QULLIQ ENERGY CORPORATION

2022/23 General Rate Application

March 2022

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1.0 INTRODUCTION AND APPLICATION

1.1 APPLICATION

Qulliq Energy Corporation ("Corporation" or "QEC") hereby submits its combined Phase I and Phase II General Rate Application ("GRA" or "Application") for the 2022/23 test year and applies, pursuant to Section 12 of the Utility Rates Review Council Act ("the Act"), for an instruction or instructions by the Minister:

- Approving the Corporation's forecast 2022/23 test year revenue requirement of $144.015 million as set out in Schedule 4.1;
- Approving the Corporation's proposed rates effective October 1, 2022 as set out in Schedules 8.1 and 8.2; and
- For any such further and other instructions within the Minister's authority as the Corporation may request and the Minister determines proper.

1.2 BACKGROUND

A May 26, 2011 letter from the Minister to the Utility Rates Review Council ("URRC") on the URRC's 2011-01 report noted that QEC will file general rate applications in three year intervals and where feasible, QEC intends to provide future rate applications in advance of the relevant test year.

The Corporation's most recent Phase I and II GRA for the 2018/19 test year was filed with the Minister on October 27, 2017. The Minister referred the application to the Utility Rates

Review Council for review and recommendations pursuant to Section 12 of the Utility Rates Review Council Act.

The URRC completed its review of the GRA and issued a final report (report 2018-01) on March 26, 2018. Following the review of the report, the responsible Minister provided an instruction dated May 30, 2018 (“May 30, 2018 Instruction”) with the following instructions to QEC:

a. To impose a rate increase of 6.6% split over two years, effective May 1, 2018 and April 1, 2019 with the new rates listed in the attached Rate Schedules.

b. To accept the attached Revised Terms and Conditions of Services effective May 1, 2018.

May 30, 2018 Instruction also declined QEC’s proposal to move to a territorial-wide rate structure and the Minister directed QEC to work with the Government of Nunavut’s Department of Finance in reviewing the existing Nunavut Electricity Subsidy program to ensure that the needs of all Nunavummiut are taken into consideration.

1.3 OUTLINE OF THE APPLICATION

The Application is organized as follows:

- Chapter 2 provides an overview of the Corporation;
- Chapter 3 reviews system sales and generation requirements;
- Chapter 4 reviews the revenue requirement for the Test Year;

- Chapter 5 reviews the shortfall at existing rates;
- Chapter 6 reviews the Corporation's rate base;
- Chapter 7 reviews the COS study and results;
- Chapter 8 reviews the Corporation's proposed rate design, as well as the proposed rate adjustments effective October 1, 2022; and
- Chapter 9 provides responses to previous URRC recommendations.

2.0 CORPORATE OVERVIEW

2.1 INTRODUCTION

This chapter sets out an overview of the Corporation, its operating environment, and the challenges and opportunities facing the Corporation today and in the future:

- Overview of the Corporation;
- Challenges and Opportunities facing the Corporation; and
- Measures Taken to Mitigate Impacts on Customers.

2.2 OVERVIEW OF THE CORPORATION

On April 1, 2001, Nunavut Power Corporation took up the mandate to supply electricity to communities in the Nunavut Territory. Renamed Qulliq Energy Corporation in 2003, the Corporation is 100% owned by the Government of Nunavut (GN).

Qulliq Energy Corporation is incorporated and operates under the Qulliq Energy Act. Rates for its electricity service are approved by the responsible Minister who receives advice from the Utility Rates Review Council pursuant to the Utility Rates Review Council Act.

QEC is the only generator, transmitter and distributor of electrical energy for retail supply in Nunavut and has approximately 15,500 electrical customers across the Territory. The Corporation generates and distributes electricity to Nunavummiut through the operation of stand-alone diesel plants in 25 communities meeting community peak demands ranging from approximately 200 kW at Grise Fiord to 10 MW at Iqaluit. The Corporation provides mechanical, electrical and line maintenance from three regional centers and administers the Corporation's business activities from a headquarters in Baker Lake and executive offices in Iqaluit.

2.3 CHALLENGES AND OPPORTUNITIES FACING THE CORPORATION

The Corporation serves a population of approximately 39,000 people[1] located in an area of 2.1 million square kilometres. Electricity systems are isolated and unconnected and therefore each must be planned and operated independently. This unique environment has a profound impact on the Corporation's operations throughout its service area. QEC is the only energy corporation in Canada without significant local energy resources or regional electricity transmission capability which leads to a substantial dependency on fossil fuels.

In order to continuously supply safe and reliable power, QEC undertakes long-term capital planning to determine which plants require upgrades and expansions or need to be completely rebuilt as they have reached the end of their useable lifespan. QEC also researches emerging alternative energy technologies to determine if they can be incorporated into the capital planning cycle.

The Corporation remains committed to reducing Nunavut's dependency on fossil fuels. QEC continues to explore renewable energy sources and implement conservation

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[1] Source: Nunavut Bureau of Statistics, Nunavut Population as of July 1, 2019
http://www.stats.gov.nu.ca/en/home.aspx

initiatives that are both financially and environmentally viable for the territory. Examples of this work include:

- QEC implemented a Net Metering program effective January 2018 to enable customers to install renewable energy sources that can supply surplus energy to QEC with further technical knowledge on how to implement the Net Metering process.
- QEC also launched the new Commercial and Institutional Power Producer (CIPP) program in May 2021. The program is designed to allow existing commercial and institutional customers (government departments, hamlets, businesses) to generate electricity using renewable energy systems and sell it to QEC. CIPP participants will be paid for the power they generate and sell to QEC at a rate equal to the corporation's diesel savings.
- In 2017 QEC started replacing all conventional streetlights across Nunavut with energy efficient LED (Light Emitting Diode) streetlights with a target completion of streetlight conversion by 2024. LED streetlights offer a number of advantages over conventional streetlights. Along with energy savings, LEDs last five times longer than conventional lights, allowing significant savings in operational and maintenance costs. LEDs are also brighter resulting in improved visibility on the roads during the winter season.
- QEC is in the process of a Kugluktuk power plant replacement which includes installation of a 500 KW solar panel with storage capacity as the corporation

continues to pursue funding from federal programs to invest further in wind and solar technology. As well, all of the power plant replacements undertaken by QEC have capability of integration with renewable energy sources.

2.4 MEASURES TAKEN TO MITIGATE IMPACTS ON CUSTOMERS

QEC together with the Government of Nunavut, have taken efforts to mitigate rate impacts on customers. These include efforts to contain the revenue requirement where possible, without sacrificing safety and reliability, as well as developing measures that provide customers with the benefits of a managed transition to the required higher rate levers.

Most notable measures include:

- **Improved Fuel Efficiency:** In the 2018/19 GRA QEC showed an improved fuel efficiency of 3.76 kWh/litre compared to average of 3.71 kWh/litre in the 2014/15 GRA. In the current application, QEC's corporate-wide fuel efficiency has further improved to 3.77 kWh/litre for 2022/23 forecast.

- **Station Service Improvements:** Station service has been reduced through a variety of initiatives and plant upgrades. The 2022/23 test year station service forecast is lower (3.1% of generation) than the 2018/19 forecast (3.3% of generation), as well as the 2014/15 forecast (3.5% of generation).

- **Territory-wide Rates Proposal:** In the Ministerial Instruction dated May 30, 2018, QEC was instructed to work with the Government of Nunavut's (GN) Department of Finance in reviewing the existing Nunavut Electricity Subsidy program for purposes of developing a rate structure which ensures the needs of all

Nunavummiut are taken into consideration. In this Application, the Corporation proposes moving toward territory-wide rates that avoids rate alignment related bill increases to non-government customers. This approach is better aligned with the Government of Nunavut's policy objectives and Inuit societal values. It is also consistent with the URRC's recommendation in Report 2018-01 of adopting higher revenue to cost ratios for Government customers with a view to minimizing the harmful effects of high rate increases for investment and economic growth in Nunavut. This approach also provides a higher degree of rate stability throughout the Territory and shares the benefits of QEC's renewable energy program opportunities with customers across the Territory. Further details on the Corporation's rate proposals are provided in Chapter 8.

3.0 SYSTEM SALES AND GENERATION REQUIREMENTS

3.1 INTRODUCTION

QEC's 2022/23 GRA reflects a revenue requirement based on the costs to operate the QEC system and to service the loads expected to arise in the test year.

This section sets out specific details on the QEC system, loads, generation requirements and fuel requirements including:

- System overview and comparison of 2018/19 and 2022/23 forecasts; and
- Forecast methods for 2022/23.

Schedule 3.1 sets out corporate-wide sales, revenue, line losses, generation and fuel requirements for the actual years 2018/19, 2019/20, and 2020/21, as well as forecasts for 2021/22 and 2022/23. Community-by-community detail is provided in Appendix A.

3.2 SYSTEM OVERVIEW AND DEVELOPMENTS SINCE 2014/15 GRA

3.2.1 FACILITIES

QEC is the sole generator and distributor of power for retail supply in Nunavut. QEC provides generation and distribution services to retail customers in 25 communities. Currently, QEC has no industrial or wholesale customers. All 25 communities are supplied by diesel generation.

3.2.2 MAJOR FACILITY CHANGES SINCE 2018/2019 GRA

There have been several changes to QEC's facilities since the time of the 2018/19 GRA that have a material impact on power costs in Nunavut. These changes are summarized below.

Kinngait Power Plant: QEC has completed the construction and testing of Kinngait new power plant in the 2018/19 fiscal year. QEC received a major project permit for the project by Ministerial Order dated June 7, 2011, as recommended in the URRC's report 2011-03 dated June 6, 2011.

Grise Fiord Power Plant: The Grise Fiord plant replacement project was completed in the 2018/19 fiscal year. QEC received a major project permit for the project by Ministerial Order dated March 13, 2014, as recommended in the URRC's report 2014-02 dated February 20, 2014.

Arctic Bay Power Plant: QEC was granted a major project permit for a new power plant in Arctic Bay through a Ministerial Order dated February 26, 2020, as recommended in the URRC's report 2020-01 dated February 5, 2020.

Iqaluit Bulk Fuel Tank and Fuel Supply System Upgrade: QEC upgraded bulk fuel tank and fuel supply line facilities in Iqaluit constructing a second 5.7 million litre fuel holding tank, upgrading this tank's fuel containment berm at the power plant in Iqaluit and replacing of 600 metres of existing single-walled fuel pipeline used for fuel deliveries to the Iqaluit plant. The fuel supply system upgrade project was completed in 2019/20.

Generation Set Replacements: QEC has completed generation set upgrades in Rankin Inlet, Coral Harbour, and Chesterfield Inlet in 2019/20, in Pond Inlet in 2020/21, and completing upgrades in Whale Cove, Gjoa Haven and Clyde River in 2021/22.

3.2.3 SYSTEM TRENDS SINCE 2018/19 GRA

Since the 2018/19 GRA, the system has experienced a number of changes in loads and generation. This section compares 2018/19 GRA forecasts with 2022/23 test year forecasts.

Total Sales

Table 3.1 compares total forecast sales for the 2018/19 and 2022/23 test years.

Table 3.1:
System Sales – 2018/19 GRA Forecast Compared to 2022/23

	2018/19 GRA Forecast	2022/23 Forecast	Average Annual Growth	Change in MWh
Sales by Rate Class (MWh)				
Domestic	67,763	71,135	1.2%	3,372
Commercial	109,139	110,308	0.3%	1,169
Streetlights	1,949	1,691	-3.5%	-257
Total Sales	**178,851**	**183,135**	**0.6%**	**4,284**

Total forecast sales for 2022/23 are higher than the 2018/19 GRA forecast by 4,284 MWh, corresponding to an average annual increase of 0.6%. The sales growth forecast average reflects some communities with large increases in sales and some communities with decreases in sales:

Communities with large increases in sales include Kugaaruk, Rankin Inlet, Pangnirtung, Pond Inlet, and Sanikiluaq:

- Kugaaruk forecast sales increased from 2,752 MWh in the 2018/19 GRA to 3,481 MWh in 2022/23 (an increase of 26.5%). Kugaaruk accounts for 1.9% of total corporate forecast sales.
- Rankin Inlet forecast sales increased from 17,006 MWh in the 2018/19 GRA to 18,187 MWh in 2022/23 (an increase of 6.9%). Rankin Inlet accounts for 9.9% of total corporate forecast sales.
- Pangnirtung forecast sales increased from 6,029 MWh in the 2018/19 GRA to 6,723 MWh in 2022/23 (an increase of 11.5%). Pangnirtung accounts for 3.7% of total corporate forecast sales.
- Pond Inlet forecast sales increased from 6,144 MWh in the 2018/19 GRA to 6,644 MWh in 2022/23 (an increase of 8.1%). Pond Inlet accounts for 3.7% of total corporate forecast sales.
- Sanikiluaq forecast sales increased from 3,604 MWh in the 2018/19 GRA to 4,005 MWh in 2022/23 (an increase of 11.1%). Sanikiluaq accounts for 2.2% of total corporate forecast sales.

Communities with decreases in sales include Cambridge Bay, Iqaluit, and Qikiqtarjuaq.

- Cambridge Bay forecast sales decreased from 12,388 MWh in the 2018/19 GRA to 11,986 MWh in 2022/23 (about 3.2% decrease reflecting lower actual sales in 2018/19 through 2021/22). Cambridge Bay accounts for 6.5% of total corporate forecast sales.

- Iqaluit forecast sales decreased from 57,065 MWh in the 2018/19 GRA to 55,631 MWh in 2022/23 (about 2.5% decrease reflecting lower actual sales in 2018/19 through 2021/22). Iqaluit accounts for 30.4% of total corporate forecast sales.
- Qikiqtarjuaq forecast sales decreased from 2,603 MWh in the 2018/19 GRA to 2,448 MWh in 2022/23 (about 6.0% decrease reflecting lower actual sales in 2018/19 through 2021/22). Qikiqtarjuaq accounts for 1.3% of total corporate forecast sales.

Domestic Sales

Forecast increases in domestic sales for 2022/23 relative to 2018/19 are approximately 3,372 MWh, or 1.2% average annual increase. Approximately 55.4% (or 1,869 MWh) of this increase relates to increased loads in five communities.

The communities forecast to experience material domestic sales growth are Cambridge Bay (451 MWh increase over 2018/19 forecasts, or 13.4% of the total Corporate-wide domestic sale increase), Baker Lake (324 MWh increase over 2018/19 forecasts, or 9.6% of the total Corporate-wide domestic sale increase), Arviat (421 MWh increase over 2018/19 forecasts, or 12.5% of the total Corporate-wide domestic sale increase), Pond Inlet (333 MWh increase over 2018/19 forecasts, or 9.9% of the total Corporate-wide domestic sale increase), and Sanikiluaq (340 MWh increase over 2018/19 forecasts, or 10.1% of the total Corporate-wide domestic sale increase).

The high growth in these communities is consistent with recent population growth trends, housing development and economic activity. The Nunavut Bureau of Statistics population projections for 2014 to 2035 for these communities indicate between 2018 and 2023 about 5.4% growth in Cambridge Bay, 7.3% growth in Baker Lake, 11.8% growth in Arviat, 7.6% growth in Pond Inlet, 8.3% growth in Sanikiluaq.[2]

Commercial Sales

Commercial sales are forecast to increase by 1,169 MWh, or 0.3% average annual increase for 2022/23 relative to 2018/19. This increase mainly relates to increased loads in Kugaaruk (628 MWh, or 50.8% increase over the 2018/19 GRA forecast), Rankin Inlet (968 MWh, 8.6% increase over the 2018/19 GRA forecast), and Pangnirtung (594 MWh, or 17.8% over the 2018/19 GRA forecast). These sales increases are partly offset by reduced sales forecast in Cambridge Bay (819 MWh, or decrease of 9.5% over the 2018/19 GRA forecast), Arviat (353 MWh, or decrease of 7.3% over the 2018/19 GRA forecast), and Iqaluit (939 MWh, or decrease of 2.5% over the 2018/19 GRA forecast).

Electricity Revenues at Existing Rates

Forecast electricity revenues at existing rates for 2018/19 compared to 2022/23 are shown in Table 3.2. Electricity revenue forecasts at existing rates are higher for 2022/23 compared to 2018/19, generally matching the trends in sales (MWh).

[2] Nunavut Bureau of Statistics, Nunavut Population Projections by Region and Community, 2014 to 2035. Available at: http://www.stats.gov.nu.ca/en/Population%20projections.aspx (accessed February 23, 2022).

Table 3.2:
Forecast Electricity Revenues at Existing Rates
2018/19 GRA Compared to 2022/23

	2018/19 GRA Forecast	2022/23 Forecast	Average Annual Growth
Revenue by Rate Class (000$)			
Domestic	53,700	56,742	1.4%
Commercial	74,730	76,425	0.6%
Streetlights	1,916	1,751	-2.2%
Total Revenue	**130,345**	**134,919**	**0.9%**

Generation, Losses and Station Service

Forecasts for corporate wide generation, line losses and station service are shown in Table 3.3. Forecast total generation has increased from 2018/19 to 2022/23 mirroring sales forecast increases. Line losses are forecast to increase slightly in absolute terms (915 MWh) and as a percentage of generation (4.2% in 2018/19 to 4.6% in 2022/23). Station service consumption is expected to decrease slightly, both in absolute terms (decrease of 148 MWh) and as a percentage of generation (3.3% in 2018/19 to 3.1% in 2022/23).

Table 3.3:
Generation, Losses and Station Service
2018/19 GRA Forecast Compared to 2022/23

	2018/19 GRA Forecast	2022/23 Forecast	Average Annual Growth
Generation (MWh)	**193,338**	**198,389**	**0.6%**
Losses (MWh)	**8,148**	**9,063**	**2.7%**
Losses as % of Generation	*4.2%*	*4.6%*	
Station service (MWh)	**6,340**	**6,192**	**-0.6%**
Station Service as % of Generation	*3.3%*	*3.1%*	

3.2.4 NON-ELECTRICITY REVENUE

Forecast non-electricity revenues for the 2018/19 GRA compared to the 2022/23 forecast are shown in Table 3.4.

Table 3.4:
Non-Electrical Revenue
2018/19 GRA Forecast Compared to 2022/23

	Non-Electrical Revenue ($000)						
Description	**2018/19 GRA Forecast**	**2018/19 Actual**	**2019/20 Actual**	**2020/21 Actual**	**2021/22 Forecast**	**2022/23 Forecast**	**Average Annual Growth 2022/23 over 2018/19 GRA**
Joint Use	677	666	666	580	623	602	-2.9%
Miscellaneous Charges	1,132	1,631	2,012	1,973	1,757	1,865	13.3%
Time and Materials	739	168	80	33	56	44	-50.5%
Total	**2,548**	**2,465**	**2,758**	**2,586**	**2,437**	**2,511**	**-0.4%**

Non-electrical revenues slightly decreased from $2.548 million in the 2018/19 GRA to $2.511 million in the 2022/23 test year. This decrease is mainly driven by lower time and materials revenue forecast, which is prepared based on the actual time and materials revenue in recent years. Actual 2018/19 time and material revenues were substantially lower than the GRA forecast. This reduction is largely offset by an increase in miscellaneous charges from $1.132 million in the 2018/19 GRA to $1.865 million in the 2022/23 test year.

Revenues related to the housing recoveries from employees were credited as an offset to the supplies and services based on the URRC's recommendations in its Report 2012-01 to the Minister.

3.3 LOAD FORECAST METHODS

This section provides an overview of the methods used to develop the 2022/23 GRA load forecasts. The 2022/23 load forecast has been prepared based on the load forecast methods reviewed by the URRC in the 2018/19 GRA.

QEC's load forecast is based on a two-step process:

1. A baseload forecast is prepared based on a customer forecast and a use-per-customer (UPC) forecast.
2. The baseload forecast is reviewed and adjusted if necessary for any known or reasonably expected load changes such as the addition of a major new commercial customer in a community.

QEC's load forecast includes the following components:

1. Customer forecasts by community and rate class;
2. Sales (kWh) forecasts by community and rate class;
3. Generation (kWh) forecasts by community and rate class;
4. Fuel requirements; and
5. Non-electricity revenue forecast.

3.3.1 CUSTOMER FORECAST

Customer forecasts were prepared separately for the domestic and commercial rate classes.

Domestic Customers

A baseload customer forecast is prepared for domestic customer classes using the following method:

1. Calculate the average number of customers per month using the most recently available 12 months of actual customer accounts.
2. Review annual customer changes and confirm/revise any significant change in customer counts by community (e.g., 10% and higher).
3. Calculate population growth estimates based on the population projections from the Nunavut Bureau of Statistics for each community. For this step QEC used community population projections to year 2035 from Nunavut Bureau of Statistics.
4. Apply the annual population growth rates from step 2, to the most recent year of actual customer counts from step 1.

Commercial Customers

A baseload customer forecast is prepared for commercial customer classes using the following method:

1. Calculate the average number of customers per month using the most recently available 12 months of actual customer accounts from the QEC billing data by community. Review annual customer change and confirm/revise any significant change in customer counts by community (e.g., 10% and higher).

2. Obtain population growth estimates from the Nunavut Bureau of Statistics and calculate the average growth rates. This calculation is identical to step 2 in the domestic customers forecast.

3. Apply one half of the annual population growth rates from step 2 to the most recent year of actual customer counts from step 1.[3]

Once the baseload customer forecast is completed, QEC reviews the Government of Nunavut's capital plan, and monitors news releases, planning and licensing documents for resource developments to determine if adjustments should be made to the customer forecast to capture additional loads from potential new developments. The load forecast is adjusted by community based on this information. Typically, these adjustments are only made when it is relatively certain the new development will proceed and it is of a material size. No changes have been made for the 2022/23 test year.

3.3.2 SALES FORECAST

Domestic and Commercial Customers

The load forecast is prepared by community. The baseload sales forecast for domestic and commercial customers is prepared using the average UPC method. The method involves the following steps:

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[3] This is different from the 100% growth estimate applied to domestic customers. This approach is based on the assumption that domestic growth matches the population growth while commercial growth is around half of the population growth for any given community. This approach also recognizes that material new customer additions for commercial customers are likely to be identified by the top-down adjustment following completion of the base load forecast.

1. Typically, a 3-year historic average annual UPC is calculated for each rate class by dividing actual total sales by actual average annual customer counts. However, due to the distortion of normal power consumption profiles in 2019/20 caused by the COVID-19 pandemic measures, this year was excluded from the average annual UPC forecast calculation, and a 2-year annual average UPC based on 2020/21 and 2021/22 sales was used for the baseload sales forecast.
2. The 2-year historic average annual UPC is multiplied by the customer count forecasts.

Once the baseload sales forecast is completed, QEC reviews the Government of Nunavut's capital plan and monitors news releases, planning and licensing documents for resource developments to determine if adjustments should be made to the sales forecast to capture additional loads from potential new developments. No such adjustments were made for the 2022/23 test year forecast.

Streetlights

The streetlight sales forecast is prepared using the actual sales for the most recent year as a baseload. The baseload forecast is then reviewed for any adjustments reflecting changes in the lamp counts due to community expansions, or lamp types.[4] No adjustments have been made to the streetlight sales.

[4] QEC is continuing the process of replacing conventional street light bulbs with energy efficient LED (Light Emitting Diode) lights.

3.3.3 GENERATION FORECAST

Line losses and station service are forecast based on a rolling 5-year average actual percentage of sales, excluding 2019/20 due to the COVID-19 pandemic impacts. For this calculation the model calculates the 5-year average of line losses and station service in terms of percentage of actual sales. The calculated 5-year average percentage is applied to forecast sales to calculate forecasts for line losses and station service.

Forecast generation is calculated as the sum of sales, line losses and station service.

3.3.4 FUEL REQUIREMENTS

Schedule 3.2 shows the calculation of the forecast fuel efficiencies. The forecast efficiency for each community is calculated by taking the efficiency for the 3 most recent actual years (2018/19, 2019/20 and 2021/22) and calculating a weighted average. The year with the highest efficiency is given a weighting of 3, the second highest year a weighting of 2, and the lowest efficiency year a weighting of 1. The volume of fuel required in each community is calculated by taking the forecast diesel generation and dividing it by the forecast fuel efficiency. This is consistent with the approach used in the 2018/19 GRA.

3.3.5 NON-ELECTRICITY REVENUE FORECAST

Forecasts of non-electricity revenues are prepared for three categories – joint use, miscellaneous charges, and project time and materials. Forecast joint use revenue was prepared based on the approved 2022/23 joint use rates and the existing number of connections.

Forecasts of miscellaneous charges were prepared based on the 2021/22 budget and revenues from miscellaneous charges in recent years.

Project time and materials revenues include forecasts of work done by QEC for other companies, equipment rental and recovery of time and materials on small scale repair works (for example, broken pole replacements or lighting installations). Time and materials revenue forecast was prepared based on the actual time and materials revenue in recent years.

Schedule 3.1:
Qulliq Energy Corporation 2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

QEC Summary

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	67,763	67,248	67,575	69,280	70,120	71,135
2	Customers	11,812	11,712	11,815	12,026	12,189	12,355
3	Av. MWh Sales/Cust.	5.74	5.74	5.72	5.76	5.75	5.76
4	Revenue (000s)	53,700	51,026	52,775	54,243	55,916	56,742
5	Cents/kWh	79.25	75.88	78.10	78.30	79.74	79.77
	Commercial						
6	Sales (MWh)	109,139	111,139	111,913	107,302	111,125	110,308
7	Customers	3,307	3,397	3,409	3,456	3,478	3,501
8	Av. MWh Sales/Cust.	33.00	32.72	32.83	31.05	31.95	31.51
9	Revenue (000s)	74,730	74,836	77,187	74,940	76,932	76,425
10	Cents /kWh	68.47	67.33	68.97	69.84	69.23	69.28
	Streetlights						
11	Sales (MWh)	1,949	1,593	1,677	1,691	1,691	1,691
12	Revenue (000s)	1,916	1,602	1,661	1,727	1,751	1,751
13	Cents /kWh	98.32	100.56	99.07	102.11	103.53	103.53
	Total						
14	**Sales (MWh)**	**178,851**	**179,980**	**181,165**	**178,273**	**182,937**	**183,135**
15	Customers	15,119	15,109	15,224	15,481	15,667	15,856
16	Revenue (000s)	130,345	127,463	131,623	130,910	134,599	134,919
17	Cents /kWh	72.88	70.82	72.65	73.43	73.58	73.67
	GENERATION (MWh)						
18	**Total Station Service**	**6,340**	**5,990**	**5,848**	**5,713**	**6,204**	**6,192**
19	**Station Service - % of Gen.**	3.3%	3.1%	3.0%	3.0%	3.1%	3.1%
20	**Total Losses**	**8,148**	**9,220**	**7,467**	**9,563**	**8,913**	**9,063**
21	**Losses - % of Gen.**	4.2%	4.7%	3.8%	4.9%	4.5%	4.6%
22	**Total Generation**	**193,338**	**195,190**	**194,479**	**193,549**	**198,054**	**198,389**
	Source						
23	Diesel Generation (MWh)	193,338	195,190	194,479	193,549	198,054	198,389
24	Diesel Efficiency (KWh/L)	3.76	3.75	3.75	3.73	3.77	3.77
25	Liters (000s)	51,355	52,046	51,928	51,955	52,578	52,661
	Peak						
26	Peak Load (KW)	35,951	35,442	35,879	35,395	36,349	36,405
27	Load Factor	61%	63%	62%	62%	62%	62%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule 3.2:
Qulliq Energy Corporation 2022/23 General Rate Application
Fuel Efficiency Forecast

Line No.	PLANT #	PLANT NAME	2018/19 Generation (KWh)	2018/19 Fuel consump. (Litre)	2018/19 Fuel Efficiency (kWh/L)	2019/2020 Generation (KWh)	2019/2020 Fuel consump. (Litre)	2019/2020 Fuel Efficiency (kWh/L)	2020/21 Generation (KWh)	2020/21 Fuel consump. (Litre)	2020/21 Fuel Efficiency (kWh/L)	Weighted Fuel Efficiency 3	Weighted Fuel Efficiency 2	Weighted Fuel Efficiency 1	Weighted Average Fuel Efficiency (kWh/L)
			A	B	C=A/B	D	E	F=D/E	G	H	I=G/H	J=MAX(C,F,I)x3	K=MED(C,F,I)x2	L=MIN(C,F,I)x1	M=(J+K+L)/6
1	501	Cambridge Bay	12,108,759	3,277,899	3.69	12,137,665	3,313,957	3.66	12,188,778	3,295,129	3.70	11.10	7.39	3.66	3.69
2	502	Gjoa Haven	6,167,193	1,706,322	3.61	6,234,000	1,763,805	3.53	6,108,261	1,702,249	3.59	10.84	7.18	3.53	3.59
3	503	Taloyoak	4,149,081	1,216,948	3.41	4,108,968	1,103,553	3.72	4,190,793	1,167,962	3.59	11.17	7.18	3.41	3.63
4	504	Kugaaruk	3,836,033	1,042,789	3.68	3,694,649	985,499	3.75	3,749,923	1,036,009	3.62	11.25	7.36	3.62	3.71
5	505	Kugluktuk	6,010,494	1,650,408	3.64	6,204,873	1,715,683	3.62	6,182,740	1,722,507	3.59	10.93	7.23	3.59	3.63
6	601	Rankin Inlet	19,245,754	5,219,707	3.69	19,125,103	5,203,363	3.68	18,708,873	5,129,526	3.65	11.06	7.35	3.65	3.68
7	602	Baker Lake	9,309,886	2,419,806	3.85	9,104,119	2,360,075	3.86	8,969,428	2,316,305	3.87	11.62	7.72	3.85	3.87
8	603	Arviat	9,175,780	2,482,513	3.70	9,095,854	2,385,215	3.81	9,102,718	2,431,449	3.74	11.44	7.49	3.70	3.77
9	604	Coral Harbour	3,608,600	1,042,192	3.46	3,681,735	1,033,328	3.56	3,736,800	1,038,712	3.60	10.79	7.13	3.46	3.56
10	605	Chesterfield Inlet	2,174,400	634,337	3.43	2,294,000	616,169	3.72	2,212,700	581,995	3.80	11.41	7.45	3.43	3.72
11	606	Whale Cove	2,130,430	587,076	3.63	2,023,356	556,006	3.64	2,005,185	608,612	3.29	10.92	7.26	3.29	3.58
12	607	Naujaat	4,636,690	1,254,296	3.70	4,492,960	1,233,648	3.64	4,431,901	1,243,296	3.56	11.09	7.28	3.56	3.66
13	701	Iqaluit	59,342,002	14,759,435	4.02	59,030,786	14,902,063	3.96	59,231,014	15,017,418	3.94	12.06	7.92	3.94	3.99
14	702	Pangnirtung	7,714,906	2,023,683	3.81	7,699,282	2,115,753	3.64	6,998,048	2,161,948	3.24	11.44	7.28	3.24	3.66
15	703	Cape Dorset	6,089,741	1,829,515	3.33	6,061,442	1,690,203	3.59	5,973,605	1,645,508	3.63	10.89	7.17	3.33	3.57
16	704	Resolute Bay	4,787,466	1,300,474	3.68	4,654,154	1,256,277	3.70	4,355,558	1,181,330	3.69	11.11	7.37	3.68	3.69
17	705	Pond Inlet	6,746,310	1,821,851	3.70	6,936,265	1,896,319	3.66	6,888,772	1,925,504	3.58	11.11	7.32	3.58	3.67
18	706	Igloolik	6,914,979	1,837,297	3.76	6,875,022	1,855,526	3.71	6,872,991	1,759,650	3.91	11.72	7.53	3.71	3.83
19	707	Hall Beach	3,581,272	988,706	3.62	3,474,897	948,462	3.66	3,605,376	1,032,761	3.49	10.99	7.24	3.49	3.62
20	708	Qikiqtarjuaq	2,713,703	766,022	3.54	2,667,977	741,379	3.60	2,644,608	744,622	3.55	10.80	7.10	3.54	3.57
21	709	Kimmirut	1,937,067	536,620	3.61	2,044,068	556,865	3.67	2,198,158	596,329	3.69	11.06	7.34	3.61	3.67
22	710	Arctic Bay	3,329,571	1,121,493	2.97	3,357,715	989,607	3.39	3,405,186	995,685	3.42	10.26	6.79	2.97	3.34
23	711	Clyde River	4,014,044	1,014,890	3.96	4,123,730	1,139,578	3.62	4,191,916	1,136,534	3.69	11.87	7.38	3.62	3.81
24	712	Grise Fiord	1,426,758	445,040	3.21	1,310,000	423,124	3.10	1,269,500	377,737	3.36	10.08	6.41	3.10	3.27
25	713	Sanikiluaq	4,038,890	1,066,410	3.79	4,046,643	1,142,450	3.54	4,326,103	1,106,561	3.91	11.73	7.57	3.54	3.81
26		**TOTAL**	**195,189,809**	**52,045,730**	**3.75**	**194,479,263**	**51,927,907**	**3.75**	**193,548,935**	**51,955,340**	**3.73**				**3.77**

Schedule 3.3:
Qulliq Energy Corporation 2022/23 General Rate Application
Non Electric Revenues
(in thousands of dollars)

	2018/19 GRA Forecast	**2018/19 Actual**	*Year over Year Change*	**2019/20 Actual**	*Year over Year Change*	**2020/21 Actual**	*Year over Year Change*	**2021/22 Forecast**	*Year over Year Change*	**2022/23 Forecast**
Joint Use	677	666	-	666	(86)	580	(43)	623	(64)	602
Miscellaneous Charges	1,132	1,631	382	2,012	342	1,973	126	1,757	234	1,865
Fees & Charges	*765*	*862*	*202*	*1,064*	*220*	*1,082*	*6*	*868*	*113*	*975*
Interest Income	*-*	*98*	*(57)*	*41*	*(95)*	*3*	*(58)*	*40*	*(76)*	*22*
Administration Fee - Housing Support	*367*	*387*	*5*	*392*	*7*	*394*	*10*	*397*	*9*	*395*
Other	*-*	*284*	*231*	*515*	*210*	*494*	*168*	*452*	*189*	*473*
Time and Materials	739	168	(88)	80	(136)	33	(112)	56	(124)	44
TOTAL	**2,548**	**2,465**	**293**	**2,758**	**121**	**2,586**	**(28)**	**2,437**	**46**	**2,511**

4.0 REVENUE REQUIREMENT

4.1 INTRODUCTION

QEC's revenue requirement for 2022/23 reflects the forecast cost of providing service in the test year, including a fair return on equity. The revenue requirement is recovered by way of rates charged for electrical services, as well as non-electrical revenues (such as from pole rentals and other sources). This section reviews QEC's revenue requirement for the test year 2022/23. Chapter 5 compares this revenue requirement to the revenues from existing rates (set out in Chapter 3) to calculate the shortfall in the 2022/23 test year.

Similar to previous GRA filings, there are four major components of QEC's revenue requirement:

- Operating and Maintenance costs, including, salaries and wages, supplies and services, and travel and accommodation expenses;
- Production fuel and lubricants expenses;
- Amortization expense; and
- Return on Rate Base.

Table 4.1 summarizes the 2022/23 revenue requirement and indicates where more detailed explanation on each revenue requirement category is provided. Further details on the forecast 2022/23 revenue requirement and comparisons with other years are available in Schedule 4.1.

Table 4.1:
2022/23 Revenue Requirement ($000s)

	2022/23 Forecast
Non-Fuel O&M (section 4.3)	64,620
Production Fuel (section 4.4)	51,543
Amortization (section 4.5)	13,747
Return on Rate Base (section 4.6)	14,105
Revenue Requirement	**144,015**

This chapter is organized under the following headings:

- **Revenue Requirement Changes since the 2018/19 GRA:** Provides an overview of the key drivers of revenue requirement changes since the 2018/19 GRA.
- **Non-Fuel Operations and Maintenance Expenses:** Reviews non-production fuel expenses including salaries and wages, supplies and services and travel and accommodation.
- **Production Fuel and Lubricants:** Provides an overview of forecast fuel volumes and prices for the test year.
- **Amortization Expense:** Reviews fixed asset amortization expense and refinancing cost amortization.
- **Return on Rate Base:** Discusses the forecast capital structure as well as return on equity and cost of debt in the test year.

4.2 REVENUE REQUIREMENT CHANGES SINCE THE 2018/19 GRA

Table 4.2 provides a comparison of the 2018/19 and 2022/23 test year revenue requirements.

Table 4.2:
Revenue Requirement –
2018/19 GRA Forecast Compared to 2022/23 Forecast ($000s)

	2018/19 GRA Forecast	2022/23 Forecast
Non-Fuel O&M	60,173	64,620
Production Fuel	48,820	51,543
Amortization	10,734	13,747
Return on Rate Base	13,165	14,105
Revenue Requirement	**132,893**	**144,015**

The overall revenue requirement has increased by $11.122 million from the last GRA. Revenue requirement changes are driven by the following:

- Operating and Maintenance costs have increased by approximately $4.446 million since the last GRA, or 1.8% average annual growth;
- Fuel costs have increased by $2.723 million or a 1.4% increase per year on average;
- Fixed assets amortization costs have increased by $3.013 million or 6.4% average annual growth; and
- Return on rate base has increased by $0.940 million or 1.7% average annual growth.

These revenue requirement increases are offset to a degree by increases in electricity sales revenue. Further details are provided in the following sections.

4.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

QEC's forecasts for total operating and maintenance expenses for 2022/23 are set out in Table 4.3.

Table 4.3:
Non-Fuel O&M Expense –
2018/19 GRA Forecast Compared to 2022/23 ($000s)

	2018/19 GRA Forecast	**2022/23 Forecast**
Salaries and Wages	31,287	36,371
Supplies and Services, total includes:	23,569	22,340
Supplies and Services	23,459	22,204
Site Restoration expense	161	161
Corporate donations	(50)	(25)
Travel and Accommodation	5,317	5,909
Total Non-Fuel O&M Expense	**60,173**	**64,620**

Overall, the Corporation's non-fuel 2022/23 Operation and Maintenance (O&M) expenses have increased by $4.446 million since the 2018/19 GRA or an average annual increase of 1.8%. Average annual inflation for Nunavut for the period from January 2019 to January 2022 was 1.4%[5], therefore in real terms, the average annual increase of non-fuel O&M expenses is about 0.4%. Overall, the changes in QEC's O&M expense reflect the

[5] Statistics Canada, Table 18-10-0004-01 (formerly CANSIM table 326-0020), data for Iqaluit, Nunavut. The 1.4% is average of 3-year fiscal year CPI increase (1.9% increase in January 2020 over January 2019; 0.2% increase in January 2021 over January 2020; and 2.1% increase in January 2022 over January 2021). Available at: https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000401 (accessed March 3, 2022).

Corporation's priorities on safety, reliability, efficiency and responsiveness to stakeholder concerns.

4.3.1 SALARIES AND WAGES

Forecast salaries and wages expense of $36.371 million for 2022/23 reflect a number of strategic priorities for the Corporation. The $5.084 million increase in salaries and wages expense compared to the 2018/19 GRA forecast reflects:

- Cost of living increases consistent with the Corporation's collective agreements;
- Annual step (merit) increments for employees; and
- Changes to staff complement in response to a number of strategic priorities for the Corporation.

