Planning for the Future at the CTGS Site

Report on the Decommissioning Proposal of Maritime Electric

Prepared for Carr, Stevenson, and Mackay

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EXECUTIVE SUMMARY

Synapse Energy Economics (Synapse) was retained by Carr, Stevenson & MacKay, counsel to the Island Regulatory and Appeals Commission (the Commission or IRAC), to evaluate the proposal of Maritime Electric Company Ltd. (MECL) to decommission the steam generating units at the Charlottetown Thermal Generation Station (CTGS). This plan, and MECL's associated depreciation rates study, were submitted in June 2018. They will be considered by the Commission in the upcoming General Rate Application (GRA) proceeding.

MECL proposes to start the staged shutdown of the remaining steam units at CTGS starting in 2019, and to complete site decommissioning activities by late 2023. In addition to removing Turbines 7–10, the utility proposes to:

- Demolish the entire CTGS structure and relocate the Combustion Turbine #3 (CT3) auxiliary equipment, known as the balance of plant (BOP), and the mechanical maintenance shop, to a new structure at the Charlottetown site;
- Demolish the river pumphouse and demolish and/or backfill the circulating water lines associated with CTGS operation;
- Remove concrete walls, building slabs, stack foundations, and pedestals to a depth of 0.9 meters below grade;
- Remediate the site to a degree that is compliant with statute and regulation and conducive to future energy system expansion and/or development;
- Regrade the site using gravel from crushed structural concrete, and restore it to an "open space condition."

MECL asks that the CTGS site be deemed used and useful following decommissioning, and that costs for this proposed work be recovered through depreciation rates.

Synapse has reviewed the proposal of Maritime Electric, and other associated documentation, and agrees with the decision to decommission the steam generation units at CTGS. However, we are concerned that MECL has not clearly made the case that the extent of demolition and remediation proposed is in the best interest of its ratepayers. The probable need for the utility to procure additional energy and capacity and the specific likelihood that this will be installed at the CTGS site loom large in this proceeding. Yet the study submitted by the utility takes only a general approach to formulating plans for the site.

On the following page, we provide a series of recommendations for the Commission.

Recommendations

- The Commission should approve the retirement of Turbines 7–10 at CTGS.
- The Commission should not approve the demolition of the non-BOP portion of the CTGS structure until MECL presents a more robust case for the cost-effectiveness of demolition over retention.
- The Commission should not approve demolition of the BOP-portion of the CTGS and construction of a new BOP building unless MECL can present a clearer justification, since demolition does not appear to be meaningfully less expensive than maintaining the BOP section of the CTGS.
- The Commission should deem the entire CTGS site used and useful. However, this designation should be made contingent on MECL filing a long-term plan for energy system utilization for the site in short order.
- The Commission should institute appropriate safeguards to ensure that MECL continues to minimize costs as the decommissioning process proceeds; as currently construed, there is no incentive for the utility to keep costs below the approved budget for the decommissioning.
- MECL should be required to make a clearer case for the magnitude of the mobilization-demobilization budget item, substantiating why it believes that it will be necessary to hire a contractor from outside the province.
- The Commission should ensure that MECL conducts all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning, and that it modifies its projected decommissioning budget and workplan as appropriate based on the results of subsequent testing.
- Synapse recommends that MECL conduct a simple probabilistic analysis in which the probability of occurrence for each environmental risk item is multiplied by the total cost for each associated risk item in order to produce a more accurate assessment of total environmental risk exposure for the decommissioning.
- If any revisions are made to the proposed workplan and budget, then MECL should be instructed to submit a new budget that not only reflects the modifications to the site decommissioning cost, but also adjusts the value of any other items that are assessed in proportion to the site decommissioning cost, including allowances.
- The requested increase in depreciation rates should only be granted if MECL can clearly illustrate how the lag in implementation of the previous rate change, adjusted service life assumptions, shift in net salvage, and other factors have contributed to the requested revision to the current rates.

- Decommissioning costs should not be escalated unless MECL can provide a clear justification for escalation and illustrate that this escalation is consistent with the approach taken in past CTGS-related financial calculations.

1. OVERVIEW

This document has been prepared for the Island Regulatory and Appeals Commission (the Commission or IRAC) by Synapse Energy Economics Inc. in response to the proposal to decommission the Charlottetown Thermal Generating Station (CTGS) filed by Maritime Electric Company Limited (MECL) in June 2018. Synapse has reviewed MECL's Decommissioning Study and other associated documents and we provide these comments with the aim of ensuring that provincial energy needs and ratepayer interests are best served in the upcoming process. While Synapse believes that the steam units at CTGS should be retired, it finds that MECL has not sufficiently made the case for fully demolishing the CTGS structure.

This review is divided into five sections. The first section summarizes the procedural history, noting key details and issues in the proposed decommissioning scope and timeline. The next section presents our findings on the proposed steam unit retirements, and on the scope of demolition that has been proposed. In the following section, we evaluate the costs and approach to risks in MECL's proposal. The next section addresses the rate and regulatory implications of the proposed decommissioning. We conclude with an outline of our recommendations.

1.1. Procedural History

Maritime Electric initiated the formal decommissioning process in July 2015 when it filed a Depreciation Study requesting a rate increase in anticipation of decommissioning CTGS in 2021.[1] The Commission approved this increase with a February 2016 order, and instructed MECL to submit a Decommissioning Study and an updated Depreciation Study.[2]

These requested studies were submitted by MECL in June 2018. While the utility's decommissioning plan does not alter the timeline first suggested in 2015, the projected costs have increased markedly. The 2015 study's estimated net salvage value for CTGS of approximately $6.2 million has been increased to about $11.4 million.[3]

While retirement of the steam units seems to be a near *fait accompli* in light of the 2016 Commission's February 2016 order, the scope of the decommissioning is still at issue. Retiring Turbines 7–10 does not

[1] 2014 Depreciation Study. Pg. 16.

[2] IRAC Order UE16-04.

[3] Net salvage is the cost of decommissioning less any receipts for salvage or other resale of site resources. In the 2014 Depreciation Study, the net salvage value for CTGS was estimated at 10% of the CTGS book value. See 2014 Depreciation Study. Pg. 16. Also see 2017 Depreciation Study. Pg. IV-3.

mean that the utility must demolish other on-site infrastructure or undertake remediation activities beyond what is required by legal and regulatory standards.

1.2. Summary of Decommissioning Issues

This review is primarily concerned with the "big picture" issues in this decommissioning: Should the steam units be retired? Should the CTGS building and other on-site structures be demolished? To what degree should the site be remediated? Are the proposed costs reasonable and sufficiently reflective of risks? Should the CTGS site continue to be treated as used and useful by the Commission?

Maritime Electric is uniquely positioned to assess its needs and formulate system plans, and so the credibility of the utility and its consultants will necessarily factor into the evaluation of this decommissioning plan. To that end, certain elements of the proposed decommissioning were not specifically addressed in this review. We have generally deferred to MECL on specific cost, timing, and sequencing details as they enter into the proposed decommissioning plan, and we have also generally accepted the technical and engineering findings presented by the utility.

The following is an overview of the issues reviewed in this document:

<u>Decommissioning of the steam generation units at CTGS</u>
MECL proposes to retire steam turbines 7–10. The utility claims that it is not cost-effective to invest in extending the service lives of these units.[4]

<u>Demolition of the CTGS, circulating water lines, and river pumphouse</u>
MECL proposes to demolish the CTGS building in full. The utility claims that preserving this building—for lease, other utility function, or just as a vacant structure in anticipation of potential future needs—is neither practical nor cost-effective.[5] The balance of plant (BOP) that is associated with Combustion Turbine #3 (CT3) and the mechanical maintenance shop are to be relocated to a new structure on site. MECL asserts that retaining just the BOP portion of the structure while demolishing the rest is not cost-effective compared with the costs of full demolition and construction of a new building.[6] The utility also proposes to demolish the river pumphouse, and to alternatively dig up or backfill the circulating water lines.[7]

[4] First Synapse interrogatories. IR-1.

[5] Ibid. IR-3.

[6] Preliminary Options Analysis. Pg. 6.

[7] Decommissioning Study. Pg. i.

Scope of remediation

MECL aims to restore the CTGS site to an "open space condition" that would be conducive to future utility usage, specifically for energy infrastructure upgrades and/or system expansion.[8] The Charlottetown site has hosted heavy industrial activity for more than a century, and so it is not clear whether all present environmental issues stem from CTGS activity.

