Net Metering and Community Self-Generation Policy Review

Final Report

InterGroup CONSULTANTS

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EXECUTIVE SUMMARY

The GNWT's 2030 energy strategy has an objective to reduce greenhouse gas emissions from electricity generation in diesel-powered communities by 18,000 tonnes annually by 2030. Approximately 700 tonnes is planned to be achieved through increased solar generation. To assist with achieving this objective, the Northwest Territories has had a net metering program in place since 2014. The net metering program allows customers who own renewable generation to deliver energy to the electric grid that is in excess of their own needs. Customers can also install their own renewable generation without subscribing to the net metering program. Currently, intermittent renewable generation is limited to 20 per cent of the average annual load in each thermal community.

The programs have been successful at providing an opportunity for customers to install their own generation, save money on their energy bills and reduce territorial greenhouse gas emissions. However, the current electricity rate structures do not recover all of the fixed costs of running the system through fixed customer and demand charges. As a result, when customers displace consumption with their own generation, the utilities lose more in revenue than they save in fuel expenses.

Utilities are high infrastructure cost industries and small, isolated grids in the NWT have few economies of scale. As self-generation increases, energy sales decrease but the fixed costs to operate the utility remain in the system. Over time, the utility would need to recover these costs through increased rates to electricity customers. From a cost-causation perspective, the current rate design for self-generators shifts costs to all other utility customers which is contrary to accepted rate design principles.

An analysis completed for this report estimated the net revenue loss to electric utilities from customer-owned (or non-utility) renewable generation to be $0.5 million in 2019. This amount could increase to between $1.8 million to $2.7 million by 2030 if the existing 20 per cent capacity limits are maintained.

Summary of Estimated Potential Rate Impacts of Non-Utility Owned Renewable Generation[1]

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	2030 Estimates Low Case Scenario	2030 Estimates High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$869,000	$1,289,000	$4,271,000	$3,191,000	$4,851,000
Net revenue loss	$493,000	$735,000	$2,293,000	$1,793,000	$2,715,000
Net revenue loss over 2016 levels	$410,000	$652,000	$2,210,000	$1,709,000	$2,632,000
Estimated GHG savings					
Annual GHG savings (tonnes of CO2e)	632	794	1,349	1,084	1,349
GHG savings over 2016 levels (tonnes of CO2e)	465	627	1,182	918	1,182
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$780	$927	$1,700	$1,654	$2,013
Per tonne of GHG savings over 2016 levels	$1,060	$1,173	$1,939	$1,954	$2,296

There are a number of rate policy changes that could be made to reduce the net revenue losses and ensure customers with their own generation pay their share of the costs of maintaining the electricity system. In particular, reducing the credit that net metering customers receive when they deliver surplus generation to the system to be closer to the cost of fuel and increasing fixed customer and demand charges for all customers to better match fixed costs to fixed charges could help reduce the net revenue losses. Subsidies from the Territorial government, either directly to the utilities, or paid through higher rates for government accounts, could help address the remainder of net revenue losses and ensure other customers do not face higher rates as a result of customer-owned generation. The government of the Northwest Territories will need to make policy choices that balance rate impacts on customers with providing opportunities to install renewable generation and reduce greenhouse gas emissions.

Implementation of these changes would require an application and review process before the Public Utilities Board. InterGroup recommends a joint process involving all the electric utilities to ensure coordination and harmonization of the programs.

[1] Excludes utility-owned renewable energy and power purchase agreements.

1.0 INTRODUCTION

InterGroup was retained by the Government of the Northwest Territories (GNWT) to review the existing net metering and self-generation policies and provide advice and recommendations on changes that could help maximize the use of renewable electricity, reduce greenhouse gas (GHG) emissions and minimize costs to electricity ratepayers. Installing customer-owned renewable self-generate helps achieve desirable policy outcomes including reducing greenhouse gas emissions and helping Northerners manage their energy costs. However, independent power generation is also contributing to reduced utility revenues and may result in the need for utilities to install new equipment to maintain grid stability. Both of these outcomes ultimately increase the cost of energy to other ratepayers.

The scope of the assignment includes:

<u>Financial and rate impacts</u>

- Assess the current net costs of the net metering and community self-generation.
- Project the extent to which GNWT subsidies may be required (annually) to protect the utilities and other customers.
- Investigating cost associated with extra equipment needed for grid stability; incremental or marginal cost.
- Forecast future costs using current alternative energy installation trends and known projects to 2030.