For positions covered by the Corporation's collective agreement, the average annual increase in hourly rates were 1.0% and 2.0% for 2019 and 2020 calendar years respectively. The compounded increase was approximately 3.0% over the two years.[6] Corporate wide, average annual salaries and wages per Full Time Equivalent positions (FTE) are forecast to increase from $169,000 in the 2018/19 GRA to approximately $193,000 in 2022/23, or an average annual increase of 3.4%, including both cost of living and merit increases.

[6] Collective Agreement between Qulliq Energy Corporation and Nunavut Employees Union. Expires December 31, 2020. Available at: https://www.gov.nu.ca/sites/default/files/signed_collective_agreement_-_iqaluit_final.pdf (accessed March 4, 2020). At the time of the GRA application no new collective agreement was signed.

In order to continue to provide safe and reliable service the Corporation revised its organizational structure in response to a number of strategic priorities with the objective of improving control over functional areas where organizational gaps are identified. By revising the organizational structure, the Corporation promotes better opportunities for growth through cross training and collaboration, as well as to increase Inuit Employment initiatives in management roles. Further, this organizational restructure allows for increased work efficiency between various regions improving the Corporation's ability to deliver services throughout the Territory. This activity resulted in a need to revamp existing job positions with new work accountabilities and new positions were added where the gaps were identified. Overall, in the 2018/19 GRA the forecast FTE complement was 206. For the 2022/23 test year the number of FTEs is forecast to be 209 for a net increase of three FTEs.

For the 2022/23 test year the Corporation is forecasting a vacancy rate of 10.2% which is consistent with 2018/19 GRA and URRC recommendation for 2014/15 GRA.[7] The Corporation's objectives include increasing local hiring, increasing Inuit employment and reducing turnover by promoting training and retention. QEC has developed an Inuit Employment Plan (IEP) to 2023 that addresses issues and opportunities to increase Inuit employment, sets short, medium and long-term goals to increase capacity, and contains an action plan to achieve the goals.[8] As of September 30, 2020, QEC's Inuit employment rate was 52%.

[7] In the 2014/15 GRA the URRC recommended a 10% vacancy rate for the 2014/15 GRA.
[8] QEC's Corporate Plan 2021-2024. Available at: https://www.qec.nu.ca/sites/default/files/20._qulliq_energy_corporation_-_050121.pdf (accessed March 8, 2022).

4.3.2 SUPPLIES AND SERVICES

Supplies and services expense represents the cost of maintaining the plants and equipment including materials, freight, contractors, professional development and administration. Forecast costs for supplies and services are $22.204 million for 2022/23. Compared to 2018/19 GRA levels, this reflects a decrease of $1.255 million, or an average decrease of 1.4% per year. The decrease mainly reflects reductions in materials expenses ($2.1 million lower compared to the 2018/19 GRA), external services ($0.6 million lower compared to the 2018/19 GRA), and freight ($0.3 million lower compared to the 2018/19 GRA), offset by $1.3 million increase in insurance expense.

4.3.3 TRAVEL AND ACCOMMODATION

Travel and Accommodation expense includes all of the costs associated with travel, meals and accommodation for operational, professional development and employee medical needs. Forecast travel costs of $5.909 million in 2022/23 represent an increase of $0.592 million compared to the 2018/19 GRA forecasts or about 2.7% average annual increase.

This increase represents inflationary increases as well as higher Medical Travel expenses ($0.805 million over 2018/19 GRA forecast). As indicated during the 2014/15 and 2018/19 GRAs, the Corporation's medical travel policy covers travel, accommodation, meal and incidental expenses for employees and dependents of employees who require medical treatment which is not available in their community of employment.[9]

The Corporation is forecasting decreases in relocation cost and training travel cost categories offsetting increases in other travel categories.

4.4 PRODUCTION FUEL

QEC's actual and forecast production fuel costs are set out in Schedules 4.2.1 through 4.2.5. Forecast production fuel expenses in 2022/23 are $2.723 million higher relative to the 2018/19 GRA.

The change in forecast fuel reflects the following:

- **Load Forecast ($1.317 million increase over 2018/19 GRA forecast at 2018/19 prices and fuel efficiencies).** The increased sales noted in Chapter 3 result in increased generation fuel requirements.
- **Fuel Price Change ($1.288 million increase from 2018/19 GRA forecast).** Average 2022/23 fuel prices are forecast to be $0.96/litre, an increase relative to 2018/19 average fuel prices of $0.93/litre. Further details on QEC's fuel price forecasts for 2022/23 are provided below.
- **Fuel Efficiency Change ($0.094 million reduction from 2018/19 GRA forecast).** Fuel efficiencies have improved from an average of 3.76 kWh/litres in

[9] QEC 2014/15 General Rate Application, page 4-9 and QEC 2018/19 General Rate Application, page 4-7.

the 2018/19 GRA to an average of 3.77 kWh/litres. These improvements have reduced the fuel volume by nearly 0.100 million litres which reduced overall fuel cost at the 2022/23 forecast fuel prices by $0.094 million as compared to the 2018/19 GRA forecast.

- **Lube Cost ($0.212 million increase from 2018/19 GRA forecast).** 2022/23 lube costs are higher by $0.212 million compared to the 2018/19 GRA forecast.

Table 4.4:
Generation, Fuel Consumption and Fuel Cost –
2018/19 GRA Forecast Compared to 2022/23 Forecast

	2018/19 GRA Forecast	2022/23 Forecast	Change	Average Annual Growth
Generation (MWh)	**193,338**	**198,389**		**0.6%**
2018/19 GRA Fuel efficiency (kWh/L)	3.76	3.76		
Fuel Volume at 2018/19 efficiency (L 000)	**51,355**	**52,755**		**0.7%**
2018/19 GRA average fuel price ($/L)	*0.93*	*0.93*		
Fuel cost at 2018/19 GRA fuel price and efficiency ($000)	**47,989**	**49,306**	**1,317**	**0.7%**
2022/23 forecast average fuel price ($/L)		*0.96*		
Fuel price change from 2018/19 GRA ($/L)		*0.03*		
Cost change due to fuel price ($000)		**1,288**	**1,288**	
Fuel efficiency (KWh/L)		*3.77*		
Cost change due to fuel efficiency ($000)		**-94**	**-94**	
Lube Cost ($000)	**831**	**1,043**	**212**	
Total fuel and lubricants ($000)	**48,820**	**51,543**	**2,723**	**1.4%**

Fuel Price Forecast

QEC purchases fuel through the Petroleum Products Division (PPD) of the Department of Community and Government Services (CGS) of Government of Nunavut. Approximately 35% of QEC's forecast generation fuel requirements are supplied through bulk fuel purchases in seven communities. The remaining 65% is purchased at nominated fuel prices set by the Territorial government.

Fuel costs represent approximately 36% of QEC's total 2022/23 revenue requirement. QEC's current fuel prices are slightly higher than the fuel prices included in the 2018/19 GRA. QEC captures differences between actual fuel prices and GRA approved fuel prices in the fuel stabilization rider (FSR). However, the Nunavut Electricity Subsidy Program (NESP) does not subsidize fuel stabilization riders, therefore, if fuel prices built into base energy rates are too low, customers pay the full amount of future fuel riders associated with higher fuel prices compared to the GRA forecast prices.

Based on these considerations, QEC prepared a 2022/23 GRA fuel price forecast that reflects the following:

- Summer 2022 bulk fuel prices are based on information provided by the Petroleum Products Division of the Department of Community and Government Services (C&GS) of Government of Nunavut.
- 2022/23 forecast nominated fuel prices are based on the actual retail fuel price adjustments announced by Government of Nunavut effective February 6, 2022.

Average GRA fuel prices reflect a forecast of fuel inventory and mixture of bulk and nominated fuel consistent with previous operating experience.

4.5 AMORTIZATION EXPENSE

Amortization expense comprises the sum of fixed asset amortization and amortization of financing costs.

The increase in amortization expense reflects growth in fixed assets as detailed in Section 6.3. Financing cost amortization of $0.249 million is included in the revenue requirement in accordance with the URRC Report to the responsible Minister on QEC's 2004/05 GRA.[10]

Table 4.5 shows changes to amortization expense from 2018/19 to the 2022/23 forecast.

Table 4.5:
Amortization Expense –
2018/19 GRA Forecast Compared to 2022/23 Forecast ($000s)

	2018/19 GRA Forecast	2022/23 Forecast
Fixed Asset Amortization	10,485	13,498
Add: Financing Cost Amortization	249	249
Total	**10,734**	**13,747**

4.6 RETURN ON RATE BASE

Return on rate base represents the weighted average cost of long-term debt, equity and no-cost capital required to finance the Corporation's rate base. Changes to return on rate base occur as a result of changes to the Corporation's net plant in service, changes to

[10] URRC Report to the Minister Responsible for the Qulliq Energy Corporation, February 18, 2005. Schedule B-1.

the mix of debt and equity in the Corporation's capital structure and changes to the relative costs of debt and equity.

The Corporation's capital structure, rate base and return on rate base for 2022/23 compared to the 2018/19 GRA test year are shown in Table 4.6.

Table 4.6:
Return on Rate Base –
2018/19 GRA Forecast Compared to 2022/23 Forecast ($000s)

	2018/19 GRA Forecast	2022/23 Forecast
Mid-Year Net Plant in Service	219,415	272,277
Working Capital	27,326	33,147
Mid Year Rate Base	**246,741**	**305,425**
Average Rate of Return on Rate Base	5.34%	4.62%
Return on Rate Base	**13,165**	**14,105**

Return on rate base is forecast to increase by $0.940 million relative to the 2018/19 test year. This change relates to increases in mid-year rate base with an offsetting reduction in the average rate of return on rate base. Since the last GRA, significant investment in new infrastructure and re-investment in existing infrastructure has been undertaken to ensure the Corporation can continue to meet load growth in a safe and reliable manner. The forecast growth in net mid-year rate base from the 2018/19 test year to the 2022/23 test year is $58.683 million. These increases are partially offset by a reduction in the overall cost of capital. The average rate of return on rate base is forecast to decrease from 5.34% in the 2018/19 GRA to 4.62% in the 2022/23 test year (which reduces return on rate base by about $2.191 million). This decrease reflects the reduction in the average cost of long-term debt. Calculation of the return on rate base is detailed in Schedule 4.4.

4.6.1 CAPITAL STRUCTURE

Section 25 of the Qulliq Energy Corporation Act requires the Corporation's borrowings not to exceed three times its equity at any time. In its Report 2011-01 to the Minister respecting QEC's 2010/11 GRA, the URRC considered a 40% equity ratio to be appropriate for the determination of a fair return on rate base in 2010/11.[11] QEC's proposed capital structure shown in Schedule 4.4 reflects a deemed 40% equity ratio consistent with the URRC Report 2011-01 as well as QEC's 2018/19 GRA and the URRC Report 2018-01. A continuity schedule of the Corporation's capitalization is provided in Schedule 4.5.

4.6.2 AVERAGE COST OF LONG-TERM DEBT

The forecast average cost of long-term debt decreased from 3.37% in the 2018/19 GRA to 2.17% for 2022/23. The reduction in average cost of long-term debt reflects overall lower interest rates for new debt. In the 2021/22 and 2022/23 fiscal years the Corporation forecasts it will take on new long-term debt of $8.1 million and $37.7 million, respectively, at an interest rate of 1.95%. This interest rate is based on the Bank of Canada business prime rate.[12] The most recent actual long-term debt the Corporation secured has an interest rate of prime minus 0.5% per annum. However, the Corporation expects that the cost of debt for the forecast years will increase. This expectation is also consistent with

[11] Page 34, URRC Report 2011-01 to the Minister responsible for Qulliq Energy Corporation, March 2, 2011.
[12] The Bank of Canada, Daily Digest. Available at: http://www.bankofcanada.ca/rates/daily-digest/ (accessed March 2, 2022).

the recent increase of the interest rate announced by the Bank of Canada.[13] Schedule 4.6 shows the calculation of the average cost of long-term debt consistent with the URRC recommendation in the URRC Report 2014-04 based on mid-year balance of the debt.

4.6.3 NO COST CAPITAL

No cost capital includes the notional hearing cost reserve account balance. The hearing cost reserve account reflects the combined Hearing and Reserve for Injuries and Damages (RFID) balances, reduced by the hearing costs charged to the account. Hearing costs for 2018/19 to 2020/21 are recorded on an actual basis and forecast 2021/22 and 2022/23 expenses reflect the expected cost of the current rate application review process.

4.6.4 RETURN ON EQUITY

QEC is proposing return on equity (ROE) for the 2022/23 test year of 8.30% which is consistent with QEC's approved ROE for the 2018/19 GRA as recommended by the URRC in Report 2018-01.

In considering the proposed ROE for the 2022/23 test year, QEC also reviewed the ROE rates for other northern utilities and notes that the proposed ROE rate is similar or lower than those of the reviewed utilities:

[13] The Bank of Canada announced on March 2, 2022, that increased its target for the overnight rate to 0.5%, with the Bank Rate at 0.75% and the deposit rate at 0.5%. Available at: https://www.bankofcanada.ca/2022/03/fad-press-release-2022-03-02/ (accessed March 2, 2022).

- **Northwest Territories Power Corporation (NTPC):** In Decision 16-2017 the NWT PUB approved NTPC's requested ROE of 8.0% for each of the 2016/17, 2017/18, and 2018/19 test years.[14]

- **Yukon Electrical Company Limited, ATCO Electric Yukon (AEY):** In its Order 2017-01 the Yukon Utilities Board (YUB) approved an ROE of 8.75% for ATCO Electric Yukon (AEY) for the 2016 and 2017 test years based on the British Columbia Utilities Commission (BCUC) generic cost of capital model.[15]

- **Yukon Energy Corporation (YEC):** In its most recent 2021 GRA, currently ongoing proceeding, YEC requested ROE of 8.70%, at the same level as approved by YUB for 2017 and 2018 test years.[16]

[14] Northwest Territories Public Utilities Board. Decision 16-2017, page 48. Available at https://www.nwtpublicutilitiesboard.ca/sites/nwtpub/files/supporting/16-2017%20DECISION%20NTPC%202016-19%20Phase%20I%20GRA.pdf (accessed March 4, 2022).

[15] YUB Order 2017-01, Appendix A: Reasons for Decision, page 37. Available at https://yukonutilitiesboard.yk.ca/pdf/Board_Orders_2010/Board_Order_2017-01_Appendix_A_-_Reasons.pdf (accessed March 4, 2022).

[16] YEC 2021 GRA, Table 3.15 and subsection 3.5.2. Available at: https://yukonutilitiesboard.yk.ca/pdf/YEC_2021_GRA/2021_General_Rate_Application.pdf (accessed March 4, 2022).

Schedule 4.1:
Qulliq Energy Corporation 2022/23 General Rate Application
Revenue Requirement ($000)

Line No.		2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast
1	**Operation & Maintenance Expense**						
2	Salaries and Wages	$ 31,287	$ 33,188	$ 36,797	$ 36,833	$ 36,150	$ 36,371
3	Supplies and Services	23,459	20,717	22,193	26,895	21,605	22,204
4	Site Restoration Expense	161	240	(247)	238	161	161
5	Travel and Accommodation	5,317	5,124	5,140	3,261	6,222	5,909
6	**Non-Fuel Operation & Maintenance Expense**	**60,223**	**59,268**	**63,883**	**67,227**	**64,138**	**64,645**
7	Less: Corporate Donations	(50)	(8)	(14)	(6)	(40)	(25)
8	**Non-Fuel Operation & Maintenance Expense for GRA**	**60,173**	**59,261**	**63,870**	**67,221**	**64,098**	**64,620**
9	**Fuel and Lubricants Expense**	**48,820**	**50,166**	**48,784**	**47,340**	**45,497**	**51,543**
10	**Amortization**						
11	Fixed Asset Amortization	10,485	10,906	10,391	10,716	12,252	13,498
12	Add: Financing Cost Amortization	249	249	249	249	249	249
13	**Total Net Amortization Expense**	**10,734**	**11,155**	**10,640**	**10,965**	**12,501**	**13,747**
14	**Total Return on Rate Base**	**13,165**	**8,580**	**13,770**	**7,425**	**13,151**	**14,105**
15	**Total Revenue Requirement**	**132,893**	**129,163**	**137,064**	**132,952**	**135,246**	**144,015**

Schedule 4.2.1:
Qulliq Energy Corporation 2022/23 General Rate Application
2018/19 Actual Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,109	3.69	3,278	0.95	3,119	26	3,145
2	502	Gjoa Haven	6,167	3.61	1,706	1.02	1,742	22	1,764
3	503	Taloyoak	4,149	3.41	1,217	0.98	1,189	24	1,213
4	504	Kugaaruk	3,836	3.68	1,043	1.00	1,045	25	1,070
5	505	Kugluktuk	6,010	3.64	1,650	0.95	1,563	31	1,594
6	601	Rankin Inlet	19,246	3.69	5,220	0.92	4,817	89	4,906
7	602	Baker Lake	9,310	3.85	2,420	0.96	2,314	38	2,352
8	603	Arviat	9,176	3.70	2,483	0.91	2,258	70	2,327
9	604	Coral Harbour	3,609	3.46	1,042	0.96	995	25	1,020
10	605	Chesterfield Inlet	2,174	3.43	634	0.95	602	19	621
11	606	Whale Cove	2,130	3.63	587	0.95	558	32	590
12	607	Naujaat	4,637	3.70	1,254	0.99	1,238	23	1,261
13	701	Iqaluit	59,342	4.02	14,759	0.95	14,005	215	14,219
14	702	Pangnirtung	7,715	3.81	2,024	0.92	1,868	8	1,876
15	703	Kinngait	6,090	3.33	1,830	0.94	1,718	8	1,726
16	704	Resolute Bay	4,787	3.68	1,300	0.95	1,233	14	1,247
17	705	Pond Inlet	6,746	3.70	1,822	0.95	1,729	24	1,753
18	706	Igloolik	6,915	3.76	1,837	0.94	1,732	35	1,767
19	707	Sanirajak	3,581	3.62	989	0.95	937	21	957
20	708	Qikiqtarjuaq	2,714	3.54	766	0.95	725	29	754
21	709	Kimmirut	1,937	3.61	537	0.94	506	-7	499
22	710	Arctic Bay	3,330	2.97	1,121	0.95	1,066	28	1,094
23	711	Clyde River	4,014	3.96	1,015	0.92	938	37	975
24	712	Grise Fiord	1,427	3.21	445	0.84	375	25	399
25	713	Saniqiluaq	4,039	3.79	1,066	0.95	1,018	18	1,036
26		**TOTAL**	**195,190**	**3.75**	**52,046**	**0.95**	**49,287**	**879**	**50,166**

Schedule 4.2.2:
Qulliq Energy Corporation 2022/23 General Rate Application
2019/20 Actual Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,138	3.66	3,314	0.84	2,771	44	2,814
2	502	Gjoa Haven	6,234	3.53	1,764	0.95	1,682	24	1,706
3	503	Taloyoak	4,109	3.72	1,104	0.98	1,084	16	1,101
4	504	Kugaaruk	3,695	3.75	985	0.97	953	26	979
5	505	Kugluktuk	6,205	3.62	1,716	0.84	1,444	22	1,466
6	601	Rankin Inlet	19,125	3.68	5,203	0.89	4,637	-8	4,629
7	602	Baker Lake	9,104	3.86	2,360	0.96	2,272	34	2,306
8	603	Arviat	9,096	3.81	2,385	0.88	2,102	50	2,153
9	604	Coral Harbour	3,682	3.56	1,033	0.92	949	20	969
10	605	Chesterfield Inlet	2,294	3.72	616	0.98	604	15	619
11	606	Whale Cove	2,023	3.64	556	0.97	537	13	549
12	607	Naujaat	4,493	3.64	1,234	0.92	1,129	20	1,149
13	701	Iqaluit	59,031	3.96	14,902	0.96	14,367	105	14,472
14	702	Pangnirtung	7,699	3.64	2,116	0.94	1,989	25	2,014
15	703	Kinngait	6,061	3.59	1,690	0.94	1,588	0	1,588
16	704	Resolute Bay	4,654	3.70	1,256	0.95	1,189	15	1,204
17	705	Pond Inlet	6,936	3.66	1,896	0.95	1,797	27	1,825
18	706	Igloolik	6,875	3.71	1,856	0.93	1,720	14	1,733
19	707	Sanirajak	3,475	3.66	948	0.90	849	21	870
20	708	Qikiqtarjuaq	2,668	3.60	741	0.95	705	21	726
21	709	Kimmirut	2,044	3.67	557	0.94	524	21	545
22	710	Arctic Bay	3,358	3.39	990	0.94	934	12	946
23	711	Clyde River	4,124	3.62	1,140	0.85	969	9	978
24	712	Grise Fiord	1,310	3.10	423	0.86	365	11	376
25	713	Saniqiluaq	4,047	3.54	1,142	0.93	1,060	8	1,068
26		**TOTAL**	**194,479**	**3.75**	**51,928**	**0.93**	**48,221**	**563**	**48,784**

Schedule 4.2.3:
Qulliq Energy Corporation 2022/23 General Rate Application
2020/21 Actual Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,189	3.70	3,295	0.86	2,841	62	2,903
2	502	Gjoa Haven	6,108	3.59	1,702	0.94	1,595	35	1,629
3	503	Taloyoak	4,191	3.59	1,168	0.95	1,105	38	1,144
4	504	Kugaaruk	3,750	3.62	1,036	0.96	993	0	993
5	505	Kugluktuk	6,183	3.59	1,723	0.86	1,479	28	1,507
6	601	Rankin Inlet	18,709	3.65	5,130	0.81	4,169	90	4,259
7	602	Baker Lake	8,969	3.87	2,316	0.92	2,134	48	2,181
8	603	Arviat	9,103	3.74	2,431	0.88	2,143	7	2,150
9	604	Coral Harbour	3,737	3.60	1,039	0.91	947	20	967
10	605	Chesterfield Inlet	2,213	3.80	582	0.97	564	-3	561
11	606	Whale Cove	2,005	3.29	609	0.85	520	4	524
12	607	Naujaat	4,432	3.56	1,243	0.93	1,153	18	1,172
13	701	Iqaluit	59,231	3.94	15,017	0.93	13,988	83	14,071
14	702	Pangnirtung	6,998	3.24	2,162	0.88	1,909	46	1,955
15	703	Kinngait	5,974	3.63	1,646	0.90	1,488	26	1,515
16	704	Resolute Bay	4,356	3.69	1,181	0.91	1,078	12	1,091
17	705	Pond Inlet	6,889	3.58	1,926	0.86	1,661	20	1,682
18	706	Igloolik	6,873	3.91	1,760	0.84	1,487	23	1,510
19	707	Sanirajak	3,605	3.49	1,033	0.87	901	22	923
20	708	Qikiqtarjuaq	2,645	3.55	745	0.90	673	16	689
21	709	Kimmirut	2,198	3.69	596	0.91	542	2	543
22	710	Arctic Bay	3,405	3.42	996	0.91	904	14	919
23	711	Clyde River	4,192	3.69	1,137	0.87	992	8	1,000
24	712	Grise Fiord	1,270	3.36	378	0.87	330	8	338
25	713	Saniqiluaq	4,326	3.91	1,107	0.98	1,081	32	1,114
26		**TOTAL**	**193,549**	**3.73**	**51,955**	**0.90**	**46,678**	**662**	**47,340**

Schedule 4.2.4:
Qulliq Energy Corporation 2022/23 General Rate Application
2021/22 Forecast Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,772	3.69	3,461	0.78	2,712	66	2,778
2	502	Gjoa Haven	6,061	3.59	1,688	0.90	1,524	31	1,555
3	503	Taloyoak	4,221	3.63	1,163	0.90	1,049	22	1,071
4	504	Kugaaruk	3,923	3.71	1,057	0.90	954	20	974
5	505	Kugluktuk	6,171	3.63	1,700	0.76	1,284	32	1,316
6	601	Rankin Inlet	19,840	3.68	5,391	0.73	3,934	102	4,037
7	602	Baker Lake	9,201	3.87	2,378	0.90	2,146	47	2,193
8	603	Arviat	9,385	3.77	2,489	0.73	1,824	48	1,872
9	604	Coral Harbour	3,670	3.56	1,031	0.90	930	19	949
10	605	Chesterfield Inlet	2,213	3.72	595	0.90	537	11	548
11	606	Whale Cove	2,126	3.58	594	0.90	536	11	547
12	607	Naujaat	4,477	3.66	1,223	0.90	1,104	23	1,127
13	701	Iqaluit	59,869	3.99	15,005	0.85	12,688	308	12,997
14	702	Pangnirtung	7,460	3.66	2,038	0.90	1,839	38	1,878
15	703	Kinngait	6,096	3.57	1,708	0.90	1,541	31	1,572
16	704	Resolute Bay	4,600	3.69	1,247	0.90	1,125	24	1,149
17	705	Pond Inlet	7,186	3.67	1,958	0.90	1,767	37	1,804
18	706	Igloolik	7,042	3.83	1,839	0.90	1,659	36	1,695
19	707	Sanirajak	3,631	3.62	1,003	0.90	905	19	924
20	708	Qikiqtarjuaq	2,729	3.57	764	0.90	690	14	704
21	709	Kimmirut	2,094	3.67	571	0.90	515	11	526
22	710	Arctic Bay	3,486	3.34	1,044	0.90	942	18	960
23	711	Clyde River	4,200	3.81	1,102	0.81	891	22	913
24	712	Grise Fiord	1,366	3.27	418	0.90	377	7	384
25	713	Saniqiluaq	4,236	3.81	1,112	0.90	1,003	22	1,025
26		**TOTAL**	**198,054**	**3.77**	**52,578**	**0.85**	**44,477**	**1,020**	**45,497**

Schedule 4.2.5:
Qulliq Energy Corporation 2022/23 General Rate Application
2022/23 Forecast Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,617	3.69	3,419	0.93	3,179	66	3,246
2	502	Gjoa Haven	6,118	3.59	1,704	0.98	1,674	32	1,706
3	503	Taloyoak	4,297	3.63	1,184	0.98	1,163	23	1,186
4	504	Kugaaruk	3,848	3.71	1,037	0.98	1,019	20	1,039
5	505	Kugluktuk	6,291	3.63	1,733	0.92	1,596	33	1,629
6	601	Rankin Inlet	19,595	3.68	5,325	0.91	4,857	103	4,960
7	602	Baker Lake	9,282	3.87	2,399	0.98	2,356	49	2,405
8	603	Arviat	9,367	3.77	2,485	0.90	2,247	49	2,296
9	604	Coral Harbour	3,765	3.56	1,057	0.98	1,039	20	1,059
10	605	Chesterfield Inlet	2,219	3.72	596	0.98	586	12	598
11	606	Whale Cove	2,108	3.58	589	0.98	579	11	590
12	607	Naujaat	4,573	3.66	1,249	0.98	1,228	24	1,252
13	701	Iqaluit	60,181	3.99	15,083	0.96	14,486	316	14,802
14	702	Pangnirtung	7,233	3.66	1,976	0.98	1,941	38	1,980
15	703	Kinngait	6,086	3.57	1,705	0.98	1,675	32	1,707
16	704	Resolute Bay	4,588	3.69	1,243	0.98	1,221	24	1,246
17	705	Pond Inlet	7,106	3.67	1,936	0.98	1,902	37	1,940
18	706	Igloolik	7,059	3.83	1,843	0.98	1,811	37	1,848
19	707	Sanirajak	3,659	3.62	1,011	0.98	993	19	1,012
20	708	Qikiqtarjuaq	2,734	3.57	766	0.98	752	14	767
21	709	Kimmirut	2,176	3.67	593	0.98	583	11	594
22	710	Arctic Bay	3,500	3.34	1,048	0.98	1,030	18	1,048
23	711	Clyde River	4,293	3.81	1,127	0.94	1,058	23	1,081
24	712	Grise Fiord	1,347	3.27	412	0.98	405	7	412
25	713	Saniqiluaq	4,348	3.81	1,141	0.98	1,121	23	1,144
26		**TOTAL**	**198,389**	**3.77**	**52,661**	**0.96**	**50,500**	**1043**	**51,543**

Schedule 4.3:
Qulliq Energy Corporation 2022/23 General Rate Application
Amortization Provision by Functions ($000)

Line No.	Amortization Provision by Major FERC Category	2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast
1	**Diesel Plant**						
2	Amortization	8,874	9,726	9,100	9,408	10,713	10,830
3	Add (Less): Adjustments		0	0	0	0	0
4	Total Diesel Plant Amortization	8,874	9,726	9,100	9,408	10,713	10,830
5	**Distribution Plant**						
6	Amortization	1,001	819	868	848	902	1,123
7	Add (Less): Adjustments		0	0	0	0	0
8	Total Distribution Plant Amortization	1,001	819	868	848	902	1,123
9	**General Plant**						
10	Amortization	1,275	1,205	1,267	1,304	1,481	2,389
11	Add (Less): Adjustments		0	0	0	0	0
12	Total General Plant Amortization	1,275	1,205	1,267	1,304	1,481	2,389
13	**Energy Utilization Group**						
14	Amortization	6	0	0	0	0	0
15	Add (Less): Adjustments		0	0	0	0	0
16	Total EUG Amortization	6	0	0	0	0	0
17	**Insurance Proceeds**						
18	Amortization	-671	-844	-844	-844	-844	-844
19	Add (Less): Adjustments		0	0	0	0	0
20	Total Insurance Proceeds Amortization	-671	-844	-844	-844	-844	-844
21	**Total Rate Base Amortization**	**10,485**	**10,906**	**10,391**	**10,716**	**12,252**	**13,498**
22	Add: Financing Cost Amortization	249	249	249	249	249	249
23	**Total Amortization**	**10,734**	**11,155**	**10,640**	**10,965**	**12,501**	**13,747**

Note:
1. Amortization expenses are net of Residual Heat.
2. Amortization expenses reflect exclusion of the disallowed amount of $1.745 million from utility plant in service per the URRC directive from the Final Report on QEC's 2004/05 GRA.
3. Generation Plant Amortization expense reflects exclusion of the amount for Government of Nunavut contributions.
4. Distribution Plant Amortization expense reflects exclusion of the amount for customer contributions.

Schedule 4.4:
Qulliq Energy Corporation 2022/23 General Rate Application
Return on Rate Base – Mid year ($000)

Line No.		Mid-Year Capitalization	Deemed Mid-Year Capital Ratios [1]	Mid-Year Rate Base	Mid-Year Cost Rate	Return
	2018/19 GRA Forecast					
1	Common Equity	130,215	40.00%	98,697	8.30%	8,192
2	Long Term Debt	203,081	59.76%	147,453	3.37%	4,974
3	No Cost Capital	802	0.24%	592	0.00%	0
4	**TOTAL**	**$ 334,098**	***100.00%***	**$ 246,741**	**5.336%**	**$ 13,165**
	2018/19 Actuals					
5	Common Equity	129,946	42.54%	103,996	4.32%	4,492
6	Long Term Debt	174,873	57.25%	139,951	2.92%	4,088
7	No Cost Capital	662	0.22%	529	0.00%	0
8	**TOTAL**	**$ 305,480**	***100.00%***	**$ 244,477**	**3.510%**	**$ 8,580**
	2019/20 Actuals					
9	Common Equity	136,761	41.93%	110,872	8.24%	9,138
10	Long Term Debt	188,738	57.87%	153,010	3.03%	4,632
11	No Cost Capital	660	0.20%	535	0.00%	0
12	**TOTAL**	**$ 326,159**	***100.00%***	**$ 264,416**	**5.208%**	**$ 13,770**
	2020/21 Actuals					
13	Common Equity	142,976	42.83%	112534.3187	2.93%	3,292
14	Long Term Debt	190,172	56.97%	149681.3795	2.76%	4,132
15	No Cost Capital	660	0.20%	519.3366043	0.00%	0
16	**TOTAL**	**$ 333,808**	***100.00%***	**$ 262,735**	**2.826%**	**$ 7,425**
	2021/22 Forecast					
17	Common Equity	149,203	40.00%	110,385	8.30%	9,162
18	Long Term Debt	177,464	59.83%	165,106	2.42%	3,989
19	No Cost Capital	559	0.17%	472	0.00%	0
20	**TOTAL**	**$ 327,227**	***100.00%***	**$ 275,963**	**4.765%**	**$ 13,151**
	2022/23 Forecast					
21	Common Equity	158,854	40.00%	122,170	8.30%	10,140
22	Long Term Debt	174,416	59.87%	182,869	2.17%	3,965
23	No Cost Capital	421	0.13%	386	0.00%	0
24	**TOTAL**	**$ 333,692**	***100.00%***	**$ 305,425**	**4.618%**	**$ 14,105**

Note:
1. Uses deemed capital ratio based on URRC's recommendation (URRC Final Report, paragraph 7, page 34, March 2, 2011).

Schedule 4.5:
Qulliq Energy Corporation 2022/23 General Rate Application
Capitalization – Mid year ($000)

Line No.		2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast
1	COMMON EQUITY						
2	Opening Balance	126,119	127,700	132,192	141,330	144,622	153,784
3	Net Income/Loss before GN Contributions	8,192	4,492	9,138	3,292	9,162	10,140
4	(Dividends)/Contributions						
5	Closing Balance	134,311	132,192	141,330	144,622	153,784	163,924
6	Mid Year Balance [(L2+L5)/2]	130,215	129,946	136,761	142,976	149,203	158,854
7	DEBT - LONG TERM						
8	Opening Balance	199,723	163,263	186,483	190,994	189,350	165,578
9	Issue	24,999	37,066	19,238	15,930	8,058	37,697
10	Repayment	(18,284)	(13,846)	(14,727)	(17,574)	(31,830)	(20,019)
11	Closing Balance	206,438	186,483	190,994	189,350	165,578	183,255
12	Mid Year Balance [(L8+L11)/2]	203,081	174,873	188,738	190,172	177,464	174,416
13	NO COST CAPITAL						
	GN No-Cost Loan						
14	Opening Balance	0	0	0	0	0	0
15	Issue	0	0	0	0	0	0
16	Repayment	0	0	0	0	0	0
17	Closing Balance	0	0	0	0	0	0
18	Mid Year Balance [(L14+L17)/2]	0	0	0	0	0	0
	Hearing Reserve and Reserve for Injuries and Damages						
19	Opening Balance	802	663	660	660	660	459
20	Additions	0	0	0	0	0	0
21	Use	0	(4)	0	0	(201)	(75)
22	Closing Balance	802	660	660	660	459	384
23	Mid Year Balance [(L19+L22)/2]	802	662	660	660	559	421
24	No Cost Capital Mid Year Balance [L18+L23]	802	662	660	660	559	421
25	TOTAL MID YEAR CAPITALIZATION						
26	[L6+L12+L24]	334,098	305,480	326,159	333,808	327,227	333,692

Schedule 4.6:
Qulliq Energy Corporation 2022/23 General Rate Application
Cost of Long-Term Debt ($000)

Line No.		2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast		
							Effective Interest Rate	Mid-Year Debt Balance	Interest Expense on Mid-year Balance
1	**MID-YEAR DEBT BALANCE (MAD)**	203,081	174,873	188,738	190,172	177,464		174,416	
2	**INTEREST EXPENSE**								
	Interest on Long Term Debt								
	$61m Debenture debt	1,884	1,949	1,689	1,412	596			
	$7m Capital loan (Facility B)	53	54	35	14	0			
	$8m Capital loan (Facility C)	68	69	45	19	1			
	$8m Capital loan (Facility D)	97	98	64	28	1			
	$4.8m Capital loan (Facility E)	154	154	145	136	116			
	$13m Capital loan (Facility F)	180	182	121	57	4			
	Capital loan (Facility G)	347	355	331	305	280	2.63%	5,333	140
	Capital loan (Facility H)	1,193	2,135	3,179	3,181	3,117	2.28%	132,910	3,028
	Capital loan (Facility J)	304	112	105	97	92	0.96%	9,267	89
	New loan 2017	751							
	New loan 2018	1,451							
	New loan 2019	369							
	New loan 2021/22					79	1.95%	8,058	157
	New loan 2022/23						1.95%	18,848	368
	Total Interest Expense	6,850	5,108	5,714	5,250	4,287			3,782
3	**EFFECTIVE COST OF LONG TERM DEBT (L2/L1)**	3.373%	2.921%	3.027%	2.761%	2.416%			2.168%

5.0 VARIANCE FROM REVENUES AT EXISTING RATES

5.1 INTRODUCTION

QEC's 2022/23 revenue requirement (as set out in Chapter 4) results in a variance compared to revenues at existing rates (as set out in Chapter 3).

This section reviews the variance in the test year on a Corporate-wide basis by two components:

- **Variances compared to 2018/19 revenue requirement:** QEC's existing base rates reflect the 2018/19 revenue requirement and load forecast. Changes to test year forecasts for 2022/23 result in a shortfall, compared to the 2018/19 revenue requirement.
- **Variances compared to existing base energy rates:** When 2022/23 revenue requirements are compared to 2018/19 base energy rates, it results in a net requirement to increase energy revenues from customers of approximately 5.1%.

5.2 VARIANCES COMPARED TO 2014/15 REVENUE REQUIREMENT

QEC's revenue requirement and revenues at existing base rates are set out in Table 5.1.

Table 5.1:
Variance from Revenues at Existing Rates 2022/23 ($000s)

	2022/23 Forecast
Non-Fuel O&M	64,620
Production Fuel	51,543
Fixed Asset Amortization	13,747
Return on Rate Base	14,105
Revenue Requirement	144,015
less: Non-Electrical Revenues	2,511
Revenues at Existing Rates	134,919
Surplus/(Shortfall)	(6,585)
MW.h sales	183,135
Surplus/(Shortfall) (cents per kW.h)	(3.60)
Shortfall as % of Existing Revenues	*4.9%*
Mid-Year Rate Base	305,425

Table 5.1 indicates a shortfall from revenues at existing base rates of $6.585 million in 2022/23, incorporating all elements of the revenue requirement described in Chapter 4. As a percentage of existing rate revenues this reflects a shortfall of 4.9% or an average of 3.60 cents/kWh.

Table 5.2 provides a comparison of revenue requirement, revenues and shortfalls between the 2018/19 and 2022/23 test year forecasts. Compared to the 2018/19 GRA forecast, the revenue requirement increased by $11.122 million, however, this is offset by additional revenues from load growth ($4.573 million).

Table 5.2:
Variance from Revenues at Existing Rates
2018/19 GRA Forecast Compared to 2022/23 ($000s)

	2018/19 GRA Forecast	2022/23 Forecast	Changes 2018/19 to 2022/23
Non-Fuel O&M	60,173	64,620	4,446
Production Fuel	48,820	51,543	2,723
Fixed Asset Amortization	10,734	13,747	3,013
Return on Rate Base	13,165	14,105	940
Revenue Requirement	132,893	144,015	11,122
Less: Non-Electrical Revenues	2,548	2,511	(36)
Revenues at Existing Rates	130,345	134,919	4,573
Surplus/(Shortfall)	(0)	(6,585)	(6,585)
MWh sales	178,851	183,135	4,284
Shortfall (cents per kWh)	0.00	3.60	3.60
Shortfall as % of Existing Revenues	*0%*	*4.9%*	

5.3 VARIANCES COMPARED TO EXISTING BASE RATES PLUS RIDERS

The shortfall amount for 2022/23 test year is $6.585 million. This shortfall amount results in required across-the-board rate increases of 5.1% over the existing base energy rates to recover the full 2022/23 test year revenue requirement.[17]

Table 5.3 illustrates the calculation of the required increase to existing base energy rates for the 2022/23 test year.

