to Creative Energy's short-term debt rate; and

- **Refinancing Cost Deferral Account (RCDA):** The RCDA records the refinancing costs that Creative Energy is required to pay when debt facilities mature and where facilities are required to renew its debt agreement, but which cannot be forecast at the time of filing an RRA.

Appendix D

Additional Tables

List of Tables

Table D- 1: Total Core & NEFC O&M by Business Function

		2023	2024	2024	2025
Acct. #	Account Name	Actual	Approved	Projected	Test Year
	Steam Production-Operationit				
500	Supervision and Labour	1,777,359	1,739,960	1,914,084	1,899,098
502	Steam Expenses	1,400,331	1,399,855	1,505,054	1,570,795
	Total Steam Production-Operation	**3,177,690**	**3,139,815**	**3,419,138**	**3,469,893**
	Steam Production-Maintenance				
506	Structures and Improvements	0	0	0	0
512	Steam Production Equipment	0	0	0	0
	Total Steam Production-Maintenance	**0**	**0**	**0**	**0**
	Distribution Expenses-Operation				
870	Supervision & Labour	884,223	919,892	1,028,803	998,824
874	Mains & Services	35,713	26,376	14,044	36,281
878	Removing & Resetting Meters				
880	Other Distribution Operation				
933	Transportation	27,522	12,288	1,753	12,911
	Total Distribution Expenses-Operation	**947,457**	**958,555**	**1,044,600**	**1,048,017**
	Distribution Expenses - Maintenance				
885	Supervision & Labour				
886	Structures & Improvements				
887	Mains & Services	76,719	86,891	49,759	75,000

		2023	2024	2024	2025
Acct. #	**Account Name**	**Actual**	**Approved**	**Projected**	**Test Year**
889	Meters & House Regulators	61,731	196,798	201,141	215,167
894	Other Distribution Maintenance				
	Total Distribution Expenses-Maintenance	**138,450**	**283,690**	**250,900**	**290,167**
	Customer Accounts Expenses-Operation				
901	Supervision		0	0	0
902	Meter Reading & Billing Delivery		0	0	0
903	Customer Records & Collection Exp		0	0	0
904	Uncollectible Accounts		0	0	0
	Total Customer Accounts Exp-Operation	**0**	**0**	**0**	**0**
	Sales Promotion Expenses-Operation				
910	Sales Expense	255,932	187,543	195,056	83,140
911	Advertising				
	Total Sales Promotion Exp - Operation	**255,932**	**187,543**	**195,056**	**83,140**
	Administrative & General - Operation				
915	Directors Fees	105,959	49,313	31,916	48,418
920	Admin & General Salaries	1,271,171	1,921,704	2,048,517	2,251,779
921	Office Supplies & Exp	113,193	71,471	51,927	91,593
922	Admin & General Exp	62,510	15,769	-38,147	47,881
923	Special Services	710,329	342,173	464,643	616,409

		2023	2024	2024	2025
Acct. #	**Account Name**	**Actual**	**Approved**	**Projected**	**Test Year**
924	Insurance	216,308	243,240	247,909	338,207
925	Injuries & Damages-WCB	7,650	11,646	12,440	13,179
926	Employee Benefits	142,339	219,954	227,921	252,385
930.1	Institutional or Goodwill Advert Exp	0	0	0	0
930.2	Other Admin. And General Exp	0	0	0	0
	Total Admin & General-Operation	**2,629,460**	**2,875,270**	**3,047,126**	**3,694,676**
	Administrative & General - Maintenance				
932	Maintenance of General Plant	28,770	32,240	44,028	59,500
	Total Admin & General-Operation	**28,770**	**32,240**	**44,028**	**59,500**
	Regulatory Gross O&M Expense	**7,177,759**	**7,477,113**	**8,000,847**	**8,645,392**
	O&M Expenses Allocated to Capital %				
	O&M Expenses Allocated to Capital $				
	O&M Allocated to Affiliate				
	Regulatory Net O&M Expense	**7,177,759**	**7,477,113**	**8,000,847**	**8,645,392**

Table D- 2: Steam Production Supervision and Labour – Account 500 – Variance

Account 500 Supervision and Labour	Control	2024 Approved to 2025 Test Year	
Wages	Internal	73,027	4.20%
Overtime	Internal	5,554	0.32%
Benefits	Internal	32,516	1.87%
Pension Costs	External	48,042	2.76%
Total		**159,138**	**9.15%**
	Internal	111,096	6.38%
	External	48,042	2.76%

Table D- 3: Distribution Supervision and Labour – Account 870 - Variance

Account 870 Supervision and Labour	Control	2024 Approved to 2025 Test Year	
Wages	Internal	27,189	2.96%
Overtime	Internal	4,261	0.46%
Benefits	Internal	23,282	2.53%
Pension	External	24,201	2.63%
Total		**78,933**	**8.58%**
	Internal	54,732	5.95%
	External	24,201	2.63%

Table D- 4: Management Labour and Benefits – Accounts 920 and 926 - Variance

Account 920 Admin & General Salaries	Control	2024 Approved to 2025 Test Year	
Wages	Internal	330,075	15.41%
Account 926 Employee Benefits			
Benefits	Internal	27,499	1.28%
Pension	External	4,932	0.23%
Subtotal		32,431	1.51%
Total		**362,506**	**16.93%**
	Internal	357,575	16.70%
	External	4,932	0.23%

Table D- 5: Details of the General IT and Cyber Security Costs

	2024 Approved	2025 Test Year
General IT		
Software	63,208	117,000
Supplies	27,168	22,600
Licences	102,000	75,000
Internet Service Provider	52,200	83,920
SaaS Subscriptions	84,000	239,500
Data Backup and Recovery	4,800	6,000
Development Costs	40,200	25,000
Managed Service Provider	200,700	199,200
IT Contractor Costs	114,000	1,500
Professional Development	25,200	25,000
Cyber Security		
Managed Security Service Provider	0	70,000
Security Tools	125,441	112,400
Security Audits	45,000	45,000
Grand Total	**883,917**	**1,022,120**
Charged to non-regulated	-292,525	-311,402
	591,392	710,718
Allocated to Other Regulated Systems	-89,116	-102,372
Allocated to Core TES	**502,276**	**608,346**

Table D- 6: Special Services – Account 923 – Variance

Account 923 Special Services	**Control**	**2024 Approved to 2025 Test Year**	
Audit Fees	External	34,361	10.04%
Legal Fees	Internal	6,295	1.84%
Outside Services	Internal	318,271	93.01%
Regulatory	External	241,177	70.48%
Steam Distribution Network Study	Internal	0	0.00%
Opportunity Assessments and 3rd Party Engineering	Internal	0	0.00%
Total		**600,105**	175.38%
	Internal	324,566	94.85%
	External	275,538	80.53%

Table D- 7: Water and Electricity Related Expenses – Account 502 Partial and Account 874 – Variance

Account	**Control**	**2024 Approved to 2025 Test Year**

502 Steam Expenses - Partial			
Water	External	52,948	4.83%
Electricity	External	-2,337	-0.21%
Water Treatment	External	38,744	3.53%
Subtotal	External	89,355	8.15%
874 Mains and Services			
Electricity	External	-6	0.00%
Water Mains	External	9,911	0.90%
NEFC Operating Costs	External	0	-
Subtotal	External	9,905	0.90%
Total		**99,260**	**9.05%**
	Internal	0	-
	External	99,260	9.05%

Table D- 8: Maintenance– Multiple Accounts – Variance

Account	Control	2024 Approved to 2025 Test Year	
502 Steam Expenses - Partial	Internal	30,280	4.27%
506 Structures and Improvements	Internal	0	0.00%
880 Other Distribution Operation	Internal	0	0.00%
933 Transportation	Internal	624	0.09%
887 Mains and Services	Internal	-11,891	-1.68%
889 Meters & House Regulators	Internal	18,369	2.59%
932 Maintenance of General Plant	Internal	27,260	3.85%
Total		**64,641**	9.12%
	Internal	64,641	9.12%
	External	0	-

Table D- 9: Other General & Administrative – Multiple Accounts - Variance

Account	Control	2024 Approved to 2025 Test Year	
915 Directors Fees	Internal	-896	-0.23%
921 Office Supplies & Expenses	Internal	54,946	14.04%
922 Admin & General Expenses	Internal	32,112	8.20%
924 Insurance	External	94,968	24.26%
925 Injuries & Damages - WCB	Internal	1,534	0.39%
Total		**182,664**	46.66%
	Internal	87,696	22.40%
	External	94,968	24.26%

Table D- 10: Municipal Taxes – Consolidated Core and NEFC

	2023 Actual	2024 Approved	2025 Test Year
Revenue Requirement	13,469,482	16,140,653	16,244,395
Tax Rate	1.25%	1.25%	1.25%
Municipal Tax on Steam Revenue	168,369	201,758	203,055
Prior Year Flat Fee	166,920	170,258	173,663
Rate Increase	2%	2%	2%
Escalated Flat Fee	170,258	173,663	177,136
Total Municipal Tax	**338,627**	**375,421**	**380,191**

Table D- 11: Calculation of the MMBTU Gas Adjustment

	2023 Actual	2024 Approved	2025 Test Year
Steam M#	1,144,000	1,077,614	1,115,063
Rate to convert M# to MMBTU	1.19	1.19	1.19
Gas BTU	1,361,360	1,282,361	1,326,925
Tariff Rate	0.41	0.41	0.41
Adjustment	558,158	525,768	544,039

Table D- 12: Core Asset Classes and Depreciation Rates

Acct. #	Account Name	Dep. Rate	Acct. #	Account Name	Dep. Rate	Acct. #	Account Name	Dep. Rate
	Steam Production Plant			**Distribution Plant**			**General Plant**	
311	Structures & Improvements	1.50%	376	Mains	2.00%	390	Structures & Improvements	1.50%
312.1	Boiler Plant Equipment	2.50%	378	Manhole Structures	1.50%	391	Office Furniture & Equipment	5.00%
312.2	Boiler Tanks Equipment	2.50%	380	Services	2.00%	391.1	Office Electronics	20.00%
312.3	Boiler Auxiliary Equipment	5.00%	381	Meters	3.00%	392	Transportation Equipment	15.00%
315	Accessory Electric Equipment	5.00%	382	House Regulators & Meter Instal.	3.00%	393	Stores Equipment	5.00%
316	Other Steam Production Equipment	5.00%	387	Other Distribution Equipment	5.00%	394	Tools & Work Equipment	5.00%
						398	Other General Equipment	5.00%

Table D- 13: Working Capital – Approved Net Lead (Lags) Days

	2023 Actual	2024 Approved	2025 Test Year
Natural Gas & Oil Purchases	0.09	0.09	0.09
Operation & Maintenance Expense	21.1	21.1	21.1
Other	136.88	136.88	136.88
Municipal Taxes	-247.91	-247.91	-247.91
Income Tax Expense	-142.91	-142.91	-142.91
Insurance	182.5	182.5	182.5
Property Taxes	136.88	136.88	136.88

Appendix E

Capital Additions

Table E- 1: Summary Table for Capital Expenditures

	2022 Actual	2023 Actual	2024 Projected	2025 Test Year
Total Capital Additions	2,307,913	2,914,495	5,724,024	5,081,365
Steam Plant	445,527	468,670	1,078,367	776,896
Distribution System	1,169,893	2,201,011	151,269	3,218,780
Customer Building Services	644,207	159,907	365,686	328,770
Customer Connections	0	-9,073	984	0
Butterfly	0	0	3,256,708	0
Other	48,286	93,980	871,010	756,919

Table E- 2: Detailed Capital Expenditures

	2023 Approved	2023 Actual	Variance	2024 Approved	2024 Projected	Variance	2025 Test Year
Steam Production Plant							
Refractory	0	337,783	337,783	-	211,415	211,415	38,142
Feedwater Pump	0	91,487	91,487	100,000	85,532	-14,468	68,000
Burner Management	0	29,400	29,400	-	0	0	53,718
Fan Rebuilds	0	10,000	10,000	-	0	0	267,037
Dearator	0	0	0	80,000	143,538	63,538	0
Boiler 3	0	0	0	180,000	0	-180,000	120,000
Boiler 4	0	0	0	-	393,055	393,055	0
Water Softeners and Resin	0	0	0	-	115,280	115,280	0
DEA 3 Control Valves	0	0	0	-	11,320	11,320	0
Boiler 2	0	0	0	-	0	0	45,000
Air Compressor	0	0	0	-	0	0	25,000
Delta V	0	0	0	-	0	0	40,000
Core Management	0	0	0	-	118,227	118,227	120,000
Miscellaneous Boiler Work	85,000	0	-85,000	-	0	0	0
Subtotal	**85,000**	**468,670**	**383,670**	**360,000**	**1,078,367**	**718,367**	**776,897**
Steam Distribution System							

	2023 Approved	2023 Actual	Variance	2024 Approved	2024 Projected	Variance	2025 Test Year
MB-1 Manhole Rebuild	880,050	1,034,477	154,427	0	0	0	0
MB-2 Manhole Rebuild	718,667	801,050	82,383	0	6,194	6,194	0
MA-12 Manhole Rebuild	-	-	0	0	16,096	16,096	0
MC-6 Steam Leak	-	-	0	0	90,156	90,156	0
MJ-3 Manhole Rebuild	-	-	0	0	0	0	944,104
MJ-5 Manhole Rebuild	-	-	0	0	0	0	948,582
Manhole Reassessment	-	0	0	60,000	0	-60,000	0
MJ-1 Manhole Rebuild	-	0	0	800,000	0	-800,000	750,094
MP1	-	318	318	0	0	0	0
MD-1 Manhole Rebuild	850,000	0	-850,000	875,279	0	-875,279	0
Insulation Hamilton/Dunsmuir	-	198,347	198,347	0	0	0	0
Steam Network Bonding							576,000
177 West Pender Line Rebuild	50,000	166,819	116,819	0	38,823	38,823	0
Subtotal	**2,498,717**	**2,201,011**	**-297,706**	**1,735,279**	**151,269**	**-1,584,010**	**3,218,780**
Building Services							
Meter Upgrades	95,000	112,613	17,613	100,000	124,968	24,968	99,996
Rebuild Pressure Reducing Valves	75,000	47,294	-27,706	60,000	60,000	0	60,000
SDS Equipment Upgrade	-	-	0	0	125,718	125,718	110,000
BC Place Repiping	-	-	0	0	55,000	55,000	0
Dominion Building	-	-	0	0	0	0	58,773
Vehicles	-	-	0	0	0	0	100,469
Meter Upgrades (NEFC)	0	0	0	0	0	0	0
Heat Exchanger (NEFC)	55,856	0	-55,856	0	0	0	0
Subtotal	**225,856**	**159,907**	**-65,949**	**160,000**	**365,686**	**205,686**	**429,238**
Customer Connections							
YMCA Burrard	0	0	0	0	984	984	0
Other Customer Connections	0	-9,073	-9,073	0	3,256,708	3,256,708	0
Subtotal	**0**	**-9,073**	**-9,073**	**0**	**3,257,692**	**3,257,692**	**0**
Other (Office Electronics)							
Ricoh Laserfiche (AP Automation)	19,240	0	-19,240	50,000	0	-50,000	0

	2023 Approved	2023 Actual	Variance	2024 Approved	2024 Projected	Variance	2025 Test Year
Vena (Reporting and FP&A software)	63,680	0	-63,680	150,000	0	-150,000	0
IT Capital Costs	163,385	0	0	648,719	871,010	0	606,450
Office and Other	0	93,980	93,980	24,000	0	-24,000	50,000
Subtotal	**246,305**	**93,980**	**-152,325**	**872,719**	**871,010**	**-1,709**	**656,450**
Total	**3,055,878**	**2,914,495**	**-141,383**	**3,127,998**	**5,724,024**	**2,596,026**	**5,081,365**

Appendix F

Management Allocations

Table F- 1: Management Allocations

	2025 Test Year							2024 Approved						
	Time Allocation		CEVP and TES Affiliate in BC					Time Allocation		CEVP and TES Affiliate in BC				
			Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA				Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA	
	CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.	CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.
Roles Charging Expense to Core System Allocated Via Mass Formula														
Chief Executive Officer	50%	50%	20%	80%	40%	n/a	Yes	50%	50%	0%	100%	50%	n/a	Yes
Chief Financial Officer	50%	50%	20%	80%	40%	n/a	Yes	50%	50%	0%	100%	50%	n/a	Yes
SVP, Engineering and Innovation	60%	40%	75%	25%	15%	n/a	Yes	55%	45%	100%	0%	0%	n/a	n/a
VP, Legal	10%	90%	0%	100%	10%	n/a	Yes	5%	95%	n/a	n/a	0%	n/a	n/a
Director, Regulatory Affairs	100%	0%	5%	95%	95%	n/a	Yes	90%	10%	17%	83%	75%	n/a	Yes
Director, Operations	100%	0%	0%	100%	100%	n/a	Yes	100%	0%	0%	100%	100%	n/a	Yes
Controller	60%	40%	33%	67%	40%	n/a	Yes	60%	40%	0%	100%	60%	n/a	Yes
Director, Finance	35%	65%	29%	71%	25%	n/a	Yes	Role existed in 2024, but did not charge to regulated operations						
Systems Analyst	80%	20%	62%	38%	30%	n/a	Yes	75%	25%	33%	67%	50%	n/a	Yes
Manager, Financial Reporting	50%	50%	30%	70%	35%	n/a	Yes	50%	50%	0%	100%	50%	n/a	Yes
Senior Analyst	35%	65%	29%	71%	25%	n/a	Yes	Role existed in 2024, but did not charge to regulated operations						
Senior Accountant	60%	40%	25%	75%	45%	n/a	Yes	40%	60%	0%	100%	40%	n/a	Yes

	2025 Test Year							2024 Approved						
	Time Allocation		CEVP and TES Affiliate in BC					Time Allocation		CEVP and TES Affiliate in BC				
			Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA				Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA	
	CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.	CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.
Senior Manager, FP&A	25%	75%	0%	100%	25%	n/a	Yes	10%	90%	100%	0%	0%	n/a	n/a
Junior Accountant	50%	50%	10%	90%	45%	n/a	Yes	50%	50%	0%	100%	50%	n/a	Yes
Office Coordinator	50%	50%	20%	80%	40%	n/a	Yes	50%	50%	0%	100%	50%	n/a	Yes
AP Clerk	55%	45%	27%	73%	40%	n/a	Yes	50%	50%	0%	100%	50%	n/a	Yes
Systems Engineer	95%	5%	63%	37%	35%	n/a	Yes	95%	5%	79%	21%	20%	n/a	Yes
Senior Manager, Regulatory	100%	0%	5%	95%	95%	n/a	Yes	90%	10%	17%	83%	75%	n/a	Yes
Project Engineer	100%	0%	75%	25%	25%	n/a	Yes	100%	0%	100%	0%	0%	n/a	n/a
Senior Manager, IT	70%	30%	36%	64%	45%	n/a	Yes	90%	10%	0%	100%	90%	n/a	Yes
Manager, Enterprise Applications	90%	10%	72%	28%	25%	n/a	Yes	90%	10%	0%	100%	90%	n/a	Yes
Security Analyst	100%	0%	15%	85%	85%	n/a	Yes	90%	10%	0%	100%	90%	n/a	Yes
Regulatory Analyst	100%	0%	0%	100%	100%	n/a	Yes	90%	10%	0%	100%	90%	n/a	Yes
Commercial Manager	60%	40%	0%	100%	60%	n/a	Yes	90%	10%	0%	100%	90%	n/a	Yes
Automation Specialist	95%	5%	100%	0%	0%	n/a	Yes	80%	20%	81%	19%	15%	n/a	Yes

