CREATIVEENERGY

1 February 2021

Via E-filing

Ms. Marija Tresoglavic
Acting Commission Secretary
BC Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Tresoglavic:

Re: British Columbia Utilities Commission (BCUC, Commission)
Creative Energy Mount Pleasant Limited Partnership
Application for Rates for the Mount Pleasant District Cooling System (DCS)(Application)

Creative Energy Mount Pleasant Limited Partnership writes to file the enclosed Application. We respectfully request the approvals set out in section 1.4.

For further information, please contact the undersigned.

Sincerely,

Rob Gorter
Director, Regulatory Affairs and Customer Relations

Enclosure.

CREATIVEENERGY

Creative Energy Mount Pleasant LP

Application for Rates for the
Mount Pleasant District Cooling System (DCS)

February 1, 2021

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1. Introduction

By Order C-5-20, the Commission granted a Certificate of Public Convenience and Necessity (**CPCN**) for Creative Energy Mount Pleasant Limited Partnership (**Creative Energy**, or **CEMP**) to acquire, operate and expand a Thermal Energy System (**TES**) to provide cooling service to the Main Alley Development in the Mount Pleasant neighbourhood of Vancouver (the **Mount Pleasant District Cooling System,** or **Mount Pleasant DCS**).

Effective today, February 1, 2021, CEMP has now acquired and commenced operating the Mount Pleasant DCS and providing cooling service to the customer. Through this application, CEMP requests Commission approval on an interim and refundable basis of rates for the three-year period, effective February 1, 2021 through December 2023 (the "**Current Rate-setting Period**"), for its provision of district cooling service to the Main Alley Development (**Application**).

The proposed interim rates for the Current Rate-setting Period are designed on a levelized basis and calculated on the basis of the actual costs of the acquisition and the forecast costs to complete all phases of the Mount Pleasant DCS. The Current Rate-setting Period is defined by the forecast completion of Phase 1 of the DCS by the third quarter of 2021 and with regard to the forecast completion of Phase 2 of the DCS to put into service in 2024.

Upon the completion of Phase 1, Creative Energy will file an Evidentiary Update to reflect the requested approval of permanent rates for the Current Rate-setting Period; that is, when the actual capital costs of Phase 1 are known and the assets are fully placed into service.

With the filing of the Evidentiary Update, expected by September 2021, CEMP would propose that the Commission then establish a written public hearing to review the application for final rates for the Current Rate-setting Period. Further elaboration into forecast rate-setting periods and a proposed regulatory process follows below.

Our requests for approval in this Application are set out below in section 1.4 and a draft order is attached at Appendix A. An interim rate schedule is attached at Appendix B. Creative Energy has attached to this Application its Rates Model, which sets out the forecast revenue requirements and the determination of levelized capacity charges for the Current Rate-setting Period.

A review of the Mount Pleasant DCS and project phasing follows directly below to assist placing the requested approvals and timing into further context.

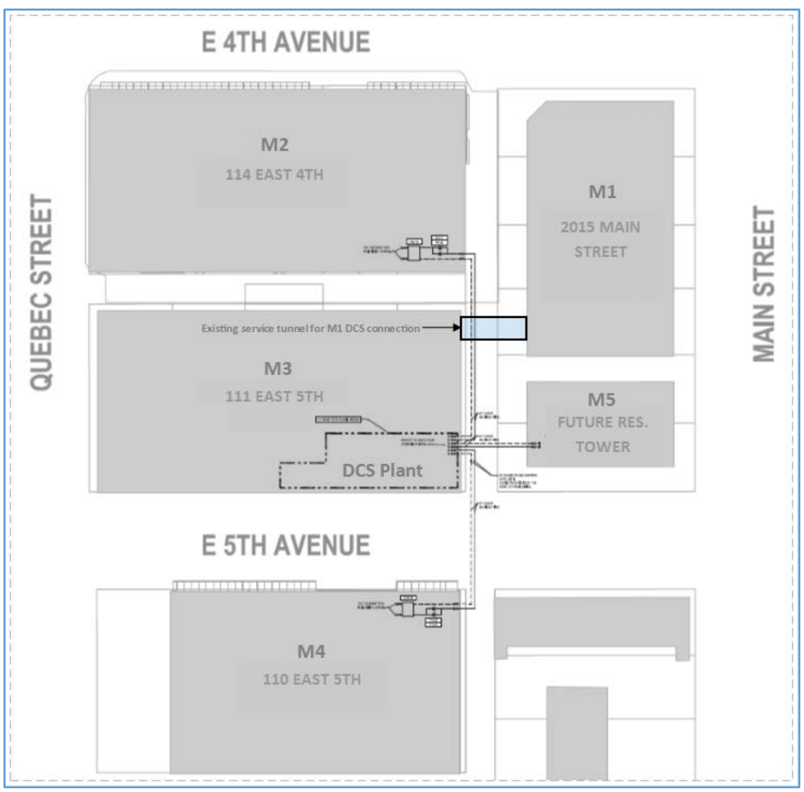
1.1. Review of the Mount Pleasant District Cooling System

Upon full build-out of the Main Alley Development, the Mount Pleasant DCS will serve five buildings, four commercial/light industrial use buildings (M1 – M4) and one residential building (M5). Please refer to Table 1. A system map is illustrated in Figure 1.

Table 1: Summary of the Main Alley Development

Building	Address	Building Size m^2	Design Peak Capacity kW	Estimated Annual Cooling MWh	Occupancy
M1	2015 Main St.	5,400	320	220	Current
M2	114 East 4th Ave.	15,979	840	655	2021
M3 (Existing /Expanded)	111 East 5th Ave.	7,880 /16,070	470 / 960	330 / 670	Current / 2027
M4	110 East 5th Ave.	19,250	1,155	790	2024
M5	2015 Main St.	11,519	390	240	2029

Figure 1: Buildings of Main Alley Development and the Mount Pleasant DCS



The M3 building has in place an existing cooling plant that serves both of the existing buildings, M1 and M3, thus comprising the assets that CEMP has acquired and is now operating.

Pursuant to a Construction and Purchase Agreement between CEMP and the Owner of the Main Alley Development[1], the Owner has agreed, in part, to: i) sell the existing cooling plant within the M3 building to CEMP; ii) allow CEMP to construct the DCS, to incorporate the cooling plant for the provision of space cooling to the buildings in the Development and to expand the DCS to serve the entire Development over time; and iii) connect the buildings to the DCS and enter into 25-year Customer Service Agreements (**CSAs**) with CEMP for the provision of space cooling services to each building. By Order C-5-20 the Commission has approved, subject to certain directives addressed separately, the CSAs for the M3 and Non-M3 Lands, respectively.

The Mount Pleasant DCS is forecast to be built in four phases through to commencement of service to M5 in 2029, with capital deployed at each phase. The construction phases of the DCS are designed to match load growth during the development lifecycle. The DCS construction phases are being coordinated with construction of the Main Alley Development so that capital is deployed only when the timing of additional load associated with the new building connections is confirmed by the customer. Under this implementation plan, the existing assets will be operated and maintained while a cost-effective upgrade and replacement construction program is executed. Please refer to Table 2.

Table 2: Summary of the DCS Phased Implementation

Phase	Description	Targeted Service Commencement	Essential Components	Total Capacity	Cumulative Peak Load Served
Initial Acquisition and Operation	Continue service to M1 & M3	September 1, 2020	• Two existing 350-ton chillers • Remove existing 150-ton chiller	2,460 kW[2]	790 kW
Phase 1	Connect M2 Upgrade M3 cooling plant capacity and reliability	2021	• DPS • ETS • Add 400-ton chiller to cooling plant	3,870 kW	1,630 kW
Phase 2	Connect M4	2024	• DPS • ETS	3,870 kW	2,785 kW
Phase 3	Serve renovated and expanded M3 Upgrade & Modernize M3	2027	• Replace two 350-ton chillers with two 400-ton chillers	4,220 kW	3,275 kW

[1] Please refer to Appendix B of Exhibit B-1 in the CPCN proceeding.
[2] One ton of chilling capacity = 3.51685 kW of chilling capacity.

Phase	Description	Targeted Service Commencement	Essential Components	Total Capacity	Cumulative Peak Load Served
	cooling plant		• Replace control system, add cooling tower, equip with modern ETS		
Phase 4	Connect M5	2029	• DPS • ETS	4,220 kW	3,665 kW

1.2. Application Overview

Levelized Capacity Charge

Creative Energy applies for approval of a levelized capacity charge to recover the fixed costs of the annual revenue requirements of the DCS on a $/kW basis.

The levelized capacity charge rate structure is reviewed in sections 1.3, 3 and 4 and the proposed interim rates are set out in Table 8. The levelized structure provides for smooth and stable rate increases over time as capital is deployed at each phase and buildings commence taking service.

The levelization of rates extends over the life of the customer service agreement terms, from 2021 (the year the first CSA commences) through the 25 year-term of the CSA for building M5 upon DCS service commencement; that is, a period of 33 years in total through to 2053. The revenues in the Rates Model also correspond to the CSA terms, with revenues commencing when a given CSA commences and continuing for the 25-year term of such CSA.