[17] The calculation of a required rate increase excludes revenues from customer and demand charges as the Corporation proposes no change to the existing customer and demand charges.

Table 5.3:
Variance from Revenues at Existing Rates ($000s)

Line No		2022/23 Forecast
1	Non-Fuel O&M	64,620
2	Production Fuel	51,543
3	Amortization Expense	13,747
4	Return on Rate Base	14,105
5=Sum(1:4)	Revenue Requirement	144,015
6	Less: Non-Electrical Revenues	2,511
7=5-6	Net Revenue Requirement	141,504
	Rate Revenues	
8	Revenue from Base Energy Rates	128,128
9	Customer charge and Demand Revenue	6,791
10=8+9	Total Existing Rates Revenues	134,919
11=10-7	Surplus/(Shortfall)	(6,585)
12	MW.h sales	183,135
13=11/12	Surplus/(Shortfall) (cents per kW.h)	-3.60
14=11/8	Shortfall as % of Base Energy Rates	*5.1%*

6.0 RATE BASE

6.1 INTRODUCTION

This chapter sets out the calculation of the Corporation's actual Mid-Year Rate Base for the 2018/19, 2019/20 and 2020/21 fiscal years as well as forecasts for 2021/22 and the 2022/23 test year. Specifically this chapter addresses the following topics:

- Gross Plant in Service, including capital additions and disposals;
- Accumulated Amortization (amortization expense is discussed in more detail in Chapter 4); and
- Working Capital.

The Corporation's mid-year rate base is forecast to be $305.425 million for the 2022/23 test year as shown in Schedule 6.1. The Corporation's mid-year rate base excludes residual heat related assets and disallowed amounts for the Baker Lake and Grise Fiord plants.[18]

6.2 CUSTOMER AND GOVERNMENT CONTRIBUTIONS

Under public sector accounting (PSA) standards, revenue received from customers and government contributions for the purpose of purchasing tangible capital assets are recognized as revenue when the related assets are acquired. However, for ratemaking purposes, the Corporation's approach is to ensure that customers continue to see the

[18] Disallowed amount of $1.745 million for Baker Lake plant per the URRC directive from the Final Report on QEC's 2004/05 GRA, as well as $3.939 million for Grise Fiord plant replacement per URRC Report 2018-01 on QEC's 2018/19 GRA.

benefits of customer contribution revenues in the calculation of rate base. Therefore, for GRA purposes, the Corporation treats customer and government contributions as an offset to rate base, consistent with the treatment as deferred revenue in rate applications prior to adopting the PSA standards.

6.3 GROSS PLANT IN SERVICE

Gross plant in service represents the accounting cost of all QEC assets in service related to the provision of electricity service. Each year the gross plant in service calculation considers the opening balance, plus capital additions, less disposals or other adjustments to arrive at the ending balance. The mid-year gross plant figures are the simple average of the opening gross plant balance and the ending gross plant balance. Gross plant in service calculations for 2018/19 through 2022/23 are set out in Schedule 6.2. Actual and forecast capital additions, as well as descriptions of capital additions greater than $400,000 are set out in Appendix B.

Table 6.1 summarizes the changes to the gross plant in service from the 2018/19 GRA forecast to the 2022/23 test year forecast.

Table 6.1:
Gross Plant in Service ($000)

Gross Plant by Function	2018/19 GRA	2022/23 Forecast	Increase
Diesel Plant	308,167	363,454	55,287
Distribution Plant	46,289	58,529	12,240
General Plant	34,415	65,559	31,143
Less: Insurance Proceeds	-22,714	-28,965	-6,251
Total	**366,157**	**458,576**	**92,419**

Notes:
1. Assets in the amount of $176,000 which were classified as Energy Utilization Group in 2018/19 GRA have been re-classified to diesel plant category.

Forecast 2022/23 gross plant in service increased by $92.419 million compared to the 2018/19 GRA forecast. The majority of the increase in gross plant in service is driven by additions to diesel plant ($55.287 million), offset by customer contributions, and general plant ($31.143 million). Major diesel plant additions include the Grise Fiord power plant ($18.839 million), and the Arctic Bay replacement power plant ($30.878 million). Distribution plant increased by $12.240 million (or 13% of the total increase), offset by customer contributions. The additions to general plant mainly reflect the head office building in Baker Lake ($16.596 million) with projected capitalization in 2022/23.

Detailed discussion of the actual and forecast capital additions is provided in Appendix B.

6.4 ACCUMULATED AMORTIZATION

Accumulated Amortization represents the collected amortization for QEC's assets in service related to the provision of electricity service. For each year from 2018/19 through 2022/23 the Accumulated Amortization calculation considers the opening balance, plus amortization expense, less disposals and other adjustments to arrive at the ending balance. Schedule 6.3 sets out the calculation of the Mid-Year Accumulated Amortization.

A comparison of 2018/19 GRA forecast accumulated amortization to the 2022/23 test year forecast is provided in Table 6.2.

Table 6.2:
Accumulated Amortization ($000)

Accumulated Amortization by Function	2018/19 GRA	2022/23 Forecast	Increase
Diesel Plant	117,343	146,410	29,067
Distribution Plant	13,279	16,033	2,754
General Plant	14,453	19,703	5,249
Less: Insurance Proceeds	-3,573	-7,972	-4,400
Total	**141,502**	**174,173**	**32,671**

Notes:
1. Accumulated amortization in the amount of $195,000 which was previously classified as Energy Utilization Group has been re-classified to diesel plant category.

2022/23 forecast accumulated amortization has increased by $32.671 million compared to the 2018/19 GRA forecast. The change reflects continued amortization of the Corporation's assets offset by disposals.

6.5 WORKING CAPITAL

Cash working capital has been calculated based on the results of a lead-lag study provided in the 2010/11 GRA (Appendix D of 2010/11 Phase I GRA), which returned a result of 14.63 net lag days. The net lag days figure is multiplied by average daily expenses and added to the impact of GST lag to calculate a cash working capital provision for each year.

Other components of working capital are supplies inventory, fuel inventory and pre-payments of rent and insurance. Schedule 6.4 shows the calculation of the working capital provision for 2018/19 through 2022/23. Schedules 6.5 through 6.9 set out the calculation of cash working capital for each year.

The supplies inventory component of working capital also includes the balances of significant spare parts, which previously were capitalized.

Schedule 6.1:
Qulliq Energy Corporation 2022/23 General Rate Application Rate Base

Line No.		2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast
1	**Gross Plant in Service**						
2	Beginning of Year	345,193	321,721	365,035	377,690	374,878	420,827
3	Add: Additions and Adjustments	20,964	46,567	12,694	2,335	45,949	37,749
4	Less: Disposals and Transfers	-	(3,254)	(39)	(5,147)	-	-
5	End of Year	366,157	365,035	377,690	374,878	420,827	458,576
6	Mid Year Balance =(L2+L5)/2	355,675	343,378	371,362	376,284	397,852	439,702
7	**Accumulated Amortization**						
8	Beginning of Year	131,017	124,850	132,502	142,854	148,424	160,675
9	Add: Amortization Expense	10,485	10,906	10,391	10,716	12,252	13,498
10	Less: Disposals and Transfers	-	(3,254)	(39)	(5,147)	-	-
11	End of Year	141,502	132,502	142,854	148,424	160,675	174,173
12	Mid Year Balance = (L8+L11)/2	136,260	128,676	137,678	145,639	154,549	167,424
13	**Mid Year Net Plant in Service (L6 - L12)**	219,415	214,702	233,684	230,645	243,303	272,277
14	**Add: Mid-Year Working Capital**	27,326	29,775	30,733	32,090	32,660	33,147
15	**Mid Year Rate Base**	**246,741**	**244,477**	**264,416**	**262,735**	**275,963**	**305,425**

Notes
1. Gross Plant in Service and Accumulated amortization are net of Residual Heat.
2. Gross Plant in Service and Accumulated amortization reflect exclusion of the disallowed amount of $1.745 million for Baker Lake plant per the URRC directive from the Final Report on QEC's 2004/05 GRA as well as $3.9 million for Grise Fiord plant replacement per URRC Report 2018-01 on QEC's 2018/19 GRA.
3. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs and accumulated amortization reflect exclusion of government and customer contributions.

Schedule 6.2:
Qulliq Energy Corporation 2022/23 General Rate Application Gross Plant in Service

Line No.	Gross Plant by Major FERC Category	2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast
	Diesel Plant						
1	Beginning of Year	288,545	274,906	314,520	325,248	322,321	361,339
2	Add: Additions	19,623	42,597	10,728	1,982	39,019	2,115
3	Add/Less: Adjustments						
4	Less: Disposals		(2,983)		(4,909)		
5	End of Year	308,167	314,520	325,248	322,321	361,339	363,454
6	**Mid-Year Diesel Plant**	298,356	294,713	319,884	323,784	341,830	362,397
	Distribution Plant						
7	Beginning of Year	45,900	43,565	45,556	45,760	45,733	47,812
8	Add: Additions	389	2,262	205	-	2,079	10,717
9	Add/Less: Adjustments						
10	Less: Disposals		(271)		(27)		
11	End of Year	46,289	45,556	45,760	45,733	47,812	58,529
12	**Mid-Year Distribution Plant**	46,094	44,560	45,658	45,747	46,773	53,171
	General Plant						
13	Beginning of Year	33,462	32,200	33,924	35,647	35,789	40,641
14	Add: Additions	953	1,724	1,762	353	4,851	24,918
15	Add/Less: Adjustments						
16	Less: Disposals			(39)	(211)		
17	End of Year	34,415	33,924	35,647	35,789	40,641	65,559
18	**Mid-Year General Plant**	33,939	33,062	34,785	35,718	38,215	53,100
	Insurance Proceeds						
19	Beginning of Year	(22,714)	(28,950)	(28,965)	(28,965)	(28,965)	(28,965)
20	Add: Additions		(15)	-	-	-	-
21	Add/Less: Adjustments		-	-	-	-	-
22	Less: Disposals		-	-	-	-	-
23	End of Year	(22,714)	(28,965)	(28,965)	(28,965)	(28,965)	(28,965)
24	**Mid-Year Insurance Proceeds**	(22,714)	(28,958)	(28,965)	(28,965)	(28,965)	(28,965)
25	**Total Beginning of Year Gross Plant in Service**	**345,193**	**321,721**	**365,035**	**377,690**	**374,878**	**420,827**
26	**Total End of Year Gross Plant in Service**	**366,157**	**365,035**	**377,690**	**374,878**	**420,827**	**458,576**
27	**Total Mid-Year Gross Plant in Service**	**355,675**	**343,378**	**371,362**	**376,284**	**397,852**	**439,702**

Notes
1. Gross Plant in Service is net of Residual Heat.
2. Gross Plant in Service reflect exclusion of the disallowed amount of $1.745 million for Baker Lake plant per the URRC directive from the Final Report on QEC's 2004/05 GRA as well as $3.9 million for Grise Fiord plant replacement per URRC Report 2018-01 on QEC's 2018/19 GRA.
3. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs reflect exclusion of government and customer contributions.
4. Assets in the amount of $176,000 which were classified as Energy Utilization Group in 2018/19 GRA have been re-classified to diesel plant category.

Schedule 6.3:
Qulliq Energy Corporation 2022/23 General Rate Application Accumulated Amortization

Line No.	Accumulated Amortization by Major FERC Category	2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast
1	**Diesel Plant**						
2	Beginning of Year	108,463	104,525	111,268	120,368	124,868	135,581
3	Add: Amortization	8,880	9,726	9,100	9,408	10,713	10,830
4	Less: Disposals and Adjustments	-	(2,983)		(4,909)		
5	End of Year	117,343	111,268	120,368	124,868	135,581	146,410
	Mid-Year Diesel Plant	112,903	107,897	115,818	122,618	130,224	140,995
6	**Distribution Plant**						
7	Beginning of Year	12,278	11,772	12,320	13,188	14,008	14,910
8	Add: Amortization	1,001	819	868	848	902	1,123
9	Less: Disposals and Adjustments	-	(271)		(27)		
10	End of Year	13,279	12,320	13,188	14,008	14,910	16,033
	Mid-Year Distribution Plant	12,778	12,046	12,754	13,598	14,459	15,471
11	**General Plant**						
12	Beginning of Year	13,178	12,306	13,511	14,739	15,832	17,313
13	Add: Amortization	1,275	1,205	1,267	1,304	1,481	2,389
14	Less: Disposals and Adjustments	-		(39)	(211)		
15	End of Year	14,453	13,511	14,739	15,832	17,313	19,703
	Mid-Year General Plant	13,816	12,908	14,125	15,285	16,573	18,508
16	**Insurance Proceeds**						
17	Beginning of Year	(2,902)	(3,752)	(4,596)	(5,440)	(6,284)	(7,128)
18	Add: Amortization	(671)	(844)	(844)	(844)	(844)	(844)
19	Less: Disposals and Adjustments	-					
20	End of Year	(3,573)	(4,596)	(5,440)	(6,284)	(7,128)	(7,972)
	Mid-Year Insurance Proceeds	(3,237)	(4,174)	(5,018)	(5,862)	(6,706)	(7,550)
21	**Total Beginning of Year Accumulated Amortization**	**131,017**	**124,850**	**132,502**	**142,854**	**148,424**	**160,675**
22	**Total End of Year Accumulated Amortization**	**141,502**	**132,502**	**142,854**	**148,424**	**160,675**	**174,173**
23	**Total Mid-Year Accumulated Amortization**	**136,260**	**128,676**	**137,678**	**145,639**	**154,549**	**167,424**

Notes
1. Accumulated amortization is net of Residual Heat.
2. Accumulated amortization and annual amortization reflect exclusion of the disallowed amount of $1.745 million for Baker Lake plant per the URRC directive from the Final Report on QEC's 2004/05 GRA as well as $3.9 million for Grise Fiord plant replacement per URRC Report 2018-01 on QEC's 2018/19 GRA.
3. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, accumulated amortization and annual amortization reflect exclusion of government and customer contributions.
4. Accumulated amortization in the amount of $195,000 which was previously classified as Energy Utilization Group has been re-classified to diesel plant category.

Schedule 6.4:
Qulliq Energy Corporation 2022/23 General Rate Application Working Capital Requirement

Line No.		2018/19 GRA Forecast	2018/19 Actuals	2019/20 Actuals	2020/21 Actuals	2021/22 Forecast	2022/23 Forecast
1	**Cash Working Capital**	**4,287**	**4,277**	**4,393**	**4,434**	**4,237**	**4,493**
2	**Less: Mid-Year Customer Deposits**	**-1,423**	**-1,448**	**-1,485**	**-1,590**	**-1,609**	**-1,628**
3	**Add: Supplies Inventory**						
4	Beginning of Year (note 1)	**14,428**	15,708	16,301	17,621	19,092	19,092
5	End of Year	14,428	16,301	17,621	19,092	19,092	19,092
6	**Mid-Year Balance**	**14,428**	**16,005**	**16,961**	**18,357**	**19,092**	**19,092**
7	**Fuel Average Monthly Balance**	**8,018**	**8,632**	**8,423**	**7,992**	**8,177**	**8,190**
8	**Mid-Year Rent Prepayment**	**1,169**	**1,336**	**1,375**	**1,533**	**1,443**	**1,501**
9	**Mid-Year Insurance Prepayment**	**849**	**973**	**1,065**	**1,365**	**1,320**	**1,500**
10	**Total Mid-Year Working Capital Requirement**	**27,326**	**29,775**	**30,733**	**32,090**	**32,660**	**33,147**

Note:
1. Actual and forecast years include spare parts, supplies and lubricants and other inventory. The significant spare parts, previously capitalized, were reclassified as “inventory for use” to comply with PSA Standards.

Schedule 6.5:
Qulliq Energy Corporation 2022/23 General Rate Application
2018/19 Actual Cash Working Capital

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	33,188	91	14.63	1,327
2	Fuel and Lubricants	50,166	137	14.63	2,005
3	Supplies and Services	16,339	45	14.63	653
4	Travel and Accomodation	5,124	14	14.63	205
5	**Total Expenses**	**104,816**	**286**		**4,190**
6	GST Expenditure Lag	3,581	10	14.87	146
7	GST Remittance Lag	6,581	18	(3.30)	-59
8	**Total GST**				**87**
9	**Total Cash Working Capital**				**4,277**

Schedule 6.6:
Qulliq Energy Corporation 2022/23 General Rate Application
2019/20 Actual Cash Working Capital

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	36,797	101	14.63	1,471
2	Fuel and Lubricants	48,784	133	14.63	1,950
3	Supplies and Services	17,065	47	14.63	682
4	Travel and Accomodation	5,140	14	14.63	205
5	**Total Expenses**	**107,786**	**294**		**4,309**
6	GST Expenditure Lag	3,549	10	14.87	145
7	GST Remittance Lag	6,749	18	(3.30)	-61
8	**Total GST**				**84**
9	**Total Cash Working Capital**				**4,393**

Schedule 6.7:
Qulliq Energy Corporation 2018/19 General Rate Application
2020/21 Actual Cash Working Capital

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	36,833	101	14.63	1,472
2	Fuel and Lubricants	47,340	129	14.63	1,892
3	Supplies and Services	21,337	58	14.63	853
4	Travel and Accomodation	3,261	9	14.63	130
5	**Total Expenses**	**108,771**	**297**		**4,348**
6	GST Expenditure Lag	3,597	10	14.87	147
7	GST Remittance Lag	6,753	19	(3.30)	-61
8	**Total GST**				**86**
9	**Total Cash Working Capital**				**4,434**

Schedule 6.8:
Qulliq Energy Corporation 2022/23 General Rate Application
2021/22 Forecast Cash Working Capital

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	36,150	99	14.63	1,445
2	Fuel and Lubricants	45,497	124	14.63	1,819
3	Supplies and Services	16,240	44	14.63	649
4	Travel and Accomodation	6,222	17	14.63	249
5	**Total Expenses**	**104,108**	**284**		**4,162**
6	GST Expenditure Lag	3,398	9	14.87	138
7	GST Remittance Lag	7,015	19	(3.30)	-63
8	**Total GST**				**75**
9	**Total Cash Working Capital**				**4,237**

Schedule 6.9:
Qulliq Energy Corporation 2022/23 General Rate Application
2022/23 Forecast Cash Working Capital

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	36,371	99	14.63	1,454
2	Fuel and Lubricants	51,543	141	14.63	2,060
3	Supplies and Services	16,363	45	14.63	654
4	Travel and Accomodation	5,909	16	14.63	236
5	**Total Expenses**	**110,186**	**301**		**4,405**
6	GST Expenditure Lag	3,691	10	14.87	150
7	GST Remittance Lag	6,880	19	(3.30)	-62
8	**Total GST**				**88**
9	**Total Cash Working Capital**				**4,493**

7.0 COST OF SERVICE STUDY AND RESULTS

7.1 INTRODUCTION

This chapter presents the Corporation's cost-of-service study (COS study) results for the 2022/23 test year. A COS study is commonly used as an analytical tool in the ratemaking process. A COS study can provide useful information such as unit costs to serve different customers (such as $/kWh, $/customer month) and revenue to cost coverage ratios. However, it must be recognized that any COS study involves estimation and a degree of professional judgement and therefore the results cannot be considered exact.

The purpose of a COS study is to fairly allocate a utility's revenue requirement among the different customer classes. While there are many potential allocation methods, the core objective is to allocate costs to the customer classes consistent with principles of cost causation based on customer characteristics such as energy consumption and peak demand.

There is no absolute right or wrong allocation method, as each utility's operating circumstances and cost drivers are different. The objective for the utility is to select methods which best represent cost causation and the equitable sharing of costs among customers in a manner appropriate for the unique circumstances of the utility.

To provide services to its customers, the Corporation must receive sufficient revenues to recover its costs. Adequate cost recovery is a necessary condition for maintaining reliable service by the Corporation. The COS study methods used in this Application apply cost-of-service concepts to embedded accounting costs in order to calculate the fair share of the Corporation’s total revenue requirement for each customer class.

The last COS study methodology review by the URRC was conducted as part of QEC’s 2010/11 GRA. URRC Report 2012-01 to the Minister recommended accepting QEC's proposal to adopt a Nunavut wide COS approach.[19]

The Corporation filed its last COS study for Nunavut communities as part of its 2018/19 GRA. The 2018/19 GRA COS study was prepared applying the principles recommended by the URRC in Report 2012-01. The URRC Report 2018-01 to the Minister recommended accepting QEC's 2018/19 COS study.[20]

The Corporation’s 2022/23 COS study, based on the Nunavut wide COS approach, is provided in Appendix D. All methods used in the current COS study are consistent with the previous URRC reviews. The results of the COS study are used as inputs in developing the rate proposals for the Application.

7.2 CLASS REVENUE TO COST COVERAGE RATIOS AND UNIT COSTS

Results of the Corporation’s 2022/23 COS study are presented in Table 7.1. Detailed COS study schedules for the territory-wide COS study are provided in Appendix D.

The following information is provided for each customer class:

- 2022/23 forecast revenue at equal percentage across-the-board rate increase;

[19] URRC Report 2012-01 from January 27, 2012 on QEC’s 2010/11 Phase II GRA.
[20] URRC Report 2018-01 from March 26, 2018.

- 2022/23 COS study class revenue requirements;
- Revenue cost coverage (RCC) ratio;
- Average COS unit costs for:
    - o Demand ($/kW);
    - o Energy (cents/kWh); and
    - o Customer ($/month).

Table 7.1:
2022/23 Cost of Service Results and Average Unit Costs

Customer Class	Revenue at Equal Percentage Across-the-Board Rate Increases	COS Customer Class Revenue Requirement	Revenue Cost Coverage Ratio	COS Demand Charge	COS Customer Charge	COS Energy Charge
	$000	$000		$/kW	$/Cust./Month	cents/kWh
Domestic	59,522	61,720	96.4%		42.85	77.83
Commercial	80,141	77,923	102.8%	70.97	68.27	34.89
Streetlighting	1,841	1,861	98.9%		42.85	108.47
Total	**141,504**	**141,504**				

The results indicate that, if rate increases were applied on an equal-percentage-across-the-board basis, the domestic and streetlighting rate classes RCC ratio would be slightly below 100%, while the commercial rate class RCC ratio would be somewhat above 100% - however all rate classes would have an RCC ratio within the 95% to 105% zone of reasonableness.

The results also indicate that the existing demand and customer charges ($8/kW for commercial customers and $18/month for residential customers, respectively) are low compared to the COS study outputs.

Maintaining the existing demand and customer charges in the COS study results in higher average energy unit costs as shown in Table 7.2.

Table 7.2:
Cost of Service Results and Average Energy Unit Costs under Existing Demand and Customer Charges

Customer Class	Revenue at Equal Percentage Across-the-Board Rate Increases	COS Customer Class Revenue Requirement	Revenue Cost Coverage Ratio	COS Result with Existing Customer/Demand Charge		
				Existing Demand Charge	Existing Customer Charge	COS Energy Charge
	$000	$000		$/kW	$/Cust./Month	cents/kWh
Domestic	59,522	61,720	96.4%		18.00	83.01
Commercial	80,141	77,923	102.8%	8.00		66.90
Streetlighting	1,841	1,861	98.9%			110.02
Total	**141,504**	**141,504**				

Maintaining demand and customer charges at the existing level result in 5.18 cents/kWh higher energy rates for the domestic rate class, 32.01 cents/kWh higher energy rates for the commercial rate class, and 1.55 cents/kWh higher energy rates for the streetlighting rate class.

8.0 RATE DESIGN

8.1 INTRODUCTION

This chapter reviews the Corporation's proposed rates and rate structures to be implemented effective October 1, 2022.

Section 8.2 reviews the Corporation's recommended approach with respect to the rate structure in Nunavut consistent with the recommended single territory-wide COS approach.

Section 8.3 of this chapter reviews the rate design criteria and objectives of the Corporation for this application.

Section 8.4 summarises the Corporation's proposal for rates effective October 1, 2022.

8.2 NUNAVUT RATE STRUCTURE REVIEW

QEC currently has a community-specific rate structure, where energy rates are different for each community. This rate structure predates QEC and was inherited from the Northwest Territories Power Corporation (NTPC). Under the existing rate structure domestic non-government rates vary from a low of 58.56 cents/kWh to a high of 116.05 cents/kWh, and commercial non-government rates vary from a low of 48.31 cents/kWh to a high of 112.87 cents/kWh.

The last substantial rate rebalancing for Nunavut communities was implemented as part of NTPC's 1995/98 GRA, nearly 25 years ago. That application was prepared on the basis of a "community-based" approach to rate design.

The current situation where approved rates for customer classes in some communities are more than double than the rates for the same customer class in other communities is the direct result of the on-going application of a community-based rate structure since the division of the Corporation from NTPC.

It is important to note however that in 2010 the community-based electricity rate structure was abolished in the Northwest Territories and replaced with zone-based rate structure.

In the past applications, QEC has reviewed rate options including maintaining the past practice of implementing rate adjustments on an equal percentage basis to all customers; rate rebalancing towards full community-based rates and rate rebalancing toward a single territory-wide rate structure. In the 2010/11 Phase II GRA, the URRC supported QEC's proposal to transition to a single territory-wide rate structure. In the 2018/19 GRA, the URCC, in the Report 2018-01, again recommended approving transition to a single territory-wide rate structure to the Minister responsible for QEC. While the Minister's Instruction from May 30, 2018 declined QEC's proposal to move to a territory-wide rate structure, the rates for the new LED streetlights were approved at territory-wide rates. The Minister's Instruction from May 30, 2018 also directed QEC to work with the Government of Nunavut's Department of Finance in reviewing the existing Nunavut Electricity Subsidy Program to ensure the needs of all Nunavummiut are taken into consideration in the territory-wide rate structure proposal.

In Report 2018-01, the URRC also recommended that QEC be directed to examine an approach to rate realignment including the adoption of higher revenue to cost ratios for

Government customers with a view to minimizing the harmful effects of high rate increases for investment and economic growth in Nunavut, at the next GRA.

In this Application, the Corporation is proposing to replace the current community based rate structure with a territory-wide rate structure in 2022/23 Test Year consistent with the recommended single territory-wide COS approach. The Corporation is proposing to transition to territory-wide rates for a number of reasons including:

- The current differential rates by community do not accurately reflect community based costs. If the intent of community based rates is to reflect different costs of service in each community, then the current community-based rates do not accomplish this objective as was illustrated in the 2018/19 GRA.[21]
- The recent practice of increasing rates by equal percentages for all rate classes results in proportionately higher rate increases for communities with higher starting points. This means that the gap (in dollars) between the lowest cost communities and the highest cost communities gets wider every time rate increases are applied on an equal percentage basis to all customer classes.
- Large capital projects put enormous upward pressure on rates, particularly for smaller communities. In some cases communities would face rate increases in excess of 50% in order to pay for required capital projects.

[21] QEC 2018/19 GRA, pages 8-3 through 8-6.

- As QEC continues with the implementation of renewable energy programs, current rate structure puts smaller communities at a disadvantage of renewable energy projects development compared to larger communities.

Further discussion on each of these topics is provided in the following section.

8.2.1 COMPARISON OF EXISTING RATES TO COMMUNITY BASED COS RATES

The last COS based rates for Nunavut communities were approved effective March 29, 1999 by the Northwest Territories Public Utilities Board in Decision 2-99. Since then, rate adjustments have generally been implemented on an equal percentage basis across all rate classes with the following timeline:

- 16.5% rate increase effective April 1, 2005;
- 5.9% rate increase effective October 1, 2006;
- 18.9% rate increase effective April 1, 2011;
- 7.1% rate increase effective May 1, 2014;
- 3.3% rate increase effective May 1, 2018; and
- 3.3% rate increase effective April 1, 2019.

Table 8.1 shows the cumulative rate increase for non-government domestic and commercial rate classes in Iqaluit (a lower rate community) and Kugaaruk (one of the higher rate communities).

Table 8.1:
Historical Rate Increase Comparison

Community	Rates per NWT PUB Order 2-99	Rates Effective April 1, 2005	Rates Effective October 1, 2006	Rates Effective April 1, 2011	Rates Effective May 1, 2014	Rates Effective May 1, 2018	Existing Rates Effective April 1, 2019	Cumulative Rate Increase Since Division
Rate Variance		**16.5%**	**5.91%**	**18.88%**	**7.1%**	**3.3%**	**3.3%**	
	cent/KWh	**cent/KWh**	**cent/KWh**	**cent/KWh**	**cent/KWh**	**cent/KWh**	**cent/KWh**	**cent/kWh**
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H=G-A**
Domestic Non-Government								
Iqaluit	31.58	36.80	39.39	52.39	60.29	56.69	58.56	26.98
Kugaaruk	65.89	76.77	81.72	102.71	114.16	112.34	116.05	50.16
Commercial Non-Government								
Iqaluit	25.47	29.67	31.84	43.42	50.68	46.76	48.31	22.84
Kugaaruk	58.00	67.57	71.98	91.13	101.77	99.54	102.82	44.82

A review of Table 8.1 shows that while the rate adjustments were largely implemented on an equal percentage basis across all communities[22], the cumulative rate increases in absolute terms vary by community. The increase in Kugaaruk was nearly twice the increase in Iqaluit on a cents/kWh basis. As such, equal percentage rate adjustments put more burden on communities with relatively higher existing rates, which also are typically communities with smaller customer bases.

8.2.2 IMPACT OF CAPITAL PROJECTS ON ENERGY RATES

Under a community-based rate structure, rate impacts for communities requiring substantial capital upgrades (e.g., power plant replacements or major distribution system upgrades) are very high, even with significant government contribution against the capital costs. Table 8.2 illustrates this with the example of the Kugaaruk Power Plant project, which is currently under review by the URRC.

[22] The only exception when rate adjustments were implemented on a cents/kWh basis was on November 1, 2005 to implement capital stabilization-rebalancing levy rate riders.

Table 8.2:
Kugaaruk New Power Plant Average Rate Impact Comparison

Net Capital Cost ($ 000)	16,472
Amortization Period (year)	40
GRA Approved Return on Ratebase	6.45%
Revenue Requirement Impacts	
Amortization Expense ($ 000)	412
Return on Ratebase ($ 000)	1,062
sub-total: Revenue Requirement Increase ($ 000)	**1,473**
Total Revenue Requirement Impact ($ 000)	**1,473**
Kugaaruk 2026/27 Forecast Sales (MWh)	*3,641*
Average Community-Based Rate Increase (c/kWh)	40.47
Territorial 2026/27 Forecast Sales (MWh)	*198,032*
Average Territorial Rate Increase (c/kWh)	0.74
Existing Kugaaruk Rate (c/kWh)	116.05
Rate increase under community-based approach	**34.9%**
Rate increase under Territory-wide approach	**0.6%**

As shown in Table 8.2, the rate impact for Kugaaruk under community-based rates would be 34.9%. This compares to a 0.6% increase for all ratepayers under the territory-wide approach. It is important to note that the above rate impact estimate is for the project costs after the government contribution. The full cost of the new power plant in Kugaaruk is projected at $38.9 million, and accordingly the rate impact difference between community-based and territory-wide would be even larger without the government contribution.

8.2.3 RENEWABLE ENERGY OPPORTUNITIES UNDER DIFFERENT RATE STRUCTURES

The Corporation supports the development and expansion of electricity supply options from renewable energy sources. Recently, QEC has introduced a Commercial and Institutional Power Producers (CIPP) program that allows existing commercial and institutional customers generate electricity from eligible energy sources installed on-site and sell it to QEC in order to: (i) develop renewable energy without a risk of increases to customer rates; (ii) integrate renewable energy generation in Nunavut's electricity generation mix to help decrease Nunavut's dependency on diesel fuel; and (iii) reduce carbon emissions and help promote Nunavut's energy self-reliance. The guiding principles of the program of the program are Piliriqatigiinniq/Ikajuqtigiinniq (working together for a common cause); Qanuqtuurniq (being innovative and resourceful); and Avatittinnik Kamatsiarniq (respect and care for the land, animals, and the environment). Under the program policy, all generation must take place on site and be sold to QEC in its entirety, and CIPPs are responsible for all capital and operating costs of their renewable generating facility. QEC compensates CIPPs for the electricity supplied to QEC at an avoided cost of diesel generation, while CIPPs are charged at existing community rates for any energy they purchase from QEC. Avoided cost of diesel generation is similar in all communities in Nunavut, implying that CIPPs will get similar compensation for the electricity sold to QEC in all communities. Their own electricity purchase costs however will be lower if they are located in larger communities due to lower electricity rates in those communities under the existing community-based rate structure. As such, the existing community-based electricity rate structure puts smaller communities at a disadvantage to establish CIPP facilities and maintaining the existing rate structure will further increase the rate differences between communities making programs like CIPP less desirable to establish in smaller communities.

8.2.4 SUMMARY

In the past applications, QEC has reviewed rate options including maintaining the past practice of implementing rate adjustments on an equal percentage basis to all customers; rate rebalancing towards full community-based rates and rate rebalancing toward a single territory-wide rate zone. In this application, QEC is proposing to implement a territory-wide rate zone for the following reasons:

- The past practice of applying rate increases on an equal percentage basis has resulted in cumulative rate increases since 1999 that are substantially higher on a cents per kWh basis for communities like Kugaaruk compared to Iqaluit.
- A community based rate structure imposes substantial cost increases on communities that require significant reinvestment in generation and distribution assets. For example, the new power plant in Kugaaruk would require a 34.9% rate increase to recover the full cost of the project from the community, compared to a 0.6% increase if the costs are spread across a territory-wide rate structure. And this difference would be even larger without the government contribution against the project capital cost.
- A territory-wide rate structure allows the benefits of renewable energy development programs implemented by QEC to be shared more evenly across the territory rather than being concentrated in larger communities.

8.3 RATE DESIGN CRITERIA AND OBJECTIVES

Rate design is the process that determines the rates to be charged to each customer class. The process requires balancing a number of different and sometimes competing criteria. Cost causation, as measured by a COS study, is an important input into the rate design analysis. However, the process also considers other economic, policy and administrative objectives.

The Corporation's rate design objectives for the 2022/23 GRA are:

1. **Rates must be set to recover revenue requirement.** The proposed total 2022/23 revenue to be recovered from rates is $141.5 million.

2. **Implement a territory-wide rate zone (levelized rates).** The Corporation is recommending implementing a territory-wide rate structure as discussed in Section 8.2.

3. **Move toward 95-105% revenue-cost coverage ratios for each rate class.** Based on QEC's Cost-of-service study, average rate increases would result in all rate classes (domestic, commercial and streetlighting) having RCC ratios within the 95% to 105% zone of reasonableness that is typically accepted in Canadian jurisdictions.

4. **Administrative efficiency.** The rate structure must be administratively easy to manage within QEC's existing billing system and simple to understand for QEC's customers and staff.

5. **Focus rate adjustments on energy portion of the rate:** The Corporation is not proposing changes to the existing customer and demand charges, which are already levelized across the Territory.

6. **No bill increases to non-government customer classes resulting from transitioning to a territory-wide rate structure.** Proposed rate adjustments consider higher RCC ratios for government customers to assist in developing a territorial rate design structure avoiding rate rebalancing related bill impacts on non-government electricity customers.

8.4 2022/23 RATE PROPOSAL

Consistent with the rate design objectives outlined in section 8.3, the Corporation's proposed energy rates for the domestic and commercial rate classes effective October 1, 2022 is to set separate territory-wide rates for government and non-government customers. Under this approach, the territory-wide rate for non-government customers will be set at the Iqaluit non-government rates adjusted to the overall required rate increase of 5.1% (61.57 cents/kWh for domestic and 50.79 cents/kWh for commercial customers). The territory-wide rates for government classes will then be set at the level required to recover the remaining revenue shortfall to QEC (93.44 cents/kWh for domestic and 85.35 cents/kWh for commercial customers). The development of the proposed energy rates were based on the following steps:

- Step 1: Determine revenue required from base energy rates by customer class at average rate increase of 5.1% over the existing base energy rates to recover the full 2022/23 test year revenue requirement.

- Step 2: Determine non-government revenue from base energy rates at a territory-wide base energy rate by customer class set at respective rates for Iqaluit calculated in Step 1.
- Step 3: Determine a territory-wide base energy rate by customer class for government customers based on the required revenue from government customers calculated as the difference between Step 1 and Step 2.

Under this approach, no non-government customer class will see bill impacts above the required equal percentage rate increase of 5.1% in the 2022/23 Test Year.

For the streetlighting rates, the rate adjustment is based on the overall required rate increase of 5.1%, considering that QEC targets completion of streetlight conversion to LED by 2024, which were already approved at single territory-wide rates in the 2018/19 GRA.

This approach results in the government customers energy purchase cost incremental increase of $8.5 million to subsidize non-government customers, comprising:

- Government electricity purchase cost increase of $11.3 million; and
- Nunavut Energy Subsidy Program (NESP) cost savings of $2.8 million as a result of lower non-government domestic rates.

The proposed approach is somewhat similar to the approach undertaken in the Northwest Territories in 2010, which established zone-based rate structures with higher rates for government customers, which subsidize levelized non-government rates, resulting in higher effective RCC ratios for the government customer classes. Table 8.3 compares RCC ratios for government and non-government customer classes under the proposed approach for QEC to those of NTPC's thermal zone from NTPC's 2018/19 GRA.

Table 8.3:
Government and Non-Government RCC Ratios Comparison

Customer Class	RCC Ratios	
	QEC - Proposed	NTPC Thermal Zone
Domestic - Non-Government	75%	84%
Domestic - Government	112%	130%
Commercial - Non-Government	77%	81%
Commercial - Government	126%	130%

Government RCC ratios for QEC would be notably higher under the proposed approach, but still lower than the respective RCC ratios for NTPC's government customers.

The 2022/23 rate proposal presented in this section is the preferred option that QEC is recommending that the Minister approve for QEC.

Schedules 8.1 and 8.2 summarize the Corporation's rate proposal for 2022/23 by rate class. Schedules 8.3.1-8.3.3 provide a proof of revenue calculation for 2022/23 based on the proposed rates for each customer class.

8.5 BILL IMPACTS ESTIMATES UNDER THE 2022/23 RATE PROPOSAL

Bill impacts from the proposed territory-wide rate structure were estimated assuming monthly consumptions of 1,000 kWh for domestic customers and 2,000 kWh for commercial customers.

Bill impacts from changing the existing rates to the proposed rate structure under the assumed monthly consumptions are summarized in Table 8.4.

Table 8.4:
2022/23 Rate Proposal Bill Impacts Over the Existing Rates

	Iqaluit Average Bill Changes	All Other Communities Average Bill Changes
Non-government Domestic - NESP Subsidized	Increase of 5.1%	Increase of 5.1%
Non-government Domestic - Unsubsidized	Increase of 5.0%	Decrease of 46.2% (Kugaaruk) to Increase of 1.5% (Rankin Inlet)
Non-government Commercial	Increase of 4.9%	Decrease of 3.9% (Rankin Inlet) to 54.0% (Whale Cove)
Government Domestic	Increase of 57.8%	Decrease of 36.7% (Whale Cove) to Increase of 52.5% (Rankin Inlet)
Government Commercial	Increase of 68.8%	Decrease of 31.3% (Whale Cove) to Increase of 49.3% (Igloolik)

Bill impact estimates by community are provided in Schedule 8.4.