	2025 Test Year							2024 Approved						
	Time Allocation		CEVP and TES Affiliate in BC					Time Allocation		CEVP and TES Affiliate in BC				
	CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA		CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA	
			Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.			Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.
VP, HR	45%	55%	22%	78%	35%	n/a	Yes	15%	85%	0%	100%	15%	n/a	Yes
Roles Charging Expense to Core System Allocated Via Direct Charge														
Director, Development	55%	45%	9%	91%	50%	Yes	n/a	50%	50%	10%	90%	45%	Yes	n/a
Director, LTRP	100%	0%	0%	100%	100%	Yes	n/a	Not included in 2024 RRA						
Development Engineer	100%	0%	0%	100%	100%	Yes	n/a	100%	0%	5%	95%	95%	Yes	n/a
Director of Engineering	20%	80%	0%	100%	20%	Yes	n/a	65%	35%	77%	23%	15%	Yes	n/a
Project Engineer	90%	10%	89%	11%	10%	Yes	n/a	90%	10%	72%	28%	25%	Yes	n/a
Senior Manager, Commercial Development	5%	95%	0%	100%	5%	Yes	n/a	10%	90%	0%	100%	10%	Yes	n/a
Marketing Manager	20%	80%	0%	100%	20%	Yes	n/a	20%	80%	0%	100%	20%	Yes	n/a
Director of Projects	80%	20%	94%	6%	5%	Yes	n/a	80%	20%	100%	0%	0%	n/a	n/a
Roles Charging Regulated Entity, but Not Expensed to Operations														
Director of Construction	89%	11%	100%	0%	0%	n/a	n/a	88%	12%	100%	0%	0%	n/a	n/a
SVP, Development	5%	95%	100%	0%	0%	n/a	n/a	18%	82%	72%	28%	5%	Yes	n/a

	2025 Test Year							2024 Approved						
	Time Allocation		CEVP and TES Affiliate in BC					Time Allocation		CEVP and TES Affiliate in BC				
	CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA		CEVP and TES Affiliates in BC	CE Ventures and TES Affiliates outside of BC	Assignment of Capital and Expense			Net Expense Assignment to Core TES RRA	
			Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.			Direct Assignment of Capital to CEVP & TES Affiliate in BC	Expensed to CEVP and TES Affiliate in BC	Net Expense to CEVP and TES Affiliate in BC	Direct Assignment	Mass. Form.
Project Manager	15%	85%	100%	0%	0%	n/a	n/a	100%	0%	90%	10%	10%	n/a	n/a
Project Engineer	100%	0%	100%	0%	0%	n/a	n/a	100%	0%	100%	0%	0%	n/a	n/a
Project Engineer	50%	50%	100%	0%	0%	n/a	n/a	75%	25%	100%	0%	0%	n/a	n/a
Data Specialist	100%	0%	100%	0%	0%	n/a	n/a	New permanent role previously held by co-op student						
Engineering Coop Student	100%	0%	100%	0%	0%	n/a	n/a	100%	0%	100%	0%	0%	n/a	n/a
Engineering Coop Student	100%	0%	100%	0%	0%	n/a	n/a	100%	0%	100%	0%	0%	n/a	n/a
Project Coordinator	100%	0%	100%	0%	0%	n/a	n/a	Role existed in 2024, but was budgeted to charge to regulated projects						
Project Accountant	40%	60%	100%	0%	0%	n/a	n/a	70%	30%	100%	0%	0%	n/a	n/a
Project Engineer	100%	0%	100%	0%	0%	n/a	n/a	Role existed in 2024, but was budgeted to charge to regulated projects						
Roles Not Anticipated to Charge to Regulated Entity, but included in 2024 Budget														
Senior Project Manager	n/a	n/a	n/a	n/a	n/a	n/a	n/a	100%	0%	100%	0%	0%	n/a	n/a
Project Manager	n/a	n/a	n/a	n/a	n/a	n/a	n/a	95%	5%	100%	0%	0%	n/a	n/a
Project Manager	n/a	n/a	n/a	n/a	n/a	n/a	n/a	100%	0%	100%	0%	0%	n/a	n/a
Development Engineer	n/a	n/a	n/a	n/a	n/a	n/a	n/a	75%	25%	100%	0%	0%	n/a	n/a

Appendix G

Weather Normalized Steam Consumption Model Summary

MEMO

PROJECT:	Core System	Date:	August 19, 2024
SUBJECT:	Weather Normalized Steam Consumption Model Summary		

Introduction

This memo presents a statistical analysis of steam consumption patterns of Creative Energy customers, focusing on the 2022/2023 period. The analysis serves two main purposes: to develop an accurate predictive model for steam consumption based on Heating Degree Days (HDD), and to assess the hypothesis that customer consumption trends are changing total system consumption. It is believed that energy consumption patterns have been declining due to increased adoption of building energy Information obtained about selected customer buildings showed notable changes in consumption trends 2022/2023 period, prompting this analysis to quantify and understand these observations.

The analysis will aid in several areas:

- It establishes which climate station is most highly corelated to steam consumption in the downtown core will aid in any analysis where weather normalization is required;
- It enables better forecasting demand for the test year used in Revenue Rate Applications, if desired;
- It enables including long term weather climate change assumptions in long term load forecasts; and
- By comparing 2022/2023 data with historical patterns, it can confirm whether 2022/2023 changes represent a significant shift in consumption.

Various statistical techniques were used in the analysis to explore the relationship between climatological factors, particularly HDD, and steam consumption. Different data sources and model types were compared to select an accurate predictive model that will help provide insights into weather-driven consumption patterns.

Model Description

After rigorous analysis and comparison of various approaches, a univariate quadratic polynomial regression model using HDD data from the Environment and Climate Chance Canada (ECC) Climate Station (CS) in Vancouver Harbour (HARBOUR) [1] was selected to predict core steam consumption[2]. This model was chosen for its optimal balance between explanatory power and parsimony[3].

The model can be formally expressed as:

$$Y = 32707 + 151.72X + 0.3336X^2$$

Where:

Y = Core Steam Consumption (monthly total)
X = HDD (monthly total)

The quadratic term (X^2) allows the model to capture the non-linear relationship between HDD and steam consumption, reflecting the accelerating increase in consumption as temperatures drop. Key assumptions of the model are presented in Table 1. These assumptions help simplify the model and make it more useful for

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[1] "Historical Data" Environment and Climate Change Canada. Accessed June 11, 2024. https://climate.weather.gc.ca/climate_data/daily_data_e.html.
[2] Steam consumption data was sourced from FOM. Only 'Steam Tariff' data was used in this analysis.
[3] A parsimonious model uses the fewest model parameter to obtain the best fit to the data. https://www.statology.org/parsimonious-model/

predictions, while still capturing the essential relationship between air temperature (using HDD) and steam consumption. These assumptions were tested as part of the analysis to ensure they hold true for the HARBOUR and steam consumption data.

Table 1: Key Model Assumptions

Assumption	Description	Explanation / Analogy
Dataset normality	Monthly steam consumption follows a normal distribution.	Heights of adult humans in a large population typically follow a normal distribution. Most people cluster around the average height, with fewer individuals being very tall or very short, and the frequency of heights decreases symmetrically as you move away from the average in either direction.
Non-linear relationship	The relationship between HDD and steam consumption is curved rather than straight (linear).	As it gets colder heat is used more rapidly. Moving from cool to cold increases space heating demand a certain amount, but going from cold to very cold increases the demand disproportionately.
Consistent variability (Homoscedasticity)	The spread of data points around the predicted steam consumption (the model) is constant across all HDD values.	The variation in daily steps taken by individuals tends to be similar whether you are looking at sedentary office workers or active construction workers, despite the difference in their average daily steps.
Independence	Each observation of daily steam consumption is not directly influenced by previous day's observations.	How someone uses space heating today does not directly cause their energy use tomorrow to be higher or lower.
Normal distribution of errors	Prediction errors follow a bell-shaped curve, with small errors being more common than large ones.	In a large group of adults, most people's height will be close to the average, with fewer people being very tall or very short.
HDD (air temperature) is the primary factor	HDD, which is a normalized measure of air temperature, is the main driver of steam consumption, with other factors having relatively minor impacts.	While many things might affect heating use, the outside temperature is by far the most important factor.

Methodology

Data Collection and Preparation

The analysis primarily utilized steam consumption data from the 2022/2023 period, with additional data between January 2019 and May 2024 used for model validation purposes. HDD data and Cooling Degree Day (CDD) data was obtained from two ECCC sources: Vancouver International Airport (YVR)[4] and Vancouver Harbour (HARBOUR).

During the initial data review, it became apparent that both the HARBOUR and YVR datasets contained missing values, which could potentially compromise the integrity of the analysis. To address this issue, a data cleaning and gap-filling procedure was implemented (see Table 2). This process established a temperature-to-temperature relationship between the two datasets to estimate missing values daily minimum, average, and maximum temperatures accurately. These relationships are presented in Figure 1.

[4] "Historical Data" Environment and Climate Change Canada. Accessed June 11, 2024. https://climate.weather.gc.ca/climate_data/daily_data_e.html.

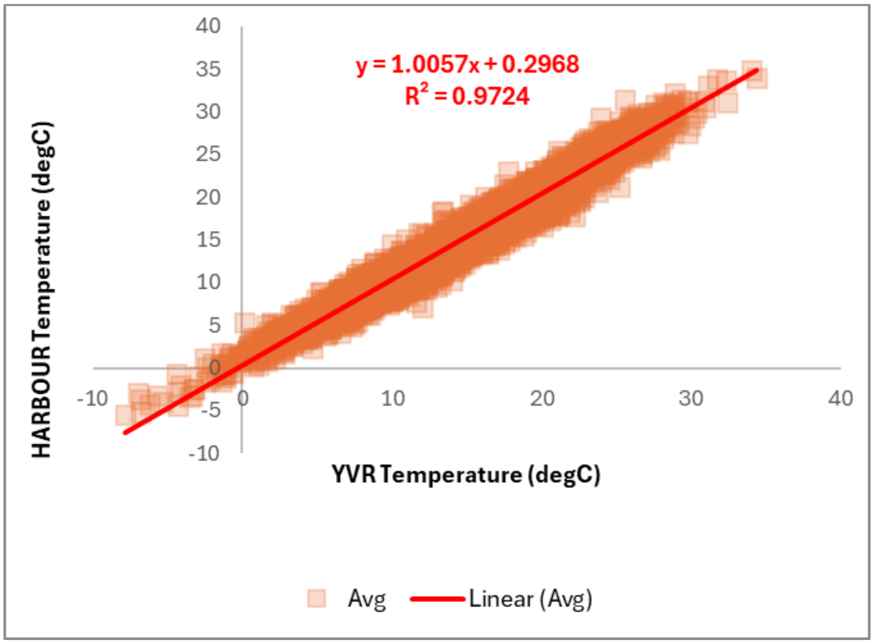


Figure 1: HARBOUR and YVR Temperature-Temperature Relationship

Table 2: Climate Data Gap-filling Procedure

Step	Procedure	Details
Step 1 **Correlation Analysis**	Performed correlation analysis between HARBOUR and YVR temperature datasets for the average temperatures.	A strong correlation between the two average temperatures indicates a robust relationship between temperatures at the two locations.
Step 2 **Regression Model Development**	Developed a linear regression model between the two average temperatures.	Avg temp model: $T_{HARBOUR,avg} = 1.0057T_{YVR,avg} + 0.2968$ A coefficient of determination close to 1 (R^2=0.9724) suggests a robust model between HARBOUR and YVR daily average temperatures, supporting their use for gap-filling.
Step 3 **Gap-Filling Process**	Identified corresponding temperatures and applied appropriate regression model for average temperatures.	For each missing HARBOUR value, the corresponding YVR temperature was input into the average temperature model. This process was then reversed for missing YVR data. This ensured comprehensive dataset for steam consumption modelling.
Step 4 **HDD Calculation**	Calculate the HDD using an 18˚C reference temperature	For each missing HDD value use the gap-filled average temperature to determine the HDD.

The gap-filling approach offers several advantages over using data the as in the form it is available from ECCC:

- It preserves the integrity of the dataset by avoiding the need to discard incomplete records, which could lead to bias in the analysis.
- It capitalizes on the strong correlation typically observed between nearby weather stations, ensuring that the filled data points are based on real, related observations.
- Unlike simple averaging or linear interpolation, this approach maintains the natural variability present in the data, providing a more realistic representation of temperature patterns.

- By maximizing the available data points, it allows for a more robust statistical analysis, improving the reliability of subsequent modeling efforts.

This data preparation process ensured that subsequent analyses would be based on a complete and reliable dataset, enhancing the credibility of the steam consumption model.

Statistical Techniques Used

The analysis employed a range of statistical techniques to develop and validate the steam consumption model. These techniques were chosen to balance complexity with ease of interpretation, ensuring that the resulting model would be both accurate and practical.

Table 3: Summary of Statistical Techniques Used

Statistical Technique	Description	Purpose
Normal Probability Plot	Tested the range of steam values to confirm dataset normality.	To assess whether a dataset follows a normal distribution and identify deviations from normality.
Polynomial Regression	Tested linear, quadratic, and cubic models to describe the relationship between HDD and steam consumption.	To identify the best functional form for the relationship, especially in extreme conditions.
Multivariate Regression	Explored models including additional variables beyond HDD, such as CDD.	To assess if considering both heating and cooling needs improves prediction accuracy.
Model Comparison	Used adjusted coefficient of determination (adjusted R^2) statistic to compare models with different numbers of parameters.	To maximize model accuracy while preserving simplicity, avoiding overly complex models that might not generalize well.
Hypothesis Testing	Conducted statistical tests at 95% confidence level to determine if models and their parameters explain the data beyond random chance.	To ensure the statistical significance of the model and its predictors.
Interval Estimation	Calculated 95% confidence intervals for predictions.	To provide a range for where individual future steam consumption data will likely fall on the graph.
Temporal Validation	Tested model built on 2022/2023 data against other years (2019-2024).	To determine if 2022/2023 data alone was best for predictions or if a larger dataset was needed, and to identify potential changes in consumption patterns.

The process used to select the final model followed this approach:

1. First, dataset normality was tested to validate the use of least-squares regression techniques.
2. The data sources were then evaluated to determine whether YVR or HARBOUR HDD data provided better predictions.
3. Then different polynomial orders were tested (linear, quadratic, cubic) to find the best fit.
4. Next, adding more variables (like CDD and CDD's interaction with HDD) was assessed to determine if it improved predictions.
5. Then separate models for different seasons were examined to determine if they performed better than a single year-round model.

6. Lastly, the optimal timeframe of data to use was assessed to determine of the reference 2022/2023 years were reflective of consumption patterns are changing over time.

Monthly steam consumption demonstrated a strong correlation with a normal distribution, with a few outliers were identified for months with low HDD values. This finding was noted and subsequently evaluated during model selection to understand their influence on predicting annual steam consumption.

At each step, statistical comparisons were used to ensure the most appropriate and robust model for predicting steam consumption was selected. This approach allowed us to develop a model that is not only accurate but also well-suited to capture any recent changes in consumption patterns.

Model Selection Process

The model selection process was conducted systematically to ensure the most appropriate and reliable model for predicting steam consumption was identified. This process involved several key steps, each designed to refine the understanding of the relationship between environmental factors and steam usage. The steps used for refining and selecting the model are outlined in Table 4 .

Table 4: Model Selection Steps

Model Selection Step	Description	Evaluation Criteria
Step 1 **Comparison of Data Sources**	Compared temperature data from Vancouver International Airport (YVR) and Vancouver Harbour (HARBOUR).	R^2 value; higher R^2 considered more accurate.
Step 2 **Evaluation of Polynomial Orders**	Tested linear, quadratic, and cubic relationships between HDD and steam consumption.	Adjusted R^2; highest value preferred, balancing accuracy and simplicity.
Step 3 **Assessment of Univariate vs. Multivariate Models**	Compared models using only HDD against models including additional factors like CDD.	Adjusted R^2; highest value preferred, balancing accuracy and simplicity.
Step 4 **Determination of Optimal Dataset Timeframe**	Investigated whether recent data (2022/2023) or longer historical dataset provided better predictions.	Tested each model's ability to predict 2022/2023 steam consumption; selected timeframe producing highest adjusted R^2 value for 2022/2023.
Step 5 **Examination of Single vs. Seasonal Models**	Explored performance of separate seasonal models against a single year-round model.	Adjusted R^2; highest value preferred, balancing accuracy and simplicity.

Throughout this process, the following statistical measures were used to guide selection of the final model:

- R^2 and adjusted R^2 values to compare model fit;
- P-values to assess the statistical significance of model and its model components;
- Prediction errors to evaluate how well models performed on new data.

Practical aspects like model simplicity and ease of interpretation were also considered with the goal of developing a model that not only performed well statistically but would also be useful and understandable for practical applications. This structured approach narrowed down options and identified the model that best captured the relationship between air temperature (using HDD) and steam consumption. This ensured that the final model was well-suited to predict steam usage accurately, while also being capable of identifying any recent changes in consumption patterns.

Results

Model Tests and Analysis

Analysis of the model yielded several key findings that provide insights into the factors influencing steam consumption and the best method for predicting it. Results of tests and the characteristics of the final selected model are presented in Table 5.

Table 5: Key Findings from Model Tests

Test	Finding	Interpretation
Test 1 **Comparison of HDD Data Sources**	HARBOUR HDD data explained 1% more of the variation in steam consumption compared to YVR HDD data.	While both data sources were good predictors, the HARBOUR data provided a slightly better fit to steam consumption patterns.
Test 2 **Comparison of Model Types**	A quadratic (curved) model outperformed both linear (straight line) and cubic (S-shaped) models.	This suggests that as it gets colder, steam consumption increases at an accelerating rate, but not so dramatically as to require a more complex cubic model.
Test 3 **Impact of Additional Variables**	Adding Cooling Degree Days (CDD) to the model did not improve its explanatory power.	This indicates that heating needs (represented by HDD) are the primary driver of steam consumption in the system, with cooling needs having minimal impact.
Test 4 **Optimal Data Timeframe**	The model performed best when using only 2022/2023 data.	This suggests that recent consumption patterns may differ from historical trends, making the most recent data the most relevant for predictions.
5. Single vs. Seasonal Models	A single model across all seasons outperformed separate seasonal models.	This indicates that the relationship between temperature and steam consumption remains consistent enough throughout the year that a single model is sufficient.

Based on these findings, the final selected model has the following characteristics:

Type: Quadratic polynomial regression

Data Source: HARBOUR HDD

Performance: R^2 value of 0.9833

Equation:

$$Monthly\ Steam\ Consumption = 32707 + 151.72HDD_{HARBOUR} + 0.3336HDD_{HARBOUR}^2$$

A figure a showing the model with prediction curve with 95% confidence and prediction intervals are attached to this report (Figure 2), together with a figure showing the size of the prediction interval around the regression line (Figure 3).

The earlier-noted observation that a few monthly steam consumption data points exhibited non-normality was revisited to understand their influence on the model's ability to predict annual steam consumption. For the two outliers identified, they reflect 9.7% of the total CI size for 2022/2023 data (0.57% out of the total 5.8% CI). Excluding these points lowers the model's ability to explain variation in the data and they were therefore not removed from the dataset.

Model Robustness

To assess the robustness of the selected model a temporal validation was completed. This process involved testing the model's performance across multiple years (2019-2024), including data from 2024 that was not used in the model's development. The results of this validation provide strong evidence for the model's reliability and predictive power. Key findings from the robustness testing are shown in Table 6.

Table 6: Key Findings from Model Testing

Aspect	Performance Measure	Result	Interpretation
Confidence Interval Performance	95% CI prediction success	Successful for all years tested	Model effectively captures underlying relationship between HDD and steam consumption
Accuracy Metrics	Average model error	0.9% (slight overestimation)	High overall accuracy in predictions
	Largest observed error	5.6% below actual (2019)	Within 95% CI of ±6.0%

The model's ability to maintain accuracy across different years is noteworthy. This temporal stability suggests that the relationship between HDD and steam consumption has remained relatively consistent over time, despite potential variations in factors such as changes in the customer usage patterns due to energy conservation. With the largest observed error (5.6% in 2019) still falling within the calculated confidence interval, this indicates the model predicts steam consumption for the post-COVID, COVID, and pre-COVID periods within the confidence interval of the model.