As introduced above and elaborated further below in section 1.3, while the levelization period is 33 years in the Rates Model, CEMP is requesting in this Application Commission approval on an interim and refundable basis only of rates for the three-year Current Rate-setting Period. An Evidentiary Update is contemplated at this time for September 2021 to seek approval of permanent rates for this period on the basis of the actual costs of Phase 1 completion. Future rate applications will follow in due course and will seek approval of permanent rates set on the basis of the actual costs to complete each phase of the Mount Pleasant DCS and corresponding to the time period that assets are placed in service.

Revenue Deficiency Deferral Account

While the levelized rates are designed to recover the cost of service over the period of levelization, the rates are forecast to recover less than the cost of service during the initial years of service. CEMP therefore also applies for approval of a rate smoothing Revenue Deficiency Deferral Account (**RDDA**) and approval of the amounts to be added to the RDDA over the Current Rate-setting period. The RDDA will enable CEMP to recover, in later years, the forecast deficiency during the initial years of service.

Thus, the RDDA allows for a levelized rate structure with low rates initially and smoothed rate changes over time recognizing that the rates will not initially recover forecast revenue requirements. With Commission approval of the levelized capacity charges and of the RDDA, forecast revenue shortfalls during initial years of service will be added to the overall balance of the RDDA to be ultimately recovered through levelized rate increases over time. The balance in the RDDA will attract interest at Creative Energy's weighted average cost of capital until the balance is reduced to zero during the 33-year term over which levelized rates will be set.

Variable, Flow-through Charge

Creative Energy applies for approval of a variable charge calculated monthly and based on actual total electricity and water costs divided by actual cooling energy consumption. The variable charge will recover the cost of service that varies directly with energy consumption by flowing-through the actual costs on a cost recovery basis. A discussion of the variable charge rate structure is set out in section 3.

Regulatory Cost Variance Deferral Account

The proceeding to review this Application has not been established and the associated costs of the proceeding and the amounts that Creative Energy will be directed to pay are not known, are uncertain and are generally outside of Creative Energy's control. Future rate applications will also be required as project phases complete. Creative Energy therefore seeks approval of a Regulatory Cost Variance Deferral Account (**RCVDA**) to record the difference between a regulatory cost forecast for each rate-setting period and final actual costs when so determined.

Regulatory expenses are difficult to forecast, are overall not in Creative Energy's control and variances from such forecast costs are in general a risk that a public utility should not have to bear. It is for these reasons that a deferral account is appropriate to record the cost variance from forecast for recovery or refund, and also why most if not all utilities regulated by the Commission have equivalent deferral accounts, including Creative Energy Vancouver Platforms Inc. in respect of its Core Steam and Northeast False Creek service areas.

Creative Energy includes an amount of $25,000 in regulatory costs in its Rates Model for each rate-setting period, which is an indicative estimate of regulatory costs for Commission fees, PACA fees and external regulatory legal support based on experience. We consider the estimate to be reasonable for the purpose of setting initial rates. We would propose that any variances will be administratively simple to recover or credit as a set percentage of a customer's total bill until the variance balance is cleared. A five percent allocation per month would be reasonable for this purpose.

1.3. Approach to Rate-setting and Regulatory Process

The coordination of each construction phase of the Mount Pleasant DCS with the phases of the Main Alley Development and the protections in place under the Construction and Purchase Agreement underpin the ability of CEMP to forecast rates under a single 33-year levelization period. That is, the forecast costs to complete the entire DCS through all four phases and the total of the peak design capacities (kW) of all buildings, which are the billing determinants for capacity charge, enable the single levelization period.

The billing determinants for the levelized capacity charges (kW of peak design capacity) stem directly from the contracted need for cooling stipulated by the Owner/Customer to serve all five buildings of the Development and through the Construction and Purchase Agreement the Owner/Customer accepts all associated risk of stranded DCS assets if the Development does not entirely proceed or is delayed.

Under the Construction and Purchase Agreement Capital will not be deployed before the timing and capacity requirement of new customer load associated with the new building connections is confirmed. CEMP will only begin constructing a next phase of the DCS when the building to be served already has financing in place and has been under construction for several months.

Therefore, CEMP is able at this time to file for the approval of rates for the three-year Current Rate-setting period of 2021-2023 in anticipation of the completion of Phase 1 this year.

We would then anticipate filing future rate applications when the future DCS assets are placed into service, coincident with each phase completion and for the following rate-setting periods as follows:

- Phase 2 Completion Rate Application: Three-year Rate setting period 2024-2026[3];
- Phase 3 Completion Rate Application: Two-year Rate setting period 2027-2029; and
- Phase 4 Completion Rate Application: Rate-setting period to be determined.

In effect, the future rate applications contemplated above will represent an Evidentiary Update to the forecast costs of each Phase that are already factored into the 33-year levelization period.

In view of the circumstances reviewed above, CEMP proposes that interim rates be approved following the Commission's internal review of the evidentiary basis provided with this Application, which closely follows the information presented in support of the CPCN application.

CEMP would expect to in mid-March issue an invoice to the customer of the Mount Pleasant DCS for February service. A Commission order in the early part of March, approving rates on an interim basis effective as of February 1, 2021, would accommodate CEMP's invoicing schedule

[3] In the CPCN application it was set out that M4 was expected to be occupied in 2023. It is now assumed under current planning that M4 will be occupied in 2024 and the DCS assets of Phase 2 will be placed into service at the start of 2024.

and also allow the Commission at least 30 days to review our request for interim approval.

CEMP proposes that upon the filing of the Evidentiary Update the Commission then establish a written public hearing to review the proposed final rates for the Current Rate-setting Period.

1.4. Requested Approvals

In this Application, Creative Energy is seeking an Order of the Commission granting the interim approvals described below pursuant to the noted sections of the legislation. A draft Commission Order is provided in Appendix A to this Application while Appendix B provides the corresponding rate schedule for approval.

At this time Creative Energy requests interim approval, effective February 1, 2021 (the date that Creative Energy begins providing service), and pursuant to sections 58 to 60 and 90 of the *Utilities Commission Act* (the **Act**) and section 15 of the *Administrative Tribunals Act*:

- the Levelized Capacity Charges set forth in section 4 and in Appendix B;
- the RDDA described in sections 1.2 and 4;
- the Variable Charge set forth in Appendix B; and
- the RCVDA described in section 1.2.

CEMP will set out in the Evidentiary Update its requested approvals of proposed final rates in the Current Rate-setting Period and the incremental additions to the RDDA in each year of the Current Rate-setting Period.

2. Revenue Requirements

2.1. Capital and Development Costs

Total forecast capital and development costs of the Mount Pleasant DCS are summarized in Table 3 below. Please refer to Appendix C for a more detailed category summary consistent with the reporting provided in the CPCN proceeding.

Table 3: Summary of Estimated Capital and Development Costs

	Initial Acquisition and Operation	Phase 1	Phase 2	Phase 3	Phase 4	Total
Purchase of Assets	419,222					419,222
Energy Center		1,086,656		3,891,813		4,978,468
DPS and ETS		322,850	345,675		273,983	942,508
Predevelopment	177,455					177,455
CPCN	22,141					22,141
Engineering		195,598		317,278		512,876
Soft Costs		229,354		547,009	40,733	817,096
Internal	77,976	88,576		229,860	67,092	463,504
Contingency		281,901	69,135	778,363	54,797	1,184,196
Total – Rate Application	696,784	2,204,935	414,810	5,764,322	436,605	9,517,457
Total – CPCN proceeding	732,793		2,619,744	5,764,322	436,605	9,553,463

The cost to acquire the existing DCS assets is the agreed-to amount set out in the Construction and Purchase Agreement based on the value of the depreciated assets.[4] The capital costs associated with the Energy Center, DPS and ETS at each applicable phase of DCS development are estimated to a Class 3 level of accuracy. Predevelopment activities comprise primarily feasibility studies and design work. Forecast engineering costs are an estimate of engineering and construction costs calculated as a percentage of hard costs. Soft costs consist of mobilization, demobilization, bonding and insurance costs. Internal costs are estimated as a percentage of applicable construction and equipment costs. Contingency is 20 percent based on the project team/design engineer's assessment of risk relating to construction costs. For further detail, please refer to Appendix 2.

2.2. Operations and Maintenance Costs

The assumptions underpinning the annual operation and maintenance costs of the DCS are summarized in Table 4. Annual costs are reported for 2021, while the escalation of these costs

[4] Please refer to Schedule K of Appendix B of Exhibit B-1 in the CPCN proceeding for a report on this valuation as accepted by both CEMP and the Owner.

over the three-year period of the requested approvals is set out further below in Table 5.