8.6 ALTERNATIVE TERRITORY-WIDE RATE STRUCTURE OPTIONS

QEC is recommending that the Minister approve the territory-wide rate structure approach proposed by the Corporation in Section 8.4. However, the Corporation also reviewed alternative territory-wide rate structures with government funding support:

1. **Alternative 1:** NESP program extension to include commercial customers and increase current subsidized rate.
2. **Alternative 2:** NESP program extension to include commercial customers with current rates below proposed Territory-wide rates.

Under Alternative 1, a single territory-wide rate will be established separately for domestic (approximately 83 cents/kWh) and commercial (approximately 67 cents/kWh) customer classes based on the COS rates by rate class. However, effective rates for non-government customers will be subsidized by the revised NESP program as follows:

- Domestic non-government customers energy charge will be subsidized to 50% of Iqaluit's community-specific rate prior to levelization, adjusted to reflect the rate increase of 5.1% (approximately 31 cents/kWh, or subsidy of 52 cents/kWh).
- Commercial non-government customers energy charge will be automatically subsidized to Iqaluit's community-specific rate prior to levelization, adjusted to reflect the rate increase of 5.1% (approximately 51 cents/kWh, or subsidy of 16 cents/kWh). It is noted that the current NESP program requires commercial non-government customers to apply for the program with specific documentation requirements.

Alternative 2 is similar to Alternative 1 where a single territory-wide rate will be established separately for domestic (approximately 83 cents/kWh) and commercial (approximately 67 cents/kWh) customer classes based on the COS rates by rate class. However, effective rates for non-government customers will be subsidized by the revised NESP program as follows:

- Domestic non-government customers energy charge will be subsidized to 50% of Iqaluit's community-specific rate prior to levelization, adjusted to reflect the rate increase of 5.1% (approximately 31 cents/kWh, or subsidy of 52 cents/kWh).

- Commercial non-government customers whose community-specific rates prior to levelization were below the new Territorial rate of approximately 67 cents/kWh – Cambridge Bay, Rankin Inlet, Baker Lake, Iqaluit, Pangnirtung, Kinngait, and Igloolik – will be automatically subsidized at the difference between their community-specific rate and the new Territorial Rate. It is noted that the current NESP program requires commercial non-government customers to apply for the program with specific documentation requirements.

Based on the analysis of the territory-wide rate structure alternatives, the Corporation recommends approval of the the territory-wide rate structure approach proposed by the Corporation in Section 8.4 for the following reasons:

- The proposed territory-wide rate structure approach can be fully implemented by QEC independently of government's existing subsidy programs and policies and is in compliance with the URRC Act.

- The proposed rate structure is easier to manage within QEC's existing billing system offering administrative efficiency and is simple to understand for QEC's customers and staff.

- The proposed territory-wide rate structure is consistent with the URRC's recommendation of adopting higher revenue to cost ratios for Government customers with a view to minimizing the harmful effects of high rate increases for investment and economic growth in Nunavut.

- Alternative rate structure approaches may not fall within the authority of the Minister responsible for QEC, as they require revisions to NESP, which is not under the responsibility of the Minister responsible for QEC and do not fall under the URRC Act governing electricity rate setting in Nunavut.

- Alternative rate structure approaches require the commitment of the GN Finance to revise NESP in sequence with QEC's new rate implementation. Any challenges in the NESP proposed revision could create rate shock to customers.

Schedule 8.1:
2022/23 Rate Proposal

		Domestic Non-Government			Domestic Government			Commercial Non-Government			Commercial Government		
		Existing Rates (cents/kWh)	Proposed Rates (cents/kWh)	Change	Existing Rates (cents/kWh)	Proposed Rates (cents/kWh)	Change	Existing Rates (cents/kWh)	Proposed Rates (cents/kWh)	Change	Existing Rates (cents/kWh)	Proposed Rates (cents/kWh)	Change
501	Cambridge Bay	75.39	61.57	-18.3%	75.39	93.44	23.9%	64.73	50.79	-21.5%	64.73	85.35	31.9%
502	Gjoa Haven	89.68	61.57	-31.3%	92.70	93.44	0.8%	85.95	50.79	-40.9%	85.95	85.35	-0.7%
503	Taloyoak	99.19	61.57	-37.9%	107.83	93.44	-13.3%	97.50	50.79	-47.9%	97.50	85.35	-12.5%
504	Kugaaruk	116.05	61.57	-46.9%	116.05	93.44	-19.5%	102.82	50.79	-50.6%	102.82	85.35	-17.0%
505	Kugluktuk	93.81	61.57	-34.4%	99.53	93.44	-6.1%	87.27	50.79	-41.8%	87.27	85.35	-2.2%
601	Rankin Inlet	60.63	61.57	1.5%	60.63	93.44	54.1%	52.96	50.79	-4.1%	58.94	85.35	44.8%
602	Baker Lake	69.25	61.57	-11.1%	69.25	93.44	34.9%	64.75	50.79	-21.6%	64.75	85.35	31.8%
603	Arviat	78.68	61.57	-21.7%	78.68	93.44	18.8%	73.22	50.79	-30.6%	73.22	85.35	16.6%
604	Coral Harbour	95.24	61.57	-35.3%	95.24	93.44	-1.9%	87.18	50.79	-41.7%	87.18	85.35	-2.1%
605	Chesterfield Inlet	98.31	61.57	-37.4%	98.31	93.44	-5.0%	91.48	50.79	-44.5%	91.48	85.35	-6.7%
606	Whale Cove	90.71	61.57	-32.1%	148.74	93.44	-37.2%	112.87	50.79	-55.0%	125.17	85.35	-31.8%
607	Naujaat	84.99	61.57	-27.6%	84.99	93.44	9.9%	74.58	50.79	-31.9%	74.58	85.35	14.4%
701	Iqaluit	58.56	61.57	5.1%	58.56	93.44	59.6%	48.31	50.79	5.1%	49.76	85.35	71.5%
702	Pangnirtung	64.38	61.57	-4.4%	69.06	93.44	35.3%	56.82	50.79	-10.6%	62.80	85.35	35.9%
703	Kinngait	67.42	61.57	-8.7%	70.92	93.44	31.8%	63.02	50.79	-19.4%	70.92	85.35	20.3%
704	Resolute Bay	102.38	61.57	-39.9%	104.30	93.44	-10.4%	97.53	50.79	-47.9%	97.53	85.35	-12.5%
705	Pond Inlet	90.21	61.57	-31.7%	98.04	93.44	-4.7%	82.67	50.79	-38.6%	82.67	85.35	3.2%
706	Igloolik	61.70	61.57	-0.2%	61.70	93.44	51.4%	56.49	50.79	-10.1%	56.49	85.35	51.1%
707	Sanirajak	89.23	61.57	-31.0%	92.74	93.44	0.7%	85.90	50.79	-40.9%	85.90	85.35	-0.6%
708	Qikiqtarjuaq	77.37	61.57	-20.4%	88.89	93.44	5.1%	73.26	50.79	-30.7%	88.89	85.35	-4.0%
709	Kimmirut	104.93	61.57	-41.3%	104.68	93.44	-10.7%	87.81	50.79	-42.2%	88.27	85.35	-3.3%
710	Arctic Bay	87.99	61.57	-30.0%	87.99	93.44	6.2%	78.50	50.79	-35.3%	78.50	85.35	8.7%
711	Clyde River	77.66	61.57	-20.7%	78.17	93.44	19.5%	68.56	50.79	-25.9%	68.56	85.35	24.5%
712	Grise Fiord	92.50	61.57	-33.4%	112.45	93.44	-16.9%	107.25	50.79	-52.6%	107.25	85.35	-20.4%
713	Sanikiluaq	82.00	61.57	-24.9%	82.00	93.44	14.0%	78.54	50.79	-35.3%	78.54	85.35	8.7%

Schedule 8.2:
2022/23 Rate Proposal – Streetlights

	Existing Rates ($/month)								**22/23 Proposed Rates ($/month)**								**Change from Existing Rates**
	High Pressure Sodium		Mercury Vapour			LED			High Pressure Sodium		Mercury Vapour			LED			All Types
	100W	**250W**	**175W**	**250W**	**400W**	**60W**	**90W**	**210W**	**100W**	**250W**	**175W**	**250W**	**400W**	**60W**	**90W**	**210W**	
Cambridge Bay	41.26	67.19	40.93	50.60	66.49	21.81	32.71	76.33	43.38	70.64	43.03	53.21	69.91	22.93	34.39	80.25	5.1%
Gjoa Haven	45.71	74.40	45.38	56.08	73.70	21.81	32.71	76.33	48.06	78.22	47.72	58.96	77.49	22.93	34.39	80.25	5.1%
Taloyoak	62.60	102.04	62.27	76.98	101.34	21.81	32.71	76.33	65.82	107.28	65.47	80.94	106.54	22.93	34.39	80.25	5.1%
Kugaaruk	51.55	83.97	51.22	63.30	83.27	21.81	32.71	76.33	54.20	88.29	53.85	66.55	87.55	22.93	34.39	80.25	5.1%
Kugluktuk	65.43	106.72	65.10	80.55	106.02	21.81	32.71	76.33	68.80	112.21	68.45	84.69	111.47	22.93	34.39	80.25	5.1%
Rankin Inlet	38.16	62.10	37.83	46.74	61.39	21.81	32.71	76.33	40.12	65.29	39.78	49.15	64.55	22.93	34.39	80.25	5.1%
Baker Lake	38.49	62.62	38.16	47.17	61.92	21.81	32.71	76.33	40.47	65.84	40.12	49.59	65.10	22.93	34.39	80.25	5.1%
Arviat	33.67	54.73	33.34	41.16	54.02	21.81	32.71	76.33	35.40	57.54	35.05	43.27	56.80	22.93	34.39	80.25	5.1%
Coral Harbour	61.66	100.54	61.33	75.86	99.84	21.81	32.71	76.33	64.83	105.71	64.48	79.76	104.97	22.93	34.39	80.25	5.1%
Chesterfield Inlet	63.90	104.24	63.57	78.66	103.54	21.81	32.71	76.33	67.19	109.60	66.84	82.71	108.86	22.93	34.39	80.25	5.1%
Whale Cove	70.15	114.42	69.82	86.36	113.72	21.81	32.71	76.33	73.76	120.30	73.41	90.80	119.56	22.93	34.39	80.25	5.1%
Naujaat	53.27	86.80	52.93	65.45	86.09	21.81	32.71	76.33	56.00	91.26	55.66	68.81	90.52	22.93	34.39	80.25	5.1%
Iqaluit	36.94	60.10	36.61	45.23	59.39	21.81	32.71	76.33	38.84	63.19	38.49	47.56	62.45	22.93	34.39	80.25	5.1%
Pangnirtung	34.84	56.65	34.51	42.64	55.94	21.81	32.71	76.33	36.63	59.56	36.28	44.83	58.82	22.93	34.39	80.25	5.1%
Kinngait	45.85	74.62	45.52	56.26	73.92	21.81	32.71	76.33	48.21	78.45	47.86	59.15	77.71	22.93	34.39	80.25	5.1%
Resolute Bay	90.44	147.62	90.11	111.51	146.92	21.81	32.71	76.33	95.09	155.21	94.74	117.24	154.47	22.93	34.39	80.25	5.1%
Pond Inlet	66.29	108.09	65.96	81.58	107.39	21.81	32.71	76.33	69.70	113.65	69.35	85.77	112.91	22.93	34.39	80.25	5.1%
Igloolik	46.17	75.18	45.84	56.65	74.48	21.81	32.71	76.33	48.54	79.04	48.20	59.56	78.30	22.93	34.39	80.25	5.1%
Sanirajak	63.13	102.91	62.79	77.68	102.20	21.81	32.71	76.33	66.37	108.19	66.02	81.67	107.46	22.93	34.39	80.25	5.1%
Qikiqtarjuaq	52.69	85.86	52.36	64.74	85.16	21.81	32.71	76.33	55.40	90.27	55.05	68.06	89.53	22.93	34.39	80.25	5.1%
Kimmirut	67.70	110.39	67.36	83.31	109.69	21.81	32.71	76.33	71.18	116.06	70.83	87.60	115.32	22.93	34.39	80.25	5.1%
Arctic Bay	52.99	86.36	52.66	65.11	85.66	21.81	32.71	76.33	55.72	90.80	55.37	68.46	90.06	22.93	34.39	80.25	5.1%
Clyde River	62.17	101.34	61.83	76.48	100.64	21.81	32.71	76.33	65.36	106.55	65.01	80.41	105.81	22.93	34.39	80.25	5.1%
Grise Fiord	75.78	123.62	75.45	93.36	122.92	21.81	32.71	76.33	79.68	129.97	79.33	98.15	129.23	22.93	34.39	80.25	5.1%
Sanikiluaq	53.31	86.90	52.98	65.53	86.20	21.81	32.71	76.33	56.05	91.37	55.70	68.89	90.63	22.93	34.39	80.25	5.1%

Schedule 8.3.1:
Base Rate Change and Proof of Revenue: 2022/23 Forecast Electricity Sales (MWh)

Line No.	Plant No.	Plant Name	By Rate Class							Total Sales
			Domestic			Commercial			Streetlights	
			Non-Government	Government	Total	Non-Government	Government	Total		
			A	B	C=A+B	D	E	F=D+E	G	H=C+F+G
1	501	Cambridge Bay	2,104	2,017	4,120	5,105	2,671	7,776	90	11,986
2	502	Gjoa Haven	592	1,946	2,538	981	1,972	2,953	77	5,567
3	503	Taloyoak	325	1,594	1,918	828	1,166	1,994	50	3,962
4	504	Kugaaruk	394	1,192	1,586	1,061	804	1,864	31	3,481
5	505	Kugluktuk	900	1,915	2,815	1,322	1,683	3,005	43	5,862
6	601	Rankin Inlet	3,431	2,390	5,822	5,797	6,467	12,264	101	18,187
7	602	Baker Lake	1,513	2,631	4,144	2,063	2,215	4,278	113	8,535
8	603	Arviat	1,467	2,837	4,305	2,056	2,442	4,499	115	8,919
9	604	Coral Harbour	474	1,088	1,561	808	1,084	1,892	55	3,509
10	605	Chesterfield Inlet	215	575	791	640	602	1,242	26	2,059
11	606	Whale Cove	204	560	764	415	662	1,077	43	1,883
12	607	Naujaat	327	1,407	1,734	1,019	1,416	2,435	45	4,213
13	701	Iqaluit	13,274	5,137	18,411	20,137	16,904	37,042	178	55,631
14	702	Pangnirtung	709	1,936	2,645	1,457	2,478	3,935	143	6,723
15	703	Kinngait	563	1,657	2,220	1,316	1,941	3,257	75	5,552
16	704	Resolute Bay	244	286	530	1,090	2,303	3,393	48	3,972
17	705	Pond Inlet	745	2,239	2,983	1,420	2,103	3,523	137	6,644
18	706	Igloolik	853	2,181	3,034	1,305	2,223	3,528	95	6,658
19	707	Sanirajak	229	1,237	1,467	854	937	1,791	37	3,295
20	708	Qikiqtarjuaq	183	831	1,014	596	806	1,401	32	2,448
21	709	Kimmirut	205	663	868	442	606	1,048	32	1,948
22	710	Arctic Bay	357	1,147	1,504	494	1,124	1,618	34	3,156
23	711	Clyde River	423	1,564	1,987	402	1,391	1,793	19	3,798
24	712	Grise Fiord	102	226	328	223	565	788	23	1,140
25	713	Saniqiluaq	334	1,712	2,046	624	1,288	1,911	48	4,005
26		**Total**	**30,167**	**40,968**	**71,135**	**52,457**	**57,851**	**110,308**	**1,691**	**183,135**

Schedule 8.3.2:
Base Rate Change and Proof of Revenue: 2022/23 Proposed Base Rates (cents/KWh)

Plant No.	Plant Name	Domestic		Commercial		Streetlights ($ per month per bulb)							
		Non-Government	Government	Non-Government	Government	HPS 100 watt (30 watt Ballast)	HPS 250 watt (44 watt Ballast)	MV 175 watt (30 watt ballast)	MV 250 watt (35 watt ballast)	MV 400 watt (55 watt ballast)	LED 60W	LED 90W	LED 210W
		A	B	C	D	E	F	G	H	I	J	K	L
501	Cambridge Bay	61.57	93.44	50.79	85.35	43.38	70.64	43.03	53.21	69.91	22.93	34.39	80.25
502	Gjoa Haven	61.57	93.44	50.79	85.35	48.06	78.22	47.72	58.96	77.49	22.93	34.39	80.25
503	Taloyoak	61.57	93.44	50.79	85.35	65.82	107.28	65.47	80.94	106.54	22.93	34.39	80.25
504	Kugaaruk	61.57	93.44	50.79	85.35	54.20	88.29	53.85	66.55	87.55	22.93	34.39	80.25
505	Kugluktuk	61.57	93.44	50.79	85.35	68.80	112.21	68.45	84.69	111.47	22.93	34.39	80.25
601	Rankin Inlet	61.57	93.44	50.79	85.35	40.12	65.29	39.78	49.15	64.55	22.93	34.39	80.25
602	Baker Lake	61.57	93.44	50.79	85.35	40.47	65.84	40.12	49.59	65.10	22.93	34.39	80.25
603	Arviat	61.57	93.44	50.79	85.35	35.40	57.54	35.05	43.27	56.80	22.93	34.39	80.25
604	Coral Harbour	61.57	93.44	50.79	85.35	64.83	105.71	64.48	79.76	104.97	22.93	34.39	80.25
605	Chesterfield Inlet	61.57	93.44	50.79	85.35	67.19	109.60	66.84	82.71	108.86	22.93	34.39	80.25
606	Whale Cove	61.57	93.44	50.79	85.35	73.76	120.30	73.41	90.80	119.56	22.93	34.39	80.25
607	Naujaat	61.57	93.44	50.79	85.35	56.00	91.26	55.66	68.81	90.52	22.93	34.39	80.25
701	Iqaluit	61.57	93.44	50.79	85.35	38.84	63.19	38.49	47.56	62.45	22.93	34.39	80.25
702	Pangnirtung	61.57	93.44	50.79	85.35	36.63	59.56	36.28	44.83	58.82	22.93	34.39	80.25
703	Kinngait	61.57	93.44	50.79	85.35	48.21	78.45	47.86	59.15	77.71	22.93	34.39	80.25
704	Resolute Bay	61.57	93.44	50.79	85.35	95.09	155.21	94.74	117.24	154.47	22.93	34.39	80.25
705	Pond Inlet	61.57	93.44	50.79	85.35	69.70	113.65	69.35	85.77	112.91	22.93	34.39	80.25
706	Igloolik	61.57	93.44	50.79	85.35	48.54	79.04	48.20	59.56	78.30	22.93	34.39	80.25
707	Sanirajak	61.57	93.44	50.79	85.35	66.37	108.19	66.02	81.67	107.46	22.93	34.39	80.25
708	Qikiqtarjuaq	61.57	93.44	50.79	85.35	55.40	90.27	55.05	68.06	89.53	22.93	34.39	80.25
709	Kimmirut	61.57	93.44	50.79	85.35	71.18	116.06	70.83	87.60	115.32	22.93	34.39	80.25
710	Arctic Bay	61.57	93.44	50.79	85.35	55.72	90.80	55.37	68.46	90.06	22.93	34.39	80.25
711	Clyde River	61.57	93.44	50.79	85.35	65.36	106.55	65.01	80.41	105.81	22.93	34.39	80.25
712	Grise Fiord	61.57	93.44	50.79	85.35	79.68	129.97	79.33	98.15	129.23	22.93	34.39	80.25
713	Saniqiluaq	61.57	93.44	50.79	85.35	56.05	91.37	55.70	68.89	90.63	22.93	34.39	80.25

Schedule 8.3.3:
Base Rate Change and Proof of Revenue: Revenue Forecast at 2022/23 Proposed Rates ($000)

Line No.	Plant No.	Plant Name	By Rate Class							Customer Charges and Demand Revenue			Total
			Domestic			Commercial							
			Non-Government	Government	Total	Non-Government	Government	Total	Streetlights	Customer Charges	Demand Revenue	Total	
			A	B	C=A+B	D	E	F=D+E	G	H	I	J=H+I	K=C+F+G+J
1	501	Cambridge Bay	*1,295*	*1,884*	*3,180*	*2,593*	*2,279*	*4,872*	*98*	*163*	*265*	428	8,578
2	502	Gjoa Haven	*365*	*1,818*	*2,183*	*498*	*1,683*	*2,181*	*83*	*82*	*108*	191	4,638
3	503	Taloyoak	*200*	*1,489*	*1,689*	*420*	*995*	*1,415*	*54*	*59*	*119*	178	3,337
4	504	Kugaaruk	*242*	*1,114*	*1,356*	*539*	*686*	*1,225*	*34*	*50*	*85*	134	2,749
5	505	Kugluktuk	*554*	*1,789*	*2,343*	*671*	*1,436*	*2,108*	*47*	*108*	*128*	236	4,734
6	601	Rankin Inlet	*2,113*	*2,233*	*4,346*	*2,945*	*5,519*	*8,464*	*110*	*222*	*507*	729	13,649
7	602	Baker Lake	*932*	*2,458*	*3,390*	*1,048*	*1,890*	*2,938*	*123*	*151*	*244*	395	6,846
8	603	Arviat	*903*	*2,651*	*3,555*	*1,044*	*2,085*	*3,129*	*125*	*157*	*155*	313	7,122
9	604	Coral Harbour	*292*	*1,016*	*1,308*	*411*	*925*	*1,336*	*60*	*59*	*67*	126	2,830
10	605	Chesterfield Inlet	*133*	*537*	*670*	*325*	*514*	*839*	*29*	*30*	*52*	82	1,619
11	606	Whale Cove	*125*	*523*	*649*	*211*	*565*	*776*	*47*	*29*	*49*	78	1,549
12	607	Naujaat	*201*	*1,315*	*1,516*	*517*	*1,209*	*1,726*	*49*	*56*	*74*	130	3,421
13	701	Iqaluit	*8,173*	*4,800*	*12,973*	*10,228*	*14,428*	*24,656*	*194*	*772*	*1,076*	1,847	39,670
14	702	Pangnirtung	*437*	*1,808*	*2,245*	*740*	*2,115*	*2,855*	*156*	*105*	*217*	322	5,578
15	703	Kinngait	*347*	*1,548*	*1,895*	*668*	*1,657*	*2,325*	*82*	*94*	*131*	225	4,526
16	704	Resolute Bay	*151*	*267*	*418*	*554*	*1,965*	*2,519*	*53*	*21*	*167*	187	3,177
17	705	Pond Inlet	*458*	*2,092*	*2,550*	*721*	*1,795*	*2,516*	*150*	*97*	*121*	219	5,435
18	706	Igloolik	*525*	*2,038*	*2,563*	*663*	*1,897*	*2,560*	*103*	*103*	*116*	220	5,447
19	707	Sanirajak	*141*	*1,156*	*1,297*	*434*	*800*	*1,234*	*40*	*46*	*70*	116	2,687
20	708	Qikiqtarjuaq	*113*	*777*	*889*	*303*	*688*	*990*	*35*	*44*	*67*	111	2,026
21	709	Kimmirut	*126*	*620*	*746*	*224*	*517*	*742*	*35*	*31*	*62*	93	1,616
22	710	Arctic Bay	*220*	*1,072*	*1,292*	*251*	*959*	*1,210*	*37*	*54*	*62*	116	2,655
23	711	Clyde River	*260*	*1,461*	*1,721*	*204*	*1,188*	*1,392*	*20*	*63*	*62*	125	3,258
24	712	Grise Fiord	*63*	*212*	*274*	*113*	*482*	*596*	*25*	*14*	*35*	49	945
25	713	Saniqiluaq	*205*	*1,600*	*1,805*	*317*	*1,099*	*1,416*	*52*	*59*	*81*	140	3,414
26		**Total**	***18,574***	***38,279***	***56,853***	***26,643***	***49,376***	***76,019***	**1,841**	***2,669***	***4,122***	**6,791**	**141,504**

27	**2022/23 GRA Revenue Requirement**	**144,015**	
28	**Less: 2022/23 GRA Non-electricity Revenue**	**2,511**	
29	**2022/23 GRA Firm Rate Revenue Requirement**		**141,504**
30	**Shortfall/Surplus at Proposed Rates**		**0**

Schedule 8.4:
2022/23 Rate Proposal Bill Impact Estimates

Based on monthly consumption of 1,000 kWh for domestic customers and 2,000 kWh for commercial customers.

		Domestic Subsidized Bills		% of Difference from Existing	Domestic Full Bills		% of Difference from Existing	Commercial Bills		% of Difference from Existing	Gov Domestic Bills		% of Difference from Existing	Gov Commercial Bills		% of Difference from Existing
Plant No.	Community	Existing	Proposed		Existing	Option 1		Existing	Option 1		Existing	Option 1		Existing	Option 1	
501	Cambridge Bay	$ 307.45	$ 323.25	5.1%	$ 810.49	$ 665.40	-17.9%	$ 1,401.32	$ 1,108.59	-20.9%	$ 810.49	$ 999.98	23.4%	$ 1,401.32	$ 1,834.36	30.9%
502	Gjoa Haven	$ 307.45	$ 323.25	5.1%	$ 960.52	$ 665.40	-30.7%	$ 1,847.03	$ 1,108.59	-40.0%	$ 992.23	$ 999.98	0.8%	$ 1,847.03	$ 1,834.36	-0.7%
503	Taloyoak	$ 307.45	$ 323.25	5.1%	$ 1,060.35	$ 665.40	-37.2%	$ 2,089.50	$ 1,108.59	-46.9%	$ 1,151.11	$ 999.98	-13.1%	$ 2,089.50	$ 1,834.36	-12.2%
504	Kugaaruk	$ 307.45	$ 323.25	5.1%	$ 1,237.38	$ 665.40	-46.2%	$ 2,201.32	$ 1,108.59	-49.6%	$ 1,237.38	$ 999.98	-19.2%	$ 2,201.32	$ 1,834.36	-16.7%
505	Kugluktuk	$ 307.45	$ 323.25	5.1%	$ 1,003.88	$ 665.40	-33.7%	$ 1,874.60	$ 1,108.59	-40.9%	$ 1,063.94	$ 999.98	-6.0%	$ 1,874.60	$ 1,834.36	-2.1%
601	Rankin Inlet	$ 307.45	$ 323.25	5.1%	$ 655.54	$ 665.40	1.5%	$ 1,154.15	$ 1,108.59	-3.9%	$ 655.54	$ 999.98	52.5%	$ 1,279.64	$ 1,834.36	43.3%
602	Baker Lake	$ 307.45	$ 323.25	5.1%	$ 746.07	$ 665.40	-10.8%	$ 1,401.77	$ 1,108.59	-20.9%	$ 746.07	$ 999.98	34.0%	$ 1,401.77	$ 1,834.36	30.9%
603	Arviat	$ 307.45	$ 323.25	5.1%	$ 845.00	$ 665.40	-21.3%	$ 1,579.70	$ 1,108.59	-29.8%	$ 845.00	$ 999.98	18.3%	$ 1,579.70	$ 1,834.36	16.1%
604	Coral Harbour	$ 307.45	$ 323.25	5.1%	$ 1,018.90	$ 665.40	-34.7%	$ 1,872.80	$ 1,108.59	-40.8%	$ 1,018.90	$ 999.98	-1.9%	$ 1,872.80	$ 1,834.36	-2.1%
605	Chesterfield Inlet	$ 307.45	$ 323.25	5.1%	$ 1,051.16	$ 665.40	-36.7%	$ 1,963.11	$ 1,108.59	-43.5%	$ 1,051.16	$ 999.98	-4.9%	$ 1,963.11	$ 1,834.36	-6.6%
606	Whale Cove	$ 307.45	$ 323.25	5.1%	$ 971.39	$ 665.40	-31.5%	$ 2,412.19	$ 1,108.59	-54.0%	$ 1,580.69	$ 999.98	-36.7%	$ 2,670.56	$ 1,834.36	-31.3%
607	Repulse Bay	$ 307.45	$ 323.25	5.1%	$ 911.33	$ 665.40	-27.0%	$ 1,608.16	$ 1,108.59	-31.1%	$ 911.33	$ 999.98	9.7%	$ 1,608.16	$ 1,834.36	14.1%
701	Iqaluit	$ 307.45	$ 323.25	5.1%	$ 633.80	$ 665.40	5.0%	$ 1,056.45	$ 1,108.59	4.9%	$ 633.80	$ 999.98	57.8%	$ 1,086.93	$ 1,834.36	68.8%
702	Pangnirtung	$ 307.45	$ 323.25	5.1%	$ 694.86	$ 665.40	-4.2%	$ 1,235.27	$ 1,108.59	-10.3%	$ 744.05	$ 999.98	34.4%	$ 1,360.76	$ 1,834.36	34.8%
703	Kinngait	$ 307.45	$ 323.25	5.1%	$ 726.80	$ 665.40	-8.4%	$ 1,365.47	$ 1,108.59	-18.8%	$ 763.55	$ 999.98	31.0%	$ 1,531.29	$ 1,834.36	19.8%
704	Resolute Bay	$ 307.45	$ 323.25	5.1%	$ 1,093.85	$ 665.40	-39.2%	$ 2,090.17	$ 1,108.59	-47.0%	$ 1,114.02	$ 999.98	-10.2%	$ 2,090.17	$ 1,834.36	-12.2%
705	Pond Inlet	$ 307.45	$ 323.25	5.1%	$ 966.12	$ 665.40	-31.1%	$ 1,778.02	$ 1,108.59	-37.7%	$ 1,048.36	$ 999.98	-4.6%	$ 1,778.02	$ 1,834.36	3.2%
706	Igloolik	$ 307.45	$ 323.25	5.1%	$ 666.74	$ 665.40	-0.2%	$ 1,228.33	$ 1,108.59	-9.7%	$ 666.74	$ 999.98	50.0%	$ 1,228.33	$ 1,834.36	49.3%
707	Sanirajak	$ 307.45	$ 323.25	5.1%	$ 955.81	$ 665.40	-30.4%	$ 1,845.91	$ 1,108.59	-39.9%	$ 992.68	$ 999.98	0.7%	$ 1,845.91	$ 1,834.36	-0.6%
708	Qikiqtarjuak	$ 307.45	$ 323.25	5.1%	$ 831.33	$ 665.40	-20.0%	$ 1,580.37	$ 1,108.59	-29.9%	$ 952.23	$ 999.98	5.0%	$ 1,908.66	$ 1,834.36	-3.9%
709	Kimmirut	$ 307.45	$ 323.25	5.1%	$ 1,120.63	$ 665.40	-40.6%	$ 1,886.03	$ 1,108.59	-41.2%	$ 1,118.06	$ 999.98	-10.6%	$ 1,895.66	$ 1,834.36	-3.2%
710	Arctic Bay	$ 307.45	$ 323.25	5.1%	$ 942.82	$ 665.40	-29.4%	$ 1,690.40	$ 1,108.59	-34.4%	$ 942.82	$ 999.98	6.1%	$ 1,690.40	$ 1,834.36	8.5%
711	Clyde River	$ 307.45	$ 323.25	5.1%	$ 834.36	$ 665.40	-20.2%	$ 1,481.77	$ 1,108.59	-25.2%	$ 839.74	$ 999.98	19.1%	$ 1,481.77	$ 1,834.36	23.8%
712	Grise Ford	$ 307.45	$ 323.25	5.1%	$ 990.10	$ 665.40	-32.8%	$ 2,294.32	$ 1,108.59	-51.7%	$ 1,199.62	$ 999.98	-16.6%	$ 2,294.32	$ 1,834.36	-20.0%
713	Sanikiluaq	$ 307.45	$ 323.25	5.1%	$ 879.85	$ 665.40	-24.4%	$ 1,691.29	$ 1,108.59	-34.5%	$ 879.85	$ 999.98	13.7%	$ 1,691.29	$ 1,834.36	8.5%

9.0 RESPONSE TO URRC RECOMMENDATION

9.1 INTRODUCTION

This chapter sets out the Corporation's responses to the directions and recommendations identified in the following URRC Reports:

- 2018-01: 2018/19 GRA Report;
- 2017-02: Net Metering Program Report

9.2 URRC REPORT 2018-01 ON QEC'S 2018/19 GRA

9.2.1 MECHANISM TO ENSURE ACCOUNTABILITY FOR RETIREMENTS, DISPOSITIONS AND WRITE-OFF OF FIXED ASSETS

In the URRC's view, while the apparent lack of controls over movement of spare parts was the subject of the AG's report, on a similar vein, the mechanisms in place to ensure accountability for retirements, dispositions and write-off of fixed assets including major assets such as generating units, transformers etc., have also not been demonstrated. Accordingly, it is recommended that QEC be directed to implement or augment mechanisms to ensure due accountability, controls and approvals for all activities including retirements, dispositions and write offs with a view to minimizing the potential for leakage of value arising from such transactions. QEC should report on this matter at the time of the next GRA.

QEC's Response:

In response to the Auditor General of Canada report QEC has undertaken the following measures with respect to the spare parts and related fixed assets accountability:

1) Inventory count is undertaken for all the 25 communities each year since 2018
2) Submission of usage reports to the Finance Department on a monthly basis
3) Purchase of sea-cans for storage at communities
4) QEC hired external consultants to review the inventory process
5) QEC formed an inventory committee comprising of Finance, Operations, Engineering and IT in Dec 2021 to review the process

9.2.2 MECHANISM TO FACILITATE VERIFIABILITY OF PHYSICAL INVENTORY

In the URRC's view, a qualified audit report is a serious matter in any business setting, requiring immediate management attention to address the matter. Given the AG's concerns respecting supplies inventory level, the URRC is not convinced that QEC has provided sufficient justification for the 2.5 times increase in the supplies inventory level since the last GRA. Therefore, it is recommended that QEC be directed to implement or augment mechanisms to facilitate verifiability of physical inventory (quantities and values) and to take immediate steps to implement procedures and practices for efficient management of inventory levels and the exercise of appropriate controls over all inventory transactions. QEC is directed to report on this matter at the time of the next GRA.

QEC's Response:

In response to the Auditor General of Canada report QEC has undertaken the following measures with respect to the spare parts and related fixed assets accountability:

1) Inventory count is undertaken for all the 25 communities each year since 2018;
2) Submission of usage reports to the Finance Department on a monthly basis;
3) Purchase of sea-cans for storage at communities;
4) QEC hired external consultants to review the inventory process; and
5) QEC formed an inventory committee comprising of Finance, Operations, Engineering and IT in Dec 2021 to review the process.

However, the current inventory levels remain higher than in previous years. In addition to routine maintenance, QEC purchases inventory for capital projects. The capital projects are multi year projects and delays in execution have a direct impact on carrying value of inventory. Due to short sea-lift season, QEC must procure the materials earlier and is unable to further optimize the inventory levels.

9.2.3 REMOVAL OF ASSETS NO LONGER IN USE FROM DEPRECIATION STUDY

Accordingly, it is recommended that QEC be directed to bring forward at the next GRA a depreciation study and analysis whereby assets that are that are no longer in use and assets that are the subject of insurance claims, are removed from the regulatory accounting records, before applying the applicable depreciation rates.

QEC's Response:

The Corporation notes that the usual industry practice is to implement a depreciation study every second GRA, where GRAs are filed on a 3-4 year interval. The Corporation will address this recommendation in preparing its next GRA.

9.2.4 NET SALVAGE PROVISION

Although the practice of expensing the costs of retirement associated with interim retirements is directed under the accounting standards followed by QEC, the URRC continues to be concerned that absence of a provision for negative salvage for regulatory purposes would not be consistent with prudent utility practice for the reasons stated in Report 2010-01 quoted above. In view of this, although the accumulated depreciation account has merged the net salvage reserve with the life portion for PSA accounting, for regulatory purposes the identities of the life portion and the salvage portion must be tracked separately; it is recommended that QEC be directed accordingly for the purposes of the next GRA. Further, for the next GRA, it is recommended that QEC be directed to address the appropriate treatment of a provision for negative salvage including future retirement and site restoration as part of the next depreciation study.

QEC's Response:

Prior to the 2010/11 GRA, QEC maintained a reserve for Future Removal and Site Restoration. This account was eliminated as a required part of the Government of Nunavut's direction to QEC to transition to Public Sector Accounting (PSA) effective April

1, 2011. As stated by QEC's depreciation expert in the Depreciation Study conducted for the 2010/11 GRA, under PSA standards, all costs of removal are charged to the income statement in the year of the expenditure of the funds[23] and no separate reserve is permitted.

In the URRC Report 2011-01, the URRC also recommended QEC to continue to account for net salvage and Future Removal and Site Restoration expenses as part of the amortization rates and annual amortization expense for regulatory purposes (even though this was not permitted for financial accounting purposes). In the response to the URRC, dated May 26, 2011, the Minister did not accept this recommendation stating that it could create transparency and consistency problems between QEC's audited financial statements and future rate applications.

The current application has been prepared in accordance with PSA standards that QEC follows effective April 1, 2011 in compliance with the Government of Nunavut's direction.

9.2.5 HIGHER GOVERNMENT REVENUE TO COST RATIOS IN RATE REALIGNMENT

Accordingly, the URRC recommends that QEC be directed to examine an approach to rate realignment including the adoption of higher revenue to cost ratios for Government customers with a view to minimizing the harmful effects of high rate increases for investment and economic growth in Nunavut, at the next GRA.

[23] 2010/11 GRA, Appendix C, p. C-5.

QEC's Response:

The Corporation's proposed rate realignment approach is discussed in Chapter 8 of the Application.

9.3 URRC REPORT 2017-02 ON QEC'S NET METERING PROGRAM APPLICATION

9.3.1 LOSS OF LOAD AND REVENUE FROM NET METERING

The URRC recommended that QEC provide the estimated impact of the loss of load and any related loss of revenue due to net metering on other customers, together with QEC's proposals for addressing such loss of revenue at the GRA following the full implementation of the Net Metering Program.

QEC's Response:

QEC performed analysis of the estimated impact of the Net Metering Program on QEC's load and revenue from sales based on the net metering uptake since the start of the program in January 2018. As of March 2022 QEC total installed capacity under net metering program is 150.8 kW. Net revenue loss associated with the current level of the net metering uptake is approximately $58,000, or approximately 0.05% of QEC's forecast 2022/23 revenue requirement of $144.0 million. Considering immaterial amount of net revenue loss, QEC does not propose to recover this lost revenue from customers.

9.3.2 RENEWABLE ENERGY PROGRAMS STRATEGIC PLAN

The URRC recommended that QEC address, at the GRA following full implementation of the Net Metering Program, its strategic plan for successful and orderly introduction, integration and uptake of the Net Metering Program, as well as other potentially larger renewable energy programs (example IPPs) with a view to progressively reducing dependence on diesel fuel while enabling a foreseeable path towards affordability and reduction in carbon emissions, over the next five years.