Costs and cost-estimation procedure

The proposed decommissioning appears to be costly relative to industry standards, at approximately 19 percent of the book value of the CTGS, net of positive salvage.[9] There are a few elements that contribute heavily to overall expenses. Demolition of the concrete stacks is expected to be nearly 20 percent of the total project budget (32 percent of site decommissioning costs), while allowances represent almost 19 percent of the total plan costs. Allowances are divided into contingencies for unidentified items (about 6 percent of total budget), and allowances for health, safety, mobilization-demobilization, and bonds (about 12 percent of total budget).[10] Maritime Electric has also requested that decommissioning costs be escalated to 2022 nominal dollars.

Risk methodology

The principal risks concern environmental contamination of the CTGS site and hazardous materials in the building, and the potential for changes in future land use. These elements may interact, as a change in land use could present the need for additional testing and/or remediation.[11] Subsequent testing and the commencement of decommissioning activities might expose the need for additional, costly remediation. Though MECL has provided an estimate of the total value of major risk items, the level of risk has not been evaluated probabilistically, leading to several potentially high-cost items being left out of the budget. [12]

Regulatory issues

MECL is seeking an increase in depreciation rates to cover both historical under-depreciation of the CTGS and the increase in projected decommissioning costs. Though the decommissioning is planned to conclude in 2022, MECL is requesting that amortization of the reserve variance be stretched over the period 2019–2023 to prevent rate shock. The utility is also seeking a used-and-useful designation for the remaining assets at the Charlottetown site, including all land, following decommissioning. MECL describes two mechanisms for continued regulatory engagement. The utility proposes to file a report on decommissioning progress every six months and suggests that the reserve variance deferral account be

[8] Ibid.

[9] 2017 Depreciation Study. Pg. IV-3.

[10] Decommissioning Study. Table 9.1 Pg. 1-2. Note that stack demolition and asbestos abatement are included in the total site decommissioning cost figure, while allowances and internal labor costs are not.

[11] Table 5.1. Options analysis.

[12] First Synapse interrogatories. IR-2.

used to reconcile changes to the decommissioning budget as the process proceeds. MECL does not propose any other ongoing regulatory oversight to ensure that costs are minimized or that the decommissioning plan is modified as appropriate, following approval, to maximize project efficiency, safety, or other priorities.

1.3. Summary of MECL's Proposal with Key Dates and Stages

Maritime Electric provided a conceptual decommissioning schedule in its 2018 study,[13] and an updated timeline in its GRA.[14] The table below presents MECL's GRA timeline for decommissioning:

Table 1. Proposed timeline for decommissioning

Phase of Activity	Period
Decommissioning Study	June 28, 2018
Planning for the site and preparing draft tendering document	2018-2019
Developing proposed project plans	2019
Civil work for construction of the new CT3 BOP building	April 2020 – August 2020
Relocation of CT3 BOP equipment to new building	August 2020 – November 2020
Environmental Impact Assessment (EIA) process, including stakeholder and public meetings	2020 - 2021
Full demolition of CTGS building, stacks, etc.	January 2022 – January 2023
Landscaping and final site cleanup work	April 2023 – October 2023

Source: General Rate Application.

1.4. Documents Reviewed

MECL presents its case for decommissioning in its 2018 Decommissioning Study, which is supported by an updated Environmental Site Assessment, the Preliminary Options Analysis, and other records. Synapse reviewed these documents, as well as documents from two rounds of interrogatories propounded to MECL by Synapse.

Other documents consulted in this study include MECL's General Rate Application, submitted in November 2018, and responses to associated interrogatories by Commission staff, the post-mortem report on the November 2018 storm outages and associated interrogatory responses from MECL, and the 2017 Integrated Resource Plan (IRP) filed by the utility.

[13] Decommissioning Study. Figure 12.

[14] GRA. Pg. 38.

Synapse also reviewed several past decommissioning studies from Canada and the United States, as well as guidance reports to assess the state of practice in the field and provide context to the proposal of MECL.

A complete list of documents reviewed is provided in Appendix 3.

2. Decommissioning Scope and Site Remediation

2.1. Decommissioning Turbines 7-10 at CTGS

The Commission signaled overall support for decommissioning these units in its 2016 order,[15] and in its approval of the decommissioning of Turbine 6, completed in 2017. Synapse agrees with this judgement.

MECL reports that it would cost approximately $41 million[16] to extend the service lives of Turbines 7–10 —an investment that MECL argues would not be cost-effective. To support its decision to retire these units, MECL provides a series of justifications, which include the following:

- The units at CTGS are all at least 55 years old, compared to an average lifespan of 48 years for oil plants retired from 1999 to 2012.[17]
- Bunker C fuel oil is no longer favorable for MECL, given its associated greenhouse gas emissions in the context of global climate change and air pollutant risks.[18]
- The CTGS plant is no longer needed for reliability purposes, since a contract for firm capacity with New Brunswick Power through the two new 180 MW submarine cables will be active from March 2019 through February 2024.[19]

Synapse notes that while the contract with NB Power and the increase in cable capacity are enabling factors in the retirement of the steam units, they do not provide a rationale for retirement. Indeed, the utility's capacity needs have only been resolved for the short term. In responses to Commission interrogatories, MECL indicated that it will be facing a capacity shortfall as soon as 2022, and that its long-term plan is to procure additional capacity on PEI.[20] The utility describes the Charlottetown site as

15 Order UE16-04.

16 GRA. Pg. 30.

17 Second Synapse interrogatories. IR-1.

18 Ibid.

19 GRA. Pg. 31.

20 Commission interrogatories on General Rate Application. IR-18.

"ideal for future generation assets,"[21] and thus believes that the CTGS site continues to be used and useful. We discuss these issues further in the following sections.

2.2. Demolition of the CTGS

Without certainty about the future use for the CTGS site, the decommissioning plan was scoped using a general objective—to maximize flexibility for future energy system activity. The utility proposes to demolish the CTGS structure in full and to move the CT3 auxiliary equipment and other equipment that is to be preserved into a new balance of plant (BOP) building. Synapse does not find that MECL has made a sufficient case for full demolition. We note that without more detail about future site utilization plans, the utility and its ratepayers risk doing too little, too much, or simply taking the wrong tack in this decommissioning.

The Repurposing Study and Preliminary Options Analysis

Since the BOP for CT3 is housed inside the CTGS building and might plausibly remain there whether the rest of the building is to be preserved or not, the utility conducted a bifurcated, phased evaluation of potential scenarios. First, it considered alternatives to demolishing the CTGS structure in the Repurposing Study. Then, after concluding that the non-BOP portion of the CTGS structure should be demolished, it considered the question of preserving the BOP section against relocating it to a new structure in the Preliminary Options Analysis.[22]

The Repurposing Study

The Repurposing Study considers costs and feasibility for several alternatives to demolition, and it offers a high-level analysis of technical feasibility and expected costs. Yet the study does not satisfactorily resolve whether the CTGS building *should* be demolished.

Separately, in response to the first Synapse interrogatories, MECL reported that it believed that the most probable future use for the CTGS site was as a "parking lot or open field," and that this provided the baseline against which the alternative options were evaluated.[23] In reporting expected costs for each of the alternatives, MECL assumed that general site remediation costs would be constant. In a later response to the second Synapse interrogatories, MECL indicated that changes to future land use (excluding residential usage) would likely only require negligible additional remediation.[24]

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[21] Ibid. IR-9.

[22] Combustion Turbine 3 (referred to as CT3) is located outdoors adjacent to the CTGS building and is to remain in service through 2056. See first Synapse Interrogatories, IR-1.

[23] First Synapse interrogatories. IR-3.

[24] Second Synapse interrogatories. IR-6.

The following table from MECL's report shows the results. The differential figures in the final column are derived from the difference between the cost of the specified option and that of its nearest alternative.

Table 2. Repurposing Study results

Option	Title	Probable Cost	Probable Cost Differential
A	Transformer Shop	$3,500,000	Not applicable
B-1, B-2	Head Office (with or without Energy Control Centre integration)	$9,500,000	Not applicable
C1	Combustion Turbine (compared to the Exterior Turbine cost on site for cost differential)	$72,000,000	+$4,000,000
C2	Combustion Turbine (compared to Greenfield Turbine Site cost for cost differential)	$80,000,000	-$8,000,000
D SF6	GIS SF6 Substation (compared to low profile substation for cost differential)	$9,200,000	$3,300,000
D Air	GIS Air Substation (compared to low profile substation for cost differential)	$9,600,000	$3,700,000
E	Leased Industrial Space	$2,700,000	Not applicable
F	Retain Empty Shell	$1,360,000	Not applicable

Source: Repurposing Study.