Table 4: Operations and Maintenance Costs – 2021

Component	2021	Assumption
Maintenance	0	1% of Capital - N/A for 2021 given capital budget for existing plant and new plant
Operators	275,000	3x Operators @ $100K per FTE, pro-rated for 11 months of service in 2021
Lease	36,667	2,000 sq.ft x $20/sq.ft per Contribution Agreement, pro-rated for 11 months of service in 2021
Property Tax	0	N/A - responsibility of landlord
Municipal Access Fees	5,821	1.25% of Fixed and Variable Revenue
Insurance	9,135	0.29% of plant-in-service, and 2-Years of Projected EBITDA
Financing Fees	2,432	0.30% of Deemed Debt
Corporate Overhead	75,709	3-Factor Massachusetts formula allocation based on 2021 allocable overhead
Regulatory Costs	25,000	Third-party costs and external legal support to rates application preparation and review process

Maintenance

The forecast is based on Creative Energy's experience that an amount of 1 percent of actual construction costs per year is sufficient and appropriate for both routine and sustained annual maintenance.

Maintenance costs do not include a reserve to replace equipment. Creative Energy is of the opinion that the estimate of 1 percent per year is sufficient to cover any replacement items that are required in the normal course of operation.

Emergency repair costs have not been factored into the estimates of maintenance costs for this project. As the magnitude and timing of emergency repair costs cannot be predicted, we have refrained from forecasting them. Should extraordinary events require maintenance costs that exceed our estimate of recurring maintenance costs, Creative Energy will apply for recovery of those costs at that time as applicable and only if necessary.

Operator

The Mount Pleasant DCS fits in the category of plants requiring 'General Supervision' per the requirements of Technical Safety BC, which broadly implies a requirement for two full-time operators, on site 7 days a week. CEMP is therefore planning to this level of supervision and expects therefore to employ 3 operators in total to operate the DCS.

Operator costs are estimated based on the requirement for 3 full-time operators at $100,000 per year.

Lease Payments

Lease payments are based on the cooling plant space requirement of 2,000 square feet at a rate of $20 per square foot and escalating at inflation. The amounts are pursuant to a Contribution Agreement between CEMP and the Owner, as reviewed in the CPCN proceeding.[5]

Municipal Access Fee

While CEMP does not have a Municipal Access Agreement ("MAA") with the City of Vancouver, it has been working under the MAA to perform work in the laneway and CEMP foresees no issues with obtaining all necessary approval in accordance with City of Vancouver Street Utilities Bylaws. The MAA fees in the Rates Model are thus indicative of the fees that will likely apply. MAA fees are assumed to be equal to 1.25% of fixed and variable revenues.

Insurance

Insurance costs consist of business interruption and replacement insurance. Business interruption insurance is calculated based on two-years of projected EBITDA while replacement insurance is based on the accumulated construction costs of the project, each at the applicable rate of 0.29 percent and escalated at inflation.

The Mount Pleasant DCS asset is insured directly for property insurance and business interruption insurance. It is also covered under Creative Energy Vancouver Platform Inc.'s general liability, umbrella, director and officers and errors and omissions policies.

Property insurance and business interruption insurance will be directly charged to the DCS, while general liability and the other policies are included in Administration costs as allocated.

Financing Fees

The reported amounts are the annual refinancing fees of 30 basis points on the credit facilities consistent with HSBC term sheet and allocated pro rata to the DCS on the basis of deemed debt.

Corporate Overhead

General and Administration expense is allocated under the Commission-approved Massachusetts Formula currently in effect and in accordance with Creative Energy's Transfer Pricing Policy, attached at Appendix E. The Transfer Pricing Policy is being reviewed separately as a component of Creative Energy Vancouver Platform Inc.'s 2021 Revenue Requirements Application for its Core Steam system in the process established by Order G-11-21A.

The following categories of General and Administration costs comprise the allocable overhead

[5] Refer to Appendix C of Exhibit B-1 in the CPCN proceeding.

and do not include any expenses that can be directly assigned:

- Directors fees;
- Residual salaries and benefits (such costs are first directly assigned to utility projects);
- Office supplies & expenses;
- General legal and audit fees; and
- General liability, umbrella and other insurance not directly charged.

Regulatory Costs

Regulatory costs are estimated as reviewed in section 1.3.

Cost Escalation Factor

For the purpose of setting rates over the 2021-2023 period, and as set out in the attached Rates Model, Creative Energy has assumed an annual inflation rate of 2 percent on applicable costs. This assumption accords with the current Bank of Canada inflation control target, which can be referenced at the following link: https://www.bankofcanada.ca/rates/indicators/key-variables/inflation-control-target/

2.3. Variable Electricity and Water Costs

As reported in Table 5 below, the total annual revenue requirements of the DCS reflect indicative estimates of electricity and water costs based on the estimated demand for cooling energy and the applicable rates for electricity and water, which expenses will be directly flowed-through based on actual invoiced amounts on variable usage (as explained further in section 3).

- Actual electricity costs will be the amounts invoiced by BC Hydro each month for the electricity usage of the Cooling Plant under the rates for Large General Service; and

- Actual water costs will be equal to the City of Vancouver's water rates for water consumption multiplied by the usage of water by the Cooling Plant, as measured by a sub-meter downstream of the City of Vancouver 'property line' water meter.

The rates for electricity and water consumption are externally set, and the volumes of electricity and water consumed by the DCS are driven directly by variable cooling usage. Creative Energy does not control or manage either of these factors and accordingly proposes a variable charge to flow-through these expenses on an actual as-incurred basis.

The Application includes indicative estimates of these costs; however, under the proposed fixed and variable rate design these estimates have no material effect on the revenue requirements of the DCS for the purpose of rate setting.

2.4. Annual Revenue Requirements

Please refer to Table 5 for a summary of annual requirements over the requested rates approval period.

Table 5: Annual Revenue Requirements 2021-2023

Component	**2021**	**2022**	**2023**
Depreciation	117,509	117,509	117,509
Cost of Debt	32,433	63,514	65,774
Cost of Equity	56,933	111,494	115,462
Income Tax	15,372	30,103	31,175
Cost of Electricity	33,833	48,991	50,461
Water/Chemical Costs	2,369	3,501	3,571
Maintenance	0	29,965	30,564
Operators	275,000	306,000	312,120
Rent	36,667	40,800	41,616
Property Tax	0	0	0
Municipal Access Fees	5,821	8,457	8,632
Insurance	9,135	9,516	12,108
Financing Fees	2,432	4,764	4,933
Corporate Overhead	75,709	77,223	78,768
Regulatory Costs	25,000	0	25,000
Fixed Cost of Service	**652,011**	**799,345**	**843,661**
Variable Cost of Service	**36,203**	**52,493**	**54,032**
Total Cost of Service	**688,213**	**851,837**	**897,694**

Depreciation

Annual depreciation is the sum of straight-line depreciation over 25 years for each phase of capital based on the year it enters service. This assumption is reasonable and effectively equal to weighted average depreciation period in years of all components of Capital and Development costs as shown in Table 6.

Table 6: Depreciation Period

	Capital & Development ($)	Depreciation Period (years)	Annual Depreciation ($)
Energy Center	4,978,469	20	248,923
DPS and ETS	942,508	40	23,563
Predevelopment	177,445	30	5,915
CPCN	22,141	30	738
Engineering	512,876	30	17,096
Soft Costs	817,096	30	27,237
Internal	463,504	30	15,450
Contingency	1,184,196	25	47,368
Total / Average	9,098,235	24	386,289

Income Tax

The amounts are calculated based on 27 percent of the return on equity plus depreciation less capital cost allowance (**CCA**), the latter consistent with the Class 17 designation that this type of asset would be categorized under.

Return on Capital

Projected financing costs reflect a deemed capital structure of 57.5 percent debt and 42.5 percent equity and an equity risk premium of 75 basis points above the low-risk benchmark. The corresponding allowed return on equity (**ROE**) is 9.5 percent and Creative Energy estimates that an overall cost of debt of 4.0% is reasonable at this time and consistent with the current average debt rate in effect under rate approvals for Creative Energy's Core steam system.

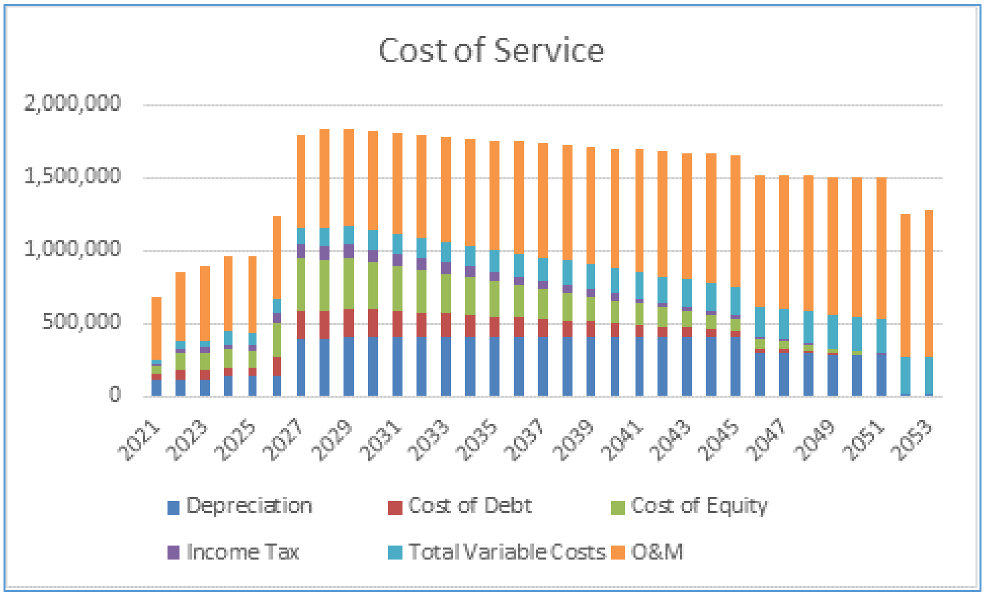
Creative Energy submits that it is reasonable to use the default deemed capital structure and ROE consistent with the Commission's direction as set through the Generic Cost of Capital (**GCOC**) Stage 2 Decision of a default equity thickness of 42.5 percent and an equity risk premium of 75 basis points for regulated thermal energy systems, of which the Mount Pleasant DCS is an example.