QEC's Response:

As a next step in the strategy to increase renewable energy generation in Nunavut, QEC also launched the new Commercial and Institutional Power Producer (CIPP) program in May 2021. The program is designed to allow existing commercial and institutional customers (government departments, hamlets, businesses) to generate electricity using renewable energy systems and sell it to QEC. CIPP participants will be paid for the power they generate and sell to QEC at a rate equal to the corporation's diesel savings. As well, in response to the URRC comments that a CIPP power purchase agreement (PPA) price based solely on the avoided cost of fuel would be insufficient to encourage the development of renewable generation in Nunavut and in accordance with the Minister's direction from November 4, 2020, QEC is working on a revised CIPP pricing framework aimed at facilitating the desired increase in renewable generation while avoiding cost increases to customers.

QEC is also conducting a review of its Net Metering Program, as well as a study on intermittent renewable energy penetration level in the communities which will inform potential revisions to the Net Metering and CIPP programs. QEC will submit its finding and recommendations to the Government of Nunavut upon completion of these studies.

APPENDIX A

SUMMARY OF GENERATION SALES AND REVENUE

Schedule A-1

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

500 Total of Kitikmeot Area

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	11,773	12,100	12,250	12,683	12,880	12,977
2	Customers	1,922	1,979	2,035	2,098	2,119	2,140
3	Av. MWh Sales/Cust.	6.12	6.12	6.02	6.04	6.08	6.06
4	Revenue (000s)	10,806	11,028	11,584	11,864	12,431	12,534
5	Cents/kWh	91.79	91.14	94.56	93.55	96.52	96.59
	Commercial						
6	Sales (MWh)	17,817	17,756	17,788	17,247	17,672	17,591
7	Customers	647	678	680	682	685	688
8	Av. MWh Sales/Cust.	27.54	26.18	26.17	25.31	25.80	25.55
9	Revenue (000s)	13,892	14,403	14,993	14,658	14,804	14,759
10	Cents /kWh	77.97	81.11	84.29	84.99	83.77	83.90
	Streetlights						
11	Sales (MWh)	352	279	291	291	291	291
12	Revenue (000s)	359	281	280	317	320	320
13	Cents /kWh	101.81	100.72	96.14	108.96	109.89	109.89
	Total						
14	**Sales (MWh)**	**29,943**	**30,136**	**30,329**	**30,220**	**30,844**	**30,859**
15	Customers	2,569	*2,657*	2,715	2,780	2,804	2,829
16	Revenue (000s)	25,057	25,712	26,856	26,840	27,555	27,613
17	Cents /kWh	83.68	85.32	88.55	88.81	89.34	89.48
	GENERATION (MWh)						
18	**Total Station Service**	**611**	**642**	**565**	**492**	**598**	**599**
19	**Station Service - % of Gen.**	1.9%	2.0%	1.7%	1.5%	1.8%	1.8%
20	**Total Losses**	**1,686**	**1,494**	**1,486**	**1,708**	**1,707**	**1,712**
21	**Losses - % of Gen.**	5.2%	4.6%	4.6%	5.3%	5.1%	5.2%
22	**Total Generation**	**32,240**	**32,272**	**32,380**	**32,420**	**33,148**	**33,171**
	Source						
23	Diesel Generation (MWh)	32,240	32,272	32,380	32,420	33,148	33,171
24	Diesel Efficiency (KWh/L)	3.68	3.63	3.65	3.63	3.65	3.65
25	Liters (000s)	8,760	8,894	8,882	8,924	9,070	9,077
	Peak						
26	Peak Load (KW)	5,988	5,786	5,919	5,801	6,033	6,020
27	Load Factor	61%	64%	62%	64%	63%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.1

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

501 Cambridge Bay

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	3,670	3,847	3,866	4,002	4,126	4,120
2	Customers	632	685	707	743	750	757
3	Av. MWh Sales/Cust.	5.81	5.62	5.47	5.39	5.50	5.45
4	Revenue (000s)	2,923	2,975	3,071	3,132	3,272	3,270
5	Cents/kWh	79.65	77.34	79.43	78.27	79.31	79.36
	Commercial						
6	Sales (MWh)	8,595	7,786	7,679	7,537	7,908	7,776
7	Customers	266	267	275	281	283	284
8	Av. MWh Sales/Cust.	32.31	29.17	27.89	26.79	27.98	27.38
9	Revenue (000s)	5,817	5,048	5,234	5,142	5,383	5,298
10	Cents /kWh	67.68	64.83	68.15	68.23	68.07	68.14
	Streetlights						
11	Sales (MWh)	123	72	90	90	90	90
12	Revenue (000s)	112	71	83	97	98	98
13	Cents /kWh	91.01	98.13	92.24	107.71	109.04	109.04
	Total						
14	**Sales (MWh)**	**12,388**	**11,705**	**11,635**	**11,629**	**12,124**	**11,986**
15	Customers	898	*951*	983	1,024	1,032	1,041
16	Revenue (000s)	8,852	8,094	8,388	8,372	8,754	8,666
17	Cents /kWh	71.45	69.15	72.09	71.99	72.20	72.30
	GENERATION (MWh)						
18	**Total Station Service**	170	116	101	115	138	134
19	**Station Service - % of Gen.**	1.3%	1.0%	0.8%	0.9%	1.1%	1.1%
20	**Losses**	670	287	401	446	510	496
21	**Losses - % of Gen.**	5.1%	2.4%	3.3%	3.7%	4.0%	3.9%
22	**Total Generation**	**13,228**	**12,109**	**12,138**	**12,189**	**12,772**	**12,617**
	Source						
23	Diesel Generation (MWh)	13,228	12,109	12,138	12,189	12,772	12,617
24	Diesel Efficiency (KWh/L)	3.70	3.69	3.66	3.70	3.69	3.69
25	Liters (000s)	3,575	3,278	3,314	3,295	3,461	3,419
	Peak						
26	Peak Load (KW)	2,343	2,040	2,231	2,099	2,249	2,223
27	Load Factor	64%	68%	62%	66%	65%	65%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.2

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

502 Gjoa Haven

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,333	2,283	2,411	2,470	2,514	2,538
2	Customers	337	339	359	371	376	380
3	Av. MWh Sales/Cust.	6.93	6.73	6.72	6.66	6.69	6.67
4	Revenue (000s)	2,112	2,066	2,244	2,274	2,394	2,417
5	Cents/kWh	90.53	90.49	93.10	92.06	95.22	95.23
	Commercial						
6	Sales (MWh)	3,115	3,154	3,171	2,906	2,945	2,953
7	Customers	103	126	118	118	118	119
8	Av. MWh Sales/Cust.	30.18	25.07	26.87	24.71	24.89	24.80
9	Revenue (000s)	2,608	2,818	2,846	2,729	2,640	2,646
10	Cents /kWh	83.73	89.33	89.75	93.91	89.62	89.62
	Streetlights						
11	Sales (MWh)	77	77	77	77	77	77
12	Revenue (000s)	81	72	74	74	74	74
13	Cents /kWh	105.55	94.00	96.69	96.69	96.70	96.70
	Total						
14	**Sales (MWh)**	**5,525**	**5,514**	**5,658**	**5,453**	**5,536**	**5,567**
15	Customers	440	*465*	477	489	494	499
16	Revenue (000s)	4,801	4,956	5,165	5,077	5,107	5,137
17	Cents /kWh	86.91	89.87	91.27	93.11	92.26	92.28
	GENERATION (MWh)						
18	**Total Station Service**	103	151	111	101	129	134
19	**Station Service - % of Gen.**	1.7%	2.5%	1.8%	1.6%	2.1%	2.2%
20	**Losses**	326	502	465	555	397	416
21	**Losses - % of Gen.**	5.5%	8.1%	7.5%	9.1%	6.5%	6.8%
22	**Total Generation**	**5,953**	**6,167**	**6,234**	**6,108**	**6,061**	**6,118**
	Source						
23	Diesel Generation (MWh)	5,953	6,167	6,234	6,108	6,061	6,118
24	Diesel Efficiency (KWh/L)	3.70	3.61	3.53	3.59	3.59	3.59
25	Liters (000s)	1,609	1,706	1,764	1,702	1,688	1,704
	Peak						
26	Peak Load (KW)	1,067	1,080	1,070	1,040	1,069	1,066
27	Load Factor	64%	65%	67%	67%	65%	66%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.3

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

503 Taloyoak

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,718	1,867	1,771	1,867	1,902	1,918
2	Customers	270	262	268	266	269	272
3	Av. MWh Sales/Cust.	6.37	7.12	6.61	7.03	7.08	7.06
4	Revenue (000s)	1,735	1,768	1,825	1,916	2,081	2,099
5	Cents/kWh	101.00	94.71	103.06	102.59	109.42	109.43
	Commercial						
6	Sales (MWh)	1,942	1,976	2,018	2,015	1,936	1,994
7	Customers	82	83	80	77	77	78
8	Av. MWh Sales/Cust.	23.56	23.83	25.20	26.17	25.00	25.58
9	Revenue (000s)	1,792	1,947	2,113	2,084	2,007	2,063
10	Cents /kWh	92.23	98.57	104.73	103.43	103.65	103.48
	Streetlights						
11	Sales (MWh)	56	56	50	50	50	50
12	Revenue (000s)	59	27	45	69	70	70
13	Cents /kWh	105.55	47.98	89.89	137.99	139.57	139.57
	Total						
14	**Sales (MWh)**	**3,717**	**3,899**	**3,839**	**3,932**	**3,888**	**3,962**
15	Customers	352	*345*	348	343	346	350
16	Revenue (000s)	3,586	3,742	3,983	4,069	4,158	4,232
17	Cents /kWh	96.49	95.99	103.77	103.47	106.93	106.82
	GENERATION (MWh)						
18	**Total Station Service**	93	98	95	99	98	101
19	**Station Service - % of Gen.**	2.3%	2.4%	2.3%	2.4%	2.3%	2.3%
20	**Losses**	241	153	175	160	235	234
21	**Losses - % of Gen.**	5.9%	3.7%	4.3%	3.8%	5.6%	5.5%
22	**Total Generation**	**4,051**	**4,149**	**4,109**	**4,191**	**4,221**	**4,297**
	Source						
23	Diesel Generation (MWh)	4,051	4,149	4,109	4,191	4,221	4,297
24	Diesel Efficiency (KWh/L)	3.58	3.41	3.72	3.59	3.63	3.63
25	Liters (000s)	1,131	1,217	1,104	1,168	1,163	1,184
	Peak						
26	Peak Load (KW)	775	780	750	750	786	800
27	Load Factor	60%	61%	63%	64%	61%	61%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.4

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

504 Kugaaruk

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,484	1,529	1,540	1,535	1,575	1,586
2	Customers	203	218	226	225	228	231
3	Av. MWh Sales/Cust.	7.30	7.00	6.83	6.83	6.92	6.87
4	Revenue (000s)	1,591	1,762	1,837	1,809	1,877	1,890
5	Cents/kWh	107.18	115.22	119.31	117.86	119.17	119.19
	Commercial						
6	Sales (MWh)	1,236	1,932	1,835	1,754	1,939	1,864
7	Customers	65	75	81	81	81	82
8	Av. MWh Sales/Cust.	19.15	25.93	22.61	21.67	23.80	22.74
9	Revenue (000s)	1,191	2,004	1,995	1,911	2,078	2,002
10	Cents /kWh	96.32	103.73	108.73	108.97	107.17	107.36
	Streetlights						
11	Sales (MWh)	31	31	31	31	31	31
12	Revenue (000s)	33	29	30	30	30	30
13	Cents /kWh	105.55	94.27	96.99	96.99	96.99	96.99
	Total						
14	**Sales (MWh)**	**2,752**	**3,492**	**3,406**	**3,320**	**3,545**	**3,481**
15	Customers	268	*293*	307	306	309	313
16	Revenue (000s)	2,815	3,796	3,863	3,750	3,985	3,922
17	Cents /kWh	102.28	108.68	113.40	112.97	112.41	112.65
	GENERATION (MWh)						
18	**Total Station Service**	77	82	77	80	90	85
19	**Station Service - % of Gen.**	2.5%	2.1%	2.1%	2.1%	2.3%	2.2%
20	**Losses**	200	262	212	351	288	281
21	**Losses - % of Gen.**	6.6%	6.8%	5.7%	9.3%	7.4%	7.3%
22	**Total Generation**	**3,029**	**3,836**	**3,695**	**3,750**	**3,923**	**3,848**
	Source						
23	Diesel Generation (MWh)	3,029	3,836	3,695	3,750	3,923	3,848
24	Diesel Efficiency (KWh/L)	3.78	3.68	3.75	3.62	3.71	3.71
25	Liters (000s)	801	1,043	985	1,036	1,057	1,037
	Peak						
26	Peak Load (KW)	710	806	719	795	805	790
27	Load Factor	49%	54%	59%	54%	56%	56%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.5

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

505 Kugluktuk

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,568	2,574	2,663	2,809	2,764	2,815
2	Customers	481	474	475	494	497	501
3	Av. MWh Sales/Cust.	5.34	5.43	5.60	5.68	5.56	5.62
4	Revenue (000s)	2,445	2,456	2,606	2,733	2,808	2,858
5	Cents/kWh	95.22	95.44	97.87	97.32	101.59	101.54
	Commercial						
6	Sales (MWh)	2,928	2,908	3,084	3,035	2,944	3,005
7	Customers	131	128	125	125	125	126
8	Av. MWh Sales/Cust.	22.40	22.72	24.64	24.35	23.53	23.94
9	Revenue (000s)	2,484	2,586	2,804	2,792	2,696	2,750
10	Cents /kWh	84.83	88.92	90.92	91.98	91.60	91.52
	Streetlights						
11	Sales (MWh)	66	43	43	43	43	43
12	Revenue (000s)	74	82	47	47	47	47
13	Cents /kWh	112.71	190.13	109.94	108.30	109.95	109.95
	Total						
14	**Sales (MWh)**	**5,562**	**5,525**	**5,790**	**5,887**	**5,751**	**5,862**
15	Customers	612	*602*	601	619	622	626
16	Revenue (000s)	5,003	5,125	5,458	5,572	5,552	5,655
17	Cents /kWh	89.96	92.74	94.26	94.65	96.54	96.47
	GENERATION (MWh)						
18	**Total Station Service**	169	195	181	98	143	144
19	**Station Service - % of Gen.**	2.8%	3.3%	2.9%	1.6%	2.3%	2.3%
20	**Losses**	249	290	234	198	277	284
21	**Losses - % of Gen.**	4.2%	4.8%	3.8%	3.2%	4.5%	4.5%
22	**Total Generation**	**5,980**	**6,010**	**6,205**	**6,183**	**6,171**	**6,291**
	Source						
23	Diesel Generation (MWh)	5,980	6,010	6,205	6,183	6,171	6,291
24	Diesel Efficiency (KWh/L)	3.64	3.64	3.62	3.59	3.63	3.63
25	Liters (000s)	1,643	1,650	1,716	1,723	1,700	1,733
	Peak						
26	Peak Load (KW)	1,093	1,080	1,149	1,117	1,124	1,141
27	Load Factor	62%	64%	62%	63%	63%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

600 Total of Kivalliq Area

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	17,920	17,967	17,793	18,529	18,774	19,120
2	Customers	3,074	3,079	3,100	3,153	3,205	3,259
3	Av. MWh Sales/Cust.	5.83	5.84	5.74	5.88	5.86	5.87
4	Revenue (000s)	14,315	13,603	13,957	14,614	14,961	15,246
5	Cents/kWh	79.88	75.71	78.45	78.87	79.69	79.74
	Commercial						
6	Sales (MWh)	26,969	28,239	27,740	26,625	28,087	27,687
7	Customers	831	859	860	876	883	890
8	Av. MWh Sales/Cust.	32.45	32.86	32.26	30.39	31.80	31.10
9	Revenue (000s)	19,278	19,655	19,870	19,244	20,242	19,993
10	Cents /kWh	71.48	69.60	71.63	72.28	72.07	72.21
	Streetlights						
11	Sales (MWh)	490	448	498	498	498	498
12	Revenue (000s)	506	441	474	492	491	491
13	Cents /kWh	103.31	98.49	95.16	98.65	98.55	98.55
	Total						
14	**Sales (MWh)**	**45,379**	**46,654**	**46,030**	**45,653**	**47,360**	**47,305**
15	Customers	3,905	*3,938*	3,960	4,029	4,089	4,149
16	Revenue (000s)	34,099	33,699	34,302	34,349	35,694	35,730
17	Cents /kWh	75.14	72.23	74.52	75.24	75.37	75.53
	GENERATION (MWh)						
18	**Total Station Service**	**1,515**	**1,567**	**1,494**	**1,593**	**1,566**	**1,575**
19	**Station Service - % of Gen.**	3.1%	3.1%	3.0%	3.2%	3.1%	3.1%
20	**Total Losses**	**1,767**	**2,060**	**2,292**	**1,921**	**1,985**	**2,029**
21	**Losses - % of Gen.**	3.6%	4.1%	4.6%	3.9%	3.9%	4.0%
22	**Total Generation**	**48,661**	**50,282**	**49,817**	**49,168**	**50,912**	**50,909**
	Source						
23	Diesel Generation (MWh)	48,661	50,282	49,817	49,168	50,912	50,909
24	Diesel Efficiency (KWh/L)	3.72	3.69	3.72	3.68	3.72	3.72
25	Liters (000s)	13,087	13,640	13,388	13,350	13,701	13,700
	Peak						
26	Peak Load (KW)	9,463	9,707	9,520	10,037	9,938	9,950
27	Load Factor	59%	59%	60%	56%	58%	58%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.1

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

601 Rankin Inlet

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	5,568	5,630	5,572	5,599	5,796	5,822
2	Customers	951	964	969	998	1,013	1,027
3	Av. MWh Sales/Cust.	5.86	5.84	5.75	5.61	5.72	5.67
4	Revenue (000s)	3,803	3,535	3,597	3,617	3,733	3,752
5	Cents/kWh	68.30	62.79	64.55	64.59	64.41	64.44
	Commercial						
6	Sales (MWh)	11,295	12,206	12,221	11,727	12,539	12,264
7	Customers	253	268	274	289	292	294
8	Av. MWh Sales/Cust.	44.73	45.50	44.58	40.51	43.01	41.76
9	Revenue (000s)	7,033	7,077	7,277	7,065	7,542	7,389
10	Cents /kWh	62.27	57.98	59.55	60.25	60.15	60.25
	Streetlights						
11	Sales (MWh)	142	101	101	101	101	101
12	Revenue (000s)	134	107	104	90	91	91
13	Cents /kWh	93.90	105.71	102.80	89.24	90.35	90.35
	Total						
14	**Sales (MWh)**	**17,006**	**17,937**	**17,894**	**17,427**	**18,436**	**18,187**
15	Customers	1,204	*1,233*	1,243	1,288	1,304	1,321
16	Revenue (000s)	10,970	10,719	10,978	10,772	11,366	11,232
17	Cents /kWh	64.51	59.76	61.35	61.81	61.65	61.76
	GENERATION (MWh)						
18	**Total Station Service**	618	674	606	616	661	668
19	**Station Service - % of Gen.**	3.4%	3.5%	3.2%	3.3%	3.3%	3.4%
20	**Losses**	757	634	625	666	743	741
21	**Losses - % of Gen.**	4.1%	3.3%	3.3%	3.6%	3.7%	3.8%
22	**Total Generation**	**18,382**	**19,246**	**19,125**	**18,709**	**19,840**	**19,595**
	Source						
23	Diesel Generation (MWh)	18,382	19,246	19,125	18,709	19,840	19,595
24	Diesel Efficiency (KWh/L)	3.77	3.69	3.68	3.65	3.68	3.68
25	Liters (000s)	4,876	5,220	5,203	5,130	5,391	5,325
	Peak						
26	Peak Load (KW)	3,278	3,317	3,437	3,757	3,596	3,553
27	Load Factor	64%	66%	64%	57%	63%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.2

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

602 Baker Lake

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	3,819	3,917	3,859	4,085	4,045	4,144
2	Customers	670	685	681	682	691	700
3	Av. MWh Sales/Cust.	5.70	5.72	5.67	5.99	5.85	5.92
4	Revenue (000s)	2,897	2,783	2,866	2,976	2,951	3,021
5	Cents/kWh	75.84	71.06	74.26	72.85	72.94	72.90
	Commercial						
6	Sales (MWh)	4,337	4,446	4,434	4,172	4,303	4,278
7	Customers	173	176	171	173	174	175
8	Av. MWh Sales/Cust.	25.08	25.30	25.87	24.11	24.70	24.40
9	Revenue (000s)	3,072	2,969	3,061	2,939	3,030	3,014
10	Cents /kWh	70.82	66.79	69.03	70.43	70.41	70.45
	Streetlights						
11	Sales (MWh)	111	111	113	113	113	113
12	Revenue (000s)	104	80	87	97	98	98
13	Cents /kWh	93.22	72.07	77.05	85.63	86.46	86.46
	Total						
14	**Sales (MWh)**	**8,268**	**8,473**	**8,406**	**8,371**	**8,461**	**8,535**
15	Customers	843	*860*	852	855	865	875
16	Revenue (000s)	6,072	5,833	6,014	6,011	6,078	6,133
17	Cents /kWh	73.44	68.83	71.54	71.82	71.84	71.85
	GENERATION (MWh)						
18	**Total Station Service**	235	233	225	235	233	235
19	**Station Service - % of Gen.**	2.6%	2.5%	2.5%	2.6%	2.5%	2.5%
20	**Losses**	396	604	472	364	507	513
21	**Losses - % of Gen.**	4.4%	6.5%	5.2%	4.1%	5.5%	5.5%
22	**Total Generation**	**8,898**	**9,310**	**9,104**	**8,969**	**9,201**	**9,282**
	Source						
23	Diesel Generation (MWh)	8,898	9,310	9,104	8,969	9,201	9,282
24	Diesel Efficiency (KWh/L)	3.88	3.85	3.86	3.87	3.87	3.87
25	Liters (000s)	2,293	2,420	2,360	2,316	2,378	2,399
	Peak						
26	Peak Load (KW)	1,981	2,061	1,992	2,079	2,080	2,108
27	Load Factor	51%	52%	52%	49%	51%	50%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.3

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

603 Arviat

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	3,884	3,900	3,840	4,148	4,185	4,305
2	Customers	688	673	683	697	713	729
3	Av. MWh Sales/Cust.	5.65	5.79	5.62	5.95	5.87	5.91
4	Revenue (000s)	3,179	3,131	3,175	3,546	3,446	3,544
5	Cents/kWh	81.87	80.27	82.68	85.50	82.36	82.33
	Commercial						
6	Sales (MWh)	4,852	4,790	4,459	4,228	4,625	4,499
7	Customers	146	145	146	149	150	152
8	Av. MWh Sales/Cust.	33.25	33.09	30.63	28.42	30.76	29.59
9	Revenue (000s)	3,631	3,521	3,462	3,247	3,541	3,450
10	Cents /kWh	74.83	73.51	77.65	76.81	76.57	76.68
	Streetlights						
11	Sales (MWh)	95	95	115	115	115	115
12	Revenue (000s)	92	72	80	90	90	90
13	Cents /kWh	96.88	75.72	69.99	78.35	78.46	78.46
	Total						
14	**Sales (MWh)**	**8,830**	**8,784**	**8,414**	**8,491**	**8,925**	**8,919**
15	Customers	834	*818*	829	846	863	881
16	Revenue (000s)	6,902	6,723	6,718	6,884	7,078	7,084
17	Cents /kWh	78.16	76.53	79.84	81.08	79.31	79.43
	GENERATION (MWh)						
18	**Total Station Service**	221	189	186	238	213	209
19	**Station Service - % of Gen.**	2.4%	2.1%	2.0%	2.6%	2.3%	2.2%
20	**Losses**	235	202	495	374	246	239
21	**Losses - % of Gen.**	2.5%	2.2%	5.4%	4.1%	2.6%	2.6%
22	**Total Generation**	**9,286**	**9,176**	**9,096**	**9,103**	**9,385**	**9,367**
	Source						
23	Diesel Generation (MWh)	9,286	9,176	9,096	9,103	9,385	9,367
24	Diesel Efficiency (KWh/L)	3.66	3.70	3.81	3.74	3.77	3.77
25	Liters (000s)	2,537	2,483	2,385	2,431	2,489	2,485
	Peak						
26	Peak Load (KW)	1,793	1,777	1,640	1,712	1,774	1,766
27	Load Factor	59%	59%	63%	61%	60%	61%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.4

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

604 Coral Harbour

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,495	1,440	1,465	1,524	1,518	1,561
2	Customers	270	261	260	264	269	274
3	Av. MWh Sales/Cust.	5.53	5.52	5.63	5.76	5.64	5.70
4	Revenue (000s)	1,398	1,386	1,446	1,502	1,503	1,546
5	Cents/kWh	93.46	96.28	98.71	98.58	99.07	99.03
	Commercial						
6	Sales (MWh)	1,866	1,820	1,951	1,877	1,858	1,892
7	Customers	82	80	80	80	80	81
8	Av. MWh Sales/Cust.	22.81	22.68	24.29	23.56	23.12	23.34
9	Revenue (000s)	1,578	1,614	1,768	1,702	1,686	1,717
10	Cents /kWh	84.58	88.66	90.62	90.70	90.76	90.72
	Streetlights						
11	Sales (MWh)	51	51	55	55	55	55
12	Revenue (000s)	64	66	71	70	69	69
13	Cents /kWh	125.50	129.86	128.30	127.13	124.67	124.67
	Total						
14	**Sales (MWh)**	**3,413**	**3,311**	**3,471**	**3,456**	**3,431**	**3,509**
15	Customers	352	*341*	340	344	349	355
16	Revenue (000s)	3,040	3,066	3,285	3,275	3,259	3,332
17	Cents /kWh	89.09	92.61	94.63	94.76	94.98	94.95
	GENERATION (MWh)						
18	**Total Station Service**	148	147	135	136	136	138
19	**Station Service - % of Gen.**	4.1%	4.1%	3.7%	3.6%	3.7%	3.7%
20	**Losses**	97	151	75	145	103	118
21	**Losses - % of Gen.**	2.7%	4.2%	2.0%	3.9%	2.8%	3.1%
22	**Total Generation**	**3,658**	**3,609**	**3,682**	**3,737**	**3,670**	**3,765**
	Source						
23	Diesel Generation (MWh)	3,658	3,609	3,682	3,737	3,670	3,765
24	Diesel Efficiency (KWh/L)	3.39	3.46	3.56	3.60	3.56	3.56
25	Liters (000s)	1,079	1,042	1,033	1,039	1,031	1,057
	Peak						
26	Peak Load (KW)	727	882	829	837	813	846
27	Load Factor	57%	47%	51%	51%	52%	51%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.5

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

605 Chesterfield Inlet

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	724	789	754	762	793	791
2	Customers	130	132	135	135	137	138
3	Av. MWh Sales/Cust.	5.58	5.97	5.58	5.64	5.80	5.72
4	Revenue (000s)	692	733	770	777	809	807
5	Cents/kWh	95.59	92.84	102.21	102.06	102.03	102.09
	Commercial						
6	Sales (MWh)	1,184	1,237	1,258	1,233	1,230	1,242
7	Customers	57	63	62	62	63	63
8	Av. MWh Sales/Cust.	20.60	19.51	20.42	19.84	19.67	19.76
9	Revenue (000s)	1,043	1,193	1,217	1,171	1,177	1,188
10	Cents /kWh	88.09	96.43	96.73	94.98	95.69	95.66
	Streetlights						
11	Sales (MWh)	26	26	26	26	26	26
12	Revenue (000s)	34	35	36	36	36	36
13	Cents /kWh	127.72	132.14	136.29	136.29	136.30	136.30
	Total						
14	**Sales (MWh)**	**1,934**	**2,053**	**2,038**	**2,021**	**2,049**	**2,059**
15	Customers	187	*196*	197	197	199	201
16	Revenue (000s)	1,769	1,961	2,023	1,985	2,022	2,031
17	Cents /kWh	91.44	95.51	99.27	98.19	98.67	98.65
	GENERATION (MWh)						
18	**Total Station Service**	79	73	106	116	86	88
19	**Station Service - % of Gen.**	3.8%	3.4%	4.6%	5.2%	3.9%	3.9%
20	**Losses**	73	49	150	75	77	72
21	**Losses - % of Gen.**	3.5%	2.2%	6.5%	3.4%	3.5%	3.2%
22	**Total Generation**	**2,086**	**2,174**	**2,294**	**2,213**	**2,213**	**2,219**
	Source						
23	Diesel Generation (MWh)	2,086	2,174	2,294	2,213	2,213	2,219
24	Diesel Efficiency (KWh/L)	3.46	3.43	3.72	3.80	3.72	3.72
25	Liters (000s)	603	634	616	582	595	596
	Peak						
26	Peak Load (KW)	397	480	440	430	443	447
27	Load Factor	60%	52%	60%	59%	57%	57%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.6

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

606 Whale Cove

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	762	712	702	741	753	764
2	Customers	129	123	128	128	130	132
3	Av. MWh Sales/Cust.	5.92	5.79	5.50	5.78	5.78	5.78
4	Revenue (000s)	920	678	688	726	1,032	1,046
5	Cents/kWh	120.76	95.20	97.91	97.92	137.00	137.00
	Commercial						
6	Sales (MWh)	975	1,186	1,057	1,022	1,109	1,077
7	Customers	51	55	56	55	55	55
8	Av. MWh Sales/Cust.	19.04	21.60	19.05	18.72	20.16	19.44
9	Revenue (000s)	1,076	1,386	1,246	1,282	1,384	1,346
10	Cents /kWh	110.36	116.80	117.79	125.43	124.85	125.00
	Streetlights						
11	Sales (MWh)	33	33	43	43	43	43
12	Revenue (000s)	46	48	54	58	57	57
13	Cents /kWh	138.07	142.77	125.28	135.36	134.15	134.15
	Total						
14	**Sales (MWh)**	**1,771**	**1,932**	**1,802**	**1,806**	**1,905**	**1,883**
15	Customers	180	*178*	183	183	185	187
16	Revenue (000s)	2,043	2,111	1,987	2,066	2,473	2,450
17	Cents /kWh	115.36	109.29	110.23	114.37	129.86	130.07
	GENERATION (MWh)						
18	**Total Station Service**	136	131	127	135	143	141
19	**Station Service - % of Gen.**	7.0%	6.1%	6.3%	6.7%	6.7%	6.7%
20	**Losses**	53	68	94	64	78	84
21	**Losses - % of Gen.**	2.7%	3.2%	4.6%	3.2%	3.7%	4.0%
22	**Total Generation**	**1,960**	**2,130**	**2,023**	**2,005**	**2,126**	**2,108**
	Source						
23	Diesel Generation (MWh)	1,960	2,130	2,023	2,005	2,126	2,108
24	Diesel Efficiency (KWh/L)	3.69	3.63	3.64	3.29	3.58	3.58
25	Liters (000s)	531	587	556	609	594	589
	Peak						
26	Peak Load (KW)	402	396	369	379	406	400
27	Load Factor	56%	61%	63%	60%	60%	60%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.7

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

607 Naujaat

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,667	1,579	1,600	1,670	1,685	1,734
2	Customers	236	240	244	248	253	259
3	Av. MWh Sales/Cust.	7.07	6.57	6.56	6.75	6.66	6.70
4	Revenue (000s)	1,426	1,356	1,415	1,469	1,487	1,529
5	Cents/kWh	85.54	85.91	88.46	87.96	88.24	88.22
	Commercial						
6	Sales (MWh)	2,459	2,554	2,359	2,366	2,423	2,435
7	Customers	69	72	71	68	69	70
8	Av. MWh Sales/Cust.	35.52	35.48	33.04	34.58	35.03	34.80
9	Revenue (000s)	1,844	1,896	1,840	1,837	1,881	1,890
10	Cents /kWh	74.99	74.21	77.98	77.67	77.63	77.63
	Streetlights						
11	Sales (MWh)	31	31	45	45	45	45
12	Revenue (000s)	33	34	43	51	50	50
13	Cents /kWh	107.63	111.49	94.33	112.25	110.50	110.50
	Total						
14	**Sales (MWh)**	**4,157**	**4,164**	**4,005**	**4,081**	**4,153**	**4,213**
15	Customers	305	*312*	315	316	322	329
16	Revenue (000s)	3,303	3,286	3,298	3,357	3,417	3,469
17	Cents /kWh	79.46	78.92	82.35	82.27	82.29	82.34
	GENERATION (MWh)						
18	**Total Station Service**	77	121	109	118	93	97
19	**Station Service - % of Gen.**	1.7%	2.6%	2.4%	2.7%	2.1%	2.1%
20	**Losses**	157	352	380	233	231	263
21	**Losses - % of Gen.**	3.6%	7.6%	8.4%	5.3%	5.2%	5.8%
22	**Total Generation**	**4,391**	**4,637**	**4,493**	**4,432**	**4,477**	**4,573**
	Source						
23	Diesel Generation (MWh)	4,391	4,637	4,493	4,432	4,477	4,573
24	Diesel Efficiency (KWh/L)	3.76	3.70	3.64	3.56	3.66	3.66
25	Liters (000s)	1,168	1,254	1,234	1,243	1,223	1,249
	Peak						
26	Peak Load (KW)	885	794	813	843	826	830
27	Load Factor	57%	67%	63%	60%	62%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

700 Total of Qikiqtaaluk area

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	38,070	37,181	37,532	38,067	38,466	39,038
2	Customers	6,816	6,655	6,680	6,774	6,865	6,956
3	Av. MWh Sales/Cust.	5.59	5.59	5.62	5.62	5.60	5.61
4	Revenue (000s)	28,578	26,395	27,233	27,765	28,523	28,963
5	Cents/kWh	75.07	70.99	72.56	72.94	74.15	74.19
	Commercial						
6	Sales (MWh)	64,353	65,143	66,386	63,430	65,365	65,030
7	Customers	1,829	1,860	1,870	1,898	1,910	1,922
8	Av. MWh Sales/Cust.	35.19	35.03	35.51	33.42	34.22	33.83
9	Revenue (000s)	41,560	40,778	42,324	41,037	41,886	41,672
10	Cents /kWh	64.58	62.60	63.76	64.70	64.08	64.08
	Streetlights						
11	Sales (MWh)	1,107	866	887	902	902	902
12	Revenue (000s)	1,051	879	907	919	940	940
13	Cents /kWh	95.00	101.58	102.22	101.82	104.23	104.23
	Total						
14	**Sales (MWh)**	**103,529**	**103,190**	**104,805**	**102,400**	**104,733**	**104,970**
15	Customers	8,645	*8,515*	8,550	8,672	8,775	8,878
16	Revenue (000s)	71,190	68,052	70,465	69,720	71,350	71,576
17	Cents /kWh	68.76	65.95	67.23	68.09	68.13	68.19
	GENERATION (MWh)						
18	**Total Station Service**	**4,214**	**3,781**	**3,789**	**3,628**	**4,040**	**4,018**
19	**Station Service - % of Gen.**	3.7%	3.4%	3.4%	3.2%	3.5%	3.5%
20	**Total Losses**	**4,694**	**5,666**	**3,688**	**5,933**	**5,220**	**5,321**
21	**Losses - % of Gen.**	4.2%	5.0%	3.3%	5.3%	4.6%	4.7%
22	**Total Generation**	**112,437**	**112,637**	**112,282**	**111,961**	**113,994**	**114,310**
	Source						
23	Diesel Generation (MWh)	112,437	112,637	112,282	111,961	113,994	114,310
24	Diesel Efficiency (KWh/L)	3.81	3.82	3.79	3.77	3.82	3.83
25	Liters (000s)	29,508	29,511	29,658	29,682	29,807	29,884
	Peak						
26	Peak Load (KW)	20,500	19,949	20,440	19,557	20,378	20,434
27	Load Factor	63%	64%	63%	65%	64%	64%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.1

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

701 Iqaluit

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	18,665	17,501	17,956	17,914	18,155	18,411
2	Customers	3,551	3,398	3,405	3,475	3,523	3,572
3	Av. MWh Sales/Cust.	5.26	5.15	5.27	5.16	5.15	5.15
4	Revenue (000s)	12,437	10,693	11,208	11,423	11,393	11,553
5	Cents/kWh	66.63	61.10	62.42	63.77	62.75	62.75
	Commercial						
6	Sales (MWh)	37,981	36,712	37,898	36,263	37,057	37,042
7	Customers	787	789	802	803	808	814
8	Av. MWh Sales/Cust.	48.27	46.51	47.27	45.17	45.84	45.51
9	Revenue (000s)	21,150	18,607	19,634	19,124	19,220	19,215
10	Cents /kWh	55.69	50.68	51.81	52.74	51.87	51.87
	Streetlights						
11	Sales (MWh)	419	178	178	178	178	178
12	Revenue (000s)	325	195	194	192	196	196
13	Cents /kWh	77.47	109.31	109.03	107.69	110.07	110.07
	Total						
14	**Sales (MWh)**	**57,065**	**54,391**	**56,031**	**54,356**	**55,390**	**55,631**
15	Customers	4,338	*4,187*	4,206	4,277	4,331	4,386
16	Revenue (000s)	33,912	29,494	31,036	30,739	30,809	30,964
17	Cents /kWh	59.43	54.23	55.39	56.55	55.62	55.66
	GENERATION (MWh)						
18	**Total Station Service**	2,326	2,071	2,041	1,906	2,153	2,152
19	**Station Service - % of Gen.**	3.8%	3.5%	3.5%	3.2%	3.6%	3.6%
20	**Losses**	2,066	2,880	959	2,969	2,326	2,398
21	**Losses - % of Gen.**	3.4%	4.9%	1.6%	5.0%	3.9%	4.0%
22	**Total Generation**	**61,456**	**59,342**	**59,031**	**59,231**	**59,869**	**60,181**
	Source						
23	Diesel Generation (MWh)	61,456	59,342	59,031	59,231	59,869	60,181
24	Diesel Efficiency (KWh/L)	3.98	4.02	3.96	3.94	3.99	3.99
25	Liters (000s)	15,441	14,759	14,902	15,017	15,005	15,083
	Peak						
26	Peak Load (KW)	10,259	9,600	10,087	9,671	9,864	9,940
27	Load Factor	68%	71%	67%	70%	69%	69%

Note: Revenues do not include fuel rider revenues/refunds.
1. Revenues do not include fuel rider revenues.
2. The actual losses for 2010/11 are low due to major billing error adjustments in Iqaluit.