Testing results strongly support the validity and practical utility of the model. Its consistent performance across multiple years indicates that it can predict steam consumption both for recent data and for making future projections. Whenever the model is used, the potential for errors should be considered the confidence interval presented with it is used to support decisions based on the model's predictions.

Conclusion

This statistical analysis of steam consumption patterns of Creative Energy customers has yielded a robust predictive model. The study, which focused primarily on the 2022/2023 period to validate against historical data, has successfully achieved its dual objectives of developing an accurate predictive model and validating recent consumption trends.

The quadratic relationship between HDD and steam consumption suggests that as temperatures drop (increasing HDD), steam consumption increases at an accelerating rate. This aligns with the intuitive understanding that heating needs grow more rapidly in colder conditions.

The high R^2 value (0.9833) indicates a very strong fit, suggesting the model explains the vast majority of factors influencing steam consumption. However, it is important to note that about 1.67% of the variance remains unexplained, which could be due to factors not included in the model or random variations.

The model's robustness is demonstrated by its ability to predict steam consumption within a 95% confidence interval for all years tested (2019-2024). It should be noted that the model remains statistically significant to a confidence level far higher than what should be expected from a model of this fidelity. (p value of 2.2×10^{-19}).

Key Conclusions:

- The analysis yielded a robust quadratic polynomial regression model using HARBOUR HDD data, explaining 98.33% of steam consumption variance.

- The model demonstrates excellent predictive capability and consistency across multiple years (2019-2024), with predictions consistently falling within the 95% confidence interval.
- Analysis indicates that recent consumption patterns (2022/2023) differ somewhat from historical trends, emphasizing the importance of using current data for accurate predictions.
- HDD was shown as the primary driver of steam consumption, with consumption increasing at an accelerating rate as temperatures drop. Notably, CDD and seasonal variations had minimal impact on the model's predictive power.
- These findings provide a reliable foundation for understanding and forecasting steam consumption patterns, particularly in the context of recent trends.

While the model demonstrates strong performance, it is important to acknowledge its limitations:

- The model assumes that the relationship between HDD and steam consumption remains constant over time. The recent 2022/2023 data was selected to build the model as it reflects the most recent state of the system.
- The model does not account for potential changes in the customer base or infrastructure.
- Extreme weather events outside the range of observed data may not be accurately predicted.

This analyses which supported the model’s development have produced a statistically sound model for forecasting steam consumption based on any given twelve-month Heating Degree Day (HDD) profile.

Figures

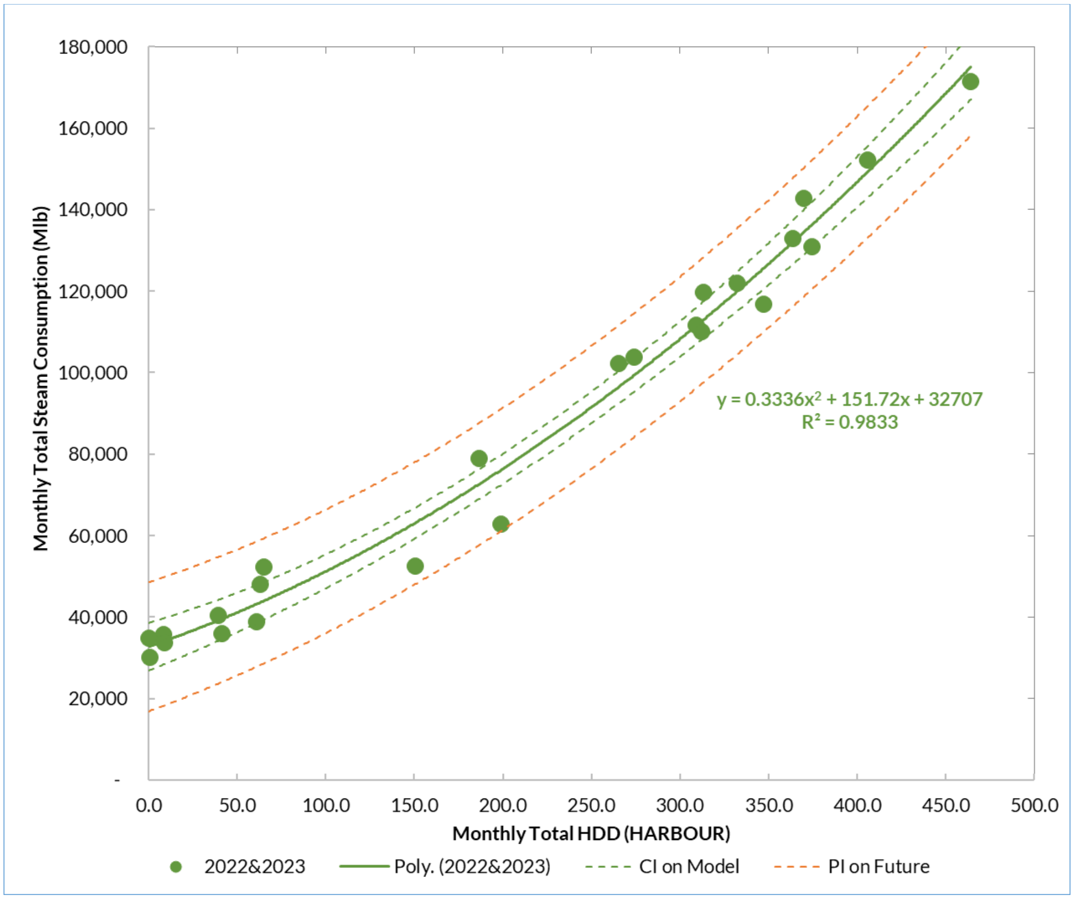


Figure 2: Model with Prediction Curve With 95% Confidence and Prediction Intervals

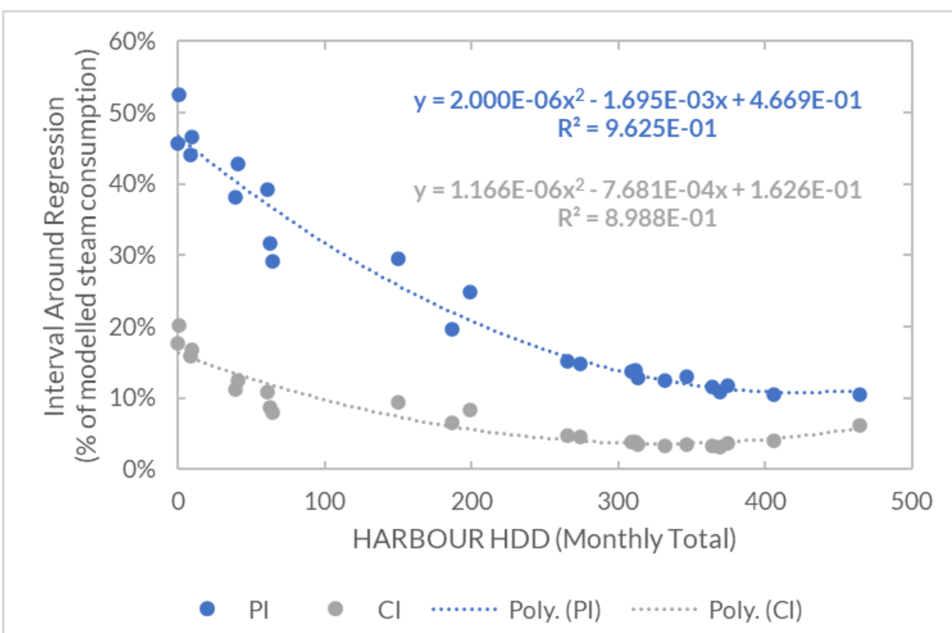


Figure 3: Size of Prediction Interval Around the Regression Line

Appendix Contents

1. Raw and Cleaned Data Sets
   - Creative Energy monthly steam consumption data (2019-2024)
   - ECCC Vancouver International Airport (YVR) monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (2019-2024)
   - ECCC Vancouver International Airport (YVR) annual Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (1973-2024)
   - ECCC Vancouver Harbour CS monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (2019-2024)
   - ECCC Vancouver Harbour CS annual Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (1973-2024)

2. Summary Model Development & Statistical Analysis
   - Full statistical outputs for all tested models, including:
     - Linear, quadratic, and cubic models
     - Univariate and multivariate models
     - Seasonal models
   - Detailed calculations of R^2, adjusted $R\text{-}^2$, and other relevant statistical measures
   - Results of temporal validation tests (2019-2024)

Creative Energy monthly steam consumption data (2019-2024)

Steam Sales / Consumption (M#)	Year				
Month	**2019**	**2020**	**2021**	**2022**	**2023**
Jan	146,574	156,891	122,129	152,154	142,799
Feb	172,643	134,627	136,269	116,753	132,952
Mar	117,880	116,719	119,254	119,791	122,001
Apr	94,183	67,067	79,556	103,868	102,265
May	58,257	48,994	53,136	78,909	52,231
Jun	42,851	45,114	39,396	48,104	40,338
Jul	43,902	41,896	26,462	35,699	30,180
Aug	35,585	32,330	32,268	34,728	33,781
Sep	50,316	37,089	42,530	35,822	38,864
Oct	86,918	66,813	83,528	52,481	62,832
Nov	102,727	108,290	109,685	130,841	109,992
Dec	141,904	137,675	165,864	171,342	111,716
Annual Total (M#)	**1,093,740**	**993,505**	**1,010,077**	**1,080,492**	**979,951**

ECCC Vancouver International Airport (YVR) monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (2019-2024)

Year-Month	Original Heat Deg Days (°C)	Original Cool Deg Days (°C)	Cleaned Heat Deg Days (°C)	Cleaned Cool Deg Days (°C)	HDD Variance After Clean	CDD Variance After Clean	Count of Days Interpolation Require
2019	**2,836.2**	**65.6**	**2,836.2**	**65.6**	**0.0**	**0.0**	**0**
1	403.3	0.0	403.3	0.0	0.0	0.0	0
2	492.7	0.0	492.7	0.0	0.0	0.0	0
3	373.2	0.0	373.2	0.0	0.0	0.0	0
4	254.2	0.0	254.2	0.0	0.0	0.0	0
5	119.2	0.0	119.2	0.0	0.0	0.0	0
6	51.5	7.3	51.5	7.3	0.0	0.0	0
7	12.0	26.1	12.0	26.1	0.0	0.0	0
8	6.0	26.2	6.0	26.2	0.0	0.0	0
9	79.3	6.0	79.3	6.0	0.0	0.0	0
10	289.3	0.0	289.3	0.0	0.0	0.0	0
11	364.3	0.0	364.3	0.0	0.0	0.0	0
12	391.2	0.0	391.2	0.0	0.0	0.0	0
2020	**2,710.4**	**51.6**	**2,747.3**	**51.6**	**36.9**	**0.0**	**3**
1	414.3	0.0	414.3	0.0	0.0	0.0	0
2	385.6	0.0	385.6	0.0	0.0	0.0	0
3	350.3	0.0	387.2	0.0	36.9	0.0	3
4	260.7	0.0	260.7	0.0	0.0	0.0	0
5	133.5	0.0	133.5	0.0	0.0	0.0	0
6	74.6	1.2	74.6	1.2	0.0	0.0	0
7	35.5	20.6	35.5	20.6	0.0	0.0	0
8	29.2	26.7	29.2	26.7	0.0	0.0	0
9	52.4	3.1	52.4	3.1	0.0	0.0	0
10	232.4	0.0	232.4	0.0	0.0	0.0	0
11	345.1	0.0	345.1	0.0	0.0	0.0	0
12	396.8	0.0	396.8	0.0	0.0	0.0	0
2021	**2,846.4**	**137.0**	**2,865.8**	**138.1**	**19.4**	**1.1**	**4**
1	394.7	0.0	394.7	0.0	0.0	0.0	0
2	408.5	0.0	408.5	0.0	0.0	0.0	0
3	363.6	0.0	363.6	0.0	0.0	0.0	0
4	258.8	0.0	258.8	0.0	0.0	0.0	0
5	165.9	0.0	169.6	0.0	3.7	0.0	1
6	48.6	43.5	50.6	44.6	2.0	1.1	2
7	2.7	44.6	2.7	44.6	0.0	0.0	0
8	17.2	43.9	17.2	43.9	0.0	0.0	0
9	92.7	5.0	92.7	5.0	0.0	0.0	0
10	258.4	0.0	258.4	0.0	0.0	0.0	0
11	304.0	0.0	317.7	0.0	13.7	0.0	1
12	531.3	0.0	531.3	0.0	0.0	0.0	0
2022	**2,909.1**	**100.2**	**2,926.5**	**113.5**	**17.4**	**13.3**	**8**
1	432.0	0.0	432.0	0.0	0.0	0.0	0
2	382.0	0.0	382.0	0.0	0.0	0.0	0
3	333.4	0.0	333.4	0.0	0.0	0.0	0
4	300.7	0.0	300.7	0.0	0.0	0.0	0
5	195.9	0.0	203.9	0.0	8.0	0.0	1
6	74.3	2.6	74.3	2.6	0.0	0.0	0
7	14.5	41.5	14.5	43.4	0.0	1.9	1
8	1.5	51.8	1.5	60.6	0.0	8.8	3
9	59.8	4.3	63.5	6.9	3.7	2.6	2
10	178.6	0.0	184.3	0.0	5.7	0.0	1
11	422.0	0.0	422.0	0.0	0.0	0.0	0
12	514.4	0.0	514.4	0.0	0.0	0.0	0
2023	**2,573.9**	**75.9**	**2,621.4**	**75.9**	**47.5**	**0.0**	**6**
1	391.0	0.0	391.0	0.0	0.0	0.0	0
2	387.2	0.0	387.2	0.0	0.0	0.0	0
3	360.2	0.0	369.0	0.0	8.8	0.0	1
4	274.6	0.0	287.5	0.0	12.9	0.0	1
5	97.8	2.3	101.3	2.3	3.5	0.0	2
6	59.2	4.4	59.2	4.4	0.0	0.0	0
7	5.2	36.0	5.2	36.0	0.0	0.0	0
8	18.3	31.8	18.3	31.8	0.0	0.0	0
9	83.1	1.4	83.1	1.4	0.0	0.0	0
10	226.3	0.0	226.3	0.0	0.0	0.0	0
11	330.0	0.0	352.3	0.0	22.3	0.0	2
12	341.0	0.0	341.0	0.0	0.0	0.0	0

ECCC Vancouver International Airport (YVR) annual Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (1973-2024)

Year	Original Heat Deg Days (°C)	Original Cool Deg Days (°C)	Cleaned **Heat** Deg Days (°C)	Cleaned **Cool** Deg Days (°C)	HDD Variance After Clean	CDD Variance After Clean	Count of Days Interpolation Require
1973	3,088.9	18.6	3,088.9	18.6	0.0	0.0	0
1974	2,978.3	25.0	2,978.3	25.0	0.0	0.0	0
1975	3,257.3	28.6	3,257.3	28.6	0.0	0.0	0
1976	3,044.1	7.3	3,044.1	7.3	0.0	0.0	0
1977	3,058.5	62.7	3,058.5	62.7	0.0	0.0	0
1978	2,986.9	52.9	2,986.9	52.9	0.0	0.0	0
1979	2,935.0	36.9	2,935.0	36.9	0.0	0.0	0
1980	3,000.8	11.8	3,000.8	11.8	0.0	0.0	0
1981	2,807.2	56.9	2,807.2	56.9	0.0	0.0	0
1982	3,095.9	37.5	3,095.9	37.5	0.0	0.0	0
1983	2,793.9	19.0	2,793.9	19.0	0.0	0.0	0
1984	3,037.0	33.1	3,037.0	33.1	0.0	0.0	0
1985	3,366.7	54.1	3,366.7	54.1	0.0	0.0	0
1986	2,795.8	40.5	2,795.8	40.5	0.0	0.0	0
1987	2,596.0	51.3	2,596.0	51.3	0.0	0.0	0
1988	2,791.5	47.3	2,791.5	47.3	0.0	0.0	0
1989	2,869.2	23.6	2,869.2	23.6	0.0	0.0	0
1990	2,910.6	87.6	2,910.6	87.6	0.0	0.0	0
1991	2,893.6	44.2	2,893.6	44.2	0.0	0.0	0
1992	2,547.8	64.4	2,608.9	64.4	61.1	0.0	4
1993	2,778.8	32.3	2,912.2	33.6	133.4	1.3	19
1994	2,686.0	59.5	2,686.0	59.5	0.0	0.0	0
1995	2,544.4	52.1	2,593.5	52.1	49.1	0.0	4
1996	3,041.4	55.2	3,058.4	58.8	17.0	3.6	3
1997	2,685.5	56.6	2,685.5	56.6	0.0	0.0	0
1998	2,538.5	112.7	2,538.5	112.7	0.0	0.0	0
1999	2,853.7	38.3	2,853.7	38.3	0.0	0.0	0
2000	2,908.1	28.2	2,908.1	28.2	0.0	0.0	0
2001	2,849.1	23.1	2,849.1	23.1	0.0	0.0	0
2002	2,841.2	57.5	2,850.0	57.5	8.8	0.0	1
2003	2,657.6	88.6	2,657.6	88.6	0.0	0.0	0
2004	2,526.9	130.2	2,526.9	130.2	0.0	0.0	0
2005	2,667.5	60.5	2,667.5	60.5	0.0	0.0	0
2006	2,724.7	59.3	2,724.7	59.3	0.0	0.0	0
2007	2,879.5	49.9	2,879.5	49.9	0.0	0.0	0
2008	3,035.3	53.1	3,035.3	53.1	0.0	0.0	0
2009	2,924.9	103.4	2,924.9	103.4	0.0	0.0	0
2010	2,616.9	62.8	2,616.9	62.8	0.0	0.0	0
2011	2,968.3	32.8	2,968.3	32.8	0.0	0.0	0
2012	2,852.6	60.3	2,852.6	60.3	0.0	0.0	0
2013	2,785.3	53.2	2,823.8	55.1	38.5	1.9	8
2014	2,622.1	78.8	2,628.2	78.8	6.1	0.0	1
2015	2,488.6	98.1	2,488.6	99.9	0.0	1.8	1
2016	2,519.2	49.4	2,538.1	49.4	18.9	0.0	3
2017	2,876.0	71.4	2,915.2	71.4	39.2	0.0	4
2018	2,707.7	85.6	2,708.0	85.6	0.3	0.0	1
2019	2,836.2	65.6	2,836.2	65.6	0.0	0.0	0
2020	2,710.4	51.6	2,747.3	51.6	36.9	0.0	3
2021	2,846.4	137.0	2,865.8	138.1	19.4	1.1	4
2022	2,909.1	100.2	2,926.5	113.5	17.4	13.3	8
2023	2,573.9	75.9	2,621.4	75.9	47.5	0.0	6

ECCC Vancouver Harbour CS monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (2019-2024)