<u>Legal and regulatory review</u>

- Review and provide options to enable utilities to enforce community intermittent generation capacity limits, including potential legislative changes, policy directions to the PUB or other legal or regulatory mechanisms that may be available now or following proposed legal or policy changes.

<u>Policy analysis</u>

- Provide policy options that would limit the future negative impact to ratepayers while still promoting the adoption of renewable energy and the reduction of GHG emissions and consider the impacts of changing the split between fixed and variable charges on net metered clients.
- Model the cost and revenue impacts of the policy options.
- Provide draft policy direction to the PUB that would achieve the revised policy objectives.
- Analyze the impact of how the current rate structure impacts the issue and provide recommendations.
- Consider the impact of higher cost recovery in government rates in the policy recommendations.

- Consider and review the structure of existing cost-of-living subsidies (Territorial Power Support Program (TPSP), GNWT Rate Equalization Program (GREP)), how they impact the issue and propose alternative subsidy structures if appropriate.

This report includes the following sections:

- Background: provides a summary of the policy background leading to the development and implementation of the current programs.
- Financial and rate impacts: provides a summary of the results of the modelling of current net costs of the net metering and community self-generation programs using a 2019 base year and estimates for 2030. This section also provides a high level summary of potential costs that might need to be incurred for extra equipment to promote grid stability.
- Legal and regulatory review: Reviews existing and potential additional legal and regulatory tools that may be available to enforce community intermittent generation capacity limits and manage rate impacts of self-generation programs on other customers.
- Policy options: Reviews policy options that could be available to limit future negative rate impacts on customers while still promoting the adoption of renewable energy and the reduction of GHG emissions. This section also provides potential near-term actions for implementation and considers implications for existing subsidy programs.

1.1 SOURCES AND LIMITATIONS

The study is based largely on publicly available historical information and forecasts from sources including:

- General rate applications and annual filings for the Northwest Territories Power Corporation (NPTC) and Northlands Utilities Limited Yellowknife (NUL-YK) and Northlands Utilities Limited Northwest Territories (NUL-NWT) (collectively referred to as NUL).
- Northwest Territories Public Utilities Board (PUB or Board) decisions.
- Information publicly available on the NTPC and NUL websites.
- Other public sources as cited throughout the document.

Some information and estimates were obtained directly from the utilities.

Modelling for this study was conducted consistent with existing rate policies and PUB approved program characteristics. Scenarios are used to consider the effects of potential changes to existing policies. These are modelled primarily for illustrative and comparison purposes and should not be construed as forecasts of future outcomes.

Concurrent with this study, the GNWT retained CIMA+ to conduct a renewable energy penetration analysis to examine maximum renewable energy penetration in five thermal generation communities. Rate and revenue impacts estimated in the CIMA+ study are similar to those prepared for this study, but not identical, because of differences in the study objectives, timeframes considered in the analysis.

2.0 BACKGROUND

The GNWT 2012-2017 solar energy strategy provided guidance and actions to promote the use of solar energy technologies in the NWT. Objectives of the 2012-17 solar strategy included:

1. Increase education and awareness of solar energy technologies for residents, businesses, communities, government departments and public power utility companies.
2. Develop policies and guidelines to reduce institutional barriers to solar energy technology deployment in the NWT.
3. Assist public power utility companies to advance solar/diesel hybrid systems in communities.
4. Promote the use of battery-based solar charging systems in remote 'off-grid' applications.
5. Increase the monitoring of solar energy systems to measure and assess their performance.

Action 5 of the 2012-2017 solar strategy was to work with power utility companies to develop a comprehensive program for grid-interconnected photovoltaic systems. To implement this action, the NWT has had a net metering program in place since 2014. The program allows customers who own renewable generation to deliver energy to the electric grid that is in excess of their own needs. Customers receive credits on their bill at the prevailing retail electricity rates that can be used to offset the costs of future purchases from their electric utility. The existing program was approved by the Public Utilities Board (PUB).

The general objectives of the program, as noted in applications by the utilities to the PUB and other public sources, include:

- Contributing to the achievement of the GNWT's greenhouse gas emissions reduction policy objective by encouraging the adoption of renewable energy and the corresponding reduction of greenhouse gas emissions particularly in thermal generation communities.
- Providing customers the opportunity to produce electricity from renewable technologies for their own consumption.
- Promoting energy conservation and efficiency to help customers manage their energy costs.
- Implementing the net metering program without negatively impacting other customers.[2]

Certain terms and conditions are in place for the net metering program to help ensure net metering customers have the opportunity to generate renewable energy to displace their own generation but limit their ability to generate substantial surplus energy. InterGroup understands these limits are intended, at least in part, to incent appropriate sizing of installations in proportion to customer loads. Such terms and conditions include:

- Net metering customers are limited to installations of 15 kW or less.