In interrogatory responses, MECL reported that it found none of the above options to be practical or cost-effective.[25] However, the figures reported above are insufficient to support any firm conclusion about cost-effectiveness.

Synapse notes two issues with this presentation of results. First, it is not possible to assess several of the above options without cost differentials. The claim that these options—including moving the head office to the plant site or leasing the plant site—do not have cost differentials is not correct. A basic principle in economics is that there is always an alternative. While there may be no directly comparable second option that involves new building or engineering, even the do-nothing scenario has its own price in opportunity costs.[26]

Concerning the first two options, installing a transformer shop in CTGS and relocating the head office to this building, the costs of not doing either are the current, status quo costs plus any foregone benefits that would result from selecting either option (e.g., rental income from leasing the current

[25] First Synapse Interrogatories. IR-3.

[26] This report asserts that these options could feasibly be implemented together, with total costs roughly equal to the sum of the constituent option costs.

Charlottetown headquarters to a new tenant).[27] In the case of Option E, leasing the building, the analysis should consider the probable rental income that is foregone by *not* leasing the building. If this exceeds the cost of readying the space for rental, then the differential should be negative.

The second issue with MECL's Repurposing Study is a lack of context. Without more information about the utility's future system needs, it is unclear how results should be interpreted. A casual reader might assume that option C2 is the best one, since it boasts the highest negative differential. Yet option C2 would only be relevant if MECL decided to procure a new combustion turbine, and then determined that an exterior installation on site (option C1) was not feasible. Of course at that point, if the proposed decommissioning had already been completed, then MECL would find itself in a bind, having already demolished the CTGS structure. The utility would thus be left either to pay for the costlier installation elsewhere or to invest in an expansion to the new BOP building that would be of uncertain cost. Either way, the ratepayer burden could increase.

Ideally, MECL would have already undertaken a holistic planning exercise that considered future energy needs with more specificity. In the absence of a clear plan for future site use, the utility should at least be compelled to make a stronger case for the cost-effectiveness of demolition by presenting these options across different energy scenarios analyses (e.g., MECL procures a new CT turbine and installs it at the CTGS site, MECL does not procure any new capacity on PEI, etc.) with complete cost-differential information, as described above. MECL may also consider evaluating differences in qualitative benefits between the scenarios (e.g., installing a turbine indoors mitigates noise pollution and pigeon control issues) in a more structured way.

The Preliminary Options Analysis and Follow-up Study

MECL planned for the BOP on the assumption that the non-BOP portion of CTGS would be demolished. While Synapse does not believe that MECL has made a strong enough case for this, we nonetheless consider the utility's BOP planning process on its own merits.

Planning for the BOP has occurred in two stages. First, in the Preliminary Options Analysis, MECL's consultant GHD considered costs for retaining the BOP section of the CTGS structure with those for demolishing the entire building and constructing a new structure to house this auxiliary equipment, the mechanical maintenance shop, and the wastewater treatment equipment. Building a new BOP was determined to be $621,050 cheaper than maintaining the existing structure, and so the utility carried forward the demolition and reconstruction option.[28,29]

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[28] Preliminary Options Analysis. Table Pg. 4.

[29] Though this estimate had an uncertainty margin of -50%/+100% that was in fact larger than the difference in estimated costs for the two alternatives, the utility indicated in interrogatory responses that they believed that the true uncertainty was less. Moreover, MECL indicated, the function of the Preliminary Options Analysis was merely to select a pathway— demolish or

Synapse is not convinced that MECL has demonstrated the cost-effectiveness of complete demolition. On review, it appears that some of the factors driving this cost differential do not bear out. Setting aside the issue of costs for constructing a new BOP,[30] we evaluated the large cost components in the cost projection for maintaining the BOP section of CTGS, focusing on stack demolition and lifecycle heating expenses.

The Preliminary Options Analysis estimates that maintaining the BOP in its current location would incur an additional $445,000 in stack demolition costs, as costlier mast climbers would be required to avoid damaging the BOP during demolition.[31,32] Yet the Decommissioning Study, which is based on the results of the Preliminary Options Analysis, concludes that mast climbers are likely to be required for demolition *in any case*, since alternative less-expensive approaches introduce intolerable risk.[33] If mast climbers will be used regardless of the BOP alternative selected, then the estimated cost difference between these two options falls to just $176,050.

There is also uncertainty in the heating cost estimate. MECL's analysis projects that total lifecycle heating costs would be $1,283,000 greater if the BOP portion of the CTGS were to be retained, after inflation and discounting adjustments.[34] This value is based upon an assumed $95,000 per year cost for heating this section, which is the higher of two figures that were provided. If the lower-end estimate, at $80,000 per year, had been used, the gap between the two BOP options would have been more than erased.[35,36] See Appendix 1 for an illustration of the difference in costs between these two scenarios.[37]

While we recognize that there may be myriad other unquantified benefits associated with a new BOP, and that retaining part of the old structure would likely make the decommissioning more complex and riskier, it is incumbent on MECL to provide a clearer rationale for constructing a new BOP structure.

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maintain the BOP section of the CTGS— not to commit funds to a specific budget, and so it is reasonable to rely on it and pursue complete demolition of CTGS. See first Synapse interrogatories. IR-6.

30 Preliminary Options Analysis. Table Pg. 2.

31 Ibid. Note that a value of $420,000 is also provided for stack demolition in the separate cost breakdown document that accompanies the options analysis.

32 As MECL explained in response to the second Synapse interrogatories, the utility made changes to the BOP plan after the Preliminary Options Analysis was submitted, determining that a new wastewater treatment facility would no longer be necessary and reducing the overall area of the proposed new BOP 8,750 square feet to 6,000 square feet. These modifications lowered the proposed BOP budget by $140,000. However, MECL also projected higher electrical costs, and modified other cost projections too. Overall, allowing for the differences in scope in the two budgets, MECL reports that the overall cost projections were quite close. See second Synapse Interrogatories. IR-2.

33 Decommissioning Study. Pg. 48.

34 Preliminary Options Analysis. Table Pg. 1.

35 MECL indicates that if differences in total volume are controlled for, the old BOP section of the CTGS is projected to be 2.3 times costlier to heat than a new structure. See email from Adam Mackenzie to Troy Small on December 7, 2017. Included with Preliminary Options Analysis.

36 Synapse notes that the utility did not fully consider other retrofits to the residual building to reduce heating costs.

37 Synapse attempted to replicate the lifecycle heating cost table that was provided by MECL with the Preliminary Options Analysis. However, our results suggested a lesser cost differential of just $1,202,667.

Specifically, MECL should provide more detail about the potential risk items related to retaining the old BOP section of the CTGS plant.[38] Such risk items include respective costs, probabilities of occurrence, and any additional related insights that have been gleaned from testing conducted after the Decommissioning Study was submitted.

Other Proposed Demolition Considerations

MECL proposes to demolish the river pumphouse and restore the riverfront to its original condition. The utility proposes to use a combination of approaches to decommission the circulating water lines that run from the pumphouse to the CTGS building.[39] Synapse find no issue with MECL's suggested approach. However, we note that the utility's case for demolishing the pumphouse is primarily aesthetic.[40]

2.3. Remediation Scope

The decommissioning will have to deal with hazardous material in plant structures and equipment, and with contamination on site. The approach that the utility has proposed appears to be methodologically sound and in line with legal and regulatory obligations in the province and standards in the Maritimes.

Since the Charlottetown site has been the locus of industrial activity for even longer than the CTGS has stood, and the area has hosted other polluting activities too, there is some uncertainty in assigning responsibility to the steam plant for all environmental contamination that is revealed by site testing. Thus, the Commission must carefully navigate how it determines remediation funding. While it is likely in the public interest to fully remediate any such contamination, it is not clear that all remediation costs should be born in full by MECL's ratepayers.

2.4. Section Recommendations

- The Commission should approve the retirement of Turbines 7–10 at CTGS.
- MECL should be instructed to prepare a more complete cost-effectiveness assessment of demolishing the CTGS structure relative to other alternatives, using a consistent approach to calculate cost differentials. If the utility is unable to provide specific energy system development plans for the CTGS site for context, then it should conduct an evaluation of the different CTGS alternatives for different energy system scenarios. The utility may also provide a more developed qualitative justification for demolition.
- It is not clear that building a new BOP will be meaningfully less expensive than retaining the old structure. MECL should be compelled to make a clearer case for the merits of new

[38] Preliminary Options Analysis. Pg. 5.