Year-Month	Original Heat Deg Days (°C)	Original Cool Deg Days (°C)	Cleaned Heat Deg Days (°C)	Cleaned Cool Deg Days (°C)	HDD Variance After Clean	CDD Variance After Clean	Count of Days Interpolation Require
2019	**2,450.4**	**127.4**	**2,478.1**	**127.4**	**27.7**	**0.0**	**4**
1	354.6	0.0	362.5	0.0	7.9	0.0	1
2	440.4	0.0	440.4	0.0	0.0	0.0	0
3	321.9	0.0	321.9	0.0	0.0	0.0	0
4	230.0	0.0	230.0	0.0	0.0	0.0	0
5	87.4	2.3	87.4	2.3	0.0	0.0	0
6	25.1	13.6	29.8	13.6	4.7	0.0	1
7	5.6	48.9	5.6	48.9	0.0	0.0	0
8	1.7	51.9	1.7	51.9	0.0	0.0	0
9	62.8	10.7	67.1	10.7	4.3	0.0	1
10	255.3	0.0	255.3	0.0	0.0	0.0	0
11	302.7	0.0	313.5	0.0	10.8	0.0	1
12	362.9	0.0	362.9	0.0	0.0	0.0	0
2020	**2,336.5**	**100.5**	**2,473.1**	**100.5**	**136.6**	**0.0**	**9**
1	273.6	0.0	395.3	0.0	121.7	0.0	7
2	363.6	0.0	363.6	0.0	0.0	0.0	0
3	355.0	0.0	355.0	0.0	0.0	0.0	0
4	211.1	0.0	218.6	0.0	7.5	0.0	1
5	104.7	0.5	112.1	0.5	7.4	0.0	1
6	62.9	4.7	62.9	4.7	0.0	0.0	0
7	22.4	39.9	22.4	39.9	0.0	0.0	0
8	12.2	41.6	12.2	41.6	0.0	0.0	0
9	36.2	13.8	36.2	13.8	0.0	0.0	0
10	208.9	0.0	208.9	0.0	0.0	0.0	0
11	321.7	0.0	321.7	0.0	0.0	0.0	0
12	364.2	0.0	364.2	0.0	0.0	0.0	0
2021	**2,496.4**	**220.6**	**2,565.9**	**220.6**	**69.5**	**0.0**	**7**
1	314.3	0.0	361.8	0.0	47.5	0.0	4
2	378.7	0.0	378.7	0.0	0.0	0.0	0
3	326.3	0.0	326.3	0.0	0.0	0.0	0
4	217.7	0.0	217.7	0.0	0.0	0.0	0
5	136.6	0.0	145.3	0.0	8.7	0.0	2
6	40.4	55.3	40.4	55.3	0.0	0.0	0
7	0.2	89.3	0.2	89.3	0.0	0.0	0
8	11.2	67.9	11.2	67.9	0.0	0.0	0
9	73.4	8.1	73.4	8.1	0.0	0.0	0
10	237.6	0.0	237.6	0.0	0.0	0.0	0
11	297.7	0.0	297.7	0.0	0.0	0.0	0
12	462.3	0.0	475.6	0.0	13.3	0.0	1
2022	**2,609.1**	**177.5**	**2,629.6**	**177.5**	**20.5**	**0.0**	**5**
1	406.1	0.0	406.1	0.0	0.0	0.0	0
2	347.1	0.0	347.1	0.0	0.0	0.0	0
3	313.4	0.0	313.4	0.0	0.0	0.0	0
4	264.1	0.0	274.3	0.0	10.2	0.0	1
5	183.3	0.0	186.5	0.0	3.2	0.0	1
6	59.8	9.2	63.1	9.2	3.3	0.0	1
7	8.5	65.2	8.5	65.2	0.0	0.0	0
8	0.1	91.9	0.1	91.9	0.0	0.0	0
9	37.5	11.2	41.3	11.2	3.8	0.0	2
10	150.5	0.0	150.5	0.0	0.0	0.0	0
11	374.4	0.0	374.4	0.0	0.0	0.0	0
12	464.3	0.0	464.3	0.0	0.0	0.0	0
2023	**2,294.2**	**170.4**	**2,325.8**	**170.4**	**31.6**	**0.0**	**3**
1	369.8	0.0	369.8	0.0	0.0	0.0	0
2	363.9	0.0	363.9	0.0	0.0	0.0	0
3	319.3	0.0	332.2	0.0	12.9	0.0	1
4	256.0	0.0	265.2	0.0	9.2	0.0	1
5	64.9	16.6	64.9	16.6	0.0	0.0	0
6	39.2	17.2	39.2	17.2	0.0	0.0	0
7	0.8	76.6	0.8	76.6	0.0	0.0	0
8	9.1	56.1	9.1	56.1	0.0	0.0	0
9	60.7	3.9	60.7	3.9	0.0	0.0	0
10	189.5	0.0	199.0	0.0	9.5	0.0	1
11	312.0	0.0	312.0	0.0	0.0	0.0	0
12	309.0	0.0	309.0	0.0	0.0	0.0	0

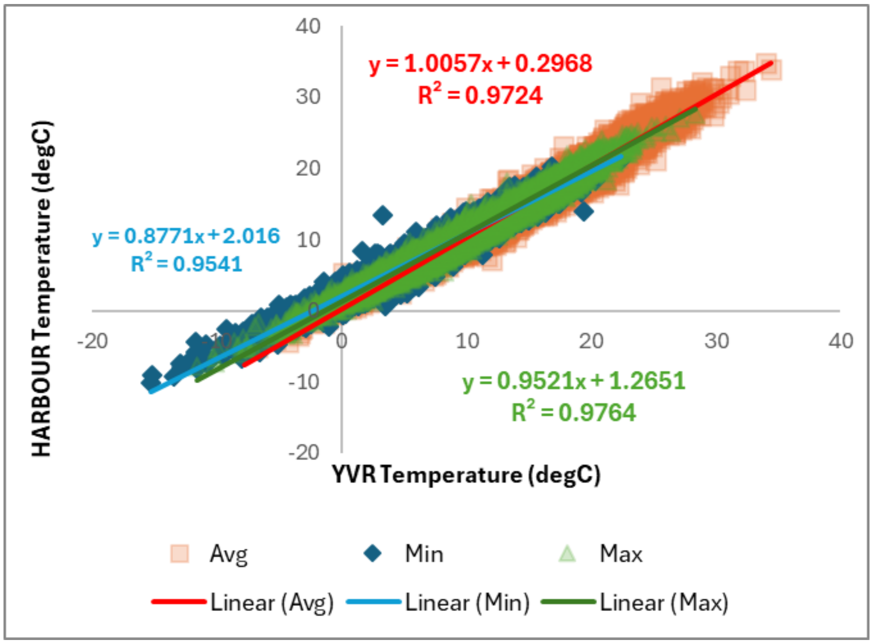
ECCC Vancouver Harbour CS annual Heating Degree Day (HDD) and Cooling Degree Day (CDD) data (1973-2024)

Year	Original Heat Deg Days (°C)	Original Cool Deg Days (°C)	Cleaned Heat Deg Days (°C)	Cleaned Cool Deg Days (°C)	HDD Variance After Clean	CDD Variance After Clean	Count of Days Interpolation Require
1973	1,751.5	19.8	2,931.7	29.4	1,180.2	9.6	147
1974	1,625.0	20.0	2,821.5	32.6	1,196.5	12.6	158
1975	1,459.9	29.1	3,085.0	43.0	1,625.1	13.9	172
1976	2,552.2	14.4	2,812.2	14.4	260.0	0.0	19
1977	2,836.9	79.3	2,836.9	79.3	0.0	0.0	0
1978	2,772.4	70.1	2,772.4	70.1	0.0	0.0	0
1979	2,693.6	53.8	2,693.6	53.8	0.0	0.0	0
1980	2,756.2	24.7	2,756.2	24.7	0.0	0.0	0
1981	2,618.7	64.7	2,618.7	64.7	0.0	0.0	0
1982	2,889.3	44.5	2,902.7	44.5	13.4	0.0	1
1983	2,624.8	30.8	2,624.8	30.8	0.0	0.0	0
1984	2,866.6	42.3	2,866.6	42.3	0.0	0.0	0
1985	3,114.3	78.6	3,114.3	78.6	0.0	0.0	0
1986	2,607.5	51.1	2,607.5	51.1	0.0	0.0	0
1987	2,434.1	50.7	2,434.1	50.7	0.0	0.0	0
1988	1,065.8	0.0	2,648.3	62.3	1,582.5	62.3	278
1989	1,011.8	2.6	2,753.8	34.2	1,742.0	31.6	243
1990	2,440.6	93.3	2,829.0	93.3	388.4	0.0	20
1991	2,491.0	49.0	2,698.3	49.0	207.3	0.0	12
1992	2,153.9	129.6	2,180.7	129.6	26.8	0.0	3
1993	2,444.2	79.4	2,444.2	79.4	0.0	0.0	0
1994	2,273.9	124.5	2,273.9	124.5	0.0	0.0	0
1995	2,240.4	89.7	2,240.4	89.7	0.0	0.0	0
1996	2,684.8	86.0	2,684.8	86.0	0.0	0.0	0
1997	2,380.1	106.6	2,417.8	106.6	37.7	0.0	7
1998	2,177.2	170.8	2,297.7	170.8	120.5	0.0	11
1999	2,606.6	76.5	2,606.6	76.5	0.0	0.0	0
2000	2,562.8	66.1	2,562.8	66.1	0.0	0.0	0
2001	2,283.6	39.4	2,486.3	39.4	202.7	0.0	17
2002	2,637.1	82.0	2,637.1	82.0	0.0	0.0	0
2003	2,369.4	109.1	2,482.6	109.1	113.2	0.0	17
2004	2,383.7	149.0	2,383.7	149.0	0.0	0.0	0
2005	2,519.8	65.3	2,524.0	65.3	4.2	0.0	3
2006	2,508.6	60.9	2,617.4	60.9	108.8	0.0	9
2007	2,051.1	68.8	2,727.9	75.5	676.8	6.7	92
2008	2,834.7	69.2	2,834.7	69.2	0.0	0.0	0
2009	2,641.2	136.5	2,731.7	136.5	90.5	0.0	5
2010	2,309.6	72.9	2,414.6	86.3	105.0	13.4	29
2011	2,047.2	26.7	2,794.7	43.3	747.5	16.6	146
2012	2,650.7	75.1	2,711.6	75.1	60.9	0.0	4
2013	2,584.2	108.5	2,618.6	122.8	34.4	14.3	6
2014	2,315.1	140.6	2,367.4	140.6	52.3	0.0	4
2015	2,134.7	164.6	2,170.6	164.6	35.9	0.0	3
2016	2,240.9	102.6	2,260.2	102.6	19.3	0.0	2
2017	2,624.4	145.1	2,632.4	146.5	8.0	1.4	2
2018	2,371.1	143.8	2,409.6	143.8	38.5	0.0	5
2019	2,450.4	127.4	2,478.1	127.4	27.7	0.0	4
2020	2,336.5	100.5	2,473.1	100.5	136.6	0.0	9
2021	2,496.4	220.6	2,565.9	220.6	69.5	0.0	7
2022	2,609.1	177.5	2,629.6	177.5	20.5	0.0	5
2023	2,294.2	170.4	2,325.8	170.4	31.6	0.0	3

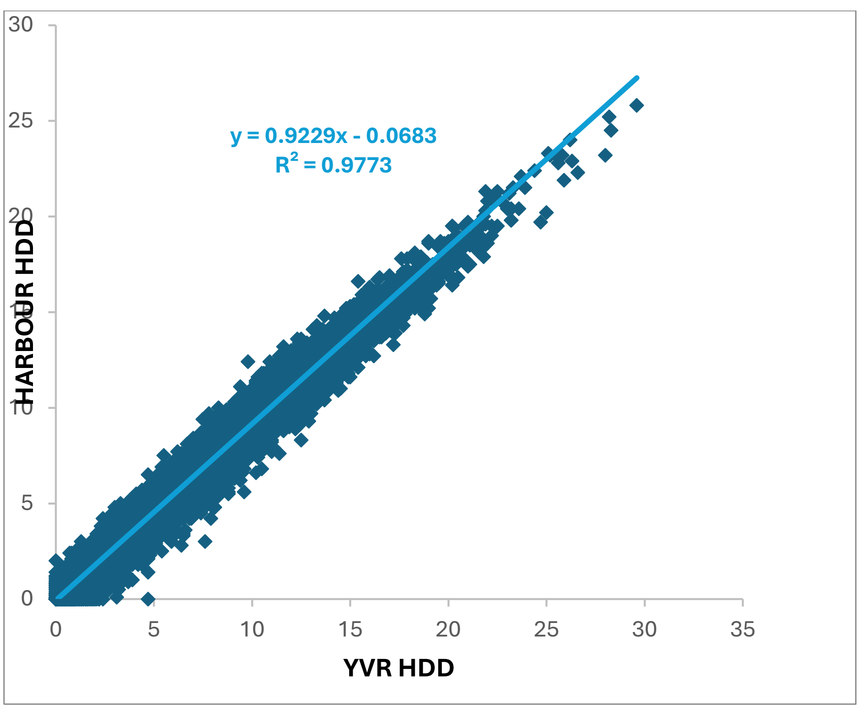
Data Cleaning and Preparation

Supplementary Models

The minimum, maximum, and average temperatures of YVR INTERNATIONAL and VANCOUVER HARBOUR CS are correlated in the following figure.



The YVR INTERNATIONAL and VANCOUVER HARBOUR CS HHDs are related in the following figure.



Using daily minimum and maximum values missing HDD and CDD data was calculated using the formulas:

$$HDD = \max\left(0{,}18°\mathrm{C}\ - \left(\frac{\mathrm{T}_{Daily\ Max} - \mathrm{T}_{Daily\ Min}}{2}\right)\right)$$

$$CDD = \max\left(0, \left(\frac{\mathrm{T}_{Daily\ Max} - \mathrm{T}_{Daily\ Min}}{2}\right) - 18°\mathrm{C}\right)$$

Where:

$T_{Daily\ Max}$ is the daily maximum temperature

$T_{Daily\ Min}$ is the daily minimum temperature

Summary Model Development & Statistical Analysis

Test 1: Comparison of Data Sources

Hypothesis
YVR data is the best ordinate variable to explain 2022/2023 steam consumption.

Hypothesis (YVR HDD)	Alternative Hypothesis (HARBOUR HDD)
Parameters: $\beta_0 = 30469$ $\beta_1 = 146.60$ $\beta_2 = 0.27075$ Diagnostics: $F\ test\ passes$ $99\%\ confidence$ $R^2 = 0.972$ $R^2_{adj} = 0.969$	Parameters: $\beta_0 = 32682$ $\beta_1 = 152.93$ $\beta_2 = 0.33088$ Diagnostics: $F\ test\ passes$ $99\%\ confidence$ $R^2 = 0.983$ $R^2_{adj} = 0.982$

Result
HARBOUR HDD data explains 1% more error than YVR HDD data for the same number of model parameters. The model and its parameters are significant to at least a 99% confidence level.

Best Model

$$Steam = 32682 + 152.93HDD_{HARBOUR} + 0.33088HDD^2_{HARBOUR}$$

Test 2: Evaluation of Polynomial Orders

Hypothesis
A univariate second order polynomial of HARBOUR HDD best explains steam 2022/2023 steam consumption.

Hypothesis (Quadratic Model)	Alternative Hypothesis 1 (Linear Model)	Alternative Hypothesis 2 (Cubic Model)
Parameters: $\beta_0 = 32682$ $\beta_1 = 152.93$ $\beta_2 = 0.33088$ Diagnostics: $F\ test\ passes$ $99\%\ confidence$ $R^2 = 0.983$ $R^2_{adj} = 0.982$	Parameters: $\beta_0 = 26651$ $\beta_1 = 286.93$ Diagnostics: $F\ test\ passes$ $99\%\ confidence$ $R^2 = 0.969$ $R^2_{adj} = 0.967$	Parameters: $\beta_0 = 34077$ $\beta_1 = 92.038$ $\beta_2 = 0.67878$ $\beta_3 = -5.0928 \times 10^{-4}$ Diagnostics: $F\ test\ passes$ $99\%\ confidence$ $R^2 = 0.984$ $R^2_{adj} = 0.981$

Result
A quadratic model explains the data better than a linear and a cubic order model, while maximizing model parsimony. The model and its parameters are significant to at least a 99% confidence level.

Best Model

$$Steam = 32682 + 152.93HDD_{HARBOUR} + 0.33088HDD^2_{HARBOUR}$$

Test 3: Assessment of Univariate vs. Multivariate Models

Hypothesis
2022/2023 steam consumption is best explained through a second order multivariate model that includes HDD and CDD:

$$Steam = \beta_0 + \beta_1 HDD_{HARBOUR} + \beta_2 HDD_{HARBOUR}^2 + \beta_3 CDD_{HARBOUR} + \beta_4 CDD_{HARBOUR}^2 + \beta_5 HDD_{HARBOUR} CDD_{HARBOUR}$$

Hypothesis (Multivariate, CDD)	Alternative Hypothesis (Univariate, HDD)
Parameters: $\beta_0 = 29269$ $\beta_1 = 175.90$ $\beta_2 = 0.29461$ $\beta_3 = -187.99$ $\beta_4 = 4.3975$ $\beta_5 = 16.322$ Diagnostics: $F\ test\ passes$ $99\%\ confidence\ test$ $R^2 = 0.984$ $R_{adj}^2 = 0.980$	Parameters: $\beta_0 = 32682$ $\beta_1 = 152.93$ $\beta_2 = 0.33088$ Diagnostics: $F\ test\ passes$ $99\%\ confidence$ $R^2 = 0.983$ $R_{adj}^2 = 0.982$

Result
Adding CDD as a variable adds no explanatory power to an HDD-exclusive model (compare the adjusted R2). In fact, while the multivariate model is significant to at least a 99% confidence level, all parameters that include the CDD terms fail to pass significance tests at a 95% confidence level.

Best Model

$$Steam = 32682 + 152.93 HDD_{HARBOUR} + 0.33088 HDD_{HARBOUR}^2$$

Test 4: Determination of Optimal Dataset Timeframe

Hypothesis
2022/2023 steam consumption is best explained through a univariate (HDD) quadratic model that only incorporates 2022/2023 data.

Model Dataset Start Year	R^2_{adj}
2019	0.981
2020	0.980
2021	0.980
2022	0.982

Result
The hypothesis is correct. The model best explains 2022/2023 data when it's dataset starts in 2022.

Best Model:

$$Steam = 32682 + 152.93HDD_{HARBOUR} + 0.33088HDD_{HARBOUR}^2$$

Test 5: Examination of Single vs. Seasonal Models

Hypothesis
A single polynomial steam consumption model over the entire domain of HDD explains the data better than two separate models (a winter + shoulder season model and a summer + shoulder season model).

<table>
<tr><th>Hypothesis
(Single Model)</th><th>Alternative Hypothesis
(Seasonal Models)</th></tr>
<tr><td rowspan="2">Parameters:
$\beta_0 = 32682$
$\beta_1 = 152.93$
$\beta_2 = 0.33088$

Diagnostics:
$R^2 = 0.983$
$R^2_{adj} = 0.982$</td><td>Summer + Shoulder

Parameters:
$\beta_0 = 32693$
$\beta_1 = 184.40$

Diagnostics:
$R^2 = 0.834$
$R^2_{adj} = 0.918$</td></tr>
<tr><td>Winter + Shoulder

Parameters:
$\beta_0 = 1913.1$
$\beta_1 = 353.37$
$\beta_2 = 0.021686$

Diagnostics:
$R^2 = 0.964$
$R^2_{adj} = 0.957$</td></tr>
</table>

Result
Subdividing the HDD domain into two separate models does a poorer job than a single model over the entire HDD domain.