The assumed capital structure and ROE is appropriate, reasonable and aligns with the precedent established by the Commission in its GCOC Stage 2 decision. CEMP is not seeking approval of a capital structure and risk premium over and above the levels set under the GCOC Stage 2 decision and in view of a pending 2021 GCOC Commission proceeding to review the underlying component of allowed returns. A risk matrix is included at Appendix D. CEMP includes reference to the risk matrices completed in respect of a few other TES to highlight the general applicability of the established deemed capital structure and equity risk premium for small TES utilities.

2.5. Summary of Revenue Requirements

Please refer to Figure 2 for an illustration of annual revenue requirements over the duration of the term of all CSAs.

Figure 2: Annual Cost of Service



3. Rate Design and Billing Determinants

Creative Energy seeks approval to recover its cost of service for the Mount Pleasant DCS through:

1. a fixed capacity charge ($/kW); and
2. a variable charge that flows through actual electricity and water input costs on a $/MWh of actual energy consumption basis.

The proposed rate design is the same rate design proposed for both of Creative Energy Vancouver Platforms' Vancouver House Heating TES and Cooling TES, which is approved on an interim basis by Orders G-260-19 and G-225-20, respectively. A process to jointly review that rate design, among other matters, was established by Order G-233-20 and is ongoing.

The merits of the rate design have been fully set out in the aforementioned proceeding, and which we consider applicable also for the purpose of establishing a rate structure and billing determinants to fairly and reasonably recover the cost of service of the Mount Pleasant DCS under a levelized rate design.

We provide below a brief review of the rate design in the context of the billing determinants of the Mount Pleasant DCS.

Subject to a Commission decision into the Vancouver House Heating TES and Cooling TES rate design, Creative Energy will if and as required carry forward any additional rate design considerations as part of its planned Evidentiary Update into this Application.

3.1. Capacity Charge

The capacity charge will recover the capital and fixed operating costs of the DCS on a $/kW basis and invoiced in accordance with the design peak capacity of each building. The capacity charge will recover all costs that do not vary with energy consumption; that is, the cost of service excepting variable electricity and water costs. In that regard, these costs are considered 'fixed' and therefore should not be recovered on a $/MWh basis.

The level of the capacity charge is set based on total design peak capacity of all buildings in the Main Alley Development, which is the overall driver of the fixed costs of the DCS. Correspondingly, the billing determinants for the allocation of capital and fixed operating costs to each building are the total design peak cooling demand in kW of each building in the Main Alley Development.

Table 7: Capacity Charge Billing Determinants

Building	**Design Peak Capacity kW at DCS project completion**
M1	320
M2	840
M3[6]	960
M4	1,155
M5	390
Total Billing Determinants	3,665

The fixed structure of the capacity charge thereby fairly and reasonably aligns with a cost causation rate setting principle under which rates ought to recover costs in a manner consistent with the factors that cause those costs; that is, in this case, with respect to costs that are not expected to vary with energy consumption. The capacity charge also supports stable and predictable rates and recovery of the revenue requirement because the recovery of fixed costs is not tied to energy use. The capacity charge is readily understood and serves customer understanding and acceptance in the particular case where the customers are effectively the buildings.

3.2. Variable Charge

The Variable Charge will recover on a flow-through basis the actual electricity and water costs of the DCS, which are driven directly by cooling energy consumption.

[6] Until M3 is expanded, the invoice for capacity charges to M3 will be based on 470kW, as shown in Appendix B.

- With respect to electricity costs, Creative Energy will determine the $/MWh variable charge each month as the invoice of BC Hydro costs ($) divided by the total metered energy consumption at the Cooling Plant for cooling all buildings in that month (in MWh). Creative Energy will bill each building customer in accordance with such calculated rate ($/MWh) multiplied by each individual building's metered cooling energy use (MWh).

- Water costs are invoiced every four months by the City of Vancouver. Creative Energy will determine for each building customer their allocated water cost for the four-month period based on their pro rata share of total cooling energy consumption over the corresponding four-month period.

The overall variable charge therefore will be expressed on a $/MWh basis, calculated monthly and equal to total monthly electricity costs plus total monthly allocated water costs divided by total monthly cooling energy consumption.

The underlying electricity and water rates are externally set, and total electricity and water costs vary directly with cooling energy consumption outside of Creative Energy management and control. The flow-through of such costs is therefore fair, readily understood and verifiable, and the mechanism to allocate these charges in the same applicable billing period is administratively simple and does not require a deferral account.

Creative Energy notes that larger utilities commonly use deferral mechanisms and periodic (quarterly or annual for example) adjustments to a rate rider to flow the utility's actual fuel costs through to customers. Such utilities may have a large portfolio of energy supply resources and thousands of customers. Creative Energy's proposal accomplishes the same thing (that is, flowing through actual fuel costs to customers) without requiring a deferral mechanism or burdensome regulatory process in respect of adjustments to the charge.

4. Proposed Levelized Capacity Charges 2021-2023

In general, levelized rates are considered advantageous for district energy utilities because such rate design supports those rate design principles that favour lower rates initially and smooth and predictable rate increases over time. This is notwithstanding the annual cost of service of a district energy utility will often be higher in the initial years when the capital costs are incurred to construct the system and decline over time as the assets depreciate.

Levelized rates that escalate gradually over time align to those rate design principles and are better understood by customers as compared to a cost of service rate set on a long-term basis that may fluctuate year to year and, particularly in the case of a small TES with a fixed base of customers, decline over time. Cost of service rates for such TES tend to be initially higher due to the allowed return on capital which is initially undepreciated and then reduces over time with accumulated depreciation, while levelized rates tend to start lower and then increase at a smooth rate of increase reflecting inflation.

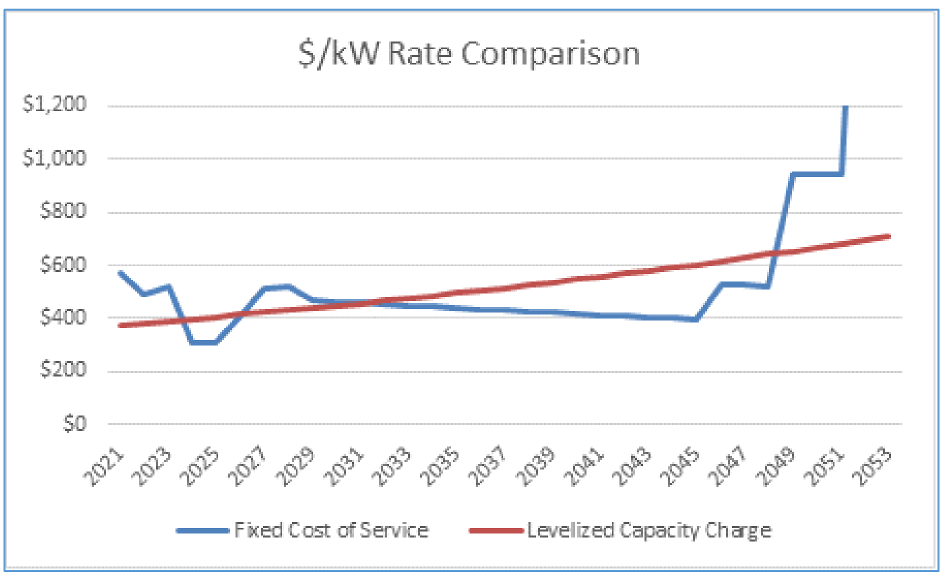
The approval of an RDDA is a necessary component to support implementation of its levelized capacity charge. Rate smoothing will be in place over the entire 33-year levelization period and the purpose of the RDDA will be complete when its balance is reduced to zero. Once the RDDA balance is reduced to zero the RDDA will be cancelled.

Table 8 sets out the proposed levelized capacity charge and fixed revenue in comparison to the corresponding annual cost of service, and the forecast additions to the RDDA determined on this basis.