[39] Decommissioning Study. Pg. 45.

[40] Ibid.

construction. The utility may also provide a more developed qualitative justification for demolition.

3. Decommissioning Cost and Risk

Maritime Electric has requested $11.3 million for the proposed decommissioning. This reflects an estimated net salvage of $10.4 in 2018 dollars, escalated to the expected 2022 price level.[41] While it is beyond the scope of this review to evaluate the budget on a line-by-line basis, Synapse offers comments in this section on several specific aspects: the contingency allowance, proposed escalation of the total to 2022 dollars, and treatment of risk. We include observations from other recent decommissions to put these costs in broader context, and provide a more detailed analysis of other decommissioning studies in Appendix 2.

The table below from MECL's Decommissioning Study provides a high-level summary of projected costs for the decommissioning. Note that this budget does not include costs associated with constructing a new BOP.

Table 3. Decommissioning cost estimate

Class B Cost Estimate for Decommissioning of the CTGS ($ million)	
Site Decommissioning Cost	$6.47
Allowances	$1.94
Project Management, Engineering and Implementation (including Owner's cost)	$2.46
Post Decommissioning and Other Miscellaneous Cost	$0.69
Potential Resalable and Salvage Values	($1.13)
Net Decommissioning Cost (including Owner's costs and net of salvage materials)	**$10.43**

Source: Decommissioning Study.

3.1. Contingencies

The proposed decommissioning budget adheres to the standards of an American Association of Costing Engineering (AACE) Class 3 estimate, with an uncertainty range of -20%/+30%.[42] MECL's requested

[41] 2017 Depreciation Study. Pg. IV-3. Note that MECL is also requesting an additional $0.115 million in recovery for net salvage of "interim requirements," raising the total request to over $11.4 million.

[42] The Decommissioning Study appears to incorrectly refer to the estimation approach as "Class B," while the General Rate Application instead deems it a "Class 3" estimate. A review of the framework of the American Association of Cost

allowances represent 30 percent of the budget for site decommissioning, which appears to be in line with the level of uncertainty. One-third of the requested allowance total, or 10 percent of the total site decommissioning cost, is for "contingency allowance," while the remainder, 20 percent of the site decommissioning cost, covers "health and safety, mobilization-demobilization, bonds."

In interrogatory responses, MECL explains that the "contingency allowance"—10 percent of the site decommissioning cost—is intended to cover the range of unforeseen expenses that might arise in the course of the decommissioning.[43] In light of the extent of uncertainty in this preliminary budget, a 10 percent allocation seems reasonable.

Synapse is concerned that the amount allocated for allowances for health and safety, mobilization-demobilization, and bonds is high. In particular, the portion for mobilization-demobilization, at $550,000, represents a significant share – about 5 percent of the overall budget. MECL has indicated that this item is required to cover accommodations and transportation for third-party decommissioning staff, who will likely travel from beyond the province, but it should make a clearer case for why it is likely to incur these costs.

For context, Synapse reviewed a set of decommissioning studies (detailed in Appendix 2). In most cases, the contingency costs were in range of approximately 10–20 percent and were calculated as a function of the total decommissioning costs.[44] The only exception is the Dalhousie plant, for which contingency costs totaled 40 percent. It is unclear why the contingency costs at Dalhousie were so much higher than for the rest of the studies reviewed; however, it may have had to do with the size of the plant or the fact that the entire site was decommissioned. In any case, while MECL's allowance costs may be reasonable, they appear to be on the high end at 30 percent of the site decommissioning budget.

3.2. Escalation

Maritime Electric has proposed to escalate decommissioning costs by 2 percent per annum to the 2022 price level.[45] Synapse has reservations about this approach. It is not clear that MECL has consistently applied the same escalation approach in past financial calculations related to CTGS. Moreover, the utility is proposing to escalate costs, in anticipation of future inflation, but is not suggesting that early recovery

Engineering (AACE) indicates that "Class 3" is the correct term. See AACE International Practice No. 18R-97. "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries." March 1, 2016.

[43] First Synapse Interrogatories. IR-3.

[44] Xcel used a contingency of 15% in its 2011 Dismantling Cost Study, Florida Power and Light used a contingency cost of 16% in its 2009 Dismantlement study which was increased by 20% in its 2016 Dismantlement study. Oklahoma Gas & Electric and Duke Energy included 20% of the direct costs as a contingency cost within its decommissioning studies. Minnesota Power used a contingency cost of 10% in its 2015 Site Decommissioning Study for coal plants. Contingencies for Dalhousie Thermal Generating Station appear highest of all. While the categories used for allowances in the Dalhousie budget differ somewhat from those used in the CTGS budget, it appears that the Dalhousie study allocates at least twice as much as the CTGS study did, as a proportion of overall site decommissioning costs, for cost overages.

[45] 2017 Depreciation Study. IV-3.

be discounted to reflect the time value of money. There is reason to believe that MECL will collect for depreciation expenses in advance of making outlays, providing the utility with an opportunity to invest and earn a return on these funds.

Synapse notes that escalation is not consistently included in decommissioning budgets. In our review, we observed that escalation was applied in the studies of OG&E in Oklahoma and FP&L in Florida,[46] but not for Xcel Energy in Colorado.[47]

Moreover, the issue of escalation can sometimes be contentious. In testimony for the OG&E case in the context of decommissioning of power generating facilities in Oklahoma, one witness argued against escalation, stating:

"The current methodology does not give customers the benefit of the time value of money because the price burden of providing revenues for projected final decommissioning costs is not evenly distributed to all generations of ratepayers. The benefit is given to OG&E because it is allowed to significantly inflate its depreciation expense and to future customers whose price burden will be significantly less than current customers."[48]

3.3. Risk

There are several unknowns that might influence the course and cost of the decommissioning. These contingencies relate to environmental conditions on and around the CTGS site, future land use, and other "risk items" that were determined to have a low probability of occurrence but could represent in excess of $3 million in additional costs.[49] These risk items have been excluded from the total budget for the decommissioning. While GHD has used probabilistic modeling to evaluate risks in planning for other decommissioning projects, no such approach was taken for CTGS.[50] It is our understanding that probabilistic analyses, while requiring some additional time and minimal additional cost, provide a more realistic cost estimate than complete exclusion due to perceived low probability risks.

An example of a risk item with potentially significant costs is the analysis of background soil quality to determine the extent to which off-site soil remediation is necessary. If the background soil quality is not naturally high in metals (as assumed in the Environmental Site Assessment report), the remediation process could be significantly more expensive. A second example is a change in land use, if the land is either sold by MECL or if it is ultimately repurposed to serve a markedly different function. There are

[46] Florida Power & Light 2016 Dismantlement Study (Corrected), Pg. 12, August 2016 and Direct Testimony of Jeffrey. T Kopp, Cause No. PUD 201700496, Direct Exhibit JTK-1.

[47] Xcel Energy Dismantling Cost Study, Pg. 27, September 2011, http://www.debarel.com/BSB_Library/8_Seymore_Exhibit_1.pdf

[48] Responsive Testimony and Exhibits of Brian Andrews, Cause No. PUD 201700496, Pg.

[49] Decommissioning Study. Pg. 49 and Table 9.1.

[50] MECL response to IR-2.

nine other risk items not included in the Decommissioning Study budget that could similarly change the cost estimates.

Prior to approving the plan for CTGS, the Commission should ensure that MECL has followed up to the extent possible on risk items and attended to other critical preliminary tasks that could influence decommissioning scope and cost.[51] The "Pre-Decommissioning Engineering" section of the Decommissioning Study provides a summary of these preliminary tasks, which include stakeholder consultation, additional sampling and hazard assessments, and securing necessary authorizations.[52]

In addition, MECL should conduct a simple analysis using probabilities of occurrence for each environmental risk item multiplied by the total cost of the risk. This should produce a more accurate probabilistic calculation of total environmental risk for the decommissioning.

3.4. Section Recommendations

- MECL should be required to make a clearer case for the magnitude of the mobilization-demobilization item, justifying why it believes that it will be necessary to hire a contractor from outside the province.

- The Commission should ensure that MECL conducts all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning, and that it modifies its projected decommissioning budget and workplan as appropriate based on the results of subsequent testing.