Best Model

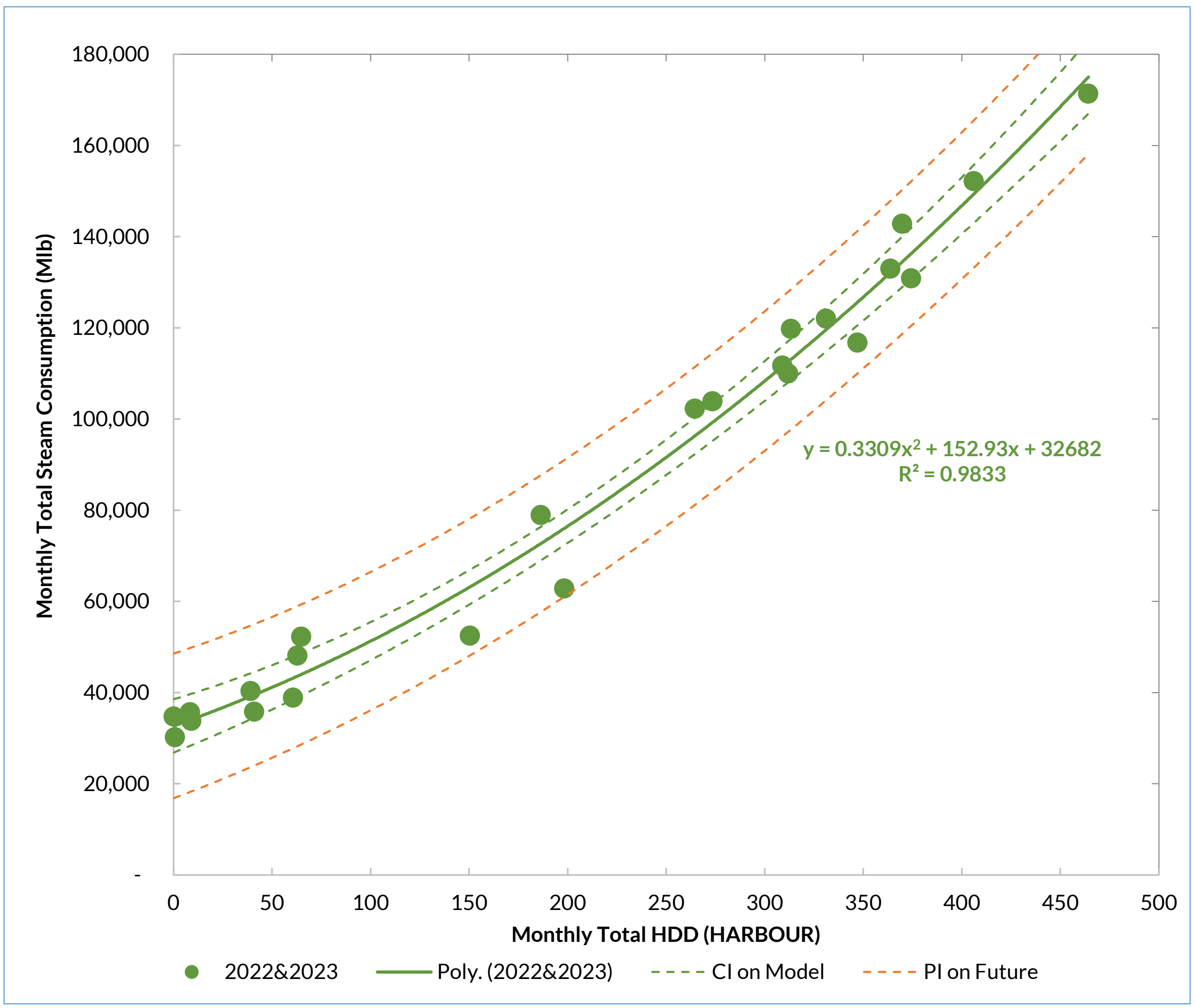
$$Steam = 32682 + 152.93HDD_{HARBOUR} + 0.33088HDD^2_{HARBOUR}$$

Selected Model

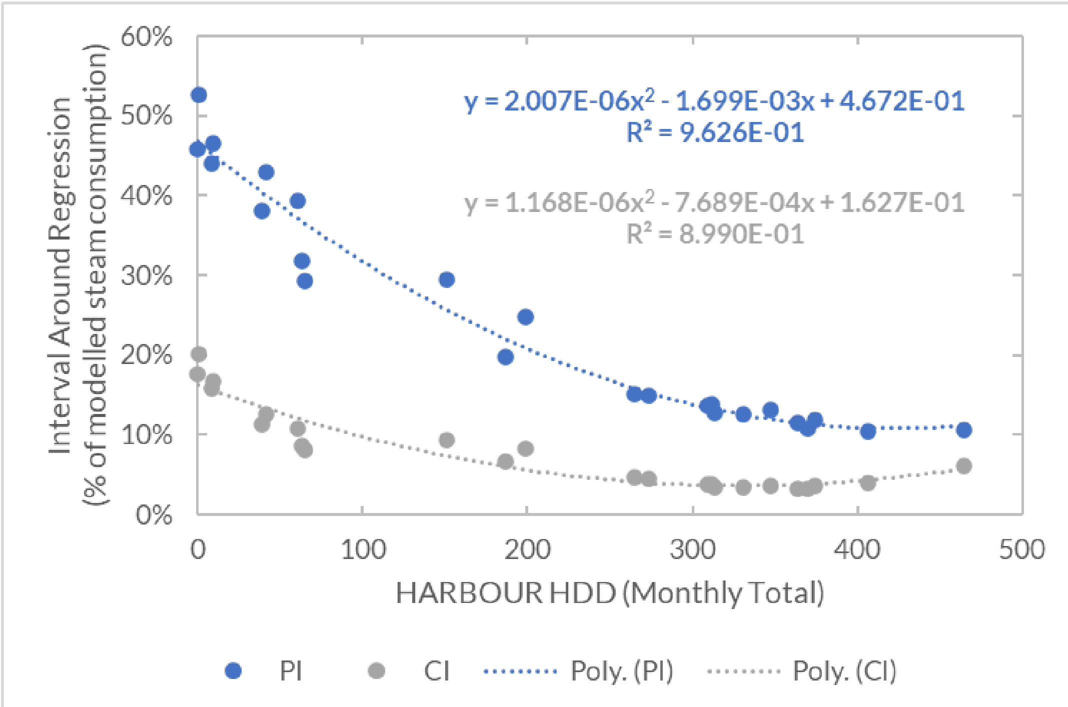
The following graph shows the model that best explains Creative Energy customer steam consumption.

- The solid green line shows the regression curve. Its equation and coefficient of determination are shown in-graph.
- Dotted green lines show the 95% confidence interval (CI) on the mean, i.e. one can be 95% confident that the regression falls within the envelope formed by the CIs.
- Dotted orange lines show the 95% prediction interval (PI) on future measurements, i.e. one can be 95% confident that future data points will fall within the envelope formed by the PIs.

Note that the CIs and PIs are symmetric around the regression line.



The size of the prediction interval around the regression line is shown below:



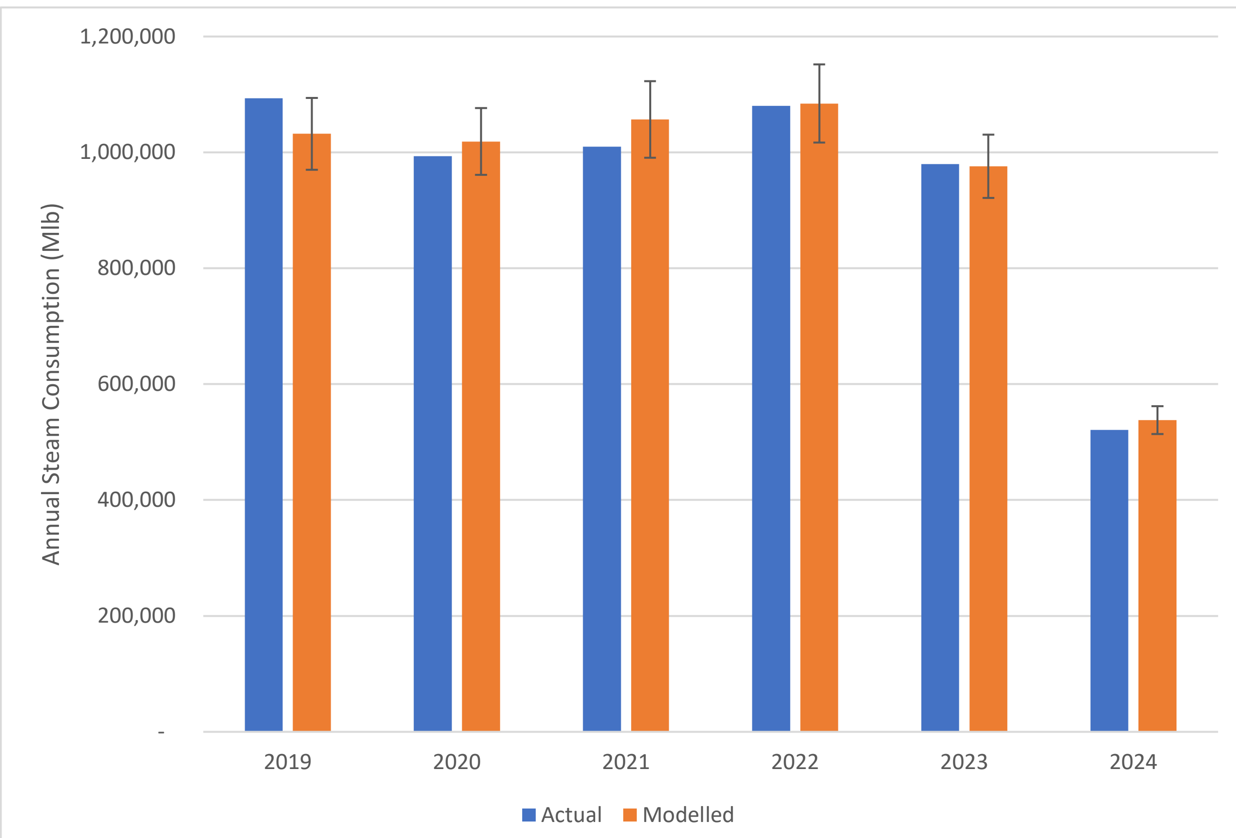
Note that:

- The CI communicates the variability in the model. Its purpose is to reflect the variability in the model. It estimates the model's mean.
- The PI communicates the variability in individual data points. Its purpose is to predict where the next data point will likely be.
- If attempting to predict where a future month's steam consumption could fall with 95% confidence, use the PI. If attempting to predict the expected steam consumption for a month, use the CI. The PI is larger than the CI because it includes two uncertainties: the uncertainty of the model; and the uncertainty of the future prediction. The CI only reflects the uncertainty of the model, while the CI only includes the uncertainty of the model. The PI is a prediction of a future value, whose error is not baked into the model. The CI is a prediction of the mean model response, limited to the data that was used to produce the model parameters.

Model Robustness

The models were developed using 2022/2023 data. The robustness of these models can be tested by predicting previous years' steam consumption (data excluded from the model parameters), and the current year's steam consumption (2024). The figure below shows the actual and modelled steam consumption, with the 95% CI around the model estimate. In all years tested, the actual steam consumption falls within the 95% confidence band of the model. For the years tested:

- The model predicts the actual steam consumption within a 95% confidence interval for all years tested.
- The average model error is 0.8% (above the actual steam consumption).
- The least accurate prediction (2019) was 5.6% below the actual steam consumption (but still within the 95% CI of ±6.0%).



Appendix H

Weather Normalized Load Forecast for the 2025 RRA Test Year

CREATIVENERGY

MEMO

PROJECT:	Core TES	Date:	December 4, 2024
SUBJECT:	Weather Normalized Load Forecast for the 2025 RRA Test Year		

Summary

This analysis establishes a weather-normalized annual load of 1,115,063 M# for Creative Energy's Core TES 2025 Rate Revenue Application (RRA) test year using two statistical models that utilize a quadratic relationship between heating demand and Heating Degree Days (HDD). These models capture over 94% and 98% of energy consumption variability for NEFC and the Core respectively, providing strong statistical confidence in the forecasting methodology. The analysis builds upon the statistical model developed in August 2024[1] while incorporating new updates, including the development of a separate NEFC model and optimization of the building demand dataset to reflect current system conditions.

Using a 50-year heating year dataset for the period 1974/1975 to 2023/2024, the analysis identified the 2005/2006 heating year as the year representative of the 50th percentile (or median) demand. The year 2005/2006 was chosen due to its close alignment with the calculated 50th percentile demand, with a deviation of 1.1% from the median, making it an appropriate baseline for forecasting purposes.

The updated statistical model establishes a load of 1,106,786 M# for the current Core + NEFC configuration in the selected representative year. Compared to the previous work done in August 2024, this figure includes the addition of the four Northeast False Creek (NEFC) buildings and the exclusion of three temporarily inactive connections. An additional 8,277 M# was then incorporated to account for projected partial-year consumption from three Butterfly buildings, resulting in the final test year demand of 1,115,063 M#.

The methodology and findings presented in this memo provide a statistically robust basis for the proposed Test Year demand, one which is grounded in historical weather patterns and the current Core TES configuration. These include the stability of aggregate building usage patterns within the system and the continued relevance of historical weather patterns for future forecasting. The strong statistical correlation and the selection of a median production provide a reliable foundation for RRA planning purposes.

Previous Work

In August 2024, Creative Energy conducted an analysis to understand the relationship between steam load and weather focusing on daily mean air temperature, expressed in Heating Degree Days (HDD). This study revealed that a quadratic relationship between HDD and steam demand explains over 98% of the steam demand variability within the Core TES. This relationship, based on 2022/2023 data, was found to have significant predictive power for the period from 2019 through mid-2024. The analysis also identified the Environment Climate Change Canada climate station at Vancouver Harbour (Vancouver Harbour CS) as having the highest correlation to Core TES steam consumption.

While this initial analysis provided valuable insights into the relationship between weather and steam consumption, further refinement was warranted to include NEFC demand data and adjust the building dataset to reflect current system conditions.

[1] "Weather Normalized Steam Consumption Model Summary", memo, Creative Energy, August 19, 2024.

Refining the Model

The previous analysis was refined by filtering historical consumption data to focus only on customer buildings that are connected at the end of October 2024, resulting in a dataset of 201 buildings. Further refinement was done by excluding three connected buildings that had no demand in 2024.[2] A second model was then developed, based on the previous analysis, for the four customer buildings connected to the NEFC hot water distribution network.

The analysis reconfirmed a quadratic relationship between daily mean air temperature (expressed in HDD) and thermal energy demand explained over 98% of the energy demand within the Core TES, and over 94% of the energy demand in NEFC. These relationships, based on monthly 2022/2023 data, are shown in Figure 1 and Figure 2 for the Core and NEFC respectively. The resulting relationships can be expressed as:

$$Monthly\ Thermal\ Energy\ Consumption_{Core}\ (M\#) = 0.3298 \times HDD_{monthly}^2 + 150.44 \times HDD_{monthly} + 32683$$

and

$$Monthly\ Thermal\ Energy\ Consumption_{NEFC}\ (M\#) = 0.0129 \times HDD_{monthly}^2 + 14.713 \times HDD_{monthly} + 1524.5$$

These models provide a robust foundation for forecasting monthly demand, accounting for both the linear and non-linear effects of temperature changes on consumption.

Methodology

The heating season in Canada spans from September to May, defined by daily average temperatures below 18°C, which is also used to calculate Heating Degree Days (HDD). For our analysis, a July to June "heating year" was chosen to encompass the full heating season, including core heating months, shoulder months, and the warmest summer months. This approach leads to more accurate long-term planning and forecasting because it aligns with seasonal cycles, avoids splitting heating seasons across calendar years, captures inter-seasonal variations in a single 12-month period, and ensures consistent comparison periods. The resulting heating year framework was then applied, improving the probability of exceedance analysis for heating demand by aligning consumption data with climatic conditions.

The 50^{th} percentile (median) is the value where at least 50% of the data points are less than or equal to this value, and at least 50% are greater than or equal to this value. Probability of exceedance refers to the likelihood that a certain value will be exceeded. In the context of heating demand, the 50^{th} percentile means there is a 50% chance that the actual heating demand will be higher than this value. As the percentile increases, the probability of exceedance decreases, and vice versa.

The 50^{th} percentile, or median production, for the Core TES (Core + NEFC) was determined using a 50-year heating year dataset for the period1974/1975 to 2024/2024. The refined monthly HDD-to-consumption models were applied to the heating year dataset to calculate what the energy demand of the Core TES would have been, in its current configuration, in each historical heating year. Monthly demand was then calculated for both the Core and NEFC using the refined models and aggregated into annual totals for each heating year. This allowed for percentiles and probabilities of exceedance for annual demand of the current system configuration to be calculated based on historical weather patterns.

To select a representative year for the weather-normalized annual demand, the analysis focused on identifying a year from the 50-year heating year dataset that closely matched the desired exceedance threshold of 50%. The 2005/2006 heating year was chosen for planning purposes as it had an annual steam consumption value within

[2] These buildings have metered connections and were locked out at the end of October during renovations and were therefore excluded from the 2025 demand forecast.

1.1% of the calculated 50% probability of exceedance value. It is important to note that a 50-year dataset was used, rather than a shorter more recent period which might reflect recent climate changes, because the longer climate record provides better statistical confidence by capturing rare events and natural cycles that might be missed in shorter periods.

The combined 50th percentile annual production, represented by the 2005/2006 heating year, was 1,106,786 M# for the Core and NEFC. The resulting monthly consumption and HDD profile for the 50% probability of exceedance reference year are set out in Table 1. This includes all 205 connected buildings after accounting for inactive connections. To this, the partial annual load for the three Butterfly buildings of 8,277 M#[3] was added. Consequently, the total annual load forecast for Core TES for the Test Year is 1,115,063 M#.

Table 1: 50% probability of exceedance Reference Year

Month	Core Consumption (M#)	NEFC Consumption (M#)	Core + NEFC Consumption (M#)	Monthly HDD
Jan	126,693	8,314	135,007	352.5
Feb	132,315	8,662	140,977	367
Mar	120,687	7,938	128,626	336.6
Apr	87,507	5,780	93,287	239.1
May	63,421	4,078	67,498	153
Jun	41,103	2,299	43,402	50.4
Jul	35,142	1,760	36,902	15.8
Aug	33,321	1,587	34,907	4.2
Sep	50,615	3,092	53,707	98.1
Oct	75,456	4,947	80,403	198.2
Nov	128,500	8,426	136,926	357.2
Dec	145,668	9,476	155,145	400.1
Annual	**1,040,428**	**66,358**	**1,106,786**	**2,572**
Add: Butterfly (2025 Projection)	8,277		8,277	
2025 Test Year Demand	**1,048,705**	**66,358**	**1,115,063**	**2,572**

[3] The annual load at full occupancy of the three 'Butterfly buildings' is 4,620 MWh. or 13,314 M#. One of the three building is only partially occupied with occupancy expected to be phased gradually over 2025. Consequently, the annual demand from these three buildings has been estimated to be 8,277 M# for the 2025 test year.