Schedule A-3.2

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

702 Pangnirtung

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,547	2,583	2,543	2,584	2,614	2,645
2	Customers	484	473	476	473	479	485
3	Av. MWh Sales/Cust.	5.26	5.46	5.34	5.46	5.46	5.46
4	Revenue (000s)	1,910	1,718	1,717	1,785	1,876	1,898
5	Cents/kWh	75.00	66.52	67.50	69.10	71.76	71.76
	Commercial						
6	Sales (MWh)	3,341	4,602	4,614	3,625	4,178	3,935
7	Customers	118	121	123	123	124	124
8	Av. MWh Sales/Cust.	28.30	38.11	37.59	29.51	33.81	31.66
9	Revenue (000s)	2,193	2,938	2,773	2,393	2,748	2,601
10	Cents /kWh	65.64	63.84	60.09	66.02	65.78	66.10
	Streetlights						
11	Sales (MWh)	141	141	143	143	143	143
12	Revenue (000s)	125	98	102	102	102	102
13	Cents /kWh	88.78	69.50	71.02	71.61	71.61	71.61
	Total						
14	**Sales (MWh)**	**6,029**	**7,326**	**7,300**	**6,352**	**6,935**	**6,723**
15	Customers	602	*594*	599	596	602	609
16	Revenue (000s)	4,229	4,754	4,591	4,281	4,726	4,602
17	Cents /kWh	70.14	64.89	62.89	67.40	68.15	68.45
	GENERATION (MWh)						
18	**Total Station Service**	299	222	234	265	311	293
19	**Station Service - % of Gen.**	4.6%	2.9%	3.0%	3.8%	4.2%	4.0%
20	**Losses**	139	167	165	381	214	217
21	**Losses - % of Gen.**	2.1%	2.2%	2.1%	5.4%	2.9%	3.0%
22	**Total Generation**	**6,467**	**7,715**	**7,699**	**6,998**	**7,460**	**7,233**
	Source						
23	Diesel Generation (MWh)	6,467	7,715	7,699	6,998	7,460	7,233
24	Diesel Efficiency (KWh/L)	3.57	3.81	3.64	3.24	3.66	3.66
25	Liters (000s)	1,811	2,024	2,116	2,162	2,038	1,976
	Peak						
26	Peak Load (KW)	1,262	1,210	1,300	1,220	1,283	1,222
27	Load Factor	58%	73%	68%	65%	66%	68%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.3

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

703 Kinngait

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,248	2,284	2,147	2,138	2,228	2,220
2	Customers	424	426	422	424	428	433
3	Av. MWh Sales/Cust.	5.30	5.36	5.09	5.05	5.20	5.12
4	Revenue (000s)	1,722	1,607	1,525	1,519	1,653	1,648
5	Cents/kWh	76.57	70.37	71.01	71.06	74.18	74.25
	Commercial						
6	Sales (MWh)	2,968	3,251	3,093	3,196	3,265	3,257
7	Customers	119	128	128	130	131	132
8	Av. MWh Sales/Cust.	24.93	25.36	24.11	24.57	24.97	24.77
9	Revenue (000s)	2,111	2,283	2,279	2,349	2,342	2,337
10	Cents /kWh	71.11	70.23	73.69	73.52	71.73	71.75
	Streetlights						
11	Sales (MWh)	76	76	75	75	75	75
12	Revenue (000s)	80	76	79	80	80	80
13	Cents /kWh	105.55	100.31	104.96	106.06	106.24	106.24
	Total						
14	**Sales (MWh)**	**5,292**	**5,610**	**5,315**	**5,408**	**5,568**	**5,552**
15	Customers	543	*555*	551	554	559	565
16	Revenue (000s)	3,912	3,966	3,883	3,948	4,075	4,065
17	Cents /kWh	73.92	70.70	73.05	73.00	73.18	73.22
	GENERATION (MWh)						
18	**Total Station Service**	169	174	207	200	176	175
19	**Station Service - % of Gen.**	3.0%	2.9%	3.4%	3.3%	2.9%	2.9%
20	**Losses**	262	305	540	365	351	358
21	**Losses - % of Gen.**	4.6%	5.0%	8.9%	6.1%	5.8%	5.9%
22	**Total Generation**	**5,724**	**6,090**	**6,061**	**5,974**	**6,096**	**6,086**
	Source						
23	Diesel Generation (MWh)	5,724	6,090	6,061	5,974	6,096	6,086
24	Diesel Efficiency (KWh/L)	3.34	3.33	3.59	3.63	3.57	3.57
25	Liters (000s)	1,714	1,830	1,690	1,646	1,708	1,705
	Peak						
26	Peak Load (KW)	1,479	1,362	1,108	1,053	1,340	1,290
27	Load Factor	44%	51%	62%	65%	52%	54%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.4

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

704 Resolute Bay

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	589	535	539	523	528	530
2	Customers	94	96	94	95	95	96
3	Av. MWh Sales/Cust.	6.26	5.56	5.76	5.53	5.55	5.54
4	Revenue (000s)	579	553	572	546	566	569
5	Cents/kWh	98.35	103.37	106.14	104.38	107.31	107.31
	Commercial						
6	Sales (MWh)	3,162	3,496	3,555	3,359	3,394	3,393
7	Customers	106	106	103	104	104	104
8	Av. MWh Sales/Cust.	29.80	32.93	34.54	32.45	32.69	32.57
9	Revenue (000s)	2,999	3,421	3,633	3,442	3,477	3,476
10	Cents /kWh	94.85	97.86	102.18	102.48	102.43	102.44
	Streetlights						
11	Sales (MWh)	40	40	48	48	48	48
12	Revenue (000s)	55	56	68	82	82	82
13	Cents /kWh	136.81	141.47	141.08	170.22	170.30	170.30
	Total						
14	**Sales (MWh)**	**3,791**	**4,070**	**4,142**	**3,930**	**3,970**	**3,972**
15	Customers	200	*202*	197	198	199	200
16	Revenue (000s)	3,633	4,030	4,273	4,070	4,125	4,127
17	Cents /kWh	95.83	99.01	103.15	103.57	103.91	103.92
	GENERATION (MWh)						
18	**Total Station Service**	337	342	303	244	331	325
19	**Station Service - % of Gen.**	7.5%	7.1%	6.5%	5.6%	7.2%	7.1%
20	**Losses**	384	376	209	181	298	291
21	**Losses - % of Gen.**	8.5%	7.8%	4.5%	4.2%	6.5%	6.3%
22	**Total Generation**	**4,511**	**4,787**	**4,654**	**4,356**	**4,600**	**4,588**
	Source						
23	Diesel Generation (MWh)	4,511	4,787	4,654	4,356	4,600	4,588
24	Diesel Efficiency (KWh/L)	3.62	3.68	3.70	3.69	3.69	3.69
25	Liters (000s)	1,246	1,300	1,256	1,181	1,247	1,243
	Peak						
26	Peak Load (KW)	817	846	851	808	832	830
27	Load Factor	63%	65%	62%	62%	63%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.5

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

705 Pond Inlet

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,650	2,783	2,861	2,911	2,919	2,983
2	Customers	434	428	429	436	443	450
3	Av. MWh Sales/Cust.	6.10	6.50	6.67	6.67	6.59	6.63
4	Revenue (000s)	2,480	2,519	2,682	2,731	2,901	2,964
5	Cents/kWh	93.60	90.51	93.75	93.84	99.37	99.35
	Commercial						
6	Sales (MWh)	3,380	3,527	3,669	3,333	3,632	3,523
7	Customers	115	114	116	125	126	127
8	Av. MWh Sales/Cust.	29.49	30.98	31.70	26.65	28.81	27.73
9	Revenue (000s)	2,740	2,953	3,177	2,871	3,123	3,034
10	Cents /kWh	81.06	83.74	86.59	86.14	85.99	86.11
	Streetlights						
11	Sales (MWh)	113	113	137	137	137	137
12	Revenue (000s)	120	121	125	125	130	130
13	Cents /kWh	105.55	106.60	90.77	90.91	94.36	94.36
	Total						
14	**Sales (MWh)**	**6,144**	**6,423**	**6,667**	**6,381**	**6,689**	**6,644**
15	Customers	549	*542*	545	561	569	577
16	Revenue (000s)	5,340	5,593	5,983	5,727	6,154	6,127
17	Cents /kWh	86.92	87.08	89.75	89.76	92.00	92.23
	GENERATION (MWh)						
18	**Total Station Service**	252	193	231	218	234	224
19	**Station Service - % of Gen.**	3.8%	2.9%	3.3%	3.2%	3.3%	3.2%
20	**Losses**	317	131	39	289	263	238
21	**Losses - % of Gen.**	4.7%	1.9%	0.6%	4.2%	3.7%	3.4%
22	**Total Generation**	**6,713**	**6,746**	**6,936**	**6,889**	**7,186**	**7,106**
	Source						
23	Diesel Generation (MWh)	6,713	6,746	6,936	6,889	7,186	7,106
24	Diesel Efficiency (KWh/L)	3.71	3.70	3.66	3.58	3.67	3.67
25	Liters (000s)	1,809	1,822	1,896	1,926	1,958	1,936
	Peak						
26	Peak Load (KW)	1,285	1,342	1,340	1,278	1,377	1,375
27	Load Factor	60%	57%	59%	62%	60%	59%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.6

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

706 Igloolik

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,762	2,875	2,886	2,938	2,998	3,034
2	Customers	449	450	451	465	472	479
3	Av. MWh Sales/Cust.	6.16	6.39	6.40	6.32	6.35	6.33
4	Revenue (000s)	1,911	1,834	1,875	1,892	1,951	1,976
5	Cents/kWh	69.19	63.79	64.97	64.42	65.10	65.11
	Commercial						
6	Sales (MWh)	3,702	3,547	3,533	3,422	3,557	3,528
7	Customers	131	131	131	134	135	136
8	Av. MWh Sales/Cust.	28.30	27.13	26.95	25.50	26.32	25.91
9	Revenue (000s)	2,314	2,145	2,143	2,045	2,125	2,110
10	Cents /kWh	62.52	60.49	60.66	59.78	59.75	59.79
	Streetlights						
11	Sales (MWh)	95	95	95	95	95	95
12	Revenue (000s)	86	67	69	67	67	67
13	Cents /kWh	90.04	70.43	72.21	70.66	70.26	70.26
	Total						
14	**Sales (MWh)**	**6,559**	**6,517**	**6,514**	**6,454**	**6,650**	**6,658**
15	Customers	579	*581*	582	599	607	615
16	Revenue (000s)	4,311	4,046	4,087	4,005	4,144	4,152
17	Cents /kWh	65.73	62.09	62.74	62.05	62.31	62.36
	GENERATION (MWh)						
18	**Total Station Service**	127	148	132	118	130	132
19	**Station Service - % of Gen.**	1.8%	2.1%	1.9%	1.7%	1.8%	1.9%
20	**Losses**	224	251	229	300	262	269
21	**Losses - % of Gen.**	3.2%	3.6%	3.3%	4.4%	3.7%	3.8%
22	**Total Generation**	**6,910**	**6,915**	**6,875**	**6,873**	**7,042**	**7,059**
	Source						
23	Diesel Generation (MWh)	6,910	6,915	6,875	6,873	7,042	7,059
24	Diesel Efficiency (KWh/L)	3.83	3.76	3.71	3.91	3.83	3.83
25	Liters (000s)	1,804	1,837	1,856	1,760	1,839	1,843
	Peak						
26	Peak Load (KW)	1,326	1,398	1,329	1,362	1,379	1,401
27	Load Factor	59%	56%	59%	58%	58%	58%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.7

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

707 Sanirajak

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,411	1,394	1,363	1,409	1,447	1,467
2	Customers	199	201	209	207	210	214
3	Av. MWh Sales/Cust.	7.09	6.94	6.52	6.82	6.88	6.85
4	Revenue (000s)	1,280	1,260	1,243	1,297	1,379	1,399
5	Cents/kWh	90.69	90.41	91.23	92.10	95.33	95.35
	Commercial						
6	Sales (MWh)	1,643	1,807	1,723	1,750	1,784	1,791
7	Customers	64	71	68	70	71	71
8	Av. MWh Sales/Cust.	25.55	25.49	25.30	24.97	25.23	25.10
9	Revenue (000s)	1,482	1,599	1,580	1,573	1,602	1,609
10	Cents /kWh	90.22	88.49	91.74	89.88	89.80	89.80
	Streetlights						
11	Sales (MWh)	42	42	37	37	37	37
12	Revenue (000s)	44	44	46	46	45	45
13	Cents /kWh	105.55	105.77	124.76	124.51	124.11	124.11
	Total						
14	**Sales (MWh)**	**3,096**	**3,243**	**3,122**	**3,195**	**3,268**	**3,295**
15	Customers	263	*272*	277	277	281	286
16	Revenue (000s)	2,806	2,903	2,869	2,916	3,027	3,053
17	Cents /kWh	90.64	89.54	91.91	91.26	92.63	92.65
	GENERATION (MWh)						
18	**Total Station Service**	262	223	252	284	257	261
19	**Station Service - % of Gen.**	7.6%	6.2%	7.3%	7.9%	7.1%	7.1%
20	**Losses**	84	115	101	126	106	104
21	**Losses - % of Gen.**	2.4%	3.2%	2.9%	3.5%	2.9%	2.8%
22	**Total Generation**	**3,441**	**3,581**	**3,475**	**3,605**	**3,631**	**3,659**
	Source						
23	Diesel Generation (MWh)	3,441	3,581	3,475	3,605	3,631	3,659
24	Diesel Efficiency (KWh/L)	3.63	3.62	3.66	3.49	3.62	3.62
25	Liters (000s)	948	989	948	1,033	1,003	1,011
	Peak						
26	Peak Load (KW)	682	796	880	709	769	782
27	Load Factor	58%	51%	45%	58%	54%	53%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.8

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

708 Qikiqtarjuaq

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,043	954	977	994	1,009	1,014
2	Customers	203	190	197	201	203	204
3	Av. MWh Sales/Cust.	5.13	5.01	4.97	4.94	4.98	4.96
4	Revenue (000s)	919	770	805	815	920	924
5	Cents/kWh	88.13	80.71	82.37	82.02	91.15	91.17
	Commercial						
6	Sales (MWh)	1,528	1,428	1,393	1,366	1,420	1,401
7	Customers	81	80	79	81	82	82
8	Av. MWh Sales/Cust.	18.82	17.95	17.57	16.78	17.36	17.07
9	Revenue (000s)	1,257	1,230	1,219	1,195	1,234	1,220
10	Cents /kWh	82.27	86.13	87.52	87.51	86.96	87.03
	Streetlights						
11	Sales (MWh)	32	32	32	32	32	32
12	Revenue (000s)	37	38	39	39	39	39
13	Cents /kWh	113.95	117.98	121.58	121.58	121.59	121.59
	Total						
14	**Sales (MWh)**	**2,603**	**2,415**	**2,402**	**2,392**	**2,461**	**2,448**
15	Customers	285	*270*	276	283	285	287
16	Revenue (000s)	2,213	2,039	2,063	2,050	2,194	2,183
17	Cents /kWh	85.01	84.42	85.88	85.69	89.13	89.20
	GENERATION (MWh)						
18	**Total Station Service**	93	50	42	42	74	76
19	**Station Service - % of Gen.**	3.2%	1.8%	1.6%	1.6%	2.7%	2.8%
20	**Losses**	172	249	225	210	194	209
21	**Losses - % of Gen.**	6.0%	9.2%	8.4%	8.0%	7.1%	7.7%
22	**Total Generation**	**2,867**	**2,714**	**2,668**	**2,645**	**2,729**	**2,734**
	Source						
23	Diesel Generation (MWh)	2,867	2,714	2,668	2,645	2,729	2,734
24	Diesel Efficiency (KWh/L)	3.50	3.54	3.60	3.55	3.57	3.57
25	Liters (000s)	819	766	741	745	764	766
	Peak						
26	Peak Load (KW)	520	484	510	489	497	498
27	Load Factor	63%	64%	60%	62%	63%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.9

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

709 Kimmirut

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	740	729	740	893	823	868
2	Customers	136	139	141	141	142	143
3	Av. MWh Sales/Cust.	5.46	5.25	5.24	6.32	5.79	6.06
4	Revenue (000s)	742	754	810	858	893	940
5	Cents/kWh	100.17	103.44	109.48	96.18	108.47	108.31
	Commercial						
6	Sales (MWh)	1,047	986	1,042	1,063	1,020	1,048
7	Customers	56	57	56	56	57	57
8	Av. MWh Sales/Cust.	18.86	17.19	18.47	18.84	18.02	18.43
9	Revenue (000s)	898	889	993	998	961	985
10	Cents /kWh	85.73	90.24	95.25	93.91	94.18	94.03
	Streetlights						
11	Sales (MWh)	33	33	32	32	32	32
12	Revenue (000s)	43	44	45	45	45	45
13	Cents /kWh	128.67	132.54	139.34	139.34	139.34	139.34
	Total						
14	**Sales (MWh)**	**1,820**	**1,747**	**1,815**	**1,988**	**1,876**	**1,948**
15	Customers	191	*196*	198	198	199	200
16	Revenue (000s)	1,682	1,687	1,848	1,902	1,899	1,971
17	Cents /kWh	92.38	96.55	101.84	95.67	101.23	101.15
	GENERATION (MWh)						
18	**Total Station Service**	61	55	84	53	62	64
19	**Station Service - % of Gen.**	3.0%	2.8%	4.1%	2.4%	3.0%	2.9%
20	**Losses**	140	135	146	157	156	164
21	**Losses - % of Gen.**	6.9%	7.0%	7.1%	7.1%	7.4%	7.5%
22	**Total Generation**	**2,022**	**1,937**	**2,044**	**2,198**	**2,094**	**2,176**
	Source						
23	Diesel Generation (MWh)	2,022	1,937	2,044	2,198	2,094	2,176
24	Diesel Efficiency (KWh/L)	3.52	3.61	3.67	3.69	3.67	3.67
25	Liters (000s)	574	537	557	596	571	593
	Peak						
26	Peak Load (KW)	396	371	386	381	393	406
27	Load Factor	58%	60%	60%	66%	61%	61%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.10

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

710 Arctic Bay

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,533	1,443	1,441	1,481	1,485	1,504
2	Customers	238	240	243	244	246	248
3	Av. MWh Sales/Cust.	6.44	6.00	5.93	6.08	6.04	6.06
4	Revenue (000s)	1,348	1,287	1,365	1,353	1,360	1,377
5	Cents/kWh	87.93	89.20	94.72	91.38	91.57	91.56
	Commercial						
6	Sales (MWh)	1,434	1,552	1,589	1,588	1,625	1,618
7	Customers	62	65	65	69	69	69
8	Av. MWh Sales/Cust.	23.30	24.03	24.54	23.19	23.61	23.40
9	Revenue (000s)	1,121	1,244	1,314	1,308	1,337	1,332
10	Cents /kWh	78.17	80.19	82.67	82.38	82.30	82.32
	Streetlights						
11	Sales (MWh)	34	34	34	34	34	34
12	Revenue (000s)	39	40	41	41	41	41
13	Cents /kWh	114.59	118.65	122.27	122.27	122.27	122.27
	Total						
14	**Sales (MWh)**	**3,001**	**3,029**	**3,064**	**3,103**	**3,144**	**3,156**
15	Customers	300	*305*	308	312	315	317
16	Revenue (000s)	2,508	2,572	2,720	2,703	2,739	2,751
17	Cents /kWh	83.57	84.91	88.77	87.11	87.11	87.15
	GENERATION (MWh)						
18	**Total Station Service**	80	85	81	79	87	88
19	**Station Service - % of Gen.**	2.4%	2.6%	2.4%	2.3%	2.5%	2.5%
20	**Losses**	250	216	213	223	255	256
21	**Losses - % of Gen.**	7.5%	6.5%	6.3%	6.5%	7.3%	7.3%
22	**Total Generation**	**3,331**	**3,330**	**3,358**	**3,405**	**3,486**	**3,500**
	Source						
23	Diesel Generation (MWh)	3,331	3,330	3,358	3,405	3,486	3,500
24	Diesel Efficiency (KWh/L)	3.58	2.97	3.39	3.42	3.34	3.34
25	Liters (000s)	930	1,121	990	996	1,044	1,048
	Peak						
26	Peak Load (KW)	689	676	697	674	707	708
27	Load Factor	55%	56%	55%	58%	56%	56%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.11

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

711 Clyde River

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,858	1,890	1,871	1,955	1,938	1,987
2	Customers	292	286	284	283	287	291
3	Av. MWh Sales/Cust.	6.36	6.60	6.59	6.90	6.75	6.83
4	Revenue (000s)	1,506	1,504	1,507	1,532	1,575	1,614
5	Cents/kWh	81.03	79.56	80.53	78.34	81.27	81.23
	Commercial						
6	Sales (MWh)	1,625	1,617	1,672	1,795	1,756	1,793
7	Customers	69	66	67	69	69	70
8	Av. MWh Sales/Cust.	23.50	24.54	25.14	26.01	25.27	25.64
9	Revenue (000s)	1,156	1,138	1,205	1,292	1,265	1,291
10	Cents /kWh	71.14	70.35	72.07	71.98	72.08	72.01
	Streetlights						
11	Sales (MWh)	25	25	19	19	19	19
12	Revenue (000s)	34	35	32	21	29	29
13	Cents /kWh	134.43	139.04	172.03	110.78	156.85	156.85
	Total						
14	**Sales (MWh)**	**3,509**	**3,533**	**3,562**	**3,769**	**3,713**	**3,798**
15	Customers	361	*352*	351	352	357	361
16	Revenue (000s)	2,697	2,677	2,744	2,844	2,870	2,934
17	Cents /kWh	76.84	75.77	77.04	75.47	77.30	77.25
	GENERATION (MWh)						
18	**Total Station Service**	90	69	71	87	90	90
19	**Station Service - % of Gen.**	2.3%	1.7%	1.7%	2.1%	2.1%	2.1%
20	**Losses**	321	412	491	336	398	404
21	**Losses - % of Gen.**	8.2%	10.3%	11.9%	8.0%	9.5%	9.4%
22	**Total Generation**	**3,920**	**4,014**	**4,124**	**4,192**	**4,200**	**4,293**
	Source						
23	Diesel Generation (MWh)	3,920	4,014	4,124	4,192	4,200	4,293
24	Diesel Efficiency (KWh/L)	3.74	3.96	3.62	3.69	3.81	3.81
25	Liters (000s)	1,048	1,015	1,140	1,137	1,102	1,127
	Peak						
26	Peak Load (KW)	808	804	840	800	845	857
27	Load Factor	55%	57%	56%	60%	57%	57%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.12

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

712 Grise Fiord

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	316	348	337	320	330	328
2	Customers	61	67	66	65	65	65
3	Av. MWh Sales/Cust.	5.17	5.18	5.10	4.96	5.07	5.02
4	Revenue (000s)	318	331	334	313	364	363
5	Cents/kWh	100.88	95.27	99.15	97.60	110.52	110.56
	Commercial						
6	Sales (MWh)	676	809	752	762	807	788
7	Customers	42	46	47	48	48	48
8	Av. MWh Sales/Cust.	16.25	17.64	15.92	15.87	16.76	16.31
9	Revenue (000s)	679	874	845	878	901	881
10	Cents /kWh	100.38	108.09	112.28	115.23	111.62	111.73
	Streetlights						
11	Sales (MWh)	23	23	23	23	23	23
12	Revenue (000s)	31	32	33	44	48	48
13	Cents /kWh	131.89	136.41	140.73	188.66	204.82	204.82
	Total						
14	**Sales (MWh)**	**1,015**	**1,180**	**1,113**	**1,105**	**1,160**	**1,140**
15	Customers	103	*113*	113	113	113	114
16	Revenue (000s)	1,028	1,237	1,212	1,234	1,313	1,291
17	Cents /kWh	101.26	104.87	108.90	111.66	113.17	113.29
	GENERATION (MWh)						
18	**Total Station Service**	36	82	51	67	57	58
19	**Station Service - % of Gen.**	3.0%	5.7%	3.9%	5.3%	4.2%	4.3%
20	**Losses**	142	165	146	97	149	148
21	**Losses - % of Gen.**	11.9%	11.6%	11.1%	7.6%	10.9%	11.0%
22	**Total Generation**	**1,193**	**1,427**	**1,310**	**1,270**	**1,366**	**1,347**
	Source						
23	Diesel Generation (MWh)	1,193	1,427	1,310	1,270	1,366	1,347
24	Diesel Efficiency (KWh/L)	3.56	3.21	3.10	3.36	3.27	3.27
25	Liters (000s)	335	445	423	378	418	412
	Peak						
26	Peak Load (KW)	214	265	259	240	247	248
27	Load Factor	64%	61%	58%	60%	63%	62%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.13

Qulliq Energy Corporation
2022/23 General Rate Application
Summary of Generation, Sales, and Revenue

713 Saniqiluaq

Line no.	Description	2018/19 GRA Forecast	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Forecast	2022/23 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,706	1,863	1,872	2,009	1,991	2,046
2	Customers	249	260	264	267	271	275
3	Av. MWh Sales/Cust.	6.84	7.17	7.09	7.53	7.35	7.44
4	Revenue (000s)	1,425	1,566	1,592	1,699	1,691	1,737
5	Cents/kWh	83.54	84.06	85.02	84.57	84.93	84.90
	Commercial						
6	Sales (MWh)	1,865	1,810	1,854	1,909	1,870	1,911
7	Customers	80	87	85	86	87	87
8	Av. MWh Sales/Cust.	23.28	20.93	21.85	22.16	21.54	21.85
9	Revenue (000s)	1,460	1,455	1,530	1,567	1,550	1,582
10	Cents /kWh	78.26	80.39	82.56	82.10	82.86	82.78
	Streetlights						
11	Sales (MWh)	33	33	33	48	48	48
12	Revenue (000s)	35	33	34	34	35	35
13	Cents /kWh	105.55	100.93	103.91	71.57	73.20	73.20
	Total						
14	**Sales (MWh)**	**3,604**	**3,706**	**3,759**	**3,966**	**3,909**	**4,005**
15	Customers	330	*346*	349	353	358	362
16	Revenue (000s)	2,920	3,054	3,157	3,300	3,276	3,354
17	Cents /kWh	81.01	82.42	83.97	83.22	83.80	83.75
	GENERATION (MWh)						
18	**Total Station Service**	83	67	61	62	78	79
19	**Station Service - % of Gen.**	2.1%	1.7%	1.5%	1.4%	1.9%	1.8%
20	**Losses**	193	266	227	298	248	263
21	**Losses - % of Gen.**	5.0%	6.6%	5.6%	6.9%	5.9%	6.1%
22	**Total Generation**	**3,881**	**4,039**	**4,047**	**4,326**	**4,236**	**4,348**
	Source						
23	Diesel Generation (MWh)	3,881	4,039	4,047	4,326	4,236	4,348
24	Diesel Efficiency (KWh/L)	3.78	3.79	3.54	3.91	3.81	3.81
25	Liters (000s)	1,027	1,066	1,142	1,107	1,112	1,141
	Peak						
26	Peak Load (KW)	762	795	853	872	845	877
27	Load Factor	58%	58%	54%	57%	57%	57%

Note: Revenues do not include fuel rider revenues/refunds.

APPENDIX B
CAPITAL ADDITIONS

TABLE OF CONTENTS

B1.0 INTRODUCTION

Appendix B summarizes actual capital spending for 2018/19-2020/21 and forecast spending for 2021/22-2022/23. This appendix also provides details for projects over $400,000 including those projects with major project permits approved by the Minister.

B2.0 ACTUAL CAPITAL PROJECTS OVER $400,000 IN 2018/19

The following section summarizes capital additions over $400,000 in 2018/19. Schedule B-1 shows the total capital additions in 2018/19 for projects greater than $100,000.

Nunavut Satellite Hub Upgrade $433,000

This project was undertaken to replace the satellite dish in Iqaluit. QEC has four satellite dishes the provide reliable communications and internet services to Iqaluit, Baker Lake

Rankin Inlet and Cambridge Bay. The dish in Iqaluit has reached the end of it's life and the vendor was unable to provide parts and servicing. The new dish has increased communication speeds and reliability. By replacing the old dish, QEC has reduced the risk of hardware failure and service interruption.

Cambridge Bay Tower Site Upgrade $760,000

This project was undertaken to improve reliability, safety, and quality of services in the community. The tower site in Cambridge Bay provides essential communication services to the community, such as the Government of Nunavut email services and Coast Guard VHF radio. The pole line that provides power to the site was in substandard condition and in need of replacement. The poles were old and dry rotting. The dry rot problem can potentially lead to poles splitting, cracking, and falling in the event of high winds. Dry rot also poses safety issues for line crews climbing poles. The primary conductor and hardware were aged and beyond the end of its life. The project has addressed the deficiencies and has improved reliability and service quality.

Cambridge Bay New Subdivision Phase 1 and 2 $582,000

This Recoverable Project was initiated through a contract with the Hamlet of Cambridge of which they were accountable for the project costs. The project which was completed in 2 phases was undertaken to construct a distribution line to a new subdivision. The work consisted of the installation of new poles, streetlights and associated hardware. The upgrade was completed and the new subdivision has its required supply of power.

Kinngait New Power Plant $27,268,000

This project was undertaken to improve reliability and quality of service in the community. Originally constructed in 1964, the old Kinngait (Cape Dorset) Power Plant has since undergone two facility additions to accommodate growth and modifications to the plant. The first of these additions was made in 1973 while the second followed in 1992. The facility systems were outdated and not up to current standards and codes. The plant had an unstable foundation and deteriorating superstructure and was in immediate need of replacement. Equally important, there were issues with reliability as the plant did not meet QEC’s required firm capacity planning criteria. This project has improved reliability and service quality to the customers and community.

Grise Fiord New Power Plant $18,839,000

This project was undertaken to improve reliability and quality of service in the community. The old Grise Fiord power plant was constructed in 1963 and had numerous problems in regard to its civil, mechanical, and electrical systems. It suffered from several deficiencies, including failing building foundation, unreliable superstructure and aging systems and equipment. The Grise Fiord facility was pass its service life and requires replacement. This was a partial closeout, where the plant was substantial completed and in service the current expenses were capitalized. There is still some minor outstanding work that has been delayed due to seasonal timing and contractor /material delays. These work will be capitalized upon their completion.

Grise Fiord Distribution System Upgrade $671,000

This project was undertaken to improve reliability, ensure safety, and quality of service in the community. This project involved the conversion of the current 600volt substandard overhead distribution system to 4,160 volts (5kV class) to alleviate customer power quality problems associated with load growth and voltage drop. The existing overhead distribution system operated in the low voltage class of 600 volts and was configured as an ungrounded delta connected system. The ungrounded system was difficult to maintain and created voltage stability issues when lightly loaded. The system also distributed voltage from the same plant with no system isolation, making it difficult to regulate voltage over peak load periods without substation transformer tap changers. This project has improved reliability and service quality.

B3.0 ACTUAL CAPITAL PROJECTS OVER $400,000 IN 2019/20

The following section summarizes actual capital additions over $400,000 in 2019/20. Schedule B-3 shows the total capital additions for 2019/20 for projects greater than $100,000.

Rankin Inlet **Genset Replacement G3** **$3,796,000**

This project was undertaken to replace the 950 kW genset G3 which consisted of a Cat. D 3516 engine. The unit was install in 1993 and has exceeded its expected operational life. The Cat. D3516 was replace with a MTU 16V4000 which has the same rating of 950 kW. QEC received AEF funding for this project.

Coral Harbour **Genset Replacement G1** **$3,737,000**

This project was undertaken to replace the 500 kW genset G1 which consisted of a Cat. D 3508 engine. The unit was install in 1994 and has exceeded its expected operational life. The Cat. D3508 was replace with a MTU 12V4000 which has the rating of 720 kW. By installing a genset with a larger output, it addresses the current and future load requirements. QEC received AEF funding for this project.

Chesterfield Inlet **Genset Replacement G3** **$1,767,000**

This project was undertaken to replace the 400 kW genset G3 which consisted of a Cat. D 379 engine. The unit was install in 1985 and has exceeded its expected operational life. The Cat. D379 was replace with a Volvo TwD1643GE which has the rating of 400 kW. QEC received AEF funding for this project.

Iqaluit **Bulk Fuel Tank Upgrade** **$4,946,000**

This project is being undertaken to improve environmental conditions and provide safe service in the community. The existing five million litre tank has been in service for approximately 23 years since it was last refurbished in 1994. This project involves constructing a second 5.7 million litre fuel holding tank and upgrading this tank's fuel containment berm at the power plant in Iqaluit. This was required to be installed and in service to maintain a fuel supply to plant before the existing tank can be taken out of service for inspection and reconditioning. In addition, the new tank will also increase storage capacity for the Iqaluit plant. By having a two tank configuration it ensures the plant has an adequate fuel supply in situations where one of the tanks has to be taken out of service for maintenance. Also, it allows QEC to purchase more bulk fuel which is lower in price then nominated fuel.

Iqaluit **Fuel Supply Line Upgrade** **$1,471,000**

The project involved the replacement of 600 metres of existing single-walled fuel pipeline used for fuel deliveries to the Iqaluit plant. The existing pipeline was installed at least 40 years ago and is in poor condition. The existing pipeline runs aboveground and is located parallel to an existing roadway. Replacement of the existing fuel supply line will ensure a reliable fuel system for Iqaluit for the next 40 years.

Grise Fiord **Transient Unit** **$452,000**

This project involved purchasing and installing a transient trailer at the Grise Fiord power plant. The transient was required to ensure contractor’s and/or maintenance personal has accommodations when on site for maintenance, repairs and upgrades. Grise Fiord has very limited accommodations within the community. If accommodations are not readily available it could delay maintenance, repair and responding to power outages.

B4.0 ACTUAL CAPITAL PROJECTS OVER $400,000 IN 2020/21

The following section summarizes actual capital additions over $400,000 in 2020/21. Schedule B-3 shows the total capital additions for 2020/21 for projects greater than $100,000.

Pond Inlet **Genset Replacement G1** **$2,707,000**

This project was undertaken to replace the 720 kW genset G1 which consisted of a Cat. D3512 engine. The unit was install in 1992 and has exceeded its expected operational life. The Cat. D3512 was replace with a MTU 12V4000 which has the rating of 720 kW. QEC received AEF funding for this project.

Igloolik **Distribution Line Conversion** **$629,000**

This Recoverable Project was initiated through a contract with Community and Government Services (C&GS) of which they were accountable for the project costs. The project was undertaken to convert the 1 phase overhead distribution line to 3 phase that runs from the community of Igloolik out to the water lake. The upgrade was required to address C&GS increased power needs.

B5.0 FORECAST CAPITAL PROJECTS OVER $400,000 FOR 2021/22

The following section summarizes forecast capital additions over $400,000 for 2021/22. Schedule B-5 shows the total capital additions in 2021/22 for projects greater than $100,000.

Nunavut **Line Hardware Storage Containers** **$460,000**

This project was undertaken to address the issue QEC was having with the control and management of inventory within the community. It has been identified that inadequate storage space affects inventory security, accounting and reconciliation. In most of the communities the line materials were stores outside and during the winter with snow cover the inventory was hard to access. With the funds from this project, QEC purchased 32 sea containers equipped with shelving and lighting and distributed them throughout Nunavut to each of the communities that required additional storage. Going forward QEC will have better control of its inventory and easier assess to the materials when conducting repairs and maintenance during winter months.

Gjoa Haven **Quonset Garage** **$500,000**

This project was undertaken to purchase and construct an insulated Quonset Garage to house the RBD Line Truck in Gjoa Haven. Without the said storage, repairs and maintenance is unmanageable in harsh conditions. The RBD line truck is an essential and critical component in power line maintenance and emergency repair. These vehicles need to be stored in a secure and controlled environment. The Quonset Garage will add years to the life of this very critical piece of equipment and will ensure the RBD will be ready and available for all distribution line maintenance and emergency services.

Gjoa Haven **Genset Replacement G4** **$3,640,000**

The existing Gjoa Haven Main Plant consisted of 3 diesel generators. The Plant was in great need of a capacity increase, but there is no sufficient space to replace an existing genset with a larger unit. The objective of this project was to add a Modular Unit to house a forth genset. The modular unit included a 550kW diesel generator, switchgear, LECP, fuel pump house and auxiliaries. The addition of the G4 modular unit will address current and future load demand as well as improve power supply continuity. The G4 was integrated into the existing system in the main plant while having independent fuel supply.

Whale Cove **Genset Replacement G2** **$2,567,000**

This project was undertaken to replace the 300 kW genset G2 which consisted of a Cat. D3412 engine. The unit was install in 1991 and has exceeded its expected operational life. The Cat. D3412 was replace with a Cat. C13 which has the same rating of 300 kW.

Whale Cove **Quonset Garage** **$561,000**

This project was undertaken to purchase and construct an insulated Quonset Garage to house the RBD Line Truck in Whale Cove. Without the said storage, repairs and maintenance become unmanageable in harsh conditions. The RBD line truck is an essential and critical component in power line maintenance and emergency repair. These vehicles need to be stored in a secure and controlled environment. The Quonset Garage will add years to the life of this very critical piece of equipment and will ensure the RBD will be ready and available for all distribution line maintenance and emergency services.

Iqaluit **Fire Pump System** **$1,111,000**

This project involved the procurement and installation of a self housed diesel operated fire pump that will supply a source of water to the Iqaluit main power plant wet fire suppression system. The existing water supply from the city is not sufficient to operate the Iqaluit power plant fire suppression system. The fire pump was connected to the adjacent city water reserve building by means of an underground piping. This system allows the power plant to be better protected from the spread of fires, limiting potential damages to QEC assets.

Cape Dorset **New Power Plant** **$897,000**

This project was undertaken to replaced Cape Dorset power plant which was constructed in the early 1970's. The plant was inadequate due to aging equipment's and the plant does not meet current and future energy requirements and regulations. The switch gear was not Arc resistant nor can it be modified which increased fire and safety risk. The new plant has a total installed capacity of 3,575 kWs, comprising of four gensets and a fuel storage system consisting of two 90 litre fuel tanks. This plant went into service in the spring of 2019 when there was a partial closeout with $27.3 million being posted to capital additions. This is the final closeout to cover expenses for miscellaneous outstanding work that was delayed due to material/contractor delays, seasonal alignment and COVID.

Resolute Bay **Feeder Conversion** **$1,564,000**

The distribution system in Resolute Bay consists of 2 feeders. The feeder supplying the town is a 12.5kV multi ground 4-wire Wye system, while the feeder supplying the airport area is a 2400V 3-wire delta system. The delta system is not recommended for use, as it is ungrounded. Such ungrounded delta system will cause over voltage and protection is not available in the distribution system. The vintage of the feeder is also becoming an issue. The project converted the existing 2400 Volt delta system supplying to a 12.4kV multi ground wye system. This also involve the replacement of aging poles and infrastructure, and the addition of storm guys to make the distribution lines more stable during extreme weather conditions. Approximately 3.5 km of underground primary feeder was converted to overhead distribution lines.

Resolute Bay **Feeder 4 Upgrade** **$626,000**

This project was undertaken to replace the existing feeder four with a new three phase with neutral distribution line between the plant and the hamlet. It was installed on the opposite site of the road on the existing feeder. The existing feeder was de-commissioned. The project was required to address the issues of the aged existing feeder that was at the end of its useful life. There were continuous trouble call and power interruptions to the community often for long periods due to having to wait for maintenance teams to be flown into Resolute Bay from the service hubs.

Pond Inlet	**Genset Replacement G4**	**$2,355,000**

This project was undertaken to replace the 550 kW genset G4 which consisted of a Guascor SF360TA engine. The unit was install in 2009 and while is only has 30,000 hours, it has proven to be very unreliable and QEC had major issue getting parts for servicing. The Guascor SF360TA was replace with a Cat. 3508C which has the same rating of 550 kW. QEC has secured AEF funding for this project.

Arctic Bay	**New Power Plant**	**$30,878,000**

This project was undertaken to improve reliability and quality of service in the community of Arctic Bay.