Table 8: Proposed Levelized Capacity Charge 2021-2023

	Unit	2021	2022	2023
Proposed Levelized Capacity Charges	$/kW/year	$375.37	$382.87	$390.53
	$/kW/mo.	$31.28	$31.91	$32.54
Billing Determinants of M1, M2 and M3	kW	1,630	1,630	1,630
Annual Capacity Charge Revenue[7]	$	429,482	624,084	636,566
Annual Fixed Cost of Service	$	652,011	799,345	843,661
Forecast RDDA additions	$	222,529	175,261	207,096

Figure 3: Levelized Capacity Charge versus Fixed Cost of Service Rate



[7] Revenues in 2021 reflect 11 months of billing M1 and M3 (effective February 2021) and 6 months of billing M2 (effective July 2021)

5. Other Rate Setting Considerations

The following discussion addresses the rate design considerations specifically noted in the TES Regulatory Framework Guidelines.

Equitable Balance of Cost and Risk

The proposed rates balance cost and risk in that a portion of the fixed charge is recovering operating costs that do not vary with consumption but that may still vary within an approval period and for which the utility would share risk if actual operating costs differ from the forecast under which rates are approved.

Amounts that accrue to the RDDA relate only to the approval of the levelized rate design put into effect for the rate-setting period. Additions to the RDDA are thus confirmed and approved by the Commission on a forecast not actual basis; that is, based on forecast cost of service and forecast revenues at approved rates. Thus, the risk of variances between actual and forecast controllable costs is not transferred to ratepayers under the RDDA and is born by the utility.

Least Deferral Mechanisms Possible

Creative Energy has proposed a RDDA as a rate smoothing mechanism and which enables the implementation of a levelized rate design. The only variance deferral mechanism that Creative Energy has applied for is the RCVDA to capture any variances between actual and forecast regulatory costs. Regulatory costs are inherently uncertain at this time and are largely outside of Creative Energy's control.

Restrict Ability of the Utility to Pass Controllable Costs onto Ratepayers

Creative Energy has not proposed any variance deferral mechanisms for the operating costs that are within its control.

Use the Least Amount of Regulatory Oversight to Protect the Ratepayer

Creative Energy's proposed levelized rate design and application for approval of rates for a three-year period provides predictable and stable rates, and supports regulatory efficiency.

Avoid Rate Shock

The levelized rates are set to fully recover the cost of service over the contract term assuming a 2 percent annual escalation factor.

Appendix A

Draft Order

Order Number
●

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

and

Creative Energy Mount Pleasant Limited Partnership.
Application for Rates for the
Mount Pleasant District Cooling System (DCS)

ORDER

WHEREAS:

A. On February 1, 2021, Creative Energy Mount Pleasant Limited Partnership (CEMP) applied to the British Columbia Utilities Commission (BCUC) for interim approval of rates, a Revenue Deficiency Deferral Account (RDDA) and a Regulatory Cost Variance Deferral Account (RCVDA), effective February 1, 2021, for its provision of cooling service at the Main Alley Development (Application);

B. CEMP's proposed rate design consists of a levelized capacity charge per kilowatt (kW) per month (Capacity Charge) and a variable charge per megawatt hour (MWh) (Variable Charge);

C. The Application requests approval of rates, initially on an interim and refundable basis, for a three-year rate-setting period effective February 1, 2021 through December 2023, the Current Rate-setting Period, which is the period defined by the forecast completion of Phase 1 of the build-out of the Mount Pleasant DCS by the third quarter of 2021 and prior to the scheduled completion of Phase 2 of the Mount Pleasant DCS by 2024;

D. CEMP advises that upon the completion of Phase 1, it will file an Evidentiary Update to support the requested approval of permanent rates for the Current Rate-setting Period; that is, when the actual capital costs of Phase 1 are known and the assets are fully placed into service. The Evidentiary Update is expected to be filed in September 2021;

E. CEMP will set out in the Evidentiary Update its proposed final rates in the Current Rate-setting Period and the forecast incremental additions to the RDDA in each year of the Current Rate-setting Period;

F. CEMP proposes that upon the filing of the Evidentiary Update the BCUC then establish a written public hearing to review the proposed final rates for the Current Rate-setting Period;

G. CEMP will seek approval of the forecast amounts to record in the RDDA as based on the annual revenue deficiencies or surpluses resulting from the difference between forecast annual revenue at final approved rates and the forecast annual cost of service;

H. CEMP requests approval of the RCVDA to record the difference between the regulatory cost forecast provided in the Application and the final actual regulatory costs; and

I. The BCUC has reviewed the Application and consider that the proposed rates should be approved on an interim basis.

NOW THEREFORE the pursuant to sections 59-61 and 90 of the Utilities Commission Act, the BCUC orders as follows:

1. CEMP is approved to charge a Capacity Charge as set out in Appendix B to the Application, on an interim and refundable basis, effective February 1, 2021 and subject to further order of the BCUC. The BCUC will determine the manner by which any variance between the approved interim rates and permanent rates, including interest if any, will be refunded to or collected from the ratepayer at the time the BCUC renders its final decision on the Application.

2. CEMP is approved to charge a Variable Charge as set out in Appendix B to the Application, on an interim and refundable basis, effective February 1, 2021 and subject to further order of the BCUC. The BCUC will determine the manner by which any variance between the approved interim rates and permanent rates, including interest if any, will be refunded to or collected from the ratepayer at the time the BCUC renders its final decision on the Application.

3. CEMP is approved to establish the RDDA as proposed in the Application.

4. CEMP is approved to establish the RCVDA as proposed in the Application.

5. CEMP is to file with the BCUC the rate schedules reflecting the interim rate approvals in this Order for endorsement by the BCUC within 15 days of the date of this Order.

6. A regulatory process and timetable for review and approval of final permanent rates will be established in due course upon the filing by CEMP of an Evidentiary Update to the Application following the completion of Phase 1 of the Mount Pleasant DCS.

DATED at the City of Vancouver, in the Province of British Columbia, this _____ day of ____ 2021.

Appendix B

Interim Rate Schedule

CREATIVE ENERGY MOUNT PLEASANT LIMITED PARTNERSHIP

1. RATE SCHEDULE

Applicability: Mount Pleasant District Cooling System (DCS) served by the Utility.

Class of Service: Thermal energy for the provision of cooling service to the three buildings at the Main Alley Development in Vancouver over the period defined below and as listed.

Rates for Service: **Capacity Charge per kilowatt per month for the period effective February 1, 2020 through December 31, 2023, as follows:**

Year	2021	2022	2023
$/kW/mo.	$31.28	$31.91	$32.54

The applicable Capacity Charge billing determinants to the three buildings at the Main Alley Development over the defined period are as follows:

Building Customer	Civic Address	Design Peak Cooling Demand (kW)
Building M1	2015 Main St.	320
Building M2	114 East 4th Ave.	840
Building M3	111 East 5th Ave.	470

Variable Charge per megawatt hour for all megawatt hours supplied during a month: $/MWh calculated monthly

The Variable Charge is to be calculated each month equal to total monthly electricity and water costs of the DCS divided by the total metered energy supplied by the DCS to the building customers during the month (in MWh).

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Issued by: ____________________________

Accepted
for Filing:______________________________

Krishnan Iyer
CEO

Creative Energy Vancouver Platforms Inc.
Suite 1, 720 Beatty Street
Vancouver, B. C. V6B 2M1