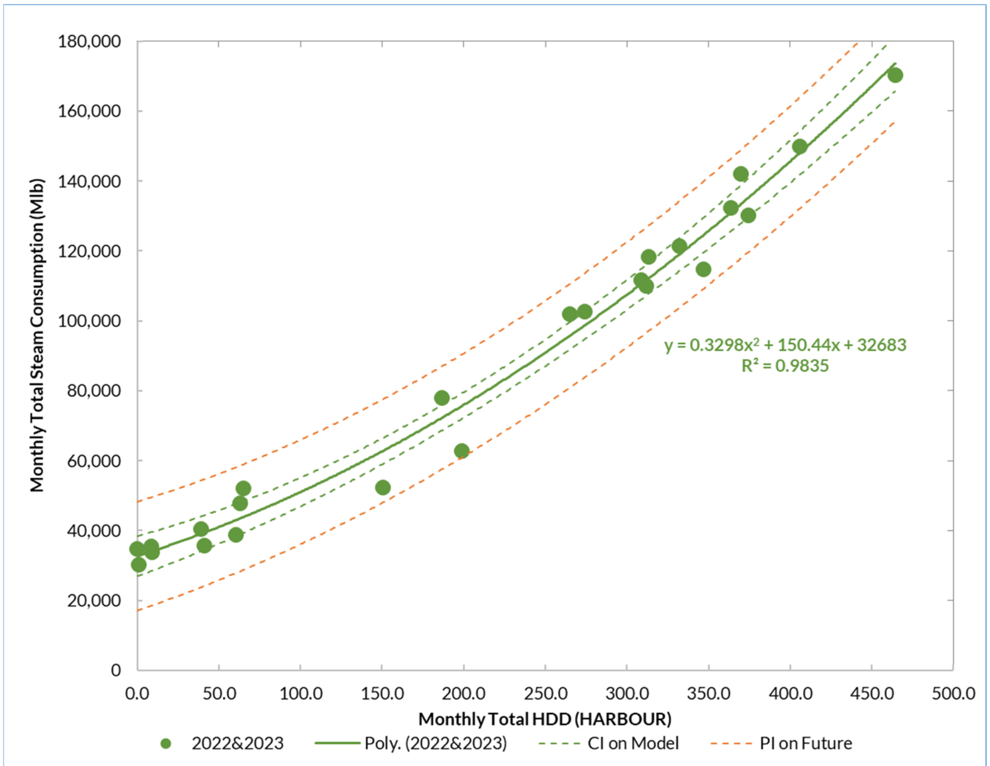


Figure 1: Core Steam Consumption Model

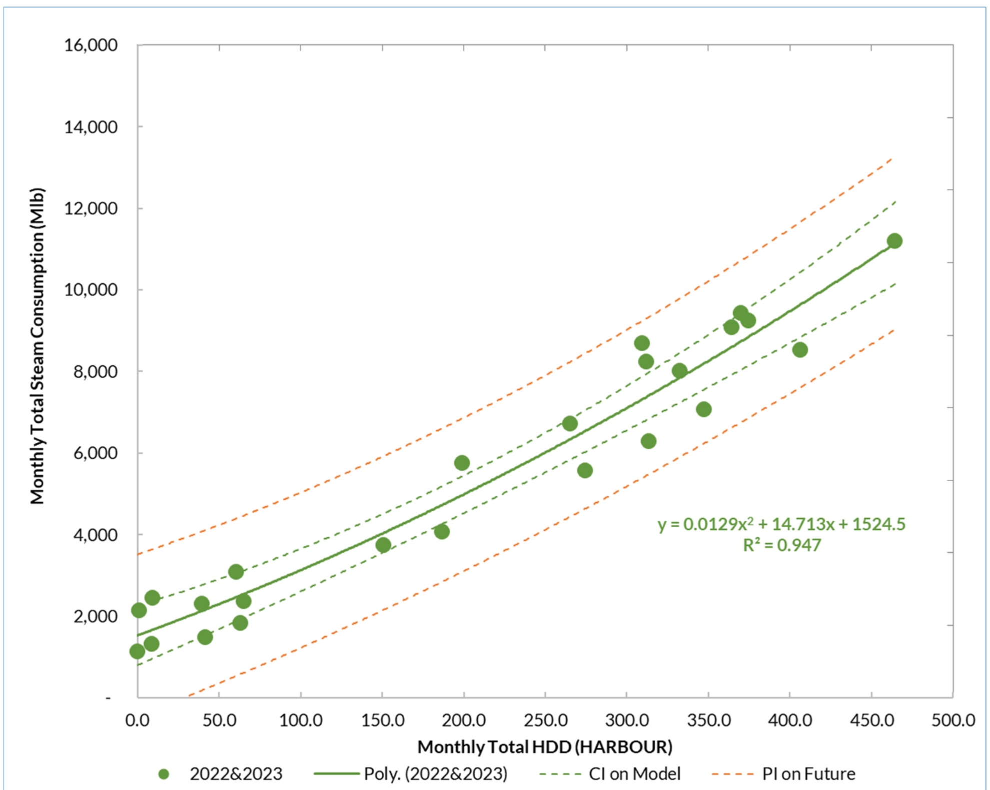


Figure 2: NEFC Consumption Model

Heating Year Production Analysis - Summary

HDD to Production Correlations

$$Monthly\ Thermal\ Energy\ Consumption_{Core}\ (M\#) = 0.3298 \times HDD_{monthly}^{2} + 150.44 \times HDD_{monthly} + 32683$$

$$Monthly\ Thermal\ Energy\ Consumption_{NEFC}\ (M\#) = 0.0129 \times HDD_{monthly}^{2} + 14.713 \times HDD_{monthly} + 1524.5$$

Selected Representative Year:	2005/2006

	50% Representative Year (2005/2006)			
Month Name	Core (M#)	NEFC (M#)	Core + NEFC (M#)	Monthly HDD
Jan	126,693	8,314	135,007	353
Feb	132,315	8,662	140,977	367
Mar	120,687	7,938	128,626	337
Apr	87,507	5,780	93,287	239
May	63,421	4,078	67,498	153
Jun	41,103	2,299	43,402	50
Jul	35,142	1,760	36,902	16
Aug	33,321	1,587	34,907	4
Sep	50,615	3,092	53,707	98
Oct	75,456	4,947	80,403	198
Nov	128,500	8,426	136,926	357
Dec	145,668	9,476	155,145	400
Annual	**1,040,428**	**66,358**	**1,106,786**	**2,572**

%-ile Annual	Prob. of Exceedance	System Load (M#)
10%	**90%**	1,027,054
15%	**85%**	1,057,270
25%	**75%**	1,068,482
35%	**65%**	1,089,101
49%	**51%**	1,106,786
50%	**50%**	1,107,727
65%	**35%**	1,147,274
75%	**25%**	1,169,026
85%	**15%**	1,197,492
90%	**10%**	1,227,775

Total Monthly Heat Deg Days (°C) per 'Heating Year'

Heating Year	M1 - Jul	M2 - Aug	M3 - Sep	M4 - Oct	M5 - Nov	M6 - Dec	M7 - Jan	M8 - Feb	M9 - Mar	M10 - Apr	M11 - May	M12 - Jun	Annual
1974/1975	65.2	26.7	53.1	207.4	327.6	378.5	463.0	414.7	374.4	309.8	192.2	109.1	**2,921.7**
1975/1976	13.1	61.9	89.1	238.5	363.3	455.9	409.5	381.0	399.6	263.6	185.8	113.2	**2,974.5**
1976/1977	37.1	54.4	71.5	216.1	322.1	358.3	454.8	293.7	359.5	228.0	195.4	61.9	**2,652.8**
1977/1978	44.5	27.0	134.7	232.7	366.3	438.4	413.7	328.9	310.8	253.2	178.6	48.6	**2,777.4**
1978/1979	20.4	37.9	117.7	200.5	387.0	475.1	509.3	374.0	319.6	263.6	147.1	70.1	**2,922.3**
1979/1980	25.2	6.8	73.6	203.6	350.2	350.5	490.9	342.8	364.8	220.5	169.7	99.9	**2,698.5**
1980/1981	39.0	46.4	103.3	194.7	301.8	382.4	360.0	331.3	289.5	262.4	165.0	121.9	**2,597.7**
1981/1982	34.8	14.8	88.5	251.5	293.8	405.2	468.4	371.5	366.0	304.0	169.5	48.4	**2,816.4**
1982/1983	46.8	44.6	87.9	216.3	378.5	400.8	345.6	310.4	286.8	245.8	130.7	77.2	**2,571.4**
1983/1984	47.7	15.2	128.6	237.7	298.2	500.9	401.4	330.0	300.9	266.0	199.4	93.7	**2,819.7**
1984/1985	28.8	22.0	117.0	265.6	340.7	501.1	459.7	387.6	370.6	277.4	158.1	76.9	**3,005.5**
1985/1986	2.5	28.5	130.8	246.0	504.0	472.2	345.4	376.9	294.8	282.6	170.1	64.6	**2,918.4**
1986/1987	53.5	9.3	97.1	198.8	335.9	378.5	398.3	306.0	297.6	216.0	146.2	66.5	**2,503.7**
1987/1988	28.4	22.1	66.8	194.6	278.6	413.0	414.2	356.9	329.5	240.9	163.1	79.5	**2,587.6**
1988/1989	29.8	15.5	101.8	197.2	320.0	399.9	440.0	472.7	369.5	216.0	147.7	56.6	**2,766.7**
1989/1990	16.9	22.6	79.4	225.8	322.3	384.3	411.0	415.5	340.2	222.1	162.8	89.8	**2,692.7**
1990/1991	12.9	15.6	57.1	246.4	330.2	525.4	487.7	298.9	377.3	256.5	173.2	112.2	**2,893.4**
1991/1992	20.5	33.2	83.3	230.5	286.1	338.9	326.1	283.3	252.3	199.0	94.4	19.9	**2,167.5**
1992/1993	5.4	4.9	86.5	172.3	299.8	436.8	486.4	357.8	285.0	214.8	81.3	40.1	**2,471.1**
1993/1994	23.1	14.8	65.2	159.5	350.1	366.1	316.5	361.9	290.4	181.2	92.6	58.8	**2,280.2**
1994/1995	10.4	1.5	37.0	194.4	352.2	377.0	367.5	316.1	303.3	220.8	91.3	38.7	**2,310.2**
1995/1996	3.5	36.4	20.5	206.6	265.6	370.1	425.5	352.9	312.0	212.2	172.0	51.0	**2,428.3**
1996/1997	18.0	12.0	100.1	223.0	346.9	459.2	402.5	335.7	345.9	234.7	104.1	55.7	**2,637.8**
1997/1998	15.2	4.8	50.2	219.4	275.8	373.8	384.8	284.4	297.5	224.9	118.2	38.3	**2,287.3**
1998/1999	12.4	5.2	48.3	192.0	276.8	414.9	377.5	324.3	339.0	245.9	195.6	100.3	**2,532.2**
1999/2000	32.3	15.2	80.6	225.3	285.2	385.4	419.1	342.1	312.8	211.2	173.4	59.5	**2,542.1**
2000/2001	20.0	17.8	68.5	202.8	336.0	399.6	350.8	338.8	301.0	210.5	151.5	84.2	**2,481.5**
2001/2002	23.0	18.0	77.5	236.0	280.1	414.9	398.1	345.8	401.5	260.7	181.9	48.4	**2,685.9**
2002/2003	21.6	11.1	84.6	236.6	284.5	362.3	335.7	350.3	314.3	251.5	155.8	42.5	**2,450.8**
2003/2004	5.9	3.4	66.3	190.3	377.6	389.0	409.3	326.7	293.4	185.3	111.3	41.4	**2,399.9**
2004/2005	5.9	8.8	97.1	207.3	321.9	375.3	409.0	358.4	283.5	219.1	107.8	72.6	**2,466.7**
2005/2006	15.8	4.2	98.1	198.2	357.2	400.1	352.5	367.0	336.6	239.1	153.0	50.4	**2,572.2**
2006/2007	14.8	23.0	79.0	243.3	364.1	394.6	447.5	329.0	331.2	266.2	150.6	75.3	**2,718.6**
2007/2008	6.5	13.1	99.5	245.4	338.8	424.8	441.3	346.2	358.1	300.5	148.8	110.9	**2,833.9**
2008/2009	15.2	34.8	88.9	228.7	279.7	481.6	471.1	355.9	393.6	250.5	146.9	27.0	**2,773.9**
2009/2010	16.4	12.4	65.0	224.9	312.2	455.8	315.4	278.5	299.5	240.9	166.4	80.5	**2,467.9**
2010/2011	14.3	19.1	73.7	190.6	360.9	374.8	409.2	391.8	333.5	310.9	199.0	71.0	**2,748.8**
2011/2012	20.7	7.4	57.6	228.3	358.1	407.2	424.7	354.5	371.7	237.6	172.8	107.8	**2,748.4**
2012/2013	23.8	9.1	74.1	225.7	304.4	405.4	450.0	344.8	321.7	242.8	127.9	54.7	**2,584.4**
2013/2014	1.7	3.2	63.9	244.3	325.1	438.5	391.8	398.0	329.3	221.9	91.8	50.0	**2,559.5**
2014/2015	5.5	0.5	48.9	141.1	323.6	365.0	343.8	265.2	266.5	233.3	71.8	11.1	**2,076.3**
2015/2016	3.5	6.6	101.7	162.1	344.6	360.4	370.8	292.0	274.4	149.2	93.4	50.1	**2,208.8**
2016/2017	7.9	8.3	87.4	200.2	247.6	478.9	444.5	381.7	341.5	240.4	137.2	53.6	**2,629.2**
2017/2018	1.2	0.1	60.9	221.9	314.7	434.7	362.7	387.6	336.7	236.8	62.5	56.2	**2,476.0**
2018/2019	3.6	8.1	87.5	214.2	279.1	374.6	362.5	440.4	321.9	230.0	87.4	29.8	**2,439.1**
2019/2020	5.6	1.7	67.1	255.3	313.5	362.9	395.3	363.6	355.0	218.6	112.1	62.9	**2,513.6**
2020/2021	22.4	12.2	36.2	208.9	321.7	364.2	361.8	378.7	326.3	217.7	145.3	40.4	**2,435.8**
2021/2022	0.2	11.2	73.4	237.6	297.7	475.6	406.1	347.1	313.4	274.3	186.5	63.1	**2,686.2**
2022/2023	8.5	0.1	41.3	150.5	374.4	464.3	369.8	363.9	332.2	265.2	64.9	39.2	**2,474.3**
2023/2024	0.8	9.1	60.7	199.0	312.0	309.0	414.0	335.9	318.5	240.7	140.7	64.4	**2,404.8**

Core Monthly Production per 'Heating Year'

$$Monthly\ Thermal\ Energy\ Consumption_{Core}\ (M\#) = 0.3298 \times HDD_{monthly}^2 + 150.44 \times HDD_{monthly} + 32683$$

Heating Year	M1 - Jul	M2 - Aug	M3 - Sep	M4 - Oct	M5 - Nov	M6 - Dec	M7 - Jan	M8 - Feb	M9 - Mar	M10 - Apr	M11 - May	M12 - Jun	Annual
1974/1975	43,894	36,935	41,601	78,071	117,362	136,872	173,036	151,788	135,238	110,942	73,781	53,022	**1,152,540**
1975/1976	34,710	43,259	48,705	87,323	130,867	169,816	149,592	137,875	145,461	95,255	72,020	53,939	**1,168,823**
1976/1977	38,718	41,843	45,125	80,594	115,356	128,925	169,320	105,316	129,390	84,128	74,671	43,259	**1,056,645**
1977/1978	40,031	36,985	58,931	85,549	132,040	162,022	151,365	117,839	111,297	91,918	70,072	40,773	**1,098,822**
1978/1979	35,889	38,858	54,959	76,104	140,297	178,600	194,848	135,079	114,451	95,255	61,949	44,849	**1,171,138**
1979/1980	36,684	33,721	45,542	76,984	125,814	125,928	186,010	123,009	131,453	81,890	67,710	51,003	**1,085,748**
1980/1981	39,052	40,373	51,743	74,476	108,125	138,438	129,583	118,723	103,876	94,866	66,484	55,922	**1,021,662**
1981/1982	38,318	34,982	48,580	91,379	105,350	147,790	175,507	134,088	131,923	108,896	67,658	40,737	**1,125,207**
1982/1983	40,446	40,049	48,455	80,653	136,872	145,959	124,066	111,155	102,957	89,587	57,979	46,263	**1,024,440**
1983/1984	40,609	35,046	57,484	87,077	106,871	190,785	146,208	118,243	107,811	96,035	75,794	49,675	**1,111,638**
1984/1985	37,289	36,152	54,799	95,905	122,220	190,882	171,535	140,541	133,732	99,793	64,711	46,202	**1,193,762**
1985/1986	33,061	37,238	58,003	89,649	192,279	177,257	123,990	136,233	105,695	101,536	67,815	43,778	**1,166,536**
1986/1987	41,676	34,111	50,400	75,625	120,427	136,872	144,924	109,599	106,663	80,565	61,727	44,146	**1,006,733**
1987/1988	37,221	36,169	44,204	74,448	100,194	151,068	151,576	128,384	118,059	88,063	65,993	46,727	**1,042,108**
1988/1989	37,459	35,094	51,416	75,175	114,595	145,586	162,726	177,488	133,298	80,565	62,098	42,254	**1,117,754**
1989/1990	35,320	36,251	46,707	83,467	115,429	139,204	150,224	152,128	122,032	82,364	65,916	48,852	**1,077,894**
1990/1991	34,679	35,110	42,348	89,775	118,317	202,764	184,496	107,114	136,393	92,969	68,633	53,714	**1,166,311**
1991/1992	35,906	38,041	47,503	84,882	102,719	121,546	116,813	101,772	91,633	75,681	49,824	35,807	**902,126**
1992/1993	33,505	33,428	48,164	68,395	107,427	161,319	183,883	128,732	102,346	80,214	47,094	39,246	**1,033,753**
1993/1994	36,334	34,982	43,894	65,068	125,776	131,962	113,334	130,322	104,184	70,771	49,442	42,669	**948,737**
1994/1995	34,283	32,909	38,701	74,392	126,578	136,273	132,511	113,190	108,650	81,979	49,167	38,999	**967,633**
1995/1996	33,214	38,596	35,906	77,841	95,905	133,535	156,406	126,846	111,724	79,457	68,315	41,213	**998,958**
1996/1997	35,498	34,536	51,047	82,632	124,559	171,308	146,665	120,352	124,180	86,158	51,918	42,086	**1,070,937**
1997/1998	35,046	33,413	41,066	81,565	99,261	134,999	139,406	102,143	106,628	83,198	55,073	38,929	**950,727**
1998/1999	34,599	33,474	40,719	73,725	99,593	151,873	136,473	116,156	121,583	89,618	74,727	51,090	**1,023,631**
1999/2000	37,886	35,046	46,951	83,318	102,414	139,649	153,660	122,746	112,010	79,167	68,686	42,802	**1,024,333**
2000/2001	35,824	35,465	44,536	76,756	120,464	145,461	126,043	121,508	107,846	78,964	63,044	47,688	**1,003,600**
2001/2002	36,318	35,498	46,323	86,555	100,696	151,873	144,841	124,142	146,249	94,317	70,960	40,737	**1,078,509**
2002/2003	36,086	34,394	47,771	86,739	102,177	130,477	120,352	125,852	112,545	91,379	64,127	39,672	**991,573**
2003/2004	33,582	33,198	44,107	73,255	136,513	141,110	149,508	117,032	105,212	71,884	53,512	39,476	**998,390**
2004/2005	33,582	34,032	50,400	78,042	115,283	135,595	149,382	128,964	101,840	81,476	52,733	45,343	**1,006,673**
2005/2006	35,142	33,321	50,615	75,456	128,500	145,668	126,693	132,315	120,687	87,507	63,421	41,103	**1,040,428**
2006/2007	34,982	36,318	46,626	88,808	131,179	143,400	166,049	117,876	118,686	96,101	62,819	45,881	**1,088,723**
2007/2008	33,675	34,710	50,917	89,462	121,508	156,104	163,299	124,293	128,848	107,671	62,371	53,423	**1,126,281**
2008/2009	35,046	38,318	48,664	84,338	100,562	181,628	176,750	127,999	142,989	91,063	61,900	36,985	**1,126,241**
2009/2010	35,239	34,599	43,855	83,198	111,796	169,771	112,939	100,161	107,323	88,063	66,848	46,931	**1,000,722**
2010/2011	34,902	35,677	45,562	73,338	129,933	135,397	149,466	142,252	119,536	111,333	75,681	45,027	**1,098,102**
2011/2012	35,938	33,814	42,443	84,218	128,848	148,627	156,061	127,460	134,167	87,046	68,527	52,733	**1,099,882**
2012/2013	36,450	34,079	45,641	83,437	109,036	147,874	167,166	123,764	115,211	88,652	57,319	41,899	**1,050,529**
2013/2014	32,940	33,168	43,643	89,119	116,448	162,066	142,252	144,800	117,986	82,305	49,273	41,030	**1,055,027**
2014/2015	33,520	32,758	40,828	60,476	115,901	131,531	123,386	95,775	96,198	85,731	45,185	34,394	**895,684**
2015/2016	33,214	33,690	51,394	65,735	123,688	129,739	133,811	104,732	98,796	62,470	49,611	41,048	**927,928**
2016/2017	33,892	33,954	48,351	76,019	90,151	180,367	164,716	138,156	122,520	87,909	59,531	41,694	**1,077,260**
2017/2018	32,864	32,698	43,068	82,305	112,689	160,400	130,633	140,541	120,725	86,800	43,374	42,179	**1,028,275**
2018/2019	33,229	33,923	48,372	80,039	100,361	135,317	130,555	162,902	115,283	84,731	48,351	37,459	**1,010,522**
2019/2020	33,536	32,940	44,262	92,586	112,259	130,711	143,687	130,984	127,652	81,329	53,692	43,451	**1,027,089**
2020/2021	36,218	34,567	38,561	78,502	115,211	131,218	130,283	136,952	116,886	81,064	61,505	39,299	**1,000,267**
2021/2022	32,713	34,409	45,502	87,046	106,698	178,831	148,166	124,635	112,224	98,763	72,211	43,489	**1,084,687**
2022/2023	33,986	32,698	39,459	62,794	135,238	173,629	133,417	131,101	119,055	95,775	43,836	39,087	**1,040,073**
2023/2024	32,804	34,079	43,030	75,681	111,724	110,659	151,492	120,427	114,054	88,001	60,379	43,739	**986,068**