The existing power plant was constructed in 1974 and now exceeds its design life. The sytems are inadequate and outdated and does not meet current and future energy requirements and regulations. The switch gear was not Arc resistant nor can it be modified, which increased fire and safety risk. Also, the building structure itself is in poor condition and there is no room for expansion. The new plant consists of a four genset lineup with a total installed capacity of 1680 kWs. The plant is equipped with modern systems than generate much less sound and air pollution. This new plant with its new gensets and advanced controls is expected to improve the fuel efficiency and reliability. Its design will allow the integration of renewable energy sources.

Clyde River	**Genset Replacement G3**	**$2,900,000**

This project was undertaken to replace the 330 kW genset G3 which consisted of a Detroit Series 60 engine. The unit was install in 2006 and has approximately 17,000 of operational hours. The Series 60 engine is being replace with a Cat. 3508C with a ranging of 550kW. The replacement is required to address the need to meet the required firm capacity. The Series 60 will be reconditioned and placed in inventory to be ready for use for future genset replacements.   QEC has secured AEF funding for this project.

Grise Fiord Quonset Garage $559,000

This project was undertaken to purchase and construct an insulated Quonset Garage to house the RBD Line Truck in Grise Fiord. Without the said storage, repairs and maintenance become unmanageable in harsh conditions. The RBD line truck is an essential and critical component in power line maintenance and emergency repair. These vehicles need to be stored in a secure and controlled environment. A controlled environment for storage and maintenance will add years to the life of this very critical piece of equipment and will ensure the RBD will be ready and available for all distribution line maintenance and emergency services.

B6.0 FORECAST CAPITAL PROJECTS OVER $400,000 FOR 2022/23

The following section summarizes forecast capital additions over $400,000 for 2022/232. Schedule B-5 shows the total capital additions in 2022/23 for projects greater than $100,000.

Taloyoak Quonset Garage $643,000

This project is being undertaken to purchase and construct an insulated Quonset Garage to house the RBD Line Truck in Taloyoak. Without the said storage, repairs and maintenance become unmanageable in harsh conditions. The RBD line truck is an essential and critical component in power line maintenance and emergency repair. These vehicles need to be stored in a secure and controlled environment. A controlled environment for storage and maintenance will add years to the life of this very critical piece of equipment and will ensure the RBD will be ready and available for all distribution line maintenance and emergency services.

Kugluktuk Transient Unit Replacement $600,000

QEC owns and maintains a property which contains a 3 bedroom detached house currently being utilized as a transient. This house is approximately 40 years old and the structure is solid, but it has not had any significant maintenance or upgrades in over 20 years. The house urgently requires renovations. The project will upgrade this house to be more energy efficient and current to building standards and codes, returning it to an acceptable and secure living condition.

Rankin Inlet Station PLC & DC Upgrade $455,000

This project is being undertaken to replace the Plant PLC System with Controllogix platform, complete with required Inputs and output modules and to replace existing battery bank and charger with new system capable to allow maintenance to be performed on the batteries while the plant is in operation. The current station PLC system and battery bank system has become obsolete and parts are becoming harder to find and systems are expensive to maintain. Replacing these systems with new up to date technology will ensure no interruption and continuous power plant operation.

Baker Lake Automated Meter Reading (AMR) $1,000,000

This project is being undertaken to upgrade and automate its meter reading systems in Baker Lake. The system shall be capable of remotely reading meters without necessitating direct access to the meters by meter readers, but still be capable of taking local manual reads. QEC current Revenue meters in Baker Lake are manually read which is labour intensive and prone to inaccuracies. Adverse weather conditions in the winter months, result in increased number of accidents/incidents due to the meter reader staff difficulties in accessing the meters. Some meters aren't read for long periods of time due to these unsafe conditions resulting in estimated billing that results in over/under billing. QEC expects to address several key operational issues with the implementation of an AMR system such as: reducing accidents/Incidents related to manual meter reading activities; reduced meter reading costs; improved meter reading efficiency and accuracy; and reducing customer billing complaints.

Baker Lake Head Office Building $16,596,000

This project is being undertaken to construct a new 13,000 square foot commercial office building in Baker Lake. The Corporation’s business activities are served out of the head office located in Baker Lake and the corporate office in Iqaluit. QEC does not own a building in Baker Lake and head office functions operate out of leased office space. QEC currently leases three buildings in Baker Lake. The largest of the three is leased from the Government of Nunavut. QEC have been informed that this lease is to cancelled in the near future as they need to take possession of the office space for their own requirements. This leaving QEC without approximately 50% of the office space required in the community. Furthermore, the present situation does not allow for an efficient, unified and organized work environment. One of the leased units is a three-bedroom house, which was not constructed as an office building. Also QEC was facing the dilemma of Baker Lake lacking available office space. This project will resolve the office space issues as well as provide the lowest overall cost over the life of the project. A new building would increase QEC's operational efficiency as all Baker Lake staff can be accommodated in one building

Baker Lake 5-Plex Renovations $1,711,000

Building unit number 2145 is a 2 storey, multi-unit residential building facility, consisting of 3 x 2 bedroom and 2 x 1bedroom apartment units and owned and operated by QEC. The apartments are rented by QEC staff who work in the Baker Lake offices. The building has experienced a number of water leaks over the past number of year, resulting in mold growth in both interior and exterior wall, and ceilings. Mold is currently 'trapped' in the walls and ceilings and does not pose an immediate danger to residents. Ventilation systems within the suites do not exist, and those basic exhaust systems (washrooms, range, and dryers) were poorly installed and woefully inadequate. Windows do not have a good energy efficient rating. There is no secure tenant storage for larger items, with some being stored in the Mechanical Room. This project will complete interior and exterior renovations and enhancements to the residential building and remediate the mold issues found within the building. The project with address all the deficiencies and bring the building up to a safe and more energy efficient building.

Arviat	**Automated Meter Reading (AMR)**	**$700,000**

This project is being undertaken to upgrade and automate its meter reading systems in Arviat. The system shall be capable of remotely reading meters without necessitating direct access to the meters by meter readers, but still be capable of taking local manual reads. QEC current Revenue meters in Arviat are manually read which is labour intensive and prone to inaccuracies. Adverse weather conditions in the winter months, result in increased number of accidents/incidents due to the meter reader staff difficulties in accessing the meters. Some meters aren't read for long periods of time due to these unsafe conditions resulting in estimated billing that results in over/under billing. QEC expects to address several key operational issues with the implementation of an AMR system such as: reducing accidents/Incidents related to manual meter reading activities; reduced meter reading costs; improved meter reading efficiency and accuracy; and reducing customer billing complaints.

Whale Cove	**Substation Upgrade**	**$1,576,000**

This project is to replace the substation platform mounted transformer banks in Whale Cove with pad mount transformers on each of the feeders. The existing substation transformer banks are outdated and not in compliance with current standards. The substation transformers are a critical part of the distribution system in any community. When a failure occurs at this point an entire feeder will be lost. Such issues typically occur near peak loads or during bad weather which adds urgency to response times and/or prevents immediate emergency response. Upgrading and modernizing the system will increase reliability, reduce outages and increase safety to the line crew.

Naujaat **Feeder Upgrade F3** **$490,000**

Naujaat currently has two feeders and both feeders are nearing their load limits which increases the potential during peak load periods of feeder breaker tripping resulting in power outages. This project proposes to address this issue by installing a new feeder. Installing a new feeder (Feeder 3) will allow for a better distribution of load on each of the feeders which will reduce the risk of overloading. This project will greatly improve the reliability of the distribution system.

Cape Dorset **Transient House Upgrade** **$420,000**

QEC owns and maintains a property which contains a 3 bedroom detached house currently being utilized as a transient. This house is approximately 35 years old and the structure is solid, but it has not had any significant maintenance or upgrades in over 25 years. The house urgently requires renovations. The project will upgrade this house to be more energy efficient and current to building standards and codes, returning it to an acceptable and secure living condition.

Resolute Bay **Transient House Upgrade** **$607,000**

QEC owns and maintains a property which contains a 3 bedroom detached house currently being utilized as a transient. This house is approximately 40 years old and the structure is solid, but it has not had any significant maintenance or upgrades in over 20 years. The house urgently requires renovations. The project will upgrade this house to be more energy efficient and current to building standards and codes, returning it to an acceptable and secure living condition.

Resolute Bay **Quonset Garage** **$667,000**

This project is to be undertaken to purchase and construct an insulated Quonset Garage to house the RBD Line Truck in Resolute Bay. Without the said storage, repairs and maintenance become unmanageable in harsh conditions. The RBD line truck is an essential and critical component in power line maintenance and emergency repair. These vehicles need to be stored in a secure and controlled environment. A controlled environment for storage and maintenance will add years to the life of this very critical piece of equipment and will ensure the RBD will be ready and available for all distribution line maintenance and emergency services.

Igloolik **Feeder Upgrade F1, F2 & F3** **$1,500,000**

This project is to be undertaken to upgrade the distribution feeder system in Igloolik. Most of the system is outdated and beyond its useful life. It is estimated that 70% of the conductors, wires and poles need replacing. The old conductors and #2 wire are no longer up to standard and many of the poles are old and dilapidated. This project will improve the reliability of power to the community by reducing outages which equates to less emergency maintenance for the line crew. Also, safety to the public and QEC line crew is greatly improved.

Sanirajak **Feeder Upgrade F1, F2 & F3** **$1,375,000**

This project is to be undertaken to upgrade the distribution feeder system in Sanirajak. Most of the system is outdated and beyond its useful life. It is estimated that 70% of the conductors, wires and poles need replacing. The old conductors and #2 wire are no longer up to standard and many of the poles are old and dilapidated. This project will improve the reliability of power to the community by reducing outages which equates to less emergency maintenance for the line crew. Also, safety to the public and QEC line crew is greatly improved.

Sanirajak **Substation Upgrade** **$1,532,000**

This project is to replace the substation platform mounted transformer banks in Sanirajak with pad mount transformers on each of the feeders. The existing substation transformer banks are outdated and not in compliance with current standards. The substation transformers are a critical part of the distribution system in any community. When a failure occurs at this point an entire feeder will be lost. Such issues typically occur near peak loads or during bad weather which adds urgency to response times and/or prevents immediate emergency response. Upgrading and modernizing the system will increase reliability, reduce outages and increase safety to the line crew.

Qikitarjuaq **Plant Yard Fencing** **$400,000**

This project is being undertaken to purchase and install a chain link fence to enclose the power plant in Qikiqtarjuaq. The power plant is located within the community and at times children and young teens gather on the power plant property. There is a potential if someone became in contact with the electrical equipment it could cause serious bodily harm and possibly death. Also, there are some inventory that is stored outside the plant in a non-secure area. The installation of a fence will secure the inventory and at the same time provide community safety, vandalism and reduce the corporation's liability.

Arctic Bay **Transient Unit Replacement** **$850,000**

This project is being undertaken to purchase and install a new transient unit at the new power plant in Arctic Bay. A transient unit is required to ensure QEC staff and other contractors have suitable accommodations when staying at Arctic Bay to conduct repairs and/or maintenance to QEC infrastructures. The new transient, will be a self-contained modular unit will be manufactured remotely and shipped and installed by the new power plant in Arctic Bay. The unit will have all facilities necessary for day to day living including: kitchen, washroom, laundry, beds and small living area. The old Transient unit was purchased in early 1970 and does not comply to current standards, and has deteriorated to a level which precludes salvage. It will be flagged for decommissioning and disposal when the new unit is commissioned.

Clyde River **Genset Replacement G2** **$2,747,000**

This project was undertaken to replace the 480 kW genset G2 which consisted of a Cat. D 3508 engine. The unit was install in 1994 and has exceeded its expected operational life. The Cat. D3508 was replace with a Cat. 3508C which has the rating of 550 kW. QEC has secured AEF funding for this project.

Grise Fiord **New Power Plant** **$1,222,000**

This project was undertaken to improve reliability and quality of service in the community. The old Grise Fiord power plant was constructed in 1963 and had numerous problems in regard to its civil, mechanical, and electrical systems. It suffered from several deficiencies, including failing building foundation, unreliable superstructure and aging systems and equipment. The Grise Fiord facility was pass its service life and requires replacement. The plant was substantial completed in 2018-19 at which time $18.8 million was the expenses were capitalized. There is still some minor outstanding work that has been delayed due to seasonal timing and contractor /material delays. This work has now been completed and this represents the remainder of the cost to be capitalized to finalize the project.

Sanikiluaq Transformer Replacement $1,223,000

This project is being undertaken to install the new step up transformers within the distribution system in Sanikiluaq. Presently, there are two step up transformer banks feeding the feeders in the community. One of these transformer banks has become problematic, it is of substandard design and in the past year there has been several powers outage related to this issue. This project intends to replace this problematic transformer bank with a new pad mounted transformer bank that meets current standards. This upgrade will increase reliability, reduce outages and increase safety to the line crew.

Schedule B-1

QULLIQ ENERGY CORPORATION
2022/23 GENERAL RATE APPLICATION
ACTUAL CAPITAL ADDITIONS FOR 2018/19
(in thousands of dollars)

Plant #	Plant Name	Description	2018/19 Additions ($000)				
			Generation	Distribution	General Plant	Total Project	Total for Plant
400	Nunavut	IT Server Replacements			174,648	174,648	
		Satellite Hub Upgrade			432,833	432,833	
							607,481
501	Cambridge Bay	Tower Site Upgrade		759,981		759,981	
		Provide power to CHARS in Cambridge Bay		341,741		341,741	
		New subdivision phase 1&2 Cambridge Bay		582,103		582,103	
		Plant Structural Upgrade	254,114			254,114	
		Upgrade Underground Fuel Supply Line	210,042			210,042	
							2,147,981
502	Gjoa Haven	Fire Alarm System	122,121			122,121	
							122,121
505	Kugluktuk	Fire Alarm System	103,333			103,333	
							103,333
602	Baker Lake	Hamlet of Baker Lake 30 yr Land Lease	240,450			240,450	
							240,450
606	Whale Cove	Fence			262,520	262,520	
							262,520
607	Naujaat	Fence			309,075	309,075	
							309,075
703	Cape Dorset	New Power Plant	26,477,484	641,810	149,150	27,268,445	
							27,268,445
706	Igloolik	Electrical service - new subdivision		130,480		130,480	
		Fence			172,918	172,918	
							303,398
712	Grise Fiord	New Power Plant	18,839,304			18,839,304	
		Distribution System Upgrade		670,752		670,752	
		Service to commercial lots		111,237		111,237	
							19,621,292
	Projects with cost less than $100,000		289,153	524,896	222,840	1,036,889	
							1,036,889
		Total for QEC	**46,536,000**	**3,763,000**	**1,723,985**	**52,022,985**	**52,022,985**
		Disallowed costs	3,939,304			3,939,304	
		Government Contributions				-	
		Customer Contributions		1,501,660		1,501,660	
		Net Costs for Schedule 6.2	**42,596,697**	**2,261,339**	**1,723,985**	**46,582,021**	

Notes:
1. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs in Schedule 6.2 of the GRA reflect exclusion of government and customer contributions.
2. The URRC in its Report 2018-01 recommended the Grise Fiord plant replacement cost to be $14.9 million. The variance between the actual cost
1 and the URRC recommended cost is added as disallowed capital cost for the GRA pupposes.

Schedule B-2

QULLIQ ENERGY CORPORATION
2022/23 GENERAL RATE APPLICATION
ACTUAL CAPITAL ADDITIONS FOR 2019/20
(in thousands of dollars)

Plant #	Plant Name	Description	2019/20 Additions ($000) Diesel	Distribution	General Plant	Total Project	Total for Plant	Government Contributions	Net Cost
503	Taloyoak	RBD Line Truck			224,166	224,166			
							224,166		
601	Rankin Inlet	Genset Replacement G3	3,795,822			3,795,822		2,341,510	1,454,312
		Power to new subdivision		174,545		174,545			
							3,970,367		
604	Coral Harbour	Genset Replacement G1	3,737,484			3,737,484		1,193,390	2,544,094
							3,737,484		
605	Chesterfield Inlet	Genset Replacement G3	1,767,047			1,767,047		1,836,292	(69,245)
							1,767,047		
606	Whale Cove	RBD Line Truck			226,366	226,366			
							226,366		
701	Iqaluit	New Bulk Fuel Tank Upgrade	4,945,543			4,945,543			
		Fuel Supply Line Upgrade	1,470,750			1,470,750			
		Napier Turbo Tooling			191,215	191,215			
							6,607,508		
704	Resolute Bay	Fire Alarm System	144,289			144,289			
							144,289		
710	Arctic Bay	Land Lease	114,572			114,572			
		Power to new subdivision		191,367		191,367			
							305,939		
711	Clyde River	Fence			201,557	201,557			
							201,557		
712	Grise Fiord	Transient Unit			452,093	452,093			
							452,093		
	Projects with cost less than $100,000		123,257	389,473	466,592	979,322			
							979,322		
		Total for QEC	**16,098,764**	**755,385**	**1,761,988**	**18,616,137**	**18,616,137**		
		Government Contributions	5,371,192			5,371,192			
		Customer Contributions		550,106		550,106			
		Net Costs for Schedule 6.2	**10,727,572**	**205,279**	**1,761,988**	**12,694,839**			

Notes:
1. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs in Schedule 6.2 of the GRA reflect exclusion of government and customer contributions.

Schedule B-3

QULLIQ ENERGY CORPORATION
2022/23 GENERAL RATE APPLICATION
ACTUAL CAPITAL ADDITIONS FOR 2020/21
(in thousands of dollars)

Plant #	Plant Name	Description	2020/21 Additions ($000) Diesel	Distribution	General Plant	Total Project	Total for Plant	Government Contributions	Net Cost
504	Kugaaruk	Quonset Garage			353,233	353,233			
							353,233		
603	Arviat	3 Phase Extension with streetlights		109,248		109,248			
							109,248		
705	Pond Inlet	Genset Replacement G1	2,707,441			2,707,441		821,998	1,885,443
							2,707,441		
706	Igloolik	Poles and Lights		628,844		628,844			
							628,844		
711	Clyde River	Transformers, Lights and Poles		196,060		196,060			
							196,060		
	Projects with cost less than $100,000		96,281	268,886	-	365,167			
							365,167		
		Total for QEC	**2,803,722**	**1,203,037**	**353,233**	**4,359,993**	**4,359,993**		
		Government Contributions	821,998			821,998			
		Customer Contributions		1,203,037		1,203,037			
		Net Costs for Schedule 6.2	**1,981,724**	**-**	**353,233**	**2,334,957**			

Notes:
1. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs in Schedule 6.2 of the GRA reflect exclusion of government and customer contributions.

Schedule B-4

QULLIQ ENERGY CORPORATION
2022/23 GENERAL RATE APPLICATION
FORECAST CAPITAL ADDITIONS FOR 2021/22
(in thousands of dollars)

Plant #	Plant Name	Description	2021/22 Additions ($000) Diesel	Distribution	General Plant	Total Project	Total for Plant	Government Contributions	Net Cost
	Nunavut	Line Hardware Storage Containers			459,735	459,735			
		Time and Attendance, HRIS software			320,470	320,470			
		IT Hardware Replacement			117,000	117,000			
							897,205		
502	Gjoa Haven	Quonset Garage			500,087	500,087			
		Genset Upgrade - G4	3,640,157			3,640,157			
		Volvo 500 KW Emergency Unit Connection	384,506			384,506			
							4,524,750		
504	Kugaaruk	Emergency Generating Unit Connection	326,466			326,466			
							326,466		
601	Rankin Inlet	Stores-Warehouse Renovation			228,372	228,372			
							228,372		
606	Whale Cove	Protection Systems Upgrade	211,555			211,555			
		Genset Replacement G2	2,566,761			2,566,761		1,732,564	834,197
		Quonset Garage			560,992	560,992			
							3,339,309		
701	Iqaluit	Fire Pump Main Plant			1,110,607	1,110,607			
							1,110,607		
703	Cape Dorset	New Power Plant	897,052			897,052			
							897,052		
704	Resolute Bay	Feeder Conversion		1,563,719		1,563,719			
		Feeder 4 Rehabilitation		626,320		626,320			
							2,190,039		
705	Pond Inlet	Genset Replacement G4	2,354,954			2,354,954		1,589,594	765,360
							2,354,954		
710	Arctic Bay	Power Plant Replacement	30,877,735			30,877,735			
							30,877,735		
711	Clyde River	Genset Replacement G3	2,899,780			2,899,780		1,957,352	942,429
		Clyde River Airport Underground line upgrade		253,830		253,830			
							3,153,610		
712	Grise Fiord	Quonset Garage			558,620	558,620			
		Material Handling Truck			256,254	256,254			
							814,874		
	Projects with cost less than $100,000		139,396	275,985	739,360	1,154,741		275,985	878,756
							1,154,741		
		Total for QEC	**44,298,363**	**2,719,853**	**4,851,498**	**51,869,714**	**51,869,714**		
		Government Contributions	5,279,509	275,985		5,555,494			
		Customer Contributions		364,868		364,868			
		Net Costs for Schedule 6.2	**39,018,853**	**2,079,000**	**4,851,498**	**45,949,351**			

Notes:
1. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs in Schedule 6.2 of the GRA reflect exclusion of government and customer contributions.

Schedule B-5

QULLIQ ENERGY CORPORATION
2022/23 GENERAL RATE APPLICATION
FORECAST CAPITAL ADDITIONS FOR 2022/23
(in thousands of dollars)

Plant #	Plant Name	Description	2022/23 Additions ($000) Diesel	Distribution	General Plant	Total Project	Total for Plant	Government Contributions	Net Cost
400	Nunavut	LED Streetlight		500,000		500,000		500,000	0
		Inventory/Asset Tracking Software			256,000	256,000			
		Housing Asset Work order Software			180,202	180,202			
		IT Hardware Replacement			117,000	117,000			
							1,053,202		
502	Gjoa Haven	RBD Line Truck			374,363	374,363			
							374,363		
503	Taloyoak	Quonset Garage			642,653	642,653			
							642,653		
504	Kugaaruk	RBD Line Truck			374,363	374,363			
							374,363		
505	Kugluktuk	Transient Unit Replacement			599,552	599,552			
							599,552		
601	Rankin Inlet	Station PLC & DC Upgrade		454,902		454,902			
		Three phase line upgrade - mine road		333,062		333,062			
							787,964		
602	Baker Lake	Automated Meter Reading (AMR)		1,000,000		1,000,000			
		Head Office Building			16,596,388	16,596,388			
		5-Plex Renovations Phase 2			1,711,000	1,711,000			
							19,307,388		
603	Arviat	Automated Meter Reading (AMR)		700,000		700,000			
							700,000		
605	Chesterfield Inlet	RBD Line Truck			374,363	374,363			
							374,363		
606	Whale Cove	Substation Upgrade		1,576,478		1,576,478			
							1,576,478		
607	Naujaat	Feeder Upgrade F3		489,538		489,538			
							489,538		
702	Pangnirtung	RBD Line Truck			374,363	374,363			
							374,363		
703	Cape Dorset	Transient House Upgrade			420,000	420,000			
							420,000		
704	Resolute Bay	Transient House Upgrade			606,742	606,742			
		Quonset Garage			666,582	666,582			
							1,273,324		
706	Igloolik	Feeder Upgrade F1, F2 & F3		1,499,888		1,499,888			
		RBD - Line Truck			374,363	374,363			
							1,874,251		
707	Hall Beach (Sanirajak)	Feeder Upgrade F1, F2 & F3		1,375,429		1,375,429			
		Substation Upgrade		1,531,800		1,531,800			
							2,907,229		
708	Qikitarjuaq	Plant Yard Fencing			400,000	400,000			
							400,000		
710	Arctic Bay	Transient Unit Replacement			850,000	850,000			
							850,000		
711	Clyde River	Genset Replacement G2	2,747,605			2,747,605		1,854,633	892,972
							2,747,605		
712	Grise Fiord	New Power Plant	1,221,617			1,221,617			
		Substation Upgrade		186,688		186,688			
							1,408,305		
713	Sanikiluaq	Transformer Replacement		1,222,933		1,222,933			
							1,222,933		
	Projects with cost less than $100,000		0	346,000	0	346,000			
							346,000		
		Total for QEC	**3,969,222**	**11,216,718**	**24,917,932**	**40,103,872**	**40,103,872**		
		Government Contributions	1,854,633	500,000		2,354,633			
		Customer Contributions				-			
		Net Costs for Schedule 6.2	**2,114,589**	**10,716,718**	**24,917,932**	**37,749,239**			

Notes:
1. Government and customer contributions towards tangible capital assets are recognized by QEC as revenue in the year received. For the GRA purposes the contributions are added as an offset to the capital cost. Therefore, net costs in Schedule 6.2 of the GRA reflect exclusion of government and customer contributions.

APPENDIX C

COST OF SERVICE STUDY METHODS

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C1.0 OVERVIEW

C1.1 PURPOSE OF THE COST OF SERVICE

A cost-of-service (COS) study is an analytical tool that supports the ratemaking process. The purpose of a COS study is to develop a method to fairly allocate the revenue requirement among the different customer classes served by the utility. While there are many potential allocation methods, the core objective is to allocate costs to customers consistent with principles of cost causation based on customer characteristics such as energy consumption and peak demand.

There is no absolute right or wrong allocation method, as each utility's operating circumstances and cost drivers are different. The objective for the utility is to select methods which best represent cost causation and the equitable sharing of costs among customers in a manner appropriate for the unique circumstances of the utility. This document describes the COS study methods based on a territory-wide approach.

A COS study can provide useful information such as unit costs to serve different customers (such as $/kWh, $/customer month) and revenue to cost coverage ratios, which are used in the ratemaking process. However, it must be recognized that any COS study involves estimation and a degree of professional judgement and therefore the results cannot be considered exact. Further, the appropriate allocation methods for a COS study can change over time as the utility's operating environment and cost drivers change.

To provide services to its customers, the Corporation must receive sufficient revenues to recover its costs. The COS study used in this Application applies cost-of-service concepts to embedded accounting costs in order to calculate the fair share of the Corporation's total revenue requirement for each customer class.

C1.2 STEPS OF THE COST OF SERVICE PROCESS

The steps involved in a COS study are the following:

1. Determining a test period;
2. Determining revenue requirement;
3. Selecting customer classes;
4. Functionalization of plant and expenses;
5. Classification of plant and expenses; and
6. Allocation of plant and expenses.

Step 1: Determining a Test Period: The test period refers to the time period over which revenues and expenses are analyzed to determine the surplus or deficiency in rates. This COS study is for the test period of April 1, 2022 to March 31, 2023.

Step 2: Determination of Revenue Requirement: This COS study uses the proposed revenue requirement for the 2022/23 test year as described in the application.

Step 3: Selection of Customer Classes: A customer class is a group of customers with similar load characteristics. The classes used in this COS study are:[1]

[1] Definitions of the customer classes are provided in QEC Terms & Conditions of Service.

i). Domestic;

ii). Commercial; and

iii). Streetlighting.

Plant investment and expenses that serve only a particular customer or class of customers are directly assigned. For example, the plant investment and expenses associated with streetlights are directly assigned to the streetlighting class.

Once the revenue requirement and customer classes have been determined, the COS study is undertaken in a three-step process described below.

<u>Functionalization</u>: Once the revenue requirement and customer classes have been determined, plant investment and expenses are separated according to function. The functions used in QEC's COS study are:

i). Generation;

ii). Distribution; and

iii). General.

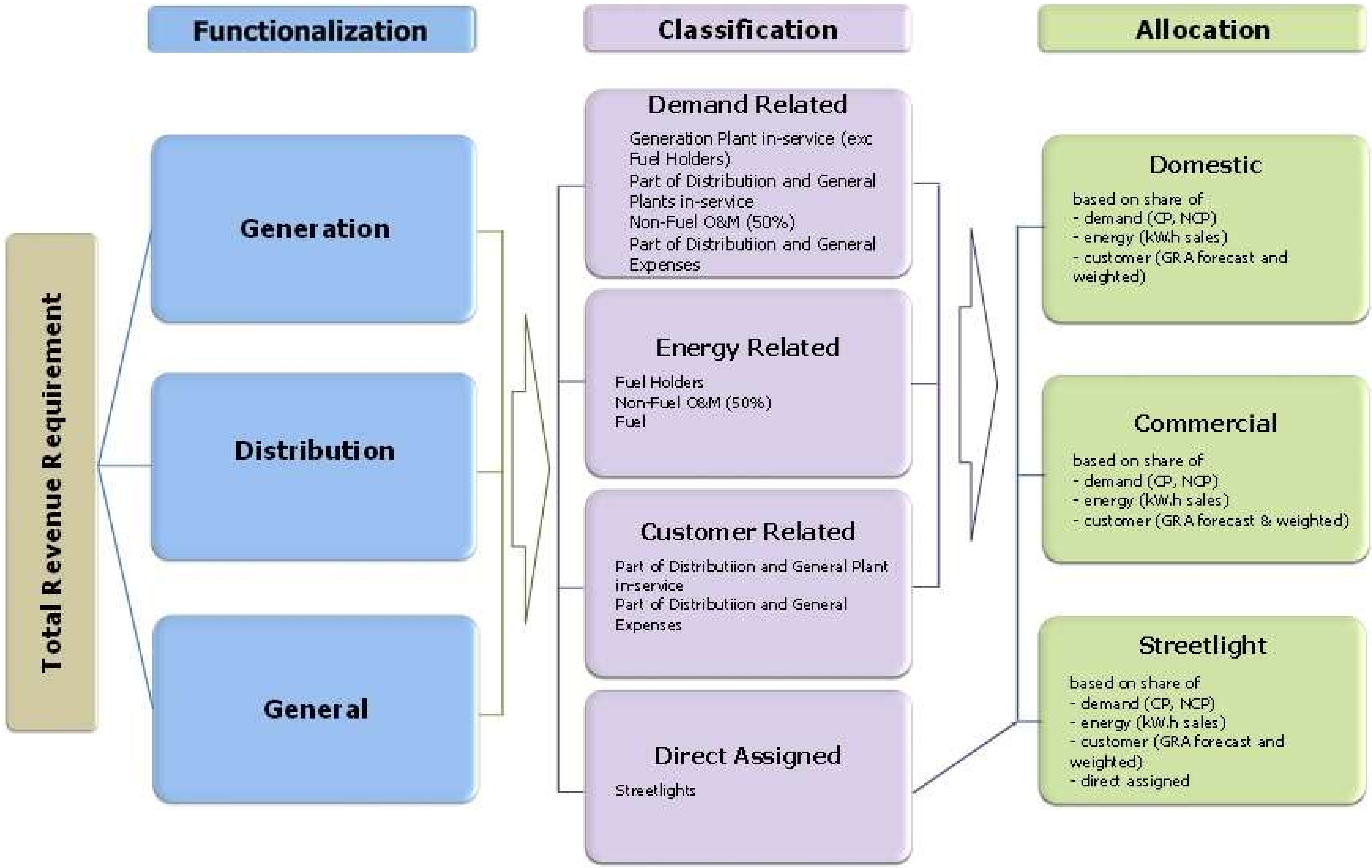
The assignment of plant investment and expenses to each function generally follows the utility's standard set of accounts. In the case of the Corporation, assets are coded to a series of functional categories based on Federal Energy Regulatory Commission ("FERC") codes. Functionalization is discussed further in Chapter 2.

Classification: This step in the COS process separates the functionalized costs into classifications based on the type of service provided. The three principal cost classifications for electric utilities are demand costs (costs that vary with the kW demand imposed by the customer), energy costs (costs that vary with the kWh of energy that the utility provides) and customer costs (costs that vary in relation to the number of customers served). Classification methods are discussed in greater detail in Chapter 3.

Allocation: The final step in the COS analysis is the allocation of classified costs to customer classes. For example, energy related costs have been allocated to customer classes based on energy usage in kilowatt-hours. The allocation factors developed for the COS study were derived using billing records, load records and the Corporation's proposed load forecast. Allocation is discussed in greater detail in Chapter 4.

Figure C1.1 provides an illustration of the steps involved in the Corporation's COS study.

Figure C1.1:
Illustrative Steps of the COS Study Process



C2.0 FUNCTIONALIZATION

The Corporation relies on diesel generation for electricity production. Each community's electricity system generally consists of a powerhouse for production facilities, distribution bus, distribution feeder system and general facilities. Currently, the Corporation does not have any transmission related assets. As such, the cost functions used in this COS study include:

Generation Function: The generation function consists of assets and expenses associated with power generation. The generation function includes power production facilities, operation and maintenance costs directly related to these facilities and production fuel expense.

Distribution Function: The distribution function includes assets and expenses that connect customers to the generation plant.

General Function: The general function includes management, administrative and other costs that cannot be assigned to the other major cost functions.

C2.1 FUNCTIONALIZATION OF PLANT

Functionalization of gross plant and accumulated amortization was carried out according to the FERC codes set out in Table C2.1, which is consistent with the approach previously reviewed by the URRC in the 2010/11 GRA.

Table C2.1: Plant Functionalization

FERC Account Number		DESCRIPTION
EUG Plant		
121		Energy Utilization
131		Residual Heating System
DIESEL Plant		
340		Land and Land Rights
341		Structures & Improvements
342		Fuel Holders, Prod., & Access.
343		Prime Movers
344		Generators
345		Accessory Electric Equipment
346		Miscellaneous Power Plant Equipment
DISTRIBUTION Plant		
360		Land and Land Rights
361		Structures & Improvements
362		Station Equipment
363		Storage Battery Equipment
364		Poles & Fixtures
365		Overhead Conductors & Devices
366		Underground Conduit
367		Underground Conductors & Devices
368		Line Transformers
369		Services
370		Meters
371		Installation on Cust. Premises
372		Leased Property on Customer Premises
373		Street Lighting
GENERAL Plant		
383		Computer Software
389		Land and Land Rights
390		Structures & Improvements
391		Office Furniture & Equipment, Computers
392		Transportation Equipment
393		Stores Equipment
394		Tools, Shop, & Garage Equipment
395		Laboratory Equipment
396		Power Operated Equipment
397		Communication Equipment
398		Miscellaneous Equipment
399		Other Tangible Property

Fuel inventory amounts in working capital were functionalized to generation (consistent with the functionalization of fuel expense). Other working capital amounts were functionalized to general plant.

C2.2 FUNCTIONALIZATION OF EXPENSES

The Corporation's expense budget for the test year is prepared by each department and plant according to the budget codes set out in Tables C2.2 and C2.3.

Table C2.2: QEC Departments

Budget Codes		DESCRIPTION
Head Office Department Codes		
1000/1100		Board & Iqaluit Admin
1200		Finance
1300		Corporate Affairs
1500		Human Resources
1600		Shared Services
1700		Property Management
2000		Territorial Operations
2250		Energy Management
2400		Health, Safety and Environment
2600		Information Technology
2700		Engineering
Regional Office Department Codes		
2100		Regional Operations
2500		Line
Communities		
2200		Plant Operations

The Corporation reviewed each of the budget expense items and determined an appropriate functionalization of each expense as illustrated in Table C2.3.

Table C2.3: Functionalization of QEC's Expenses

Expenses	Other head office departments	2000 - Territorial Operations	2100 - Regional Operations	2200 - Plant Operations	2500 - Line	2700 - Engineering
Salaries and Wages	100% General Plant	62% Generation, 35% Distribution and 3% General Plant (based on positions)	94% Generation, 5% Distribution and 1% General Plant (based on positions for each region)	70% Generation and 30% Distribution	100% Distribution	75% Generation and 25% Distribution (based on positions)
Supplies and Services	100% General Plant	62% Generation, 35% Distribution and 3% General Plant (based on Salaries and Wages)	94% Generation, 5% Distribution and 1% General Plant (based on Salaries and Wages)	70% Generation and 30% Distribution	100% Distribution	75% Generation and 25% Distribution (based on Salaries and Wages)
Travel and Accommodations	100% General Plant	62% Generation, 35% Distribution and 3% General Plant (based on Salaries and Wages)	94% Generation, 5% Distribution and 1% General Plant (based on Salaries and Wages)	70% Generation and 30% Distribution	100% Distribution	75% Generation and 25% Distribution (based on Salaries and Wages)

For some financial information, the Corporation's existing accounting systems do not allow the ideal level of information for a COS study to be tracked. In such circumstances, the Corporation consults with its operations staff to develop estimates of the proportion of expenses spent on generation and distribution related activities. The Corporation believes the estimates are reasonable and can be relied upon for ratemaking purposes.

The Corporation used the following methods to functionalize operating expenses:

- **Salaries and Wages:**
    - In order to functionalize salaries and wages for community-based employees, the Corporation reviewed the responsibilities for Plant Operations (2200) employees. Most communities (23 out of total 25) have

only one Plant Superintendent and one Assistant Operator. The responsibilities of these employees mainly relate to the generation function. However, they are also responsible for some distribution related tasks such as meter reading and customer connection/disconnection. In the 2010/11 GRA the Corporation estimated that distribution related tasks comprise about 30% of a plant operator's time. During the preparation of its 2022/23 GRA the Corporation again reviewed this functionalization and considered that 70% to generation and 30% to distribution split remains a reasonable estimate.

- All head office departments, with the exception of Territorial Operations (2000) and Engineering (2700), provide general services including administration, general finance and human resources. Salaries and wages expenses for these departments were functionalized 100% to the general function.

- The Line Department (2500) provides services directly related to distribution in the Qikiqtaaluk region, and all expenses of this department were functionalized 100% to distribution.

- For the regional office departments (2100 – Regional Operations), the Corporation reviewed each employee position and estimated a breakdown of the employee's responsibilities by each function by regional level.

  - For the remaining head office departments (2000 – Territorial Operations, 2700 – Engineering), the Corporation reviewed each employee position and estimated a breakdown of the employee’s responsibilities by each function.

- **Supplies and Services, and Travel and Accommodations:** The expense elements under these categories were functionalized following the salaries and wages functionalization ratio for each plant or department.

- **Production Fuel Expense:** Production fuel expense was functionalized 100% to generation, as it is directly used for power generation.

- **Amortization Expense:** Amortization expenses were functionalized based on FERC Codes as outlined in Table C2.1.

C3.0 CLASSIFICATION

Once costs are functionalized, they are classified based on cost drivers between demand, energy, customer and revenue. Revenue related costs include other revenue, which was treated as an offset to the revenue requirement. Where costs can be identified as being specifically incurred by a single customer class, such costs are direct assigned to that customer class. A summary of the classification categories used in the COS study is provided in Table 3.1.

Table C3.1: QEC COS Study Classification Categories

Description	Category
Coincident Peak Demand	Demand related
Non-Coincident Peak Demand	Demand related
Energy	Energy related
Customer	Customer related
Weighted Customers	Customer related
Revenue Related	Revenue requirement offset
Direct Assignments	Directly assigned

A description of the four main cost classification categories is provided below. Classification methods used for each of the functions in the COS study is provided in the following sections.

<u>Demand-Related</u>

Costs that are driven by the kilowatts of demand each customer imposes on the system are said to be demand-related. Demand-related costs can be considered in at least two sub-categories: system peak demand-related (coincident peak) and customer maximum-demand related (non-coincident peak).

Energy-Related

Energy-related costs are those determined to vary in proportion to the kilowatt-hours consumed by the customer. The principle costs in this category are fuel, and variable operation and maintenance expenses.

Customer-Related

Costs classified as customer-related are those which tend to vary in proportion to the number of customers served. At least two subcategories are generally considered; average number of customers and weighted number of customers. The latter category, weighted customers, is used when the primary cost causation is number of customers, but where certain classes of customers impose proportionately greater costs on the system. One example is meter investment. Every customer has a meter, but general service and industrial meters cost more than residential meters.