- If any revisions are made to the proposed workplan and budget, then MECL should be instructed to submit a new budget that not only reflects the modifications to the site decommissioning cost, but also adjusts the value of any other items that are assessed in proportion to the site decommissioning cost, including allowances.

- MECL should be required to justify why it believes that decommissioning costs should be escalated to the 2022 price level, though there is no discounting of recovery to reflect the time value of money. The utility should also demonstrate that it has consistently applied the same approach to escalation in all related financial calculations concerning CTGS.

- Synapse recommends that MECL conduct a simple analysis using probabilities of occurrence for each environmental risk item multiplied by the total cost of the risk in order to produce a more accurate probabilistic calculation of total environmental risk for the decommissioning.

[51] MECL has provided an update on site-testing and regulatory engagements in response to the second Synapse interrogatories. Second Synapse interrogatories. IR-7.

[52] Ibid. Pg. 63.

4. REGULATORY MATTERS

4.1. Used and Useful Designation

Maritime Electric asserts that the whole of the former CTGS site will continue to be used and useful after the proposed decommissioning has been completed.[53] MECL maintains several energy system assets at the site that will continue in service, including the CT3, the energy control center (ECC), and a substation. While there may be feasible sites in the province that could be used instead, the utility has compellingly argued for maintaining its current site in Charlottetown. In response to Commission interrogatories, MECL notes that the location of the CTGS site makes it a favorable place for fuel storage, and also to serve loads in Charlottetown and eastern PEI.[54] Further, relocating existing infrastructure would be costly, and installing new infrastructure at a second site while maintaining some activity at CTGS would likewise also incur needless additional expenses.

In any case, the enduring presence of utility activities on a portion of the CTGS site does not necessarily render the entire property used and useful, nor does the fact that empty land might be held as a hedge against future uncertainty merit the same classification. Indeed, if the CTGS site is to remain in an "open space" condition, then it will demonstrably not be *used* even if it does remain *useful*.

In light of the probable future capacity shortfall facing the province, MECL should be instructed to prepare a plan detailing its intention to use the CTGS property for energy system functions. This plan should be prepared in the near term, and it should contain a specific timeline for new development on site. If the proposed development will not use all of the CTGS site, then MECL must indicate why it is not feasible for the property to be subdivided and partially given over to other, non-utility uses.

We note that if MECL's long-term plan is to convert the CTGS site to a parking lot or otherwise to leave it in an open space condition indefinitely, then the utility must demonstrate why it believes that retaining these assets for this purpose is instrumental to its other system operations. Urban waterfront land that is retained by a utility as an open field/park or as a parking lot is not a *prima facie* case of a used and useful asset. We also note that if MECL's intention is to install new energy system assets at the CTGS site, but only after the passage of substantial time—e.g., 5 or more years—then the burden will be on the utility to demonstrate why immediate demolition of the CTGS structure is more cost-effective than retaining this structure (so called "retirement in place") and renting it out over the intervening period.

4.2. Depreciation Rates

Maritime Electric has filed two recent depreciation studies, both completed by consultant Gannett Fleming. The first was submitted in 2015 and reflected MECL's books through the end of 2014. It was

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[53] Commission interrogatories. IR-11.

[54] Ibid. IR-9.

approved by the Commission in February 2016 and was made retroactively effective as of January 1, 2016.[55] The utility submitted a second study with its decommissioning plan in June 2018, which reflected results through the end of 2017, and then filed a revised rates proposal for the CTGS on February 14, 2019 to correct errors in the second study.[56]

In the 2015 submission, MECL reported that the CTGS was under-depreciated, [57] with an estimated reserve variance of about $14.6 million.[58] To address this, the utility proposed to increase depreciation rates from 2.5 percent to 4.53 percent, and to amortize the reserve variance over the period 2015–2021 at 3.46 percent, for a total depreciation rate for CTGS of 7.99 percent per year.

In the 2018 filing, MECL reported that the total reserve variance had grown to $18.0 million. To address this growing shortfall, MECL proposed to increase both the annual accrual and the reserve variance amortization annual requirement for the period 2018–2021, at which point CTGS would be fully depreciated. In this proposal, annual accrual would be increased to 5.09 percent, while reserve amortization rates would be increased to 7.97 percent. The 2019 revised filing extends the amortization period through 2023, and makes other modifications, as illustrated in the table on the following page.

[55] Order UE16-04.

[56] Amendment to Appendix 11 of the General Rate Application.

[57] Though this issue was noted in the previous Depreciation Study, which was submitted in 2006 and was based on results through 2005, IRAC did not alter the existing rates that has been set in 1991 (Order UE07-01).

[58] The reserve variance is the difference between calculated book depreciation and the theoretical reserve.

Table 4. Depreciation Study results

	2014 Study (2015-2021)	2017 Study (2018-2021)	Revised 2017 Study (2019-2023)
Projected Retirement Date for CTGS	2021	2019-2021	2019-2021
Total Net Salvage	$6.2	$11.4	$11.4
Original Cost	$61.2	$60.7	$60.7
Book Depreciation	$33.7	$42.5	-
Actual Depreciation	$48.3	$60.5	-
Accumulated Reserve Variance	$14.6	$18.0	$16.2
Proposed Amortization of Variance	$2.1	$4.8	$3.5
Proposed Annual Depreciation	$2.8	$3.1	Variable
Proposed Total Annual Depreciation	$4.9	$7.9	Variable
Proposed Depreciation Rate (Depreciation + Reserve Variance)	7.99% (4.53% + 3.46%)	13.06% (5.09% + 7.97%)	Variable

Notes: 2014 Study changes were effective January 1, 2016 and reflect an expected 7-year depreciation period from 2015-2021; 2017 Study results exclude Turbine 6 and provide decommissioning costs escalated to 2022$. The annual accrual in the revised study are for years 2019-2023, respectively, $3.1, $3.0, $2.7, $0, $0. Source: 2014 Depreciation Study, 2017 Depreciation Study, and Amendment to Appendix 11 of the General Rate Application.

We note that the accumulated reserve variance for CTGS has increased by about $1.6 million between the first and last submission, even though the revised depreciation rates, taking effect at the start of 2016, added an additional $2.1 million in amortization for previously accumulated reserve variance. All things being equal, if the total book value for the depreciating assets has not changed and the depreciation rates have been properly calibrated, then the accumulated reserve variance should not change. Indeed, with the implementation of reserve variance amortization recovery, this balance should fall.

According to MECL, the increase in this accumulated balance that appeared in the 2017 report stemmed from several factors.

- Revisions to the estimated remaining service lives of the CTGS assets to reflect the planned staged retirement of the facility;
- Updated costing information from the CTGS Decommissioning Study regarding the estimated cost of decommissioning and removal;
- The one-year delay in the implementation of revised depreciation rates from the 2014 Depreciation Study contributing to the increase in the accumulated reserve variance; and,

- Changes in the average service life and cost of removal assumptions used by Gannett Fleming in the 2017 Study as compared to the 2014 Study.[59]

While it is difficult to precisely substantiate this claim, we have taken a general approach to verification. If the reserve variance amortization recovery for the years 2016 and 2017 are taken out of the equation, and results are adjusted for the implied annual accrual shortfall over the period 2015–2017, then the total reserve variance would appear to have grown by roughly $7 million. We note that this is larger than the increase in projected decommissioning costs of about $5.1 million.

Synapse takes no issue with the proposed recovery schedule but suggests that Maritime Electric be required to detail the basis for the changes in reserve amortization and the annual accrual. The utility should provide an annual view of the changes in the total book values, total accumulated depreciation, and reserve variance over the years 2015–2023, based on both historical data and latest projections. Where not obvious, MECL should explain why values have changed.[60]

4.3. Regulatory Oversight

Maritime Electric acknowledges that the ultimate costs for decommissioning CTGS are likely to differ from the projected figures in the decommissioning plan. To accommodate unforeseen costs, the budget includes an allowance margin of approximately 30 percent of the site decommissioning cost (including a 20 percent allowance for health and safety and a 10 percent allowance for general contingencies), and an additional provision for miscellaneous expenses that might arise after the decommissioning. However, we encourage the Commission to establish clear standards for handling overages that result from risk items or other eventualities not included in the original budget.

In the GRA, Maritime Electric indicates that the reserve variance deferral account, which is proposed for amortization over the period 2019–2023, may be modified to reflect changes in the CTGS decommissioning costs.[61]

We advise that the Commission establish clear practices and standards to ensure that MECL reasonably modifies scope in response to new information as the decommissioning progresses, and to ensure that MECL selects the cost-minimizing approach in the event that any elements in the decommissioning plan need be modified. While regulatory lag is apt to inhibit the utility from overspending where new expenses arise, we caution that there does not appear to be a symmetrical incentive to ensure that, where possible, the utility underspends the approved amount.