____
Acting Commission Secretary
British Columbia Utilities Commission

Effective Date: February 1, 2021
Approved on an interim basis by Order G-xxx-21

Appendix C

Forecast Capital and Development Costs

Mount Pleasant DCS Capital and Development Costs	Initial Acquisition and Operation	Phase 1 & 2	Phase 1			Phase 2	Phase 3	Phase 4	Total
	actual	forecast	actual	forecast	total	forecast	forecast	forecast	forecast
Purchase of Assets	419,222								419,222
Demolish Chiller #3 (150 Ton)		37,950		37,950	37,950				37,950
Supply and Install Chiller #3		819,046		819,046	819,046				819,046
Service chiller #1 & #2		17,160		17,160	17,160				17,160
Electrical Allowance		212,500		212,500	212,500		212,500		425,000
Supply and Install Chiller #1							907,532		907,532
Supply and Install Chiller #2							566,721		566,721
Demolish Chiller #1 (350 Ton)							37,950		37,950
Demolish Chiller #2 (350 Ton)							37,950		37,950
Supply and install cooling tower #4 (566 ton)							317,350		317,350
Interim cooling tower measure							825,440		825,440
Relocate cooling towers to new roof							839,520		839,520
Upgrade condenser loop (new lines to roof)							146,850		146,850
Energy Centre	-	1,086,656	-	1,086,656	1,086,656		3,891,813		4,978,469
DPS and ETS to 100 East 4th		322,850	40,000	282,850	322,850				322,850
DPS and ETS to 110 East 5th		345,675			-	345,675			345,675
DPS and ETS to Res Tower					-			273,983	273,983
DPS+ETS	-	668,525	40,000	282,850	322,850	345,675		273,983	942,508
Reshape Feasibility Study	36,000								36,000
Integral Schematic Design	70,736								70,736
Nemetz Electric Design	18,500								18,500
Div 15 Laser Scan	4,849								4,849
Brand Boss	610								610
Ethos Communication Design	-								-
Peer & Tech Reviews (KWL)	8,884								8,884
Legal Fees (Term Sheet/Def Agreements)	16,183								16,183
Internal Management Time (Feasibility and Design)	21,683								21,683
Predevelopment	177,445								177,445
CPCN Internal Regulagtory Legal support	10,805								10,805
Consulting for CPCN (Brook Pooni)	11,336								11,336
CPCN	22,141								22,141
Demolish Chiller #3 (150 Ton) (18%)		6,831		6,831	6,831				6,831
Supply and Install Chiller #3 (18%)		147,428	49,120	98,308	147,428				147,428
Service chiller #1 & #2 (18%)		3,089		3,089	3,089				3,089
Electrical allowance (18%)		38,250		38,250	38,250		38,250		76,500
Supply and Install Chiller #1							163,356		163,356
Supply and Install Chiller #2							102,010		102,010
Demolish Chiller #1 (350 Ton)							6,831		6,831
Demolish Chiller #2 (350 Ton)							6,831		6,831
Engineering		195,598	49,120	146,478	195,598	-	317,278	-	512,876
Mob/Demob/Bonding/Insurance		166,198	95,120	71,078	166,198		396,383	29,517	592,098
Mob/Demob/Bonding/Insurance - Engineering (18%)		29,916		29,916	29,916		71,349	5,313	106,578
Mob/Demob/Bonding/Insurance - Contingency (20%)		33,240		33,240	33,240		79,277	5,903	118,420
Soft Costs		229,354	95,120	134,234	229,354	-	547,009	40,733	817,096
Predevelopment (Internal Management)	47,722				-				47,722
CPCN: BCUC fees + CEC PACA	30,254				-				30,254
Construction Management		88,576		88,576	88,576		229,860	67,092	385,528
Internal	77,976	88,576	-	88,576	88,576	-	229,860	67,092	463,504
Predevelopment	-				-				-
CPCN					-				-
Energy Centre (20%)		217,331	-	217,331	217,331		778,363		995,694
DPS+ETS (20%)		133,705	-	64,570	64,570	69,135	-	54,797	188,502
Contingency		351,036	-	281,901	281,901	69,135	778,363	54,797	1,184,196
Total	696,784	2,619,745	184,240	2,020,695	2,204,935	414,810	5,764,323	436,605	9,517,457
Evidence from CPCN proceeding for comparison to above (Refer to the resposne to BCUC IR 18.2)									
Total	732,793	2,619,744				2,619,745	5,764,322	436,605	9,553,463
Variance	(36,009)	-				-	-	-	(36,006)

Appendix D

Risk Matrix

Risk Factor	***FEI Natural Gas Class of Service - Benchmark***	***UniverCity***	***Dockside Green Energy***	***River District Energy***	**Mount Pleasant DCS**
Capital Structure	*60/40 Actual*	*57.5/42.5 Deemed – Approved*	*57.5/42.5 Deemed – Approved*	*57.5/42.5 Deemed – Approved*	57.5/42.5 Deemed – Proposed – GCOC Stage 2 decision basis
Equity Risk Premium		*75 bps - Approved*	*100 bps - Approved*	*75 bps - Approved*	75 bps – Proposed – GCOC Stage 2 decision basis
1. Technology risk / system performance risk associated with chosen technologies	*Natural Gas Proven Technology*	*Natural Gas boilers proven Technology*	*Biomass gasification initiative technology …*	*Natural Gas boiler proven Technology*	Electric chillers and related equipment proven technology
2. Fuel Cost Risk and Availability	*Natural Gas: Low-medium*	*Natural gas fueled energy centre: low-medium.*	*Biomass: medium-high; natural gas: low-medium*	*Natural gas fueled energy centre: low-medium.*	Electricity – low risk related to cost and availability (regulated utility electricity supply)
3. Customer Base (e.g., diversity, certainty, growing, declining)	*Established and diverse customer base but very slow growth*	*Greenfield utility; uncertainty related to timing of full buildout*	*Greenfield utility; uncertainty related to timing of full buildout*	*Greenfield utility; uncertainty related to timing of full buildout*	Brownfield utility, relatively small customer base, development timing risk
4. Default risk of customer	*Minimal*	*Minimal*	*Minimal*	*Minimal*	Minimal
5. Property development risk	*Medium to high: there are competing energy options*	*Low: phased approach to capital deployment*	*High: phased approach to capital deployment*	*Low: phased approach to capital deployment*	Medium to high: Development of small district energy system is relatively more risk than benchmark FEI.
6. Developer / customer connection risk	*Medium to high: due to building stock changes and competitive energy sources*	*Low: mandatory connection*	*Low: mandatory connection*	*Low: mandatory connection*	Medium to high: No mandatory connection nor exclusive franchise. Competition from BC Hydro, FEI and other TES providers. City of Vancouver building codes do not guarantee new connections
7. Load forecast uncertainty	*Minimal in the short term as mature utility with deferral account; somewhat higher in the long term*	*Inherent uncertainty in load forecast*	*Inherent uncertainty in load forecast*	*Inherent uncertainty in load forecast*	Inherent uncertainty in load forecast
8. Utility size	*Large and mature*	*Small development specific utility*	*Small development specific utility*	*Small development specific utility*	Small development specific utility
9. Initial construction risk	*Depends on the nature of the individual project*	*Depends on the nature of the individual project*	*Depends on the nature of the individual project*	*Depends on the nature of the individual project*	Depends on the nature of the individual project
10. Future construction cost risk	*Depends on the nature of the individual project*	*Depends on the nature of the individual project*	*Depends on the nature of the individual project*	*Depends on the nature of the individual project*	Construction cost risk largely mitigated through Construction and Purchase Agreement
11. Operating cost risk	*Minimal as revenue requirement application to recover costs*	*Minimal as mechanism in place to recover costs*	*Minimal as mechanism in place to recover costs*	*Minimal as mechanism in place to recover costs*	Medium: Fuel costs are a proposed flow-through expense but there are no variance deferral mechanisms to cover controllable operating costs of the system that may vary from approved amounts.

Risk Factor	*FEI Natural Gas Class of Service - Benchmark*	*UniverCity*	*Dockside Green Energy*	*River District Energy*	Mount Pleasant DCS
12. Public acceptance risk	*Medium and natural gas is an established and widely used technology, but public perceives it as less than clean*	*Low as seen as a green alternative*	*Low as gasification technology part of approval process for the development …*	*Low as seen as a green alternative*	Low – a contained cooling system powered by electricity
13. Fixed/variable rate design	*15% fixed / 85% variable*	*60% fixed / 40% variable*	*50% fixed / 50% variable*	*66% fixed / 34% variable*	~92% fixed / ~8% variable; ~65% of the fixed charge recovers operating costs that may vary year to year, but that do not vary directly with energy consumption
14. Levelized approach to rates	*No*	Yes	Yes	Yes	Yes
15. Financial risk	*Low-medium: appropriate standalone financing structure for capital markets*	*Low-medium: subsidiary of parent utility*	*Low-medium: subsidiary of parent utility*	*Low-medium: subsidiary of parent utility*	Medium-high: Small public utility has more financial risk than a larger more diversified utility. A smaller utility imposes more restrictions from the banks. The availability of financial instruments and access to the capital markets is also restricted.
16. Competitive challenges	*Competitive with electricity and competition from alternative energy providers*	*Other utilities and electricity*	*Other utilities and electricity*	*Other utilities and electricity*	Other utilities and electricity. Competition from alternative energy providers and TES providers. Municipal TES can write policies affecting their competitors and are unregulated in this space.
17. Provincial climate change and energy policies	*Encourage reduction of fossil fuels to reduce GHG emissions and lower energy use*	*Favourable government policies*	*Favourable government policies*	*Favourable government policies*	Favourable government policies
18. Regulatory uncertainty	*Low to medium: uncertainty exists for service offerings within the natural gas class of service*	*Medium risk: new, uncertainty, scrutiny …*	*Medium risk: new, uncertainty, scrutiny*	*Medium risk: new, uncertainty, scrutiny*	Medium to high. New, uncertainty, scrutiny. Provincial policies, BCUC utility regulation, Municipal policies, bylaws, permitting all have an influence.
19. Business development risk	*Minimal*	*High as part of overhead costs*	*High as part of overhead costs*	*High as part of overhead costs*	Medium to high based on applicable factors above.

Appendix E

Inter-Affiliate Conduct and Transfer Pricing Policy

Creative Energy

Inter-Affiliate Conduct and Transfer Pricing Policy

INTRODUCTION

Scope of Creative Energy's Business

Creative Energy develops and finances urban energy infrastructure in North America including in British Columbia. Its vision is to become a North American leader in sustainable district energy systems.

Each functionally separate energy project developed by Creative Energy that proceeds to implementation, including applying for regulatory approvals as required, is constructed, owned, and operated by a separate wholly owned subsidiary company or partnership of Creative Energy. A subsidiary operating an energy project may be subject to regulation as a public utility, may be partially regulated in certain respects, or may not be regulated depending on the applicable regulations and guidelines in place in the jurisdiction where the project is located.