NEFC Monthly Production per 'Heating Year'

$$Monthly\ Thermal\ Energy\ Consumption_{NEFC}\ (M\#) = 0.0129 \times HDD^2_{monthly} + 14.713 \times HDD_{monthly} + 1524.5$$

Heating Year	M1 - Jul	M2 - Aug	M3 - Sep	M4 - Oct	M5 - Nov	M6 - Dec	M7 - Jan	M8 - Feb	M9 - Mar	M10 - Apr	M11 - May	M12 - Jun	Annual
1974/1975	2,539	1,927	2,342	5,131	7,729	8,941	11,102	9,844	8,841	7,321	4,829	3,283	**73,829**
1975/1976	1,719	2,485	2,938	5,767	8,572	10,913	9,713	9,003	9,464	6,299	4,704	3,355	**74,932**
1976/1977	2,088	2,363	2,642	5,306	7,602	8,452	10,884	6,958	8,481	5,550	4,892	2,485	**67,704**
1977/1978	2,205	1,931	3,740	5,647	8,645	10,454	9,819	7,759	7,343	6,077	4,564	2,270	**70,454**
1978/1979	1,830	2,101	3,435	4,993	9,150	11,426	12,364	8,832	7,544	6,299	3,968	2,619	**74,562**
1979/1980	1,903	1,625	2,677	5,055	8,259	8,266	11,856	8,084	8,609	5,396	4,393	3,123	**69,246**
1980/1981	2,118	2,235	3,182	4,878	7,140	9,037	8,493	7,815	6,865	6,273	4,303	3,510	**65,849**
1981/1982	2,052	1,745	2,928	6,041	6,961	9,604	11,246	8,771	8,637	7,189	4,389	2,267	**71,830**
1982/1983	2,241	2,206	2,917	5,310	8,941	9,494	8,150	7,334	6,805	5,920	3,668	2,737	**65,726**
1983/1984	2,256	1,751	3,630	5,751	7,059	12,131	9,509	7,785	7,120	6,351	4,971	3,016	**71,329**
1984/1985	1,959	1,854	3,423	6,342	8,035	12,136	11,014	9,165	8,749	6,599	4,173	2,732	**76,181**
1985/1986	1,561	1,954	3,670	5,925	12,217	11,348	8,145	8,902	6,983	6,713	4,400	2,529	**74,347**
1986/1987	2,349	1,662	3,075	4,959	7,922	8,941	9,431	7,235	7,046	5,304	3,951	2,560	**64,436**
1987/1988	1,953	1,856	2,565	4,876	6,625	9,801	9,832	8,419	7,773	5,817	4,267	2,776	**66,560**
1988/1989	1,974	1,756	3,156	4,928	7,554	9,471	10,496	11,362	8,722	5,304	3,979	2,399	**71,100**
1989/1990	1,777	1,864	2,774	5,504	7,607	9,084	9,751	9,865	8,023	5,429	4,262	2,950	**68,888**
1990/1991	1,716	1,757	2,407	5,933	7,789	12,816	11,768	7,075	8,912	6,147	4,460	3,338	**74,118**
1991/1992	1,832	2,027	2,840	5,601	6,790	7,992	7,694	6,728	6,058	4,963	3,028	1,822	**57,376**
1992/1993	1,604	1,597	2,894	4,443	7,095	10,412	11,733	8,440	6,766	5,280	2,806	2,135	**65,205**
1993/1994	1,871	1,745	2,539	4,199	8,257	8,640	7,473	8,539	6,885	4,614	2,998	2,434	**60,194**
1994/1995	1,679	1,547	2,087	4,872	8,307	8,905	8,674	7,464	7,174	5,402	2,975	2,113	**61,198**
1995/1996	1,576	2,077	1,832	5,115	6,342	8,737	10,120	8,323	7,371	5,227	4,437	2,308	**63,466**
1996/1997	1,794	1,703	3,127	5,447	8,181	11,001	9,536	7,917	8,157	5,688	3,196	2,384	**68,131**
1997/1998	1,751	1,595	2,296	5,373	6,564	8,827	9,096	6,752	7,043	5,486	3,444	2,107	**60,334**
1998/1999	1,709	1,601	2,265	4,825	6,585	9,850	8,917	7,653	7,995	5,922	4,896	3,130	**65,348**
1999/2000	2,013	1,751	2,794	5,494	6,770	9,111	9,957	8,068	7,389	5,207	4,464	2,446	**65,463**
2000/2001	1,824	1,790	2,593	5,039	7,924	9,464	8,273	7,990	7,122	5,193	4,050	2,855	**64,117**
2001/2002	1,870	1,794	2,742	5,715	6,658	9,850	9,426	8,155	9,511	6,237	4,628	2,267	**68,852**
2002/2003	1,848	1,689	2,862	5,728	6,754	8,548	7,917	8,261	7,423	6,041	4,130	2,173	**63,376**
2003/2004	1,612	1,575	2,557	4,792	8,919	9,200	9,708	7,708	6,952	4,694	3,322	2,156	**63,193**
2004/2005	1,612	1,655	3,075	5,129	7,597	8,863	9,700	8,455	6,732	5,367	3,260	2,661	**64,107**
2005/2006	1,760	1,587	3,092	4,947	8,426	9,476	8,314	8,662	7,938	5,780	4,078	2,299	**66,358**
2006/2007	1,745	1,870	2,767	5,868	8,592	9,339	10,692	7,761	7,812	6,355	4,033	2,706	**69,540**
2007/2008	1,621	1,719	3,116	5,912	7,990	10,102	10,530	8,164	8,447	7,111	3,999	3,315	**72,027**
2008/2009	1,751	2,052	2,934	5,564	6,649	11,602	11,319	8,395	9,314	6,020	3,964	1,931	**71,496**
2009/2010	1,769	1,709	2,535	5,486	7,375	10,911	7,448	6,623	7,088	5,817	4,330	2,792	**63,884**
2010/2011	1,738	1,810	2,679	4,797	8,515	8,851	9,705	9,269	7,866	7,346	4,963	2,634	**70,173**
2011/2012	1,835	1,634	2,415	5,556	8,447	9,655	10,100	8,361	8,776	5,749	4,452	3,260	**70,239**
2012/2013	1,882	1,659	2,686	5,502	7,198	9,609	10,758	8,131	7,593	5,857	3,617	2,368	**66,861**
2013/2014	1,550	1,572	2,517	5,889	7,671	10,457	9,269	9,424	7,768	5,425	2,984	2,292	**66,817**
2014/2015	1,606	1,532	2,275	3,857	7,636	8,613	8,108	6,334	6,362	5,659	2,647	1,689	**56,319**
2015/2016	1,576	1,622	3,154	4,248	8,126	8,503	8,754	6,921	6,533	4,007	3,011	2,294	**58,750**
2016/2017	1,642	1,648	2,909	4,987	5,958	11,529	10,613	9,020	8,053	5,807	3,786	2,350	**68,302**
2017/2018	1,542	1,526	2,468	5,425	7,432	10,358	8,558	9,165	7,941	5,732	2,494	2,392	**65,034**
2018/2019	1,578	1,645	2,911	5,268	6,636	8,846	8,553	10,506	7,597	5,591	2,909	1,974	**64,013**
2019/2020	1,607	1,550	2,570	6,122	7,405	8,563	9,356	8,580	8,373	5,357	3,336	2,501	**65,319**
2020/2021	1,861	1,706	2,074	5,161	7,593	8,594	8,536	8,946	7,699	5,339	3,935	2,140	**63,583**
2021/2022	1,527	1,691	2,674	5,749	7,048	11,440	9,627	8,186	7,403	6,531	4,717	2,504	**69,096**
2022/2023	1,650	1,526	2,154	4,031	8,841	11,137	8,729	8,587	7,836	6,334	2,534	2,121	**65,480**
2023/2024	1,536	1,659	2,465	4,963	7,371	7,303	9,827	7,922	7,519	5,813	3,850	2,526	**62,754**

Aggregate Core + NEFC Monthly Production per 'Heating Year'

Heating Year	M1 - Jul	M2 - Aug	M3 - Sep	M4 - Oct	M5 - Nov	M6 - Dec	M7 - Jan	M8 - Feb	M9 - Mar	M10 - Apr	M11 - May	M12 - Jun	Annual	Probability of Exceedance
1974/1975	46,432	38,861	43,943	83,201	125,091	145,814	184,138	161,633	144,079	118,263	78,610	56,305	**1,226,370**	**10%**
1975/1976	36,430	45,744	51,643	93,090	139,439	180,729	159,305	146,877	154,925	101,554	76,723	57,294	**1,243,755**	**4%**
1976/1977	40,806	44,206	47,768	85,901	122,958	137,377	180,204	112,274	137,871	89,677	79,563	45,744	**1,124,349**	**43%**
1977/1978	42,235	38,916	62,672	91,196	140,685	172,476	161,184	125,598	118,641	97,995	74,635	43,043	**1,169,276**	**25%**
1978/1979	37,719	40,959	58,394	81,097	149,448	190,026	207,212	143,910	121,995	101,554	65,917	47,469	**1,245,700**	**2%**
1979/1980	38,587	35,346	48,219	82,039	134,073	134,194	197,866	131,093	140,062	87,286	72,103	54,126	**1,154,994**	**31%**
1980/1981	41,170	42,608	54,925	79,354	115,265	147,475	138,077	126,537	110,741	101,140	70,788	59,432	**1,087,511**	**67%**
1981/1982	40,370	36,727	51,508	97,420	112,311	157,394	186,753	142,859	140,560	116,085	72,047	43,004	**1,197,037**	**16%**
1982/1983	42,687	42,255	51,372	85,964	145,814	155,452	132,216	118,490	109,762	95,507	61,647	49,000	**1,090,166**	**61%**
1983/1984	42,865	36,797	61,114	92,827	113,930	202,916	155,716	126,028	114,930	102,386	80,765	52,691	**1,182,967**	**21%**
1984/1985	39,248	38,007	58,222	102,247	130,255	203,018	182,549	149,706	142,481	106,392	68,884	48,934	**1,269,943**	**0%**
1985/1986	34,623	39,193	61,673	95,574	204,496	188,606	132,136	145,135	112,678	108,249	72,216	46,307	**1,240,883**	**6%**
1986/1987	44,024	35,773	53,475	80,584	128,349	145,814	154,355	116,833	113,709	85,870	65,678	46,706	**1,071,169**	**72%**
1987/1988	39,174	38,025	46,769	79,324	106,819	160,870	161,408	136,803	125,832	93,881	70,260	49,503	**1,108,668**	**49%**
1988/1989	39,433	36,850	54,572	80,103	122,149	155,057	173,222	188,850	142,020	85,870	66,077	44,653	**1,188,854**	**18%**
1989/1990	37,096	38,115	49,481	88,972	123,035	148,288	159,975	161,992	130,055	87,793	70,177	51,802	**1,146,782**	**37%**
1990/1991	36,395	36,867	44,755	95,708	126,106	215,580	196,264	114,189	145,305	99,116	73,092	57,052	**1,240,429**	**8%**
1991/1992	37,737	40,068	50,343	90,483	109,509	129,538	124,507	108,500	97,690	80,644	52,852	37,630	**959,501**	**98%**
1992/1993	35,109	35,025	51,057	72,837	114,522	171,732	195,616	137,172	109,112	85,494	49,900	41,381	**1,098,957**	**55%**
1993/1994	38,205	36,727	46,432	69,268	134,032	140,602	120,807	138,860	111,069	75,385	52,439	45,103	**1,008,931**	**94%**
1994/1995	35,962	34,456	40,787	79,264	134,885	145,178	141,185	120,655	115,824	87,381	52,143	41,112	**1,028,831**	**90%**
1995/1996	34,790	40,673	37,737	82,956	102,247	142,272	166,526	135,169	119,095	84,684	72,752	43,522	**1,062,423**	**82%**
1996/1997	37,291	36,239	54,173	88,079	132,739	182,309	156,201	128,270	132,337	91,846	55,114	44,470	**1,139,068**	**41%**
1997/1998	36,797	35,008	43,362	86,938	105,824	143,826	148,502	108,896	113,672	88,684	58,517	41,036	**1,011,062**	**92%**
1998/1999	36,308	35,076	42,984	78,550	106,179	161,723	145,390	123,809	129,578	95,541	79,623	54,220	**1,088,979**	**65%**
1999/2000	39,899	36,797	49,745	88,812	109,184	148,760	163,617	130,813	119,398	84,374	73,149	45,247	**1,089,796**	**63%**
2000/2001	37,648	37,256	47,129	81,795	128,388	154,925	134,316	129,498	114,968	84,157	67,094	50,543	**1,067,717**	**76%**
2001/2002	38,187	37,291	49,065	92,271	107,354	161,723	154,267	132,297	155,760	100,554	75,588	43,004	**1,147,361**	**35%**
2002/2003	37,935	36,083	50,632	92,467	108,932	139,026	128,270	134,113	119,969	97,420	68,257	41,846	**1,054,948**	**86%**
2003/2004	35,194	34,773	46,664	78,047	145,432	150,310	159,216	124,740	112,164	76,577	56,834	41,632	**1,061,583**	**84%**
2004/2005	35,194	35,687	53,475	83,171	122,881	144,459	159,082	137,418	108,572	86,844	55,993	48,004	**1,070,780**	**74%**
2005/2006	36,902	34,907	53,707	80,403	136,926	155,145	135,007	140,977	128,626	93,287	67,498	43,402	**1,106,786**	**51%**
2006/2007	36,727	38,187	49,393	94,675	139,771	152,738	176,741	125,637	126,498	102,456	66,852	48,587	**1,158,263**	**29%**
2007/2008	35,295	36,430	54,033	95,374	129,498	166,206	173,829	132,458	137,295	114,782	66,370	56,738	**1,198,308**	**12%**
2008/2009	36,797	40,370	51,598	89,902	107,211	193,231	188,068	136,393	152,303	97,083	65,864	38,916	**1,197,737**	**14%**
2009/2010	37,008	36,308	46,390	88,684	119,171	180,681	120,388	106,783	114,411	93,881	71,178	49,723	**1,064,607**	**78%**
2010/2011	36,639	37,487	48,241	78,135	138,447	144,248	159,171	151,521	127,402	118,679	80,644	47,661	**1,168,276**	**27%**
2011/2012	37,773	35,448	44,857	89,774	137,295	158,282	166,161	135,821	142,943	92,795	72,979	55,993	**1,170,121**	**23%**
2012/2013	38,332	35,739	48,327	88,940	116,234	157,483	177,923	131,895	122,804	94,509	60,937	44,267	**1,117,390**	**47%**
2013/2014	34,489	34,739	46,160	95,008	124,119	172,522	151,521	154,223	125,754	87,729	52,257	43,322	**1,121,844**	**45%**
2014/2015	35,126	34,290	43,103	64,333	123,538	140,145	131,494	102,109	102,560	91,390	47,832	36,083	**952,003**	**100%**
2015/2016	34,790	35,312	54,548	69,984	131,815	138,241	142,565	111,652	105,329	66,477	52,622	43,342	**986,677**	**96%**
2016/2017	35,534	35,602	51,260	81,007	96,109	191,896	175,329	147,176	130,574	93,716	63,317	44,044	**1,145,562**	**39%**
2017/2018	34,406	34,224	45,536	87,729	120,121	170,758	139,191	149,706	128,665	92,532	45,868	44,571	**1,093,309**	**57%**
2018/2019	34,806	35,568	51,282	85,307	106,997	144,163	139,108	173,408	122,881	90,322	51,260	39,433	**1,074,535**	**69%**
2019/2020	35,143	34,489	46,832	98,708	119,664	139,274	153,043	139,564	136,026	86,686	57,028	45,951	**1,092,409**	**59%**
2020/2021	38,079	36,273	40,635	83,663	122,804	139,813	138,819	145,899	124,585	86,403	65,439	41,439	**1,063,851**	**80%**
2021/2022	34,241	36,100	48,176	92,795	113,745	190,271	157,793	132,820	119,626	105,294	76,928	45,993	**1,153,783**	**33%**
2022/2023	35,636	34,224	41,613	66,825	144,079	184,765	142,146	139,688	126,891	102,109	46,369	41,208	**1,105,553**	**53%**
2023/2024	34,340	35,739	45,495	80,644	119,095	117,961	161,318	128,349	121,573	93,815	64,229	46,265	**1,048,822**	**88%**

Appendix I

Existing Steam Plant Condition Assessment Memo

CREATIVENERGY

MEMORANDUM

PROJECT	Beatty Plant Redevelopment	DATE	11/19/2024
SUBJECT	Existing Steam Plant Condition Assessment Memo		
BY	Keith Bate, Director, Engineering Ben Ellison, Director, Projects Scott Cameron, Director, Operations		

Executive Summary

The **Creative Energy Steam Plant** at 720 Beatty Street is a critical infrastructure component that ensures the reliable supply of steam to customers. This document provides a comprehensive overview of the current condition of the plant, describes recent maintenance and assessment work and identifies planned work necessary to ensure five years of continued safe and reliable operation from 2025 to 2029.

The plant comprises five main systems: Steam Boilers, Feedwater System, Venting System, Balance of Plant, and Fuel System. Each system has been inspected and evaluated for its condition, and required work has been outlined. The broad conclusion is that in the first two years, capital investments to a total of $700,000 are needed to ensure reliable operations for the five-year study period, as summarised in the table below.

SYSTEM	2025	2026
Steam Boilers	$315,000	$70,000
Feedwater System	$150,000	-
Venting System	$100,000	-
Balance of Plant	$65,000	-
Fuel System	-	-
Total	**$630,000**	**$70,000**

INTRODUCTION

This document describes the current condition of the Creative Energy Steam Plant at 720 Beatty St (Existing Plant), recent maintenance and assessment work, and additional planned work needed to ensure five years of continued safe and reliable operation (2025 to 2029).

There are five main systems that make up the Existing Plant:

- Steam Boilers
- Feedwater System
- Venting System
- Balance of Plant
- Fuel System

For each of the main systems the planned work and associated cost estimate is provided. The reason for the planned work has been categorized as essential for plant reliability, required to address potential safety issues, or both.