[2] PUB Decision 1-2014. Summarized from pages 9 and 10 and GNWT policy documents.

- Net metering customers receive credits for surplus energy delivered to the grid that can be used to offset electricity purchases in future months. The credits have no cash value and expire on March 31st, each year if they are not used.[3]

Net metering differs from net billing programs that are offered in some other jurisdictions such as Alberta. Under a net metering program, the customer receives credits at the full retail rate (i.e., rates designed to recover both variable costs related to fuel and fixed costs related to generation and distribution assets). Under a net billing program, the customer typically receives credits only at the wholesale rate, or the rate generally that recovers the variable cost of generation but not transmission or distribution assets.

In the 2013 application to the PUB to implement the net metering program, NTPC proposed an overall capacity limit for intermittent renewable generation in each isolated community in the Thermal Zones based on 20 per cent of the annual average demand of the community.[4] NTPC noted its proposed cap represented an operational estimate of the level of intermittent renewable generation that could be readily installed without causing system instability. NTPC's proposal was approved by the PUB in Decision 1-2014.[5] InterGroup understands the 20 per cent cap is intended to include all sources of intermittent renewable generation, including utility-owned intermittent generation, not solely customer-owned renewable generation subscribed to the net metering program.

NTPC committed to reviewing the energy cap on an ongoing basis in each community. If further intermittent renewable self-generation beyond the cap was desired, it could be considered.[6]

In considering NTPC's proposal, the PUB accepted that the capacity limits in the Thermal communities may be increased on a community by community basis, having regard to the performance and safety of the system.[7]

2.1 CURRENT POLICY CONTEXT

The GNWT's 2030 energy strategy has a strategic objective to reduce GHG emissions from electricity generation in diesel-powered communities by an average of 25 per cent. Guiding principles included in the 2030 Energy Strategy include:

- Secure, affordable and sustainable, balance energy security, affordability and environmental sustainability;
- Meet climate change commitments;
- Shared responsibility between residents, governments, business and industry;
- Promote partnerships with Indigenous and community governments, business and industry;

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[3] NTPC Net metering program guide. Available: https://www.ntpc.com/docs/default-source/default-document-library/ntpc-net metering-13-08-14.pdf?sfvrsn=2. Accessed November 29, 2020.

[4] The cap is currently calculated based on average load across all seasons, not only the summer. Refer to page 8 of PUB Decision 1-2014.

[5] Refer to page 19 of PUB Decision 1-2014.

[6] Summarized from page 17, PUB Decision 1-2014.

[7] Summarized from page 19, PUB Decision 1-2014.

- Indigenous and community engagement to exchange information and meet local needs;
- Lead by example;
- Innovation and impact, promote solutions that have the largest impact in northern context; and
- Transparency and accountability in implementation.[8]

The GNWT's 2030 Energy Strategy sets out a framework for participation in renewable electricity generation for diesel generation communities that includes three streams:

- Small-scale privately owned renewable generation through the net metering program.
- Mid-scale community owned renewable generation delivered directly to the grid with revenues based on the avoided cost of fuel.
- Larger-scale renewable generation owned in partnership with utilities with negotiated prices and contract terms.[9]

Figure 2-1 is an extract from the GNWT 2030 energy strategy showing the different characteristics of each stream.

The Energy Strategy notes that small-scale and mid-scale generation are subject to the existing 20 per cent capacity limit on intermittent generation. The strategy has a target to reduce average GHG emissions from electricity generation in diesel communities from 72,000 tonnes to 54,000 tonnes by 2030 (a reduction of 18,000 tonnes or 25 per cent below 2016 levels).[10] Of this 18,000 tonnes, approximately 700 tonnes is planned to be achieved through increased solar generation.[11]