Direct Assignment

Costs that can be identified as being incurred to serve a specific customer or class of customers are direct assigned to that customer (for example, streetlighting costs).

C3.1 CLASSIFICATION OF PLANT

Generation Plant

The determination of appropriate generation classification factors takes into account the relationship between capacity (peak demand) and energy requirements of the customers. The cost of capacity relates to the cost to accommodate peak loads at the time of the highest system load in the community. The cost profile of a pure energy use is that of a sustained consumption of kilowatt-hours throughout the year.

When planning generation facilities, the Corporation is primarily concerned with ensuring sufficient capacity is available to meet the community's peak. Therefore demand is the primary cost driver for generation assets. Consistent with this cost driver, generation plant assets were classified as 100% demand related with the exception of fuel holders, which were classified as 100% energy related.

This classification method is consistent with Corporation's 2010/11 GRA approach, and most other utilities in Canada that operate isolated diesel plants. Yukon Energy Corporation, ATCO Electric Yukon, Northwest Territories Power Corporation and Northland Utilities (NWT) Ltd all classify the majority of diesel generation plant 100% to demand.

Distribution Plant

Investment in distribution plant is driven by the number and location of customers and the peak demand imposed by those customers. Investment in distribution plant does not vary with the consumption of energy. Therefore distribution plant is classified to demand and customer. This is consistent with the practice followed by other Canadian northern utilities, as well as the classification of distribution plant in the National Association of Regulatory Utility Commissioners (NARUC) Manual.

The classification factors for poles, towers and fixtures, overhead conductors and underground conduits, and line transformers are based on the classification factors used by the Northwest Territories Power Corporation (NTPC) in their most recent general rate application (2016/19 GRA).

The Corporation's distribution plant facilities include the following assets:

- **Land and Land Rights, Structures & Improvements, Station Equipment, Storage Battery Equipment:** These assets are sized and built to meet system demand requirements and their size is not affected by the number of customers to be served. Therefore these assets have been classified as 100% demand-related.
- **Services, Meters and Metering Equipment:** These assets are designed to meet the needs of specific customers and their costs are dependent on the number and type of customers to be served. Therefore these assets were classified as 100% customer-related.
- **Street Lights:** These assets were directly assigned to the streetlight customer class.
- **Poles, Towers and Fixtures:** Investment in these assets is driven partly by the demand placed on the system and partly by the number of customers to be served. These assets were classified as 45% demand related and 55% customer related based on NTPC's 2016/19 Phase II rate application. The discussion on determining these classification factors is provided in Section 10.4.2.
- **Overhead Conductors / Underground Conduits:** Investment in these assets is primarily driven by the number of customers to be served, but the investment must also consider the demand of the customer. These assets were classified as 50%

demand related and 50% customer related based on NTPC's 2016/19 Phase II rate application. The discussion on determining these classification factors is provided in Section 10.4.2.

- **Line Transformers:** Investment in these assets is primarily driven by the demand imposed on the system. However some consideration is also given to the number of customers to be served. These assets were classified as 71% demand related and 29% customer related based on NTPC's 2016/19 Phase II rate application. The discussion on determining these classification factors is provided in Section 10.4.2.

Classification of distribution plant facilities is summarized in Table 3.2.

Table C3.2: Classification of Distribution Plant

	Customer		Demand		Direct Assigned	Basis
	Actual	Weighted	CP	NCP		
Distribution Plant						
Land & Rights, Sub Equipments (FERC 360-363)	0%			100%		Reviewed by URRC in Report 2012-01
Poles, Towers and Fixtures (FERC 364)	55%			45%		Based on NTPC's 2016/19 GRA
O/H Conductors (FERC 365)	50%			50%		Based on NTPC's 2016/19 GRA
Underground Conduits (FERC 366-367)	50%			50%		Based on NTPC's 2016/19 GRA
Transformers (FERC 368) - Weighted		29%		71%		Based on NTPC's 2016/19 GRA
Services and Meters (FERC 369-372) - Weighted		100%				Based on NTPC's 2016/19 GRA
Street Lights (FERC 373) - Direct Assigned					100%	Reviewed by URRC in Report 2012-01
Contributions - Weighted	32.3%	7.5%		60.2%		Weighted (FERC 360-372)

<u>General Plant</u>

General plant consists of a variety of facilities used to administer generation, distribution and customer service functions of the utility. General plant costs do not vary materially with increases in the number of customer, community demand or energy consumed, but are required to provide all services to customers. Therefore, the Corporation classified general plant assets into customer, demand, and energy related costs based on the proportion of total generation and distribution assets classified to demand, energy and customer categories.

Other rate base cost categories were classified to customer, demand, and energy related cost as follows:

- **Accumulated Amortization:**
  - Generation plant related – based on the proportion of total generation assets classified to customer, demand, and energy categories.
  - Distribution plant related – based on the proportion of total distribution assets classified to customer, demand, and energy categories.
  - General plant related – based on the proportion of total general assets classified to customer, demand, and energy categories.
- **Working Capital:**
  - Cash – based on the proportion of total general plant assets classified to customer, demand, and energy categories.
  - Materials and Supplies – based on the proportion of total general plant assets classified to customer, demand, and energy categories.
  - Fuel – 100% to energy.

C3.2 CLASSIFICATION OF EXPENSES

<u>Generation Plant</u>

Generation plant expenses include production fuel and non-fuel related operating and maintenance expenses.

Production fuel is a variable cost that is incurred in direct proportion to the amount of energy consumed by each customer class. Therefore fuel expenses were classified as 100% energy-related.

Non-fuel operating and maintenance expenses include both variable costs that are incurred in relation to the consumption of energy and non-variable cost that are related to maintaining assets in safe, reliable working order to meet the community's capacity requirements. Therefore the Corporation classified non-fuel operating and maintenance expenses 50% to demand and 50% to energy. This classification is consistent with Corporation's 2010/11 GRA and the current practice in other Northern utilities in Canada.

<u>Distribution Plant</u>

In order to classify distribution plant expenses, the Corporation calculated a classification ratio based on the total gross distribution plant classified to demand related and customer related costs. This ratio was used to classify distribution plant expenses, except the billing and customer accounting related expenses which were classified to the weighted customer category based on the URRC's recommendations in its Report 2012-01[2] to the Minister.

General Plant

General plant expenses were classified using the same classification ratios calculated for the classification of general plant assets, i.e. based on the proportion of total generation and distribution assets classified to demand, energy and customer categories.

Table 3.3 provides summary of classification of expenses by function.

Table C3.3: Classification of Expenses by Function

	Customer		Demand		Energy	Direct Assigned
	Actual	Weighted	CP	NCP		
Production Fuel	0%		0%		100%	
Non-Fuel O&M	0%		50%		50%	
Distribution	Based on Total Distribution Plant Classified to Customer / Demand					
General Plant	Based on Classification of General Plant					

[2] In its Report 2012-01, the URRC recommended that QEC classify meter reading, billing and customer accounting related expenses to the customer category. The Billing and Revenue department was merged with the General Finance department following the 2010/11 GRA. As a separate expense code for billing and customer accounting related expenses is no longer available, the Corporation prorated these costs based on the information available from the 2010/11 GRA (URRC-QEC-1-7c from November 4, 2011, Attachment 1).

Other expense categories were classified into customer, demand, and energy related as follows:

- **Amortization Expense:**
  - Generation plant related – based on the proportion of total generation assets classified to customer, demand, and energy categories.
  - Distribution plant related – based on the proportion of total distribution assets classified to customer, demand, and energy categories.
  - General plant related – based on the proportion of total general assets classified to customer, demand, and energy categories.
- **Other Revenue:** Other revenue was classified as 100% revenue related consistent with the URRC's recommendations in its Report 2012-01[3] to the Minister.

[3] See Section 10.4.4 of the Application.

C4.0 ALLOCATION

This chapter describes the methods used to develop the allocation factors used in the Corporation's COS study. The allocation factors were developed based on information from customer billing records, the Corporation's load forecast, and information from electric utilities with similar types of customer classes and operating environments.

C4.1 DEMAND ALLOCATION FACTORS

In the development of demand allocation factors for each customer group, two steps are required.

1. Determining the most appropriate method for allocation of demand-related costs; and
2. Development of the appropriate demand data.

The COS study uses two demand allocators:

- Coincident peak: is the peak for a customer class at the time of the system peak.
- Non-coincident peak: is the annual peak for a customer class in the year.

Generation demand-related costs are generally considered to be related to coincident demands (i.e., customer group peaks at the time of a system peak), since sufficient capacity must be provided to meet the demands of all customers at the time of the system peak. Therefore the Corporation allocated generation demand-related costs based on the class's share of the total plant coincident peak (CP). This method is consistent with 2010/11 GRA and industry practice for other utilities in Northern Canada.

In contrast, line transformers, poles and fixtures and other distribution system components are sized to meet the maximum demands of customers regardless of time of occurrence. For this reason, distribution and general plant demand-related costs were allocated on the basis of non-coincident demands utilizing the class non-coincident peak (NCP).

Coincident peak and non-coincident peaks are not metered at the class level. Therefore the Corporation requires estimates of the customer class load factor and coincidence factor in order to estimate the coincident and non-coincident peaks for each class. The Corporation did not undertake load research on individual customer classes across communities in Nunavut because it is not economically feasible. In developing estimates of customer class load factor and coincidence factors for the 2010/11 GRA, the Corporation reviewed the data developed by other utilities. These factors were accepted by the URRC in the Report 2012-01.[4] For the current COS study the Corporation similarly used customer class load factor and coincidence factors from NTPC's 2016/19 Phase II rate application.

A summary of the load factors and coincidence factors used by the Corporation in the COS analysis is provided in Table 4.1.

[4] URRC's report on QEC's 2010/11 Phase II GRA, 2012-01 dated from January 27, 2012, p.23.

Table C4.1:
QEC's Recommended Load Parameters

Customer Class	NCP Load Factor	Coincidence Factor
Domestic	43.8%	86.8%
Commercial	55.0%	83.2%
Streetlights	47.3%	100.0%

C4.1.1 ENERGY ALLOCATION FACTORS

Energy-related costs were allocated to customer classes based on the total kilowatt-hour sales to each customer class. The allocation ratios were developed based on the 2022/23 test year load forecast by customer class.

C4.1.2 CUSTOMER ALLOCATION FACTORS

Customer-related costs were allocated to customer classes based on number of customers and weighted number of customers.

Common industry practice is to allocate customer-related costs that do not vary with the type of customers or its consumption of electricity on the basis of actual number of customers in each class (e.g., poles and fixtures).

A weighted number of customers is typically used for costs that vary with the type of customer or its consumption of electricity. For example, metering device costs are different for commercial customers than domestic customers. The Corporation used weighted number of customers to allocate services, meters and line transformer assets, billing and customer accounting related expenses. In the 2010/11 GRA the Corporation assumed a customer weighting of 1.0 for domestic and 3.0 for commercial customers.

In its Report 2012-01 the URRC recommended to the Minister that QEC conduct a study of the appropriate customer weighting factors for domestic, commercial, street and yard lighting customers at the time of the next COS study.[5]

At the time of the 2014/15 GRA preparation, the Corporation performed a review of the customer weighting factors in accordance with the above recommendation. The analysis of transformer costs, which account for approximately 40% of the distribution plant allocated on weighted customer basis, suggest that, in general one transformer is used to serve six domestic customers, or two commercial customers. With respect to the meter costs, which account for approximately 7% of the distribution plant allocated on weighted customer basis, the review suggests that, in general, QEC's commercial meter devices are approximately 7 times more expensive than residential meter devices.

The Corporation also reviewed the service weighting analysis performed by NUL-NWT as part of its 2011-2013 GRA, and notes that on average service cost is approximately twice as much for commercial customer as compared to residential customers, which was reviewed and accepted by the Northwest Territories PUB in Decision 5-2012.[6] Taking into account the similarity of QEC's and NUL-NWT's customer base the Corporation considers it is reasonable to rely on service cost weighting factors determined by NUL-NWT. Service

[5] URRC's report on QEC's 2010/11 Phase II GRA, 2012-01 dated from January 27, 2012, p.20.
[6] NWT PUB Decision 5-2012, p. 38-41.

costs account for approximately 53% of the distribution plant allocated on weighted customer basis.

Based on the above review, the Corporation determined the updated weighting factors for domestic and commercial customers as shown in Table 4.2 which is consistent with the 2018/19 GRA COS.

Table C4.2:
Calculation of Customer Weighting Factor

	Cost Ratio by Customer Category			Weighted
	Transformer	**Meter**	**Services**	**Average**
Domestic	1	1	1	1
Commercial	3	7	2	3
Share in Allocated Distr. Plant	40%	7%	53%	

The updated weighting factor suggests that the weighting factor of 3 for commercial and 1 for domestic is still appropriate and the Corporation used these weighting factors in its 2022/23 GRA COS.

The Corporation considers customer related costs associated with streetlighting customers to be similar to those of domestic customers, and as such streetlighting customers were assigned a customer weighting factor of 1 relative to domestic customers.

C4.1.3 REVENUE OFFSET ALLOCATION FACTORS

The Corporation applied other revenue (revenue from non-electrical sales) as an offset to the Corporation’s revenue requirement. Other revenue was allocated to customer classes proportionate to their share of total 2022/23 test year forecast revenue at existing or pre-2022/23 GRA rates.

APPENDIX D

COST-OF-SERVICE STUDY SCHEDULES

2022/23 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

	Plant Description	$000 Total	Demand Related Coin. Peak CP	Demand Related NC Peak NCP	Energy Related E	Customer Related Actual CUST-1	Customer Related Weighted CUST-2	Revenue Related RR	Direct Assign. DA
	Generation Plant								
340	Land and Land Rights	$1,941.7	$1,941.7	$.0	$.0	$.0	$.0	$.0	$.0
341	Structures & Improvements	$109,462.2	$109,462.2	$.0	$.0	$.0	$.0	$.0	$.0
342	Fuel Holders, Prod., & Access.	$23,090.2	$.0	$.0	$23,090.2	$.0	$.0	$.0	$.0
343	Prime Movers	$111,383.6	$111,383.6	$.0	$.0	$.0	$.0	$.0	$.0
344	Generators	$78,424.2	$78,424.2	$.0	$.0	$.0	$.0	$.0	$.0
345	Accessory Electric Equip.	$31,119.7	$31,119.7	$.0	$.0	$.0	$.0	$.0	$.0
346	Misc. Power Plant Equip.	$33,447.7	$33,447.7	$.0	$.0	$.0	$.0	$.0	$.0
121	Wind Energy Production	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
131	Heat Recovery Systems	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
	Insurance Proceeds	-$28,965.0	-$27,245.1	$.0	-$1,719.9	$.0	$.0	$.0	$.0
	Disallowed	-$5,684.3	-$5,346.8	$.0	-$337.5	$.0	$.0	$.0	$.0
	Contributions	-$20,788.3	-$19,553.9	$.0	-$1,234.4	$.0	$.0	$.0	$.0
	Total Generation Plant	$333,431.7	$313,633.2	$.0	$19,798.5	$.0	$.0	$.0	$.0
	Distribution Plant								
360	Land and Land Rights	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
361	Structures & Improvements	$8,844.9	$.0	$8,844.9	$.0	$.0	$.0	$.0	$.0
362	Station Equipment	$12,798.3	$.0	$12,798.3	$.0	$.0	$.0	$.0	$.0
363	Storage Battery Equip.	$10.0	$.0	$10.0	$.0	$.0	$.0	$.0	$.0
364	Poles & Fixtures	$33,370.8	$.0	$15,016.9	$.0	$18,354.0	$.0	$.0	$.0
365	OH Conductors & Devices	$18,267.1	$.0	$9,133.5	$.0	$9,133.5	$.0	$.0	$.0
366	Underground Conduit	$41.2	$.0	$20.6	$.0	$20.6	$.0	$.0	$.0
367	Underground Conduct. & Devices	$379.7	$.0	$189.8	$.0	$189.8	$.0	$.0	$.0
368	Line Transformers	$7,846.0	$.0	$5,570.7	$.0	$.0	$2,275.3	$.0	$.0
369	Services	$2,045.2	$.0	$.0	$.0	$.0	$2,045.2	$.0	$.0
370	Meters	$2,119.5	$.0	$.0	$.0	$.0	$2,119.5	$.0	$.0
371	Install. on Cust. Premises	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
372	Leased Prop. on Cust. Prem.	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
373	Street Lighting	$1,432.0	$.0	$.0	$.0	$.0	$.0	$.0	$1,432.0
	Contributions	-$33,984.2	$.0	-$20,450.4	$.0	-$10,980.6	-$2,553.1	$.0	$.0
	Total Distribution Plant	$53,170.5	$.0	$31,134.3	$.0	$16,717.3	$3,886.9	$.0	$1,432.0
	Total Plant before General Plant	$386,602.2	$313,633.2	$31,134.3	$19,798.5	$16,717.3	$3,886.9	$.0	$1,432.0

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Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

	Plant Description	CP	NCP	E	CUST-1	CUST-2	RR	DA	Basis of Classification
	Generation Plant								
340	Land and Land Rights	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
341	Structures & Improvements	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
342	Fuel Holders, Prod., & Access.	0.000	0.000	1.000	0.000	0.000	0.000	0.000	100% energy
343	Prime Movers	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
344	Generators	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
345	Accessory Electric Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
346	Misc. Power Plant Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
121	Wind Energy Production	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
131	Heat Recovery Systems	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
	Insurance Proceeds	0.941	0.000	0.059	0.000	0.000	0.000	0.000	Weighted 340-346
	Disallowed	0.941	0.000	0.059	0.000	0.000	0.000	0.000	Weighted 340-346
	Contributions	0.941	0.000	0.059	0.000	0.000	0.000	0.000	Weighted 340-346
	Total Generation Plant	0.941	0.000	0.059	0.000	0.000	0.000	0.000	
	Distribution Plant								
360	Land and Land Rights	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
361	Structures & Improvements	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
362	Station Equipment	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
363	Storage Battery Equip.	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
364	Poles & Fixtures	0.000	0.450	0.000	0.550	0.000	0.000	0.000	45% demand and 55% customer
365	OH Conductors & Devices	0.000	0.500	0.000	0.500	0.000	0.000	0.000	50% demand and 50% customer
366	Underground Conduit	0.000	0.500	0.000	0.500	0.000	0.000	0.000	50% demand and 50% customer
367	Undergrd Conduct. & Devices	0.000	0.500	0.000	0.500	0.000	0.000	0.000	50% demand and 50% customer
368	Line Transformers	0.000	0.710	0.000	0.000	0.290	0.000	0.000	71% demand and 29% customer (weighted)
369	Services	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
370	Meters	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
371	Install. on Cust. Premises	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
372	Leased Prop. on Cust. Prem.	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
373	Street Lighting	0.000	0.000	0.000	0.000	0.000	0.000	1.000	100% direct assigned
	Contributions	0.000	0.602	0.000	0.323	0.075	0.000	0.000	Weighted 360-372
		0.000	0.586	0.000	0.314	0.073	0.000	0.027	

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Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

			Demand Related		**Energy**	**Customer Related**		**Revenue**	**Direct**
		$000	Coin. Peak	NC Peak	**Related**	Actual	Weighted	**Related**	**Assign.**
	Plant Description	**Total**	*CP*	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*
	General Plant								
383	Computer Software	$1,975.0	$1,602.2	$159.0	$101.1	$85.4	$19.9	$.0	$7.3
389	Land and Land Rights	$7.1	$5.8	$.6	$.4	$.3	$.1	$.0	$.0
390	Structures & Improvements	$33,967.7	$27,556.5	$2,735.5	$1,739.5	$1,468.8	$341.5	$.0	$125.8
391	Office Furniture & Equip.	$450.0	$365.0	$36.2	$23.0	$19.5	$4.5	$.0	$1.7
392	Transportation Equip.	$9,825.1	$7,970.7	$791.2	$503.2	$424.9	$98.8	$.0	$36.4
393	Stores Equip.	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
394	Tools, Shop, & Garage Equip.	$1,166.1	$946.0	$93.9	$59.7	$50.4	$11.7	$.0	$4.3
395	Laboratory Equip.	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
396	Power Operated Equip.	$233.7	$189.6	$18.8	$12.0	$10.1	$2.3	$.0	$.9
397	Communication Equip.	$1,349.2	$1,094.5	$108.7	$69.1	$58.3	$13.6	$.0	$5.0
398	Misc. Equip.	$2,830.3	$2,296.1	$227.9	$144.9	$122.4	$28.5	$.0	$10.5
399	Other Tangible Property	$1,295.5	$1,051.0	$104.3	$66.3	$56.0	$13.0	$.0	$4.8
	Total General Plant	$53,099.6	$43,077.3	$4,276.3	$2,719.3	$2,296.1	$533.9	$.0	$196.7
	Total Plant in Service	$439,701.7	$356,710.5	$35,410.6	$22,517.8	$19,013.4	$4,420.8	$.0	$1,628.6
	Less: Accum. Amortization								
	Generation Plant	$133,445.0	$125,521.4	$.0	$7,923.7	$.0	$.0	$.0	$.0
	Distribution Plant	$15,471.5	$.0	$9,059.4	$.0	$4,864.4	$1,131.0	$.0	$416.7
	General Plant	$18,507.9	$15,014.6	$1,490.5	$947.8	$800.3	$186.1	$.0	$68.6
	Total Accum. Amortization	$167,424.3	$140,536.0	$10,549.9	$8,871.5	$5,664.7	$1,317.1	$.0	$485.2
	Add: Working Capital								
	Cash	$4,493.1	$3,645.0	$361.8	$230.1	$194.3	$45.2	$.0	$16.6
	Materials & Supplies	$20,464.8	$16,602.2	$1,648.1	$1,048.0	$884.9	$205.8	$.0	$75.8
	Fuel	$8,189.5	$.0	$.0	$8,189.5	$.0	$.0	$.0	$.0
	Total Working Capital	$33,147.4	$20,247.2	$2,009.9	$9,467.6	$1,079.2	$250.9	$.0	$92.4
	Total Rate Base	$305,424.8	$236,421.8	$26,870.7	$23,113.9	$14,427.9	$3,354.6	$.0	$1,235.9

2022/23 General Rate Application
Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

Appendix D

		Basis of Classification							
		CP	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*	
	General Plant								
389	Land and Land Rights	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
390	Structures & Improvements	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
390	Structures & Improvements	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
391	Office Furniture & Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
392	Transportation Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
393	Stores Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
394	Tools, Shop, & Garage Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
395	Laboratory Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
396	Power Operated Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
397	Communication Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
398	Misc. Equip.	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
399	Other Tangible Property	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As Generation and Distribution Plants
	Total General Plant	0.811	0.081	0.051	0.043	0.010	0.000	0.004	
	Less: Accum. Amortization								
	Generation Plant	0.941	0.000	0.059	0.000	0.000	0.000	0.000	As Generation Plant
	Distribution Plant	0.000	0.586	0.000	0.314	0.073	0.000	0.027	As Distribution Plant
	General Plant	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As General Plant
	Add: Working Capital								
	Cash	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As General Plant
	Materials & Supplies	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As General Plant
	Fuel	0.000	0.000	1.000	0.000	0.000	0.000	0.000	100% Energy
	Total Working Capital								

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Territory-Wide Cost of Service
Exhibit 2 - Funct. & Classification of Net Revenue Requirements

		Demand Related		**Energy**	**Customer Related**		**Revenue**	**Direct**
	$000	Coin. Peak	NC Peak	**Related**	Actual	Weighted	**Related**	**Assign.**
Expense Description	**Total**	*CP*	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*
Generation Expense								
Non-Fuel Generation O&M	$22,895.3	$11,447.6	$.0	$11,447.6	$.0	$.0	$.0	$.0
Production Fuel	$51,543.1	$.0	$.0	$51,543.1	$.0	$.0	$.0	$.0
Total Generation Expense	$74,438.3	$11,447.6	$.0	$62,990.7	$.0	$.0	$.0	$.0
Distribution Expense								
Distribution O&M	$10,724.9	$.0	$6,280.0	$.0	$3,372.0	$784.0	$.0	$288.8
Total Distribution	$10,724.9	$.0	$6,280.0	$.0	$3,372.0	$784.0	$.0	$288.8
Total O&M before Admin & Gen.	$85,163.2	$11,447.6	$6,280.0	$62,990.7	$3,372.0	$784.0	$.0	$288.8
Admin. & General Expense								
General Plant O&M [excl. billing and cust	$28,843.1	$23,399.1	$2,322.8	$1,477.1	$1,247.2	$290.0	$.0	$106.8
Billing and Customer Accounting Related	$2,156.7	$.0	$.0	$.0	$.0	$2,156.7	$.0	$.0
Total A&G Expense	$30,999.8	$23,399.1	$2,322.8	$1,477.1	$1,247.2	$2,446.7	$.0	$106.8
Total Oper. & Maint. Expense	$116,163.0	$34,846.8	$8,602.8	$64,467.8	$4,619.2	$3,230.7	$.0	$395.7
Net Amortization Expense:								
Generation Amortization	$9,985.8	$9,392.9	$.0	$592.9	$.0	$.0	$.0	$.0
Distribution Amortization	$1,122.9	$.0	$657.5	$.0	$353.1	$82.1	$.0	$30.2
General Amortization	$2,638.3	$2,140.4	$212.5	$135.1	$114.1	$26.5	$.0	$9.8
Total Amort. Expense	$13,747.1	$11,533.3	$870.0	$728.0	$467.1	$108.6	$.0	$40.0
Total Rev. Requirement before Return	$129,910.1	$46,380.0	$9,472.9	$65,195.8	$5,086.4	$3,339.3	$.0	$435.7
Less: Other Revenue	$2,511.4	$.0	$.0	$.0	$.0	$.0	$2,511.4	$.0
Net Rev. Requirement before Return	$127,398.7	$46,380.0	$9,472.9	$65,195.8	$5,086.4	$3,339.3	-$2,511.4	$435.7
Return on Rate Base	$14,105.3	$10,918.6	$1,241.0	$1,067.5	$666.3	$154.9	$.0	$57.1
Total Net Rev. Requirement	$141,504.0	$57,298.6	$10,713.8	$66,263.3	$5,752.7	$3,494.2	-$2,511.4	$492.8

2022/23 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 2 - Funct. & Classification of Net Revenue Requirements

	Basis for Classification							
	CP	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*	
Generation Expense								
Non-Fuel O&M	0.500	0.000	0.500	0.000	0.000	0.000	0.000	50% demand and 50% energy
Production Fuel	0.000	0.000	1.000	0.000	0.000	0.000	0.000	100% energy
Total Generation Expense								
Distribution Expense								
Distribution O&M	0.000	0.586	0.000	0.314	0.073	0.000	0.027	As Distribution Plant
Total Distribution								
Total O&M before Admin & Gen.								
Admin. & General Expense								
General Plant O&M [excl. billing a	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As General Plant
Billing and Customer Accounting F	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% to weighted customer
Total A&G Expense								
Total Oper. & Maint. Expense								
Net Amortization Expense:								
Generation Amortization	0.941	0.000	0.059	0.000	0.000	0.000	0.000	As Generation Plant
Distribution Amortization	0.000	0.586	0.000	0.314	0.073	0.000	0.027	As Distribution Plant
General Amortization	0.811	0.081	0.051	0.043	0.010	0.000	0.004	As General Plant
Total Amort. Expense	0.839	0.063	0.053	0.034	0.008	0.000	0.003	
Total Rev. Requirement before Return								
Total Other Revenue	0.000	0.000	0.000	0.000	0.000	1.000	0.000	
Net Rev. Req. before Return	0.364	0.074	0.512	0.040	0.026	(0.020)	0.003	
Return on Rate Base	0.774	0.088	0.076	0.047	0.011	0.000	0.004	
Total Net Rev. Requirement	0.405	0.076	0.468	0.041	0.025	(0.018)	0.003	

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Territory-Wide Cost of Service
Exhibit 3 - Analysis of Load Data

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Hours in Year	8,760

	Total				
Domestic		**Commercial**		**Street Lighting**	
kWh Sales at the Meter	71,135,079	kWh Sales at the Meter	110,308,050	kWh Sales at the Meter	1,691,484
Load Factor	44%	Load Factor	55%	Load Factor	47%
Individ. Noncoincident Peak (NCP)(kW)	18,540	Individ. Noncoincident Peak (NCP)(kW)	22,895	Individ. Noncoincident Peak (NCP)(kW)	408
Group Coincidence Factor	100%	Group Coincidence Factor	100%	Group Coincidence Factor	100%
NCP at the Meter for the Group (kW)	18,540	NCP at the Meter for the Group (kW)	22,895	NCP at the Meter for the Group (kW)	408
System Coincidence Factor	87%	System Coincidence Factor	83%	System Coincidence Factor	100%
Coincident Peak (CP) at Meter (kW)	16,093	Coincident Peak (CP) at Meter (kW)	19,049	Coincident Peak (CP) at Meter (kW)	408

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Territory-Wide Cost of Service
Exhibit 4 - Demand Allocation Factor

	Coincident Peak Alloc. Factor	*% of Total*	*Noncoincident Peak Alloc. Factor*	*% of Total*
Domestic	16,093	45.3%	18,540	44.3%
Commercial	19,049	53.6%	22,895	54.7%
Street Lighting	408	1.1%	408	1.0%
Total	35,549	100%	41,843	100%
Allocation Factor		*CP*		*NCP*

Method of CP demand allocation:
the peak responsibility method

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Territory-Wide Cost of Service
Exhibit 5 - Energy Allocation Factor

	Energy Alloc. Factor (kWh)	*% of Total*
Domestic	71,135,079	38.8%
Commercial	110,308,050	60.2%
Street Lighting	1,691,484	0.9%
Total	183,134,612	100%
Allocation Factor		*E*

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Territory-Wide Cost of Service
Exhibit 6 - Customer Allocation Factor

	Actual Customers				
	Total Customers	*% of Total*	Weighting Factor	Weighted Customers	*% of Total*
Domestic	12,355	77.7%	1.0	12,355	53.9%
Commercial	3,501	22.0%	3.0	10,503	45.8%
Street Lighting	51	0.3%	1.0	51	0.2%
Total	15,907	100%		22,909	100%
Allocation Factor		*CUST-1*			*CUST-2*

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Territory-Wide Cost of Service
Exhibit 7 - Revenue Allocation Factor

$000	*Existing Rate Revenues*	*% of Total*
Domestic	$56,742.5	42.1%
Commercial	$76,424.9	56.6%
Street Lighting	$1,751.2	1.3%
Total	$134,918.5	100%
Allocation Factor		*RR*

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Territory-Wide Cost of Service
Exhibit 8 - Allocation of Plant in Service (Rate Base)

$000	Total Plant	Domestic	Commercial	Street Lighting	Basis of Allocation
DEMAND RELATED					
Coincident Peak	$236,421.8	$107,023.8	$126,683.1	$2,714.9	CP
Noncoincident Peak	$26,870.7	$11,905.9	$14,702.6	$262.2	NCP
Total Demand	$263,292.4	$118,929.6	$141,385.7	$2,977.1	
ENERGY RELATED	$23,113.9	$8,978.1	$13,922.3	$213.5	E
CUSTOMER RELATED					
Actual	$14,427.9	$11,206.1	$3,175.6	$46.3	CUS-1
Weighted	$3,354.6	$1,809.1	$1,538.0	$7.5	CUS-2
Total Customer	$17,782.6	$13,015.2	$4,713.6	$53.7	
REVENUE RELATED	$.0	$.0	$.0	$.0	RR
DIRECT ASSIGNMENT	$1,235.9	$.0	$.0	$1,235.9	DA
Total Plant in Service	$305,424.8	$140,923.0	$160,021.6	$4,480.2	

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Territory-Wide Cost of Service
Exhibit 9 - Allocation of Net Revenue Requirements

$000	Total Net Rev. Req.	Domestic	Commercial	Street Lighting	Basis of Allocation
DEMAND RELATED					
Coincident Peak	$46,380.0	$20,995.4	$24,852.0	$532.6	CP
Noncoincident Peak	$9,472.9	$4,197.2	$5,183.2	$92.4	NCP
Total Demand	$55,852.9	$25,192.6	$30,035.3	$625.0	
ENERGY RELATED	$65,195.8	$25,324.1	$39,269.6	$602.2	E
CUSTOMER RELATED					
Actual	$5,086.4	$3,950.5	$1,119.5	$16.3	CUS-1
Weighted	$3,339.3	$1,800.9	$1,531.0	$7.4	CUS-2
Total Customer	$8,425.7	$5,751.4	$2,650.5	$23.7	
REVENUE RELATED	-$2,511.4	-$1,056.2	-$1,422.6	-$32.6	RR
DIRECT ASSIGNMENT	$435.7	$.0	$.0	$435.7	DA
Total Net Rev. Req.	$127,398.7	$55,211.9	$70,532.8	$1,654.0	

2022/23 General Rate Application
Territory-Wide Cost of Service
Exhibit 10 - Summary

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$000	Total	Domestic	Commercial	Street Lighting
Present Rate Revenues	$134,918.5	$56,742.5	$76,424.9	$1,751.2
Allocated Rev. Req.	$127,398.7	$55,211.9	$70,532.8	$1,654.0
Rate Base	$305,424.8	$140,923.0	$160,021.6	$4,480.2
Allowed Rate of Return	4.6%	4.6%	4.6%	4.6%
Allowed Return	$14,105.3	$6,508.2	$7,390.2	$206.9
Required Rate Revenues	$141,504.0	$61,720.1	$77,923.0	$1,860.9
Balance	-$6,585.4	-$4,977.6	-$1,498.2	-$109.7
RCC ratio		91.9%	98.1%	94.1%

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Territory-Wide Cost of Service
Exhibit 11 - Average Unit Costs

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		Domestic	Commercial	Street Lighting
DEMAND - $/kW		$0.00	$70.97	$0.00
ENERGY - cents/kWh		77.83	34.89	108.47
CUSTOMER - $/Cust/Month		$42.85	$68.27	$42.85
Basic Data:				
Annual kWh		-	515,244	-
Annual kWh		71,135,079	110,308,050	1,691,484
Number of Customers		12,355	3,501	51
Revenue Check ($000):				
Demand	$36,564.8	$.0	$36,564.8	$.0
Energy	$95,692.3	$55,367.6	$38,490.0	$1,834.7
Customer	$9,246.9	$6,352.5	$2,868.2	$26.2
Total	$141,504.0	$61,720.1	$77,923.0	$1,860.9

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Territory-Wide Cost of Service
Exhibit 12 - Average Unit Costs at $18/month customer charge and $8/kW demand charge

		Domestic	Commercial	Street Lighting
DEMAND - $/kW		$0.00	$8.00	$0.00
ENERGY - cents/kWh		83.01	66.90	110.02
CUSTOMER - $/Cust/Month		$18.00	$0.00	$0.00
Revenue Check ($000):				
Demand	$4,122.0	$.0	$4,122.0	$.0
Energy	$134,713.4	$59,051.4	$73,801.1	$1,860.9
Customer	$2,668.6	$2,668.6	$.0	$.0
Total	$141,504.0	$61,720.1	$77,923.0	$1,860.9

APPENDIX E

GLOSSARY OF TERMS

Amortization

Allocation of the cost of an asset over its useful life, reflecting a reduction in the value of an asset with the passage of time, due in particular to wear and tear.

Capacity

The load at which a generation unit, generation station, or other electrical apparatus is rated either by the user or by the manufacturer.

Consumer Price Index (CPI)

A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Commercial

Customer classification for service other than domestic or street lighting.

Corporation

Qulliq Energy Corporation

Cost of Service

The total cost to the Corporation of providing energy and related utility services to its customers. Includes the cost of invested capital as well as operational costs.

Customer

Individual or entity that takes service from the utility. Similar customers are grouped into customer classes. Customer classes are usually differentiated from each other in terms of the level and type of service they require from the utility.

Customer Class

A distinction between users of electrical energy.

Demand

The rate at which electric energy is delivered to or by a system, part of a system or a piece of equipment; expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averages over any designated period of time. The primary source of demand is the power-consuming equipment of the customers.

Demand Side Management (DSM)

Techniques designed to be used by the customer to reduce their consumption of energy.

Distribution

The act or process of distributing electric energy from convenient points on the transmission or bulk power system to the consumers.

Domestic

Single family residences or an individual apartment where electrical service is provided through one meter, provided that the residence or apartment is not used for commercial purposes.

Efficiency

Engine efficiency; the amount of kilowatt-hours produced per litre of fuel.

Energy

a) Electricity;

b) Heat that is supplied through a district heating system by hot water, hot air or steam; manufactured gas, liquefied petroleum gas, natural gas, oil or any other combustible material which is supplied through a pipeline or any other distribution system directly to a customer; or

c) Any prescribed matter pursuant to a regulation under the Qulliq Energy Act.

Energy Consumption

Use of electrical energy over time, typically measured in kilowatt-hours (kWh).

FERC

Federal Energy Regulatory Commission

Fixed Asset

Tangible property used in the operations of regulated business, but not expected to be consumed or converted into cash in the ordinary course of business.

Generation

This term refers to the act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kWh.

Gross Plant in Service

Represents the accounting cost of all regulated assets current used in ordinary course of business.

Heating Degree Day (HDD)

A unit measuring the extent to which an outdoor dry-bulb temperature falls below an assumed base (18°C). One HDD is counted for each degree of deficiency below the assumed base, for each calendar day on which such a deficiency occurs.

Kilowatt (kW)

The measure of electrical capacity required by the customer at any instantaneous moment. One kilowatt equals 1,000 watts. One megawatt (MW) equals 1,000 kWs.

Kilowatt-hour (kWh)

Basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Load

The amount of electric power delivered or required at any specific point or points on a system. Load originates primarily at the power-consuming equipment of customers.

Load Forecast

An estimate of electrical demand or energy consumption at some future time.

Losses

Refers to the energy that is lost through distribution and transformation.

Maintenance Expense

Direct and indirect expenses including labour, material and others incurred for preserving the operation efficiency or physical condition of the utility plant used for power production, transmission and distribution of energy, and administrative and general operations.

O&M

Operating and Maintenance

Operating Expenses

Direct and indirect expenses, including labour, materials and others, incurred in the production of electricity.

Outage

The period during which a generation unit, distribution line, or other facility is out of service.

Plant

A facility or facilities for the generation, transformation, distribution, delivery, supply or control of energy or for the distribution, delivery or supply of water and sewerage services and includes the site of the facility or facilities, and all land, water, rights to use water, buildings, works, machinery, installations, materials, transmission lines, distribution lines, pipelines, furnishings and equipment, plant in construction, stores and supplies acquired, constructed or used or adapted for or in connection with the facility or facilities.

Power

The rate of generating, transferring, or use of electric energy, with respect to time, usually expressed in kilowatts (kW).

Rate Base

The property of the Corporation used or required to be used to provide service to the public within Nunavut.

Rates [electricity]

The prices at which electricity sold to the customers.

Residual Heating System

Residual heat recovery involves capturing some of the excess heat from the diesel engines.

Revenue Requirement

The revenue level necessary to meet the cost of providing service to the utility's customer.

Station Service

The electric energy used by the Corporation in the course of business.

URRC

Utility Rates Review Council