The Existing Plant consists of six dual-fuel (natural gas and fuel oil) fired boilers with a total nameplate steam generation capacity of 825,000lbs/hr. The boilers generate saturated steam at 209psi in normal operating conditions and have a design pressure of 250psi. The feedwater system consists of water softening and water treatment, eight feedwater pumps, two deaerators, and associated piping, values and instruments. The venting system consists of the ducting from each of the boilers to the boiler flue stacks, and the Sofame heat recovery system. The balance of plant items includes air compressors, emergency generator and sump pumps. The fuel system includes the natural gas connection from FortisBC and the fuel oil tanks, pumps, and piping required to supply fuel oil to the boilers. The fuel system connects to a fuel train at each boiler which provides the pressure regulation, controls, and safety systems for the fuel as it is fed to the burners. The fuel trains are considered part of the boiler systems.

The piping system within the plant and the associated valves and fittings are not covered by this report as Creative Energy does not expect there to be any significant maintenance work required over the next five years.

The fuel oil system is excluded from this assessment as the tanks were installed in 2022 and so should have no maintenance required over the next five years. The oil pumps were installed prior to this data but are in good working condition and no maintenance work is expected in the next five years.

DUAL-FUEL STEAM BOILERS

This section of the report includes the dual-fuel (natural gas/fuel oil) steam boilers and the dedicated ancillary systems including the fuel trains, burners and the forced draft fans.

The steam boilers in the Existing Plant are summarized in the table below.

Boiler ID	Manufacturer	Type	Year Built	Nameplate capacity (lbs/hr)	Actual capacity[1] (lbs/hr)
No. 1	Foster-Wheeler	Water-tube, field erected	1967	100,000	50,000
No. 2	Foster-Wheeler	Water-tube, field erected	1967	100,000	60,000
No. 3	B&W	Water-tube, field erected	1969	120,000	100,000
No. 4	B&W	Water-tube, field erected	1973	215,000	180,000
No. 5	Cleaver-Brooks	Water-tube, package	1983	75,000	70,000
No. 6	Foster-Wheeler	Water-tube, field erected	1990	200,000	170,000
			Total	**825,000**	**630,000**

A description of the condition of the key components for the boilers, recently completed maintenance and work needed to provide continued operation for the next five years is provided below.

Each boiler consists of four main components which are addressed separately:

- Furnace (the chamber where combustion takes place)
- Boiler tubes (where the water passes through as it turns to steam)
- Burner and burner management system
- Forced draft fan
- Fuel train

BOILER NO. 1

FURNACE

The furnace rear wall refractory is in good condition. The front wall refractory may require complete or partial rebuilding in addition to the furnace ceiling gas tight casing which shows signs of flue gas leakage and requires repairs. Failure of the furnace refractory may lead to boiler gas tight casing hotspots, potentially allowing boiler flue gas leakage into the Plant. Inspection of the refractory and front wall are scheduled for 2025 and the full extent of the repairs will not be known until this inspection is completed. An allowance of $40,000 has been added to the 2025 plan for this work.

BOILER TUBES

Boiler tubes show a small amount of scaling and annual inspections are undertaken to monitor scale buildup. Mechanical or chemical cleaning of the tubes is not required now. It is not anticipated that significant work will be required on the tubes in the next five years.

BURNER AND BURNER MANAGEMENT SYSTEM

The current burner management system (BMS) is obsolete and spare parts are no longer available. Failure of the BMS would render the boiler inoperable. Planning work for upgrades to the BMS are in progress with the

[1] As filed in the Creative Energy Application for a Certificate of Public Convenience and Necessity for the Expo and Beatty Plant Project and Application for Approvals Related to Reorganization on June 29, 2018.

upgrade work planned for 2026. The estimated cost for this work is $50,000, however this is subject to change once the final planning and complete scope of the upgrades required is determined.

FORCED DRAFT FAN

The forced draft fan is driven by an electric motor that has increased vibration, indicating degraded condition, and requires replacement. Replacement of this fan motor is planned for 2025 at an estimated cost of $20,000.

FUEL TRAIN

The fuel train on this boiler is in good condition for its age. No work is anticipated in the next 5 years.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
Front wall refractory and casing repairs	2025	$40,000	Reliability & safety
Forced draft fan motor replacement	2025	$20,000	Reliability
Burner management system and combustion control system replacement	2025	$60,000	Reliability

BOILER NO. 2

FURNACE

The furnace refractory is in reasonable shape and may require minor maintenance each year, including inspection of the refractory and casing. The air heater ducting is lined with asbestos and will require further containment. Encapsulation of the asbestos containing insulation is planned for 2025 at a, estimated cost of $40,000.

BOILER TUBES

Boiler tubes show a small amount of scaling and annual inspections are undertaken to monitor scale buildup. Mechanical or chemical cleaning of the tubes is not required now. It is not anticipated that significant work will be required on the tubes in the next five years.

BURNER AND BURNER MANAGEMENT SYSTEM

The burner management and combustion control system are in good working order, and no upgrades are planned.

FORCED DRAFT FAN

The forced draft fan is driven by a back pressure steam turbine. The turbine is in acceptable condition, however the steam control valve that controls the speed of the turbine (and in turn the fan) requires replacement. A new valve has been purchased and replacement of the existing valve is planned in 2025.

FUEL TRAIN

The fuel train on this boiler is in good condition for its age. No work is anticipated in the next 5 years.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
FD fan steam turbine control valve replacement	2025	$5,000	Reliability
Air heating ducting asbestos encapsulation	2025	$40,000	Safety

BOILER NO. 3

FURNACE

The furnace refractory is in reasonable shape and may require minor maintenance each year, including inspection of the refractory and casing.

BOILER TUBES

The boiler tubes along with the associated steam drum internals are showing signs of scale buildup. The scale leads to a drop in efficiency and the risk of boiler tubes overheating and subsequent forced outage of the boiler. Cleaning/descaling of the boiler tubes and drum internals is planned for 2025 at an estimated cost of $120,000.

BURNER AND BURNER MANAGEMENT SYSTEM

The burner management system is 40 years old and part availability is limited to the spares we have in stock in the plant. No significant upgrades are planned, however this limited availability of parts is a risk to the ongoing reliable operation of this boiler.

FORCED DRAFT FAN

There are no issues currently with the forced draft fan system on #3 Boiler. The force draft fan is driven by a back pressure steam turbine. No significant work is planned in the next five years.

FUEL TRAIN

The fuel train on this boiler is in good condition for its age. No work is anticipated in the next 5 years.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
Boiler and drum internals and tube cleaning	2025	$120,000	Reliability

BOILER NO. 4

Boiler 4 is the largest boiler in the Existing Plant and provides a significant amount of the total steam generation capacity of the plant. It is a critical boiler for the reliable operation of the plant. This boiler is equipped with a feedwater economizer.

FURNACE

The major upgrade and replacement of the furnace refractory on this boiler was completed in 2024. There was significant refractory degradation, particularly on the front wall of the boiler and around the burner throats. Following this work, no additional work is expected on the furnace in the next five years.

BOILER TUBES

The boiler tubes along with the associated steam drum internals had significant scale build p when inspected in 2024. Mechanical and chemical cleaning of the boiler tubes and steam drum internals was completed in 2024, and no further work is expected in the next five years.

BURNER AND BURNER MANAGEMENT SYSTEM

There are no issues with the burner management or combustion controls on #4 Boiler.

FORCED DRAFT FAN

The boiler force draft fan is driven by electric motor or a back pressure steam turbine. There are no issues with the electric motor. The steam turbine drives the fan through a reduction gear. The reduction gear indicates metal wear by way of lubricating oil analysis which is expected to lead to failure of the reduction gear. The electric motor only provides half of the output of the FD fan meaning the boiler can only operate at 50% capacity when the FD fan is running on the electric motor, so reliable operation of the steam turbine is critical. Replacement of the steam turbine reduction gear is planned for 2026 at an estimated cost of $XXX.

The pressure relief valves on the steam turbine are due for re-certification and may require pop testing or component replacement in the next two years, however this won't be confirmed until further inspection is undertaken.

FUEL TRAIN

The fuel train on this boiler is in good condition for its age. No work is anticipated in the next 5 years.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
FD fan steam turbine reduction gear overhaul	2026	$70,000	Reliability

BOILER NO. 5

Boiler 5 is a small package boiler that was originally installed to provide steam for the heating of the BC Place roof snow melt system. This system has been decommissioned and steam is no longer provided to this system. Boiler 5 does support our system in two capacities, however, as a low load support during the summer, and as additional capacity during peak load scenarios during the winter.

FURNACE

The furnace refractory requires minor maintenance on an annual basis.

BOILER TUBES

Boiler tube scale buildup is minimal and mechanical cleaning is not expected to be required in the next five years.

BURNER AND BURNER MANAGEMENT SYSTEM

The combustion controls are outdated, but in good working order. The burner management system is currently supported. No work is planned.

FORCED DRAFT FAN

The force draft fan motor was replaced in 2024 and should be reliable for several years. No further work is planned.

FUEL TRAIN

The fuel train on this boiler is in good condition for its age. No work is anticipated in the next 5 years.

PLANNED WORK

There is no planned capital work on Boiler 5 in the next 5 years.

BOILER NO. 6

Boiler 6 is the newest boiler in the Existing Plant and provides a significant amount of the total steam generation capacity of the plant. It is a critical boiler for the reliable operation of the plant. This boiler is equipped with a feedwater economizer.

FURNACE

The furnace refractory will need minor maintenance this year based on observation through the furnace's rear wall viewport. No significant costs are anticipated.

BOILER TUBES

The boiler tubes and steam drum internals were inspected in 2024, and only minor scale build up was noted. Tube wall thickness inspections will be carried out in 2025, and some work is expected to be required based on this inspection, and previous inspections on the other boilers where tube thinning has been found and replacement work required. An allowance of $30,000 is being carried to replace tubes where significant thinning is found.

BURNER AND BURNER MANAGEMENT SYSTEM

The burner and BMS is in good working order and no work is planned in the next five years.

FORCED DRAFT FAN

The forced draft fan is driven by a steam turbine/reduction gear unit. The prime mover and reduction gear need to be monitored for metal content in the lubricating oil. Lubricating oil analysis is typically done annually.

It was identified in 2020 that new parts would be needed soon, including the gear sets. The reduction gear was sent to Standard Machine in 2021 for inspection. Extensive repairs were made, and critical parts were replaced. A reliability test completed in May 2024 did not reveal any indicators that would require urgent attention. The reliability test indicated that the unit was in good condition.

We will continue with our PM program of completing bi-annual reliability testing and testing of oil samples. These costs are captured in our regular operating budget. No further works is expected in the next five years.

Fuel Train

The fuel train on this boiler is in good condition for its age. No work is anticipated in the next 5 years.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
Replacement of thin tube sections	2025	$30,000	Reliability & safety

FEEDWATER SYSTEM

WATER SOFTENERS

The softeners treat the incoming city water supply to reduce the risk of fouling of the boiler tubes. Failure of the softeners would result in rapid fouling of the boiler tubes. Combined with the chemical treatment of the feedwater the softeners are essential to reliable operation of the plant.

The softener resin had started to fail and was replaced in 2024. The water softener piping was also fouled and has been high pressure cleaned. No further work is expected on the softener system.

PLANNED WORK

There is no planned capital work on the water softeners in the next 5 years.

DEAERATORS

The deaerator heats the treated city water to 108°C to remove oxygen to reduce the risk of corrosion in the boilers and distribution piping. There are two deaerators in use with one deaerator operating at a time, and the other as a backup. Deaerator 3 is the main operating unit with Deaerator 2 operating as a backup, due to it being of lower capacity. Deaerator 1 is decommissioned and no longer in use.

DEAERATOR 2

This vessel was installed in 1971 and is rated at 440,000lbs/hr. Within the last 2 years there was NDE carried out on the vessel along with the re-certification of the steam safety valve. The steam safety valve will need to be re-certified in the next 3 years. This work is considered operational expense and the cost is not included in this assessment.

Deaerator 2 cannot provide the full system capacity during the winter and hence is only run as a backup unit. Deaerator 2 is primarily used in the summer to allow maintenance work to be completed on Deaerator 3.

DEAERATOR 3

This vessel was installed in 1995 and is rated at 1,000,000lbs/hr. NDE was recently conducted on both the heating and storage vessels and no issues were found. The 2 steam safety valves were recertified and are good for another 5 years. The 14” overflow valve was replaced this year. The safety valves will require re-certification in five years should the deaerator still be required to be operating.

PLANNED WORK

There is no planned capital work on the deaerators in the next 5 years.

FEEDWATER PUMPS

The feedwater pumps raise the pressure of the treated water in the deaerator up to 300psi to supply the boilers for the generation of steam. The details of the feedwater pumps are as follows:

Feedwater pump number	Capacity (lbs/hr)	Drive type
1	150,000	Steam turbine
2	150,000	Steam turbine
3	180,000	Electric motor
4	40,000	Electric motor
5	90,000	Electric Motor
6	90,000	Steam turbine
7	70,000	Steam turbine
8	190,000	Steam turbine
Total	**960,000**	

The feedwater pumps are essential to the operation of the plant, although there are several pumps and so failure of an individual pump can be managed using backup pumps.

FEEDWATER PUMP 1

This pump is a centrifugal multi-stage pump that is driven by a back pressure steam turbine. The pump was completely rebuilt in 2023, including an upgrade to the steam turbine control. The pump has a capacity of 150,000lbs/hr. The pump utilizes mechanical packing for pump shaft sealing. No further work is planned on this pump.

FEEDWATER PUMP 2

The pump is a centrifugal multi-stage pump that is driven by a back pressure steam turbine. The pump was rebuilt in 2024, including an upgrade to the steam turbine control valve. The pump has a capacity of 150,000lbs/hr. The pump utilizes mechanical packing for pump shaft sealing. No further work is planned on this pump.

FEEDWATER PUMP 3

This pump is a centrifugal multi-stage pump that is driven by an electric motor. This pump is due Two as it is basically 60 years old and appears the only upgrades were carried out on the pump shaft bearing housings. The pump runs at a constant speed and generates significant head pressure during low loads. A new electric motor and VFD will be installed on this pump in 2025 as the existing motor is at the end of its life. We will also complete a pump rebuild at the same time. The pump has a capacity of 180,000lbs/hr and utilizes mechanical packing for pump shaft sealing.

FEEDWATER PUMP 4

This pump is a centrifugal multi-stage pump that is driven by an electric motor. The pump runs at constant speed and has a capacity of 40,000lbs/hr. The pump utilizes mechanical packing for pump shaft sealing. This pump is rarely used, and no work is planned.

FEEDWATER PUMP 5

This pump is a centrifugal pump that is driven by an electric motor. The pump and motor were rebuilt within the last 3 years. The pump runs at constant speed and generates significant head pressure during low loads. This excess pressure is controlled by bypassing a portion of the feedwater to flow back to the deaerator, dropping the feedwater header pressure. A VFD will be installed on this pump in 2025 to provide speed and head pressure control. The pump has a capacity of 90,000lbs/hr and utilizes mechanical packing for pump shaft sealing.

FEEDWATER PUMP 6

This pump is a centrifugal pump that is driven by a back pressure steam turbine. The pump was rebuilt in the last 2 years and has a capacity of 90,000lbs/hr. The steam turbine may require rebuilding within the next 3 years. The pump utilizes mechanical packing for pump shaft sealing.

FEEDWATER PUMP 7

This pump is a centrifugal pump that is driven by a back pressure steam turbine. The pump was recently rebuilt in the last 2 years and has a capacity of 70,000lbs/hr. The steam turbine was recently overhauled and significant pump/turbine vibration was encountered. Due to the cost of repairing the unit the pump is used for emergency purposes only. The pump utilizes mechanical packing for pump shaft sealing.

FEEDWATER PUMP 8

This pump is a centrifugal pump that is driven by a back pressure steam turbine. The pump and steam turbine were both rebuilt in the last 6 years and this pump has a capacity of 200,000lbs/hr. Typically, this pump only operates approximately 3 months of the year during peak loads due to its high capacity. The pump utilizes mechanical packing for pump shaft sealing.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
FWP-3 rebuild, motor replacement and VFD install	2025	$100,000	Reliability
FWP-5 VFD install	2025	$50,000	Reliability

Note: the installation of VFDs does not directly improve the reliability of the associated feedwater pump. However, this is considered a reliability measure as the installation of the VFD allows the pump to meet a much greater portion of the annual duty, reducing the run hours of the steam turbine pumps, and the associated maintenance requirements on those pumps. As the steam turbine pump maintenance is more expensive than the VFD installation this is considered the most prudent way to proceed.

CONDENSATE HOTWELL AND TRANSFER PUMP

The condensate hotwell receives condensate from customers which return it to the plant and from steam traps in the plant itself. The transfer pump injects the hot condensate into the boiler feedwater line back to the deaerator.

There are 2 hotwell transfer pumps located in the steam plant. One is a small load pump driven by a fractional hp electric motor and is used during the summer months. The larger pump is driven by a backpressure steam turbine. Both pumps and prime movers are in reasonable shape and no work is planned.

Venting System

The venting system conveys the exhaust gases from the steam boilers to the atmosphere. The stacks need to remain structurally sound with no risk of leaks into the plant to ensure safe operation of the boilers. The Sofame Heat Recovery System increases the efficiency of the plant. Failure of that system would not compromise the ability of the system to serve customers but would result in increased energy costs.

BOILER STACKS

All boiler stacks are in reasonable condition with no work planned in the next five years.

SOFAME HEAT RECOVERY SYSTEM

Currently the Sofame system is offline and requires repairs. The main issue is part of the induced draft fan casing has corroded through allowing boiler flue gas to leak close to the building HVAC system. The fan inlet and discharge flex connections require replacement due to flue gas leakage. There is also an imbalance in the fan, causing vibration when the fan runs above 60% speed. Repairs are planned for 2025. The Sofame unit will be run at a maximum of 60% throughout the winter of 2024/25 to avoid vibration issues. The cost of the repair work is expected to be $100,000. The estimated simple payback period on the repair work is 2,500 hours of operation which would be less than two years.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
Sofame heat recovery system fan and motor replacement	2025	$100,000	Reliability and Plant Efficiency

Balance of Plant

COMPRESSED AIR SYSTEM

The steam plant uses compressed air for various purposes including atomization of fuel oil at the burners and plant instrumentation & equipment. There are 3 operating compressors and typically only one is needed to meet the plant compressed air demands. The plant has 2 rotary compressors and 1 reciprocating compressor driven by an electric motor. The compressed air is passed through desiccant dryers that provide dry air to the steam plant equipment. The steam plant has a diesel engine driven air compressor that may be used in emergencies. Tw of the existing air compressors at the end of their life and so to ensure the plant has a reliable back up one compressor is planned to be replaced in 2025. No other work is planned on the compressed air system.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
AC-3 replacement	2025	$30,000	Reliability

SUMP PUMPS

The two sanitary sump pumps in the plant basement handle sanitary waste and a small stream of condensate cooling water. The primary pump utilizes a float/mercury switch to start and stop the pump at set water levels in the sump. If the primary pump fails, then a secondary pump will activate to pump down the sump. Activation of the secondary pump will generate a sump level alarm in the control room. Note that both main sump pumps are connected to emergency power. A third sump pump is available that can operate from one of the plant's 5kW gas-powered generators if there is an extended hydro outage. No work is planned on the sump pumps.

EMERGENCY GENERATOR

The emergency generator was installed approximately four years ago. It is in good condition and other than continued annual planned maintenance, no work is planned for the next five years.

CONTROL SYSTEM

The main control system for the steam plant is DeltaV. This system handles the burner management for 4 of the 6 boilers. There are five operator workstations in the plant and all of them are passed the end of their life and the equipment is obsolete. To ensure the plant has at least one reliable operator workstation we will be replacing one of the workstations in 2025.

PLANNED WORK

Planned Work	Year	Capital Cost Estimate	Reason
Operator station workstation replacement	2025	$35,000	Reliability