[59] GRA. Pg. 82.

[60] Note that MECL was asked to provide workpapers for these calculations by the Commission in its interrogatories on MECL's GRA. However, the files provided by MECL were insufficient to evaluate its requested rate increases.

[61] GRA. Pg. 85.

As the Decommissioning Study indicates, the ultimate plan might include more extensive or less remediation, pending the results of follow-up testing.[62] Yet it is not clear that the mechanisms outlined in MECL's GRA will ensure that the decommissioning plan and budget are appropriately updated as new information becomes available, or that any future modifications to the current plan and budget will be both prudent and cost-effective. MECL has proposed to file a progress report on the decommissioning every six months, beginning on August 31, 2019.[63] The utility has also indicated that the reserve variance deferral account, which includes provision for decommissioning costs, will be updated to reflect changes in decommissioning costs. Synapse is not convinced that these mechanisms will provide for sufficient review of any such changes to ensure that all changes are prudent and cost-effective.

4.4. Section Recommendations

- The Commission should deem the entire CTGS site used and useful. However, this designation should be made contingent on MECL filing a long-term plan for energy system utilization for the site in short order.

- MECL should be instructed to clearly illustrate why it is proposing to modify the depreciation rates for CTGS. It should detail how the lag in implementation of the previous rate change, adjusted service life assumptions, shift in net salvage, and other factors have contributed to the need to revise the current rates.

- The Commission should ensure that there are appropriate structures in place to ensure that MECL minimizes decommissioning costs, keeping total costs under projected net salvage, if possible.

[62] Ibid. Pg. 33.

[63] General Rate Application. Pg. 166.

5. Conclusion

Synapse has reviewed the proposal of MECL for decommissioning the CTGS. As discussed in the preceding sections, the utility has made a strong case for retiring Turbines 7-10, and Synapse recommends that the Commission approve their retirement. However, Maritime Electric has not presented a sufficient justification for full demolition of the CTGS building. The probable capacity shortfall that will face PEI in the coming years must enter into this planning process more explicitly, or else ratepayers may be shouldered with an undue cost burden.

Below, we present our recommendations for the Commission as it considers MECL's decommissioning proposal in the upcoming GRA proceeding:

<u>Decommissioning Scope</u>

- The Commission should approve the retirement of Turbines 7–10 at CTGS.
- MECL should be instructed to prepare a more complete cost-effectiveness assessment of demolishing the CTGS structure relative to other alternatives, using a consistent approach to calculate cost differentials. If the utility is unable to provide specific energy system development plans for the CTGS site for context, then it should conduct an evaluation of the different CTGS alternatives for different energy system scenarios. The utility may also provide a more developed qualitative justification for demolition.
- It is not clear that building a new BOP will be meaningfully less expensive than retaining the old structure. MECL should be compelled to make a clearer case for the merits of new construction. The utility may also provide a more developed qualitative justification for demolition.

<u>Decommissioning Cost and Risk Items</u>

- MECL should be required to make a clearer case for the magnitude of the mobilization-demobilization item, justifying why it believes that it will be necessary to hire a contractor from outside the province.
- The Commission should ensure that MECL conducts all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning, and that it modifies its projected decommissioning budget and workplan as appropriate based on the results of subsequent testing.
- If any revisions are made to the proposed workplan and budget, then MECL should be instructed to submit a new budget that not only reflects the modifications to the site decommissioning cost, but

also adjusts the value of any other items that are assessed in proportion to the site decommissioning cost, including allowances.

- MECL should be required to justify why it believes that decommissioning costs should be escalated to the 2022 price level, though there is no discounting of recovery to reflect the time value of money. The utility should also demonstrate that it has consistently applied the same approach to escalation in all related financial calculations concerning CTGS.

Regulatory Matters

- The Commission should deem the entire CTGS site used and useful. However, this designation should be made contingent on MECL filing a long-term plan for energy system utilization for the site in short order.

- MECL should be instructed to clearly illustrate why it is proposing to modify the depreciation rates for CTGS. It should detail how the lag in implementation of the previous rate change, adjusted service life assumptions, shift in net salvage, and other factors each contribute to the need to revise the current rates.

- The Commission should ensure that there are appropriate structures in place to ensure that MECL minimizes decommissioning costs, keeping total costs under the approved budget, if possible.

APPENDIX 1: LIFECYCLE HEATING COSTS FOR BOP

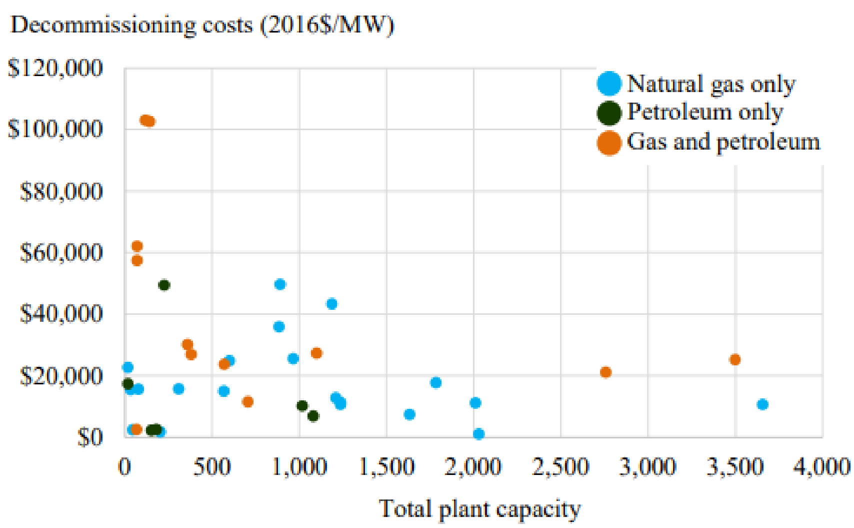
Table 5. Lifecycle Heating Cost Comparison – 2 percent escalation and 6.44% discount rate

	$95,000/year heating		$80,000/year heating	
Year	Retain CTGS	New BOP	Retain CTGS	New BOP
2020	$82,565	$14,340	$69,528	$14,340
2021	$78,793	$13,685	$66,352	$13,685
2022	$75,193	$13,060	$63,320	$13,060
2023	$71,757	$12,463	$60,427	$12,463
2024	$68,479	$11,894	$57,666	$11,894
2025	$65,350	$11,350	$55,032	$11,350
2026	$62,364	$10,832	$52,517	$10,832
2027	$59,515	$10,337	$50,118	$10,337
2028	$56,796	$9,865	$47,828	$9,865
2029	$54,201	$9,414	$45,643	$9,414
2030	$51,725	$8,984	$43,558	$8,984
2031	$49,362	$8,573	$41,568	$8,573
2032	$47,106	$8,182	$39,668	$8,182
2033	$44,954	$7,808	$37,856	$7,808
2034	$42,900	$7,451	$36,127	$7,451
2035	$40,940	$7,111	$34,476	$7,111
2036	$39,070	$6,786	$32,901	$6,786
2037	$37,285	$6,476	$31,398	$6,476
2038	$35,581	$6,180	$29,963	$6,180
2039	$33,956	$5,898	$28,594	$5,898
2040	$32,404	$5,628	$27,288	$5,628
2041	$30,924	$5,371	$26,041	$5,371
2042	$29,511	$5,126	$24,851	$5,126
2043	$28,163	$4,891	$23,716	$4,891
2044	$26,876	$4,668	$22,632	$4,668
2045	$25,648	$4,455	$21,598	$4,455
2046	$24,476	$4,251	$20,612	$4,251
2047	$23,358	$4,057	$19,670	$4,057
2048	$22,291	$3,872	$18,771	$3,872
2049	$21,272	$3,695	$17,914	$3,695
2050	$20,300	$3,526	$17,095	$3,526
2051	$19,373	$3,365	$16,314	$3,365
2052	$18,488	$3,211	$15,569	$3,211
2053	$17,643	$3,064	$14,857	$3,064
2054	$16,837	$2,924	$14,179	$2,924
Total	***$1,455,457***	***$252,790***	***$1,225,648***	***$252,790***
Cost difference	***$1,202,667***		***$972,858***	

Appendix 2: Survey of Other Decommissioning Studies

For context, Synapse reviewed a 2017 report published by Resources for the Future (RFF) and titled *Decommissioning US Power Plants: Decisions, Costs, and Key Issues*.[64] This report describes best practices for decommissioning plants by plant type (e.g. petroleum, coal, nuclear, wind). At $10.4 million (2018 CAD), or $7.5 million (2016 USD), the total cost for decommissioning the 55 MW CTGS appears high. This equates to a cost of $136,000 USD per MW. Comparing this result to the figure below, the costs of decommissioning CTGS are higher than past decommissionings of a similar size and type. The most expensive decommissioning of a gas/petroleum plant was just over $100,000 per MW, making the decommissioning costs at CTGS about 36 percent higher than similar projects. Figure 1 below illustrates these results.