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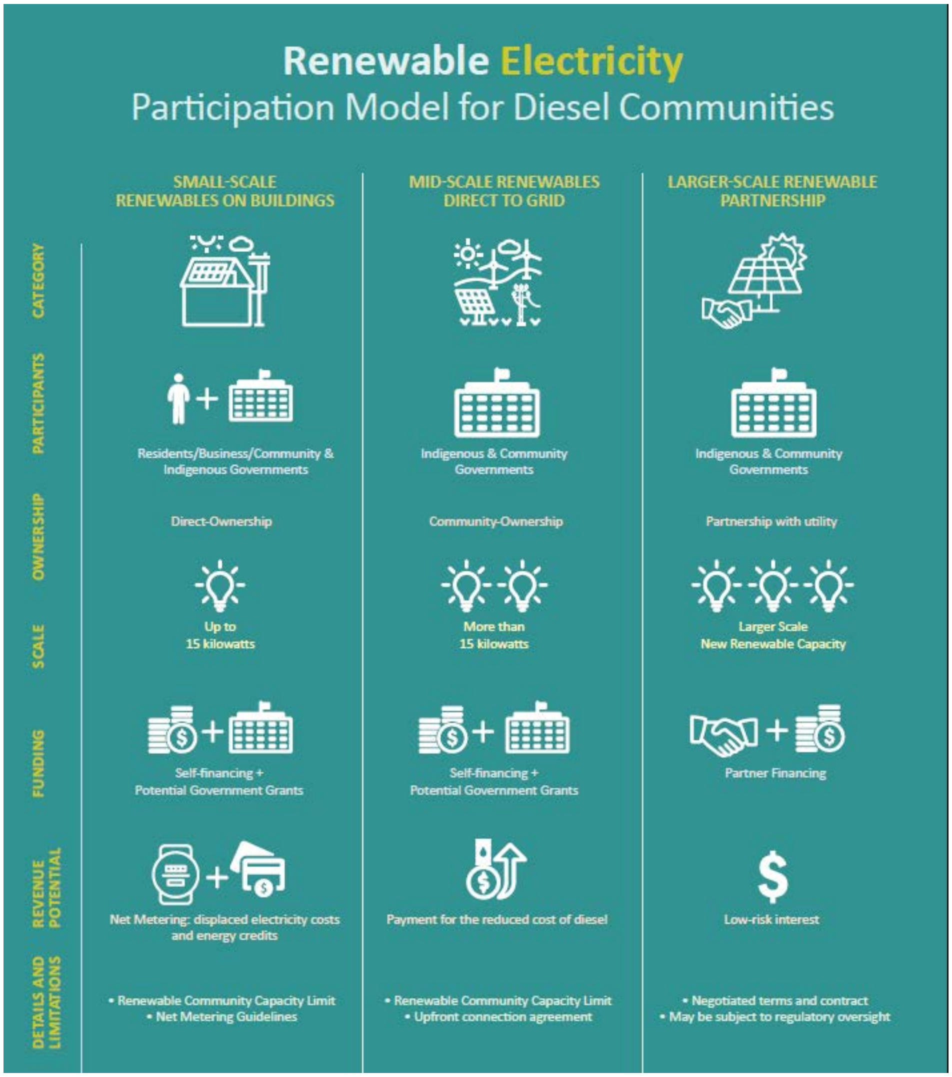
[8] Summarized from page 12. GNWT 2030 Energy Strategy.
[9] Summarized from page 18. GNWT 2030 Energy Strategy.
[10] Page 20, GNWT 2030 Energy Strategy. Page 13 of the GNWT 2030 Energy Strategy notes targets for 2030 are based on 2016 as a reference year.
[11] Page 23, GNWT 2030 Energy Strategy.

Figure 2-1: Renewable Energy Participation Models in the GNWT[12]



[12] Page 18, GNWT 2030 Energy Strategy.

2.2 GNWT GUIDELINES

The GNWT issues policy guidelines that provide context and direction to the PUB in reviewing and approving the net metering programs implemented by utilities in the NWT. The current GNWT net metering program guidelines state:

a) Costs associated with net metering should be transparent and should be tracked by utilities and reported through the PUB to the GNWT on an annual basis. Cost should be defined as the lost revenues less the avoided cost of generation or purchased power, as the case may be.

b) Costs, as defined in (a), should be borne by the applicable utility's customers, until they reach a level deemed to be material by the PUB, at which time, the PUB may recommend funding by the GNWT.

c) Government customers, with the exception of municipal governments in thermal communities, should not be eligible for net metering.

d) Net metering rates implementation criteria should consider providing a degree of certainty of benefits to customers in consideration of their willingness to make an investment in renewable energy assets.

e) The capacity for individual systems taking part in net metering should be no greater than 15 kilowatts to ensure all residents and businesses have an opportunity to participate in the net metering program.[13]

In its 2012/14 Phase II General Rate Application (GRA), NTPC proposed 1 per cent of net income as the threshold for the loss of revenue to be borne by the utility.[14] In its decision, the PUB approved NTPC's proposal and stated it considered the 1 per cent of net income threshold to be relatively immaterial and would not be unduly discriminatory to other customers.[15] Reductions in net income decrease the ability of utilities to reinvest in assets and eventually lead to increased rates for other customers on the system.