We recognize the potential benefits to the energy projects and their respective customers from all entities in the Creative Energy group sharing resources. The economies of scale of a larger organization benefit all within the organization. As a group, we are able to provide corporate services at a wider breadth and greater depth than what would be possible at a small utility by itself. The customers of the regulated utilities within the group benefit by receiving safe and reliable services at service levels comparable to a much larger utility and at lower rates.

Overall Purpose of this Inter-Affiliate Conduct and Transfer Pricing Policy

The Creative Energy group as a whole recognizes the potential for misalignment of interest between shareholders and customers of the regulated utilities within the group that may occur in the course of the affiliated businesses sharing resources and interacting with each other.

The overall purpose of this Inter-Affiliate Conduct and Transfer Pricing Policy (**Policy**) is therefore to provide for the benefit of economies of scale while also preventing customers of regulated businesses within the Creative Energy group from cross-subsidizing competitive or non-regulated activities of affiliated businesses.

Objectives

The objectives and means to support the overall purpose of this Policy include:

(a) To provide an environment in which inter-affiliate economies and efficiencies can be realized to the benefit of all businesses within the Creative Energy group and their customers;

(b) To define transparent transfer pricing policies and cost allocation methodology to ensure that customers of regulated businesses within the Creative Energy group do not cross-subsidize competitive or non-regulated activities of affiliated businesses; and

(c) To support efficient and cost-effective regulatory processes through the consistent application of a clear set of policies and methodology to inter-affiliate transactions and cost allocations, which will in turn promote utility ratepayer confidence in the rates they are charged.

Applicability of this Policy

This Policy applies to all entities within the Creative Energy group from time to time that are subject to the regulatory jurisdiction of the British Columbia Utilities Commission (**BCUC**), and to their employees, directors and officers.

Appendix A provides an organization chart of the Creative Energy group indicating the entities to whom this Policy applies. The organization chart will be updated from time to time as needed.

REGULATORY

This Policy is not meant to replace or modify in any manner, any statutory or regulatory requirement relating to regulated businesses as applicable in the jurisdiction of the business.

The BCUC has published guidelines (the “Retail Markets Downstream of the Utility Meter” Guidelines (**RMDM Guidelines**) of April, 1997) for utilities with affiliated non-regulated businesses providing goods and services downstream of the utility meter (for example, end-use appliance sales and repair services, safety and security services, financing and insurance). Creative Energy affiliates do not provide such goods and services downstream of the utility meter; however, the RMDM Guidelines provide general principles and objectives applicable to transfer pricing in transactions between a utility and its non-regulated affiliates generally. The BCUC affirmed the objectives and principles of the RMDM Guidelines in its December 2012 report into the matter of an Inquiry into the Offering of Products and Service in Alternative Energy Solutions and Other New Initiatives (**AES Inquiry Report**). This Policy has been prepared in consideration of the RMDM Guidelines and AES Inquiry Report, and where applicable, this Policy is intended to support their objectives and general principles. Applicable objectives and principles of the RMDM Guidelines and AES Inquiry Report are reproduced as Appendix B to this Policy.

Although this Policy is subject to the approval of the BCUC, such approval does not limit or modify in any way the powers of the BCUC pursuant to the *Utilities Commission Act*. Compliance with this Policy does not eliminate any requirement for specific BCUC approvals or filings where required by statute or BCUC order as applicable.

If this Policy is silent on a principle or guideline otherwise established by the BCUC, acceptance of this Policy does not imply that the principle, guideline or BCUC direction is void or invalid.

Where there is an agreement between any Creative Energy affiliates with respect to the sharing or provision of services, resources or personnel that has been reviewed and accepted by the BCUC, the terms of that agreement will continue to govern.

Amendments to this Policy

This Policy may be reviewed and amended from time to time by the BCUC on its own initiative, on application by an affected Customer, or pursuant to a request by any party to whom this Policy applies.

This Policy will be reviewed if at any time the scope of Creative Energy's business materially changes from the scope described above, and in consideration of the principles of the RMDM Guidelines and AES Inquiry Report, as applicable.

POLICY PROVISIONS

Definitions

In addition to the terms defined above, in this Policy the following words and phrases have the following meanings:

a) "Affiliate" means:

  i) a partnership, joint venture, or corporation in which Creative Energy has a controlling interest or that is otherwise subject to the control of Creative Energy;

  ii) a partnership, joint venture, or corporation deemed by the BCUC to be an affiliate for the purposes of this Policy; and

  iii) an operating unit or division of any partnership, joint venture or corporation referred to in clauses a) i) or ii) above.

b) "Affiliate Service" means any service, provided:

  i) by Creative Energy to an Affiliate; or

  ii) by an Affiliate to another Affiliate or to Creative Energy, other than a Regulated Service.

c) "Cost Recovery Basis" with respect to:

  i) the use by one Affiliate of the personnel of another Affiliate or of Creative Energy, means the fully burdened costs of such personnel for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads;

  ii) the use by one Affiliate of the equipment of another Affiliate or of Creative Energy, means an allocated share of capital and operating costs appropriate for the time period they are utilized by the Affiliate;

  iii) the use by one Affiliate of an Affiliate Service, means the complete costs of providing the service, determined in a manner acceptable to Creative Energy, acting prudently;

iv) the use by Creative Energy of the personnel or equipment of an Affiliate or of an Affiliate Service, means the costs determined in accordance with clause c) i), ii) or iii) above as appropriate; and

v) the transfer of equipment, plant inventory, spare parts or similar assets between Affiliates and Creative Energy, means the lower of fair market value or net book value of the transferred assets.

d) "Creative Energy" means Creative Energy Developments Limited Partnership.

e) "Customer" means an individual or business receiving a Regulated Service from an Affiliate and is held to be synonymous with the regulatory term 'ratepayer'.

f) "Directly Assignable Costs" means costs that are directly associated with a particular activity or operation of an Affiliate or Creative Energy.

g) "Fair Market Value" means the price reached in an open and unrestricted market between informed and prudent parties, acting at arm's length and under no compulsion to act.

h) "Fully-allocated Cost" means the sum of the Direct Costs plus a share of Indirect Costs to provide a product or service.

i) "Indirect Costs" means costs that are incurred that are for the benefit of several Affiliates and are not directly assignable to any particular Affiliate.

j) "Massachusetts Formula" means the financial composite cost allocation methodology approved by the BCUC for use to allocate shared corporate services, indirect and/or residual costs among Affiliates.

k) "Regulated Affiliate" means an Affiliate that provides Regulated Service;

l) "Regulated Service" means a service, the terms and conditions of which are set by the BCUC, and includes services for which an individual rate, joint rate, toll, fare, charge or schedule of them (rates, tolls, fares or charges) has been set by the BCUC.

m) "Services Agreement" means the agreement between Creative Energy and Creative Energy Vancouver Platforms Inc. for the provision of Affiliate Services to Creative Energy on a Cost Recovery Basis.

n) "Shared Corporate Services" means corporate and financial market services performed by Creative Energy or an Affiliate for another Affiliate in relation to the daily operation of the Affiliate's business that provide shared strategic management and policy support, relating to, but not limited to: corporate governance, strategic management, regulatory management, corporate finance and corporate accounting, billing and customer service support, accounting and accounts payable support, payroll support, pension support, tax, internal audit and treasury services, human resource management, information technology systems, risk management, legal services, health, safety and environment services, communications and public relations, and oversight of administrative and support services.

Resource Sharing

This Policy recognizes the benefits to Creative Energy, Affiliates and Customers in Creative Energy and Affiliates sharing resources, equipment and services.

While each Regulated Affiliate is regulated on a standalone basis with its own rate base, tariff structure and rates, each Regulated Affiliate and its Customer(s) benefit from the economies of scale of a larger organization. The Creative Energy group is able to provide corporate services at a wider breadth and greater depth than what would be possible at a small utility by itself.

Sharing resources across the Affiliates results in benefits, which include:

1. **Increased efficiencies through economies of scale** – shared resource initiatives are a more efficient and cost-effective approach than having each Affiliate procure these services on a standalone basis; and

2. **Functionality and cost effectiveness** – Certain capabilities, including some relating to customer interface options, cannot be cost effectively provided by small Affiliates.

The Customers of Regulated Affiliates benefit by receiving safe and reliable services at service levels comparable to a much larger utility and at lower rates than if all corporate services were contained with the small utility itself.

The risk associated with Creative Energy and its Affiliates sharing resources is the potential for Customers of Regulated Affiliates to cross-subsidize competitive or non-regulated activities of other Affiliates. This risk is mitigated through the use of transparent transfer pricing policies and cost allocation methodology, as set out in this Policy and approved by the BCUC, to ensure that Customers of Regulated Affiliates do not cross-subsidize competitive or non-regulated activities of other Affiliates.

Creative Energy and Affiliates are therefore permitted to freely share employees, equipment, and services on a Cost Recovery Basis subject to the transfer pricing policies and cost allocation methodology of this Policy as set out below.

Employees may also be transferred among Creative Energy and Affiliates.

Demonstrating Compliance

Creative Energy and Affiliate employees providing Affiliate Services, and all directors and officers shall review this Policy and support the achievement of the Policy's purpose and objectives. Employees providing Affiliate Services will support this Policy's requirements for transparent accounting and direct assignment of costs through recording and submitting time sheets and expense reports or following such other corporate procedures, as required.