Figure 1. Decommissioning cost by type of power plant



Source: Resources for the Future.

However, there is reason to believe that the $/MW metric is not representative of the cost-effectiveness of a decommissioning. For example, the cost per MW is likely to vary substantially depending on whether the decommissioning is for a single unit in a larger plant or for an entire plant. The former is unlikely to have associated demolition or remediation costs, whereas the latter is extremely likely to bear such costs. Additionally, there was no indication if the cost per MW values in the RFF report were inclusive of contingency allocations, which can add 20% or more to the total decommissioning cost.

[64] D. Raimi, 2017, Resources for the Future, Decommissioning US Power Plants: Decisions, Costs, and Key Issues. http://www.rff.org/files/document/file/RFF%20Rpt%20Decommissioning%20Power%20Plants.pdf.

Likely due to the confidential nature of decommissioning studies and cost estimates, relatively few studies were available to Synapse during this project. The table below summarizes recent studies reviewed by Synapse. The table illustrates the range in plant capacity and the range in net decommissioning costs, highlighting the extreme variability in cost estimates from plant to plant.

Table 6. Summary of recent decommissioning studies of fossil-fuel fired plants in Canada

Plant/ Unit Name	Size of Unit(s)	Fuel Type	Date of Study	Net Cost (CAD, nominal)	$/MW (CAD, nominal)	Land Resolution
CTGS	55 MW	Light Fuel Oil/ Heavy Fuel Oil	2018	$10,438,039	$189,000	TBD
CTGS/ Turbine 6	7.5 MW	Heavy Fuel Oil	2016	$291,000	$38,800	N/A
Dalhousie	320 MW	Orimulsion/ Heavy Fuel Oil	2011	$44,743,700	$139,000	Retained
St. John's	2.5 MW	Diesel	2003	*unknown*	*unknown*	*unknown*
Multiple Assets for FP&L	Various	Natural Gas, Fuel Oil, Coal and Solar	2016	Various	Various	Various
Multiple Assets for Duke Energy	Various	Natural Gas and Coal	2017	Various	Various	Various
Multiple Assets for OG&E	Various	Natural Gas, Coal, Wind and Solar	2017	Various	Various	Various
ACE Cogeneration	100 MW	Coal	2014	unknown	unknown	unknown
Multiple Assets for Xcel Energy	Various	Natural Gas/ Fuel Oil and Coal	2011	Various	Various	Various
Multiple Assets for Minnesota Power	Various	Coal and Wind	2015	Various	Various	Various

Sources: See Appendix 3 for sources.

Dalhousie Thermal Generating Station

Perhaps the closest analogue to the proposed decommissioning of CTGS is that which was proposed by New Brunswick Power in 2011 for its 320 MW Dalhousie Thermal Generating Station. We reviewed this study in depth. Note that it was also prepared by the firm GHD, and so while it was referenced for context and comparison, it cannot be treated as a completely independent example.

The total proposed cost for this decommissioning was $44,700,000 (2011 CAD), or $139,000 per MW (2011 CAD). This value is also higher than prior decommissioning cost estimates from the RFF report, indicating that costs may be higher in the Maritime provinces of Canada than in the United States. The Dalhousie Decommissioning Study proposed that all infrastructure be demolished, a complete remediation be conducted to minimize long-term maintenance, existing staff be utilized where possible, and all land be retained by the utility. Furthermore, a complete human and ecological risk assessment was performed to determine the extent of the remediation necessary. The decommissioning plan also maximized the value of existing assets by considering which assets could be repurposed at other New Brunswick Power facilities, which component parts could be sold, which turbines could be sold to secondary markets, and which power equipment items could be auctioned. Following that, several types of materials were evaluated for recycling value, including steel and other metals, concrete, plastics, and chemicals. Table 7 on the following page provides a cost comparison for Dalhousie and CTGS, in terms of both absolute costs and costs relative to the total.

There are several differences in relative cost even though Dalhousie has six times the capacity of CTGS. Most notably, the Dalhousie study includes an additional contingency budget (of 20% the estimated project cost by GHD), whereas the CTGS study does not include a 20% contingency on the estimated cost of decommissioning. Furthermore, the Dalhousie study specifically itemizes New Brunswick Power's "Labor, Property Taxes, and Insurance" costs, whereas the CTGS study only includes labor costs. Those labor costs are included in the "Project Management and Engineering", which seems to account for the large discrepancy between CTGS and Dalhousie's relative engineering costs. Nevertheless, the CTGS study seems to omit property tax and insurance in its cost estimates. Additionally, the site decommissioning costs make up a substantially larger portion of the overall for CTGS than for Dalhousie. If labor costs are relocated to the engineering category, a discrepancy of 13% still exists. It is unclear why site decommissioning costs make up a greater portion of the total cost for CTGS given the similarity between the two cost estimates, or why MECL does not include a cost item for cost estimation errors.

The remaining components of the decommissioning cost estimate are comparable given the substantial difference in total project cost.

Table 7. Comparison of total decommissioning cost estimates for CTGS and Dalhousie

Decommissioning Item	Sub-Item	CTGS		Dalhousie		Notes
		%	*CAD $, nominal*	*%*	*CAD $, nominal*	
1. Site Decommissioning Costs	-	56%	$6,472,684	33%	$14,638,750	*Includes building infrastructure, civil infrastructure, and remediation*
2. Allowances*	a. Contingency Allowance	6%	$647,268	7%	$2,928,000	*This contingency fund is for unidentified items associated with Item 1. CTGS has a 10% contingency allowance while Dalhousie had an allowance of 20%.*
	b. Additional Allowance	11%	$1,294,537	7%	$2,928,000	*Allowance for health and safety, mobilization, demobilization, bond, and insurance, contractor costs. Both CTGS and Dalhousie estimated a 20% contingency on Item 1.*
3. Project Management and Engineering	-	21%	$2,459,800	11%	$5,125,000	*CTGS formulated this value by approximating the cost of several different items, while Dalhousie estimated this as 25% of Item 1.*
4. Post-decommissioning and Misc. Costs	-	6%	$689,000	0%	$0	*This includes landscaping, environmental monitoring post-decommissioning, and other miscellaneous costs.*
5. Costs to Utility	a. Labor, Property Taxes, and Insurance	0%	$0	31%	$14,000,000	*Property taxes and insurance are not specifically listed in the CTGS cost estimate.*
	b. Total Contingency for Cost Study*	0%	$0	11%	$5,123,950	*This is a provision for a 20% cost estimation error on the estimate of items 1-5a. There is no comparable line item in the CTGS budget.*
Total Costs	-	100%	$11,563,289	100%	$44,743,700	
6. Recyclable Materials	-	-	$1,125,250	-	$0	*Dalhousie discusses recycling materials but does not estimate the revenue in the study.*
Net Cost	-	-	$10,438,039		$44,743,700	

**Note: The continencies and allowances presented here are shown as a percentage of the total cost. However, in the decommissioning studies they are shown as a percentage of the decommissioning cost subtotal.*

Turbine 6 at CTGS

In 2016, MECL submitted an application to decommission its Turbine #6 located at CTGS.[65] This turbine was 7.5 MW and was commissioned in 1951. The proposed cost of decommissioning was $291,000 (2016 CAD), equivalent to $38,800 per MW (2016 CAD). This value is consistent with decommissioning costs of a similar size and type, as illustrated in Figure 1, above – however, this decommissioning did not include any building demolition or site remediation. The primary reason for decommissioning Turbine 6 was the extraordinary cost ($4.4 million CAD) to make the necessary improvements to run the plant for an additional ten years. Owing to the positive economics of decommissioning Turbine 6, in conjunction with a confirmation that its removal would not impact energy commitments, the Commission approved the decommissioning.