With respect to the potential for the GNWT to provide a subsidy to a utility for lost revenue in excess of the 1 per cent threshold, the PUB stated its view that for ratemaking purposes the GNWT subsidy must be viewed as a transitional measure to cushion the impact on other customers of adding net metering customers to the system.[16]

[13] GNWT Net metering guidelines, dated July 11, 2018.
[14] Summarized from paragraph 114 of PUB Decision 7-2016.
[15] Paragraph 137, page 45. PUB Decision 7-2016.
[16] Paragraph 127, page 43. PUB Decision 7-2016.

2.3 ISSUES IDENTIFIED WITH CURRENT PROGRAMS

The PUB, utilities and other stakeholders have identified certain issues with the existing net metering and community generation programs, including:

1. Existing fixed charges (customer and demand charges) do not fully recover the fixed costs of the electricity system. As a result, when net metering customers buy less energy, the lost revenue will be made up by increasing rates for net metering and other utility customers in future rate applications.
2. Net metering customers receive credits at the full retail variable energy rate. This rate is higher than what a utility saves when they displace a unit of system-generated energy with a unit of energy from the renewable net metering customer. The retail variable energy rates are designed to recover not just the cost of fuel, but also generation assets to serve capacity peaks and the distribution infrastructure that connects customers to the central generation system. Generation from net metering customers can reduce fuel costs but does not reduce the need for generation capacity to meet winter peaks or distribution assets to transport power to and from customers.
3. As intermittent renewable generation increases on the system, it can reduce thermal generation efficiency as larger units are required to run to ensure the system can be supported. This means more fuel must be used for every kilo-watt hour of generation.
4. Increased intermittent renewable generation can also create capacity and reliability concerns.
5. As capital costs of renewable generation have decreased and some communities have reached the 20 per cent capacity limit, the utilities have noted concerns that renewable generation systems may continue to be installed by customers, leading to potential safety concerns as well as difficulty tracking the impacts on utility rates. These installations may occur entirely ‘behind the meter’ without delivering energy to the grid. However, these systems still result in reduced sales and therefore increase costs to utility customers.
6. Deployment of solar capacity in zones primarily served by hydroelectricity does not reduce GHG emissions while increasing fixed costs, thus contravening to two of the guiding principles of NWT’s Energy Strategy.

2.3.1 Rate Design of Fixed and Variable Charges

Electricity rates in the NWT are set for different rate zones:

- NTPC’s Snare rate zone which is largely served by hydroelectric generation.
- NTPC’s Taltson rate zone which is largely served by hydroelectric generation.
- NTPC’s Thermal rate zone which is largely served by thermal generation.
- NUL-Yellowknife which is largely served by hydroelectric generation.
- NUL-NWT’s Hydro rate zone which is largely served by hydroelectric generation.
- NUL-NWT’s Thermal rate zone which is largely served by thermal generation.

The PUB noted the net metering program has the potential to affect utility revenues and costs for a number of reasons. In particular:

- The portion of fixed generation, transmission and distribution costs included in the energy rate which will not be recovered due to netting of energy generated against energy consumed.[17]
- Where compensation rates for net metering energy delivered to the system deviates from the utility's long-run marginal cost, this may result in uneconomic allocation of resources.[18]

Current electricity fixed charges (customer charges for residential customers and demand charges for general service customers) do not fully recover the fixed costs of electricity system assets needed to provide service to customers. Much of a utility's costs are fixed, at least in the short-term, while revenue has typically been weighted more heavily to variable energy charges. As an example, Table 2-1 compares the fixed and variable components of costs and revenues as calculated by NTPC's cost of service study approved by the PUB for residential and general service customers (including both government and non-government customers).[19]

Table 2-1 shows that fixed charges recover only between 11 per cent to 33 per cent of total fixed costs for customers in each zone, while variable costs recover between 111 per cent to 219 per cent of total variable costs. As net metering increases, the amount of energy sold by the utility will decrease. This results in fewer units of energy being available to recover fixed costs. Over time, this rate design will result in more and more fixed costs needing to be recovered from other customers, otherwise the utilities will not have sufficient revenue to maintain and upgrade electricity infrastructure.