Regulated Affiliates will estimate or forecast levels of Affiliate Services to be received, and demonstrate compliance with this Policy as required in applications and filings to the BCUC (for example, revenue requirements, rates and CPCN applications).

Estimated or forecast Affiliated Services received will be accounted for as an element of the cost of service. Estimated or forecast Affiliate Services provided to an Affiliate or Creative Energy will be accounted for as a reduction to the cost of service. These estimates or forecasts will be consistent with the relevant costs and assumptions contained in the applicable application. In addition, these processes will include a review and update of all numerical inputs and cost assumptions used to calculate loading rates.

COST ALLOCATION METHODOLOGY AND TRANSFER PRICING

Principle

The methodology follows the principle that cost allocation is to match cost causation as closely as possible. This principle is achieved by directly assigning costs where possible, including the direct assignment of costs to Creative Energy pursuant to a Service Agreement if put in place. When costs are not directly assignable, Shared Corporate Services costs are allocated based on a functional allocator where appropriate. In cases where costs are not directly assigned and not functionally allocated, the Massachusetts Formula is used.

The methodology for determining a labour cost for time charges is on the basis of the fully loaded pay. There is no mark-up on Shared Corporate Services costs allocated to Regulated Affiliates.

Books of Accounts

Accounting separation shall be maintained for each Affiliate, including by maintaining separate financial records in accounting systems.

Financing

Any loan, investment, or other financial support received by an Affiliate from Creative Energy or another Affiliate shall be taken on terms no less favorable than what the Affiliate would be able to obtain as a standalone entity from the capital markets.

Any loan, investment, or other financial support provided by a Regulated Affiliate to Creative Energy or another Affiliate shall be provided on terms no more favorable than what Creative Energy or that Affiliate would be able to obtain as a standalone entity from the capital markets.

Any financing or other financial assistance that exposes Customers to additional costs or risks will not be undertaken unless approved by the BCUC.

Any loan, investment, or other financial support provided by, or received by, a Regulated Affiliate is subject to the approval of the BCUC, as required pursuant to the *Utilities Commission Act*.

Cost Allocation Methodology

The structured methodology for allocating Shared Corporate Services costs to each Affiliate is outlined in the table below.

Table 1: Steps for Allocating Corporate Costs

Item	STEP FOR ALLOCATING SHARED CORPORATE SERVICES COSTS
1.	• Shared Corporate Services costs are first categorized into homogenous categories/services.
2.	• Costs are then identified as either: (i) Directly Assignable Costs; or (ii) Indirect Costs.
3.	• All Directly Assignable Costs are directly assigned to the appropriate Affiliate or Creative Energy.
4.	• The basis of variability of the Indirect Costs are then assessed by reviewing what causes these costs to change.
5.	• Indirect Costs are then allocated either: o Using a functional allocator on the basis of variability in instances where this method is clearly applicable; or o Using the Massachusetts Formula for all other instances.

Directly Assignable Costs

These costs can be identified with a specific service or product and can be directly assigned, generally through time sheets or expense reports.

Cost are directly assigned to Creative Energy pursuant to the Service Agreement.

Indirect Costs

These costs are not directly assignable, and therefore are allocated to the Affiliate benefitting from these costs in accordance with a functional allocator, and where there is no functional allocator the costs are allocated using the Massachusetts Formula.

Functional allocators are used where the Indirect Costs can be allocated using an identified cost causation driver. Functional allocators used in the allocation process may include the following as examples:

1. **Employee headcount** – for costs that are directly correlated to the number of employees; and

2. **Number of Customers** – for costs that are directly correlated to the number of customers of a particular Affiliate.

The vast majority of Indirect Costs do not have a direct correlation with any one particular cost causation driver. Hence, most residual Indirect Costs are allocated using the Massachusetts Formula.

For Regulated Affiliates, the functional allocators will be set out in detail in the revenue requirements and rate applications submitted to the BCUC if and where applicable.

Massachusetts Formula

The Massachusetts Formula is comprised of three equally weighted factors as shown in the table below. These weightings are kept constant in order to avoid unnecessary complexity of the Cost Allocation Methodology.

Table 2: Massachusetts Formula Factors and Weighting

Factor	Weight
Operating Revenues	33.33%
Gross Property, Plant & Equipment	33.33%
Salaries or Direct Labour Expenses	33.33%

As approved by the BCUC for the allocation of residual Indirect Costs, the Massachusetts Formula allows for a just and reasonable allocation of costs in a transparent, sustainable and cost-effective manner that reflects cost causality for the shared costs that do not exhibit direct correlation with any one particular cost causation driver.

Cost Collection Procedures

The corporate accounting group will be responsible for establishing, administering and monitoring processes to ensure that the employees providing Affiliate Services charge all time spent engaged by each Affiliate or Creative Energy for all activities.

Invoicing

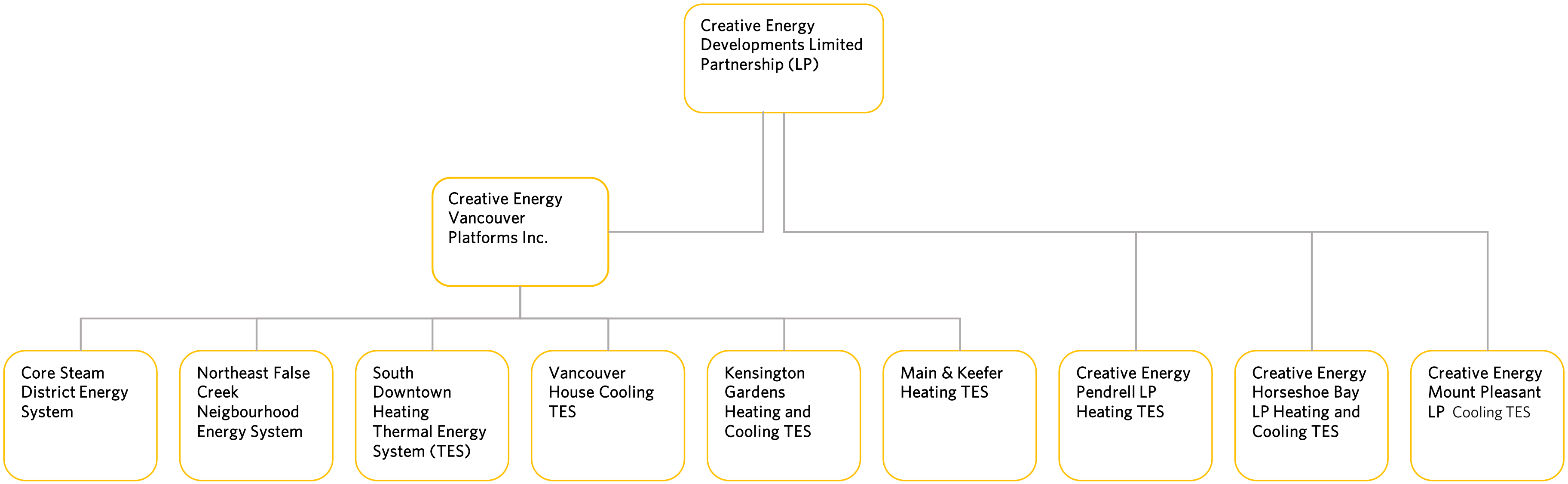
On a monthly basis, each Affiliate will be invoiced for allocated costs of services and resources provided during the period.

Asset Transfers

Any assets transferred or otherwise disposed of by Creative Energy to an Affiliate or by an Affiliate to another Affiliate shall be on a Cost Recovery Basis.

APPENDIX A

CREATIVE ENERGY GROUP ORGANIZATION CHART



APPENDIX B

BCUC RMDM GUIDELINES - OBJECTIVES

- There must be no subsidy of unregulated business activities, whether undertaken by the utility or its non-regulated business (**NRB**), by utility ratepayers.
- The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity, that is the risks must have no impact on utility ratepayers.
- The most economically efficient allocation of goods and resources for ratepayers should be sought.

BCUC RMDM GUIDELINES - TRANSFER PRICING PRINCIPLES

- The operating costs of non-regulated activities are not to be reflected in the utility's cost of service.
- The costs of developing new business ventures are to be charged to and recovered from the NRB.
- The accounting costs are to be transparent and will normally fully recover costs for all services, including overhead, space, employee benefits, inconvenience, and a profit margin where appropriate. If the service provided by the utility to the related-NRB could also be obtained from an independent supplier, the price paid by the related-NRB to the utility should be no less than the competitive market price and will never be below the incremental cost.
- The financial costs of each business are to be borne by the specific business. In the exceptional case where the utility provides guarantees for NRBs, the utility must be given financial compensation.
- Utilities will be required to file periodic reports which demonstrate that they are adhering to the transfer pricing policy. The form and timing of the report will be determined by the BCUC.

BCUC AES INQUIRY REPORT – AFFIRMATION OF RMDM GUIDELINES

- There must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB, by utility ratepayers and this principle is extended to apply to regulated businesses.