St. John's Diesel Plant

In 2003, Newfoundland Power submitted an application to decommission its 2.5 MW diesel plant in St. John's, Newfoundland. [66] No cost estimates were associated with this proposal, likely due to the small size of the plant. Several studies were performed by Newfoundland Power on the condition and feasibility of maintaining the plant. These reports recommend that the utility cease operation and decommission the plant. The reports indicate that a substantial portion of the equipment in the plant is obsolete, or is in an aged and deteriorated condition, and extensive maintenance and repairs would be required to restore the plant to a safe and reliable operating condition. No information was available pertaining to whether the utility retained the land.

Kentucky

Burns & McDonnell Engineering Company, Inc. Kansas City, Missouri, was retained by Duke Energy Kentucky to conduct a decommissioning cost study for power generation assets in Kentucky and Ohio. The assets included natural gas and coal-fired generating facilities. The purpose of the study was to review the facilities and to make a recommendation to Duke Energy regarding the total cost to decommission the facilities at the end of their useful lives. Although there were multiple assets involved, the most representative site was the Woodsdale facility in Ohio, a natural gas power plant consisting of 6 units. The total plant capacity was 564 MW. Per the study, the total decommissioning cost was $10 million (2016 USD) which included the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. The decommissioning budget also included the costs to dismantle all of the assets owned by Duke Energy at the sites, including power generating equipment and BOP facilities, as well as environmental site restoration activities.

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[65] Maritime Electric Company Limited. Decommissioning Plan for Turbine Generator No. 6 and Auxiliaries.

[66] http://www.pub.nf.ca/ARCHIVE/np03cap/files/applic/np2003CapitalBudgetapp.pdf

ACE Cogeneration

ACE Cogeneration Company, LP (ACC) submitted a petition for decommissioning of the Argus Cogeneration Expansion (ACE) project. ACE is a coal-fired circulating fluidized bed cogeneration project. The reason for decommissioning the facility was due to ACC's existing Power Purchase Agreement with Southern California Edison which was about to expire in November 2015, and for compliance with California's greenhouse gas emissions requirements. The study did not specify the decommissioning costs, however it detailed the decommissioning activities, assessed conformance of those activities with applicable laws, ordinances, regulations and standards (LORS) and evaluated the potential for significant adverse impacts. The study also discussed the alternatives considered to decommissioning and the reasons for selecting the proposed course of action. This analysis considered the prospect of re-purposing the site to meet the future energy needs through a combined heat and power (CHP) plant using solar thermal, natural gas-fired or hybrid natural gas/solar thermal technologies, though this evaluation was only qualitative. The report offers broad reasons why it was not possible to re-purpose this facility for any the considered alternative functions. [67]

Florida Power and Light

Burns &McDonnell were retained by Florida Power & Light (FPL) to conduct a Dismantlement study for all the power generation assets in Florida and Georgia that were at the end of their useful lives. The assets included a combination of natural gas, fuel oil, solar and coal facilities. The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. The decommissioning costs included the costs to dismantle all of the assets owned by FPL at the site, including power generating equipment and balance of plant facilities, as well environmental site restoration activities. Although there were multiple assets covered under the study, the total cost of decommissioning of the units varied considerably and the most analogous units to CTGS were Lauderdale ($39 million, 2016 USD), Martin ($113 million, 2016 USD) and Manatee ($73 million, 2016 USD).

Xcel Energy in Colorado

In 2011, TLG services prepared an estimate of the cost to dismantle Xcel Energy's fossil fuel generating station in Colorado with the intention of supporting financial planning for future dismantling, but not to immediately dismantle the stations. The study included a combination of 30 units and both natural gas/oil and coal units. The entire dismantling cost was $335.8 million dollars (2010 USD) for 6476 MW of dismantling. The study was based on the assumptions of complete removal of the units and common station facilities.

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[67] ACE Decommissioning Plan, Pg. 6-1, November 2014

Oklahoma

Burns & McDonnell was retained by Oklahoma Gas and Electric to conduct a study estimating decommissioning costs. The assets include natural gas-fired, coal-fired, solar, and wind generating facilities. Individuals from Burns & McDonnell visited the 11 Plants evaluated within the study in March 2017. The purpose of the study was to review the facilities and to make a recommendation to OG&E regarding the total cost to decommission the facilities at the end of their useful lives.

Mustang Power plant

In addition to the 2017 decommissioning cost study, in the direct testimony of Witness Rowlett in 2014 on behalf of OG&E, it was determined that repurposing an existing coal installation (at Mustang Power Plant) into a new generation facility would be less expensive than demolishing it and having to construct the desired facility anew. So, the Mustang Power Plant, with 462 MW of combustion turbines, was built in the space of the former 480 MW coal plant that had been retired.

The justification provided by Witness Rowlett was that:

"The Mustang location already has the necessary infrastructure in place to support a generating facility, including a secure property, roads, facilities to support operations and maintenance, water supply and rights, fuel supply facilities, and most importantly, existing switchyard interconnections to both the 138 kV and 69 kV transmission systems. As discussed by OG&E Witness Burch, utilizing this existing infrastructure at the Mustang site is estimated to save OG&E customers $45 million compared to replicating that same infrastructure at a new Greenfield facility." [68]

[68] Rowlett Direct at page 9, lines 14-20, August 2014.

APPENDIX 3: DOCUMENTS REVIEWED

Document Title	Author	Year of Publication
Decommissioning Study	GHD for MECL	2018
Updated Phase II Environmental Site Assessment (ESA)	GHD for MECL	2018
Preliminary Options Analysis	GHD for MECL	2018
Class 4 BOP Cost Estimate	Chandler Architecture	2018
Repurposing Study	CBCL Ltd.	2018
2014 Depreciation Study	Gannett Fleming	2015
2017 Depreciation Study	Gannett Fleming	2018
Amendment to Appendix 11 of the General Rate Application	MECL	2019
MECL Responses to First Synapse Interrogatories	MECL	2018
MECL Responses to Second Synapse Interrogatories	MECL	2019
Turbine 6 Decommissioning Proposal and Plan	MECL	2016
Turbine 4 Proposal	MECL	2015
Order UE16-02	IRAC	2016
Phase I Environmental Site Assessment	Jacques Whitford	1995
Phase II Environmental Site Assessment	Fundy Engineering	2002
Charlottetown Thermal Plant Audit	Conestoga Rovers	2007
Plant Condition Assessment and 15 Year Life Extension Recommendations	ROS Consulting	2009
Perform an Analysis on the Requirements to Operate the Generating Units in a Safe Manner to the End of 2018	ROS Consulting	2015
Asbestos Inventory Assessment Report	All-Tech	2018
Geotechnical Investigation Report	Fundy Engineering	2004
Geotechnical Investigation Report	Fundy Engineering	2018
Lead Paint Disposal Guidelines	NB Department of Environment and Local Government	2014
Guidelines for Disposal of Contaminated Solids in Landfills	Nova Scotia Environment and Labour	2005
General Rate Application	MECL	2018
MECL Responses to IRAC Interrogatories	MECL	2019
2019 Capital Plan	MECL	2018
2017 Integrated Resource Plan	MECL	2017
Storm Post-Mortem Report	MECL	2018
Order UE16-04	IRAC	2016
Order UE16-04R	IRAC	2016
PEI Renewable Energy Act	PEI	-
PEI Environmental Protection Act	PEI	-
PEI Regulatory and Appeals Commission Act	PEI	-
PEI Electric Power Act	PEI	-
Decommissioning Study for Dalhousie Thermal Generating Station	Conestoga Rovers	2011
Florida Power and Light Dismantlement Studies	Burns & McDonnell	2016
ACE Cogeneration Petition for Decommissioning	ACE Cogeneration	2014
Duke Energy Decommissioning Cost Estimate Study	Burns & McDonnell	2017

Document Title	Author	Year of Publication
Direct Testimony of Donald Rowlett	Oklahoma Gas and Electric Company	2014
Rebuttal Testimony of Jeffrey T. Kopp	Oklahoma Gas and Electric Company	2018
Direct Testimony of Jeffrey T. Kopp	Oklahoma Gas and Electric Company	2018
Responsive Testimony and Exhibits of Brian C. Andrews	Brubaker & Andrews	2018
Dismantling Cost Study	Xcel Energy	2011
St. John's Diesel Plant Decommissioning Order	NL Board of Commissioners of Public Utilities	2003
Decommissioning US Power Plants: Decisions, Costs, and Key Issues.	Resources for the Future	2017