NTPC's customer charges and demand charges were frozen at the existing levels in the 2016/19 Phase II GRA pursuant to a GNWT policy directive that stated:

> NTPC monthly fixed customer charges and demand charges to remain the same. Maintaining a low monthly customer charge assists residential customers to manage cost of living through conservation and efficiency. Businesses can also manage their energy consumption more easily than their demand consumption. Recovering a portion of fixed and demand charge costs through energy rates provides better price signals to businesses and residents. The current NTPC monthly customer and demand charges should remain the same until further direction is given. Monthly customer and demand charges should be comparable across zones and utilities to ensure no undue disparity between customers.[20]

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[17] Page 36. Decision 1-2014.
[18] Summarized from paragraph 126 of Decision 7-2016.
[19] NUL has not published recent cost of service studies but InterGroup understands similar relationships between costs and rates existed at the time of the last cost of service studies.
[20] Directive 7. 2017 GNWT Electricity Rate Policy Direction. Dated February 23, 2017.

Table 2-1: Comparison of 2018/19 Fixed and Variable Costs and Revenues for NTPC Customers by Zone ($000s)[21]

	Snare Zone		Taltson Zone		Thermal Zone	
	Residential	General Service	Residential	General Service	Residential	General Service
Fixed Costs (demand and customer related)	$1,186	$569	$2,021	$1,357	$8,693	$8,828
Variable Costs (energy related)	$946	$689	$2,054	$2,193	$15,990	$23,087
Fixed Revenues (customer and demand charges)	$132	$134	$273	$443	$1,046	$1,584
Variable Revenues (energy charges)	$1,660	$1,504	$2,853	$2,432	$22,373	$31,935
Fixed Revenue Cost Coverage	11%	23%	14%	33%	12%	18%
Variable Revenue Cost Coverage	176%	219%	139%	111%	140%	138%
Average Revenue to Cost Coverage per Zone	101%	101%	85%	85%	101%	101%

In the short-term, demand and customer costs are largely fixed. In the longer-term, reduced demand may help avoid the need for new capital investment to serve load growth. However, InterGroup notes:

- Recent load growth has been very flat for all three utilities.[22] NTPC's total annual energy sales have been relatively flat for several years, 302.8 GWh in 2016/17 compared to 304.5 GWh in 2019/20 (0.5 per cent increase total over three years).[23]
- Energy efficiency measures tend to decrease the average use by each customer such that load growth is often driven primarily by increases in population.
- These assets typically have long service lives (30 to 40 years) and therefore it can be decades before any related cost savings are realized by customers.

The impact of demand on the opportunities for further renewable generation is being examined in a separate study by the GNWT.

2.3.2 Compensation Rate for Generation Delivered to the Grid

The net metering program and the mid-scale community owned renewable generation programs provide different levels of compensation for renewable energy delivered to the grid.

[21] Total for both government and non-government customers. Summarized from NTPC's 2018/19 Phase II Compliance Filing cost of service study. Variable costs include those classified to energy in NTPC's cost of service study. Fixed costs include those classified to demand and customer.

[22] The most recent annual reports of finance for all three utilities show less than 0.1% load growth over the previous year.

[23] NTPC Annual report of finance to the PUB for 2016/17 and 2019/20.

- Small-scale privately owned renewable generation through the net metering program receive credits at the full retail rate, i.e., rates designed to recover both the variable costs of fuel and the fixed costs of assets that support system capacity and reliability.
- Mid-scale community owned renewable generation is delivered to the grid at a price based on the avoided cost of fuel.

For example, the current non-government residential energy rate in Fort McPherson is $0.68 per kWh.[24] However the cost of fuel built into rates in Fort McPherson is $0.36 per kWh.[25] Net metering customers receive a credit for their generation at the retail rate of $0.68 per kWh. As a result, net metering customers receive a credit for surplus generation that is $0.32 per kWh higher than the savings from displaced fuel consumption. That portion of the retail rate is ordinarily what funds the cost of assets required to provide capacity and reliability services. As the number of net metering customers increases, this results in lost revenue to the utilities that eventually is made up through increasing rates for all customers.

A mid-scale community owned renewable generator would receive a credit at the avoided cost of fuel, or about $0.36 per kWh. For these customers the utility pays a price that is based on the fuel savings and as a result there is little or no impact on utility revenues and rates charged to other customers.

2.3.3 Reliability and Fuel Efficiency

At the time the original net metering program was approved, utilities indicated a concern that too much intermittent generation could affect power quality and stability on the system and adversely impact both net metering customers and other customers. Since that time there have been concerns noted that utility generation fuel efficiency can be affected as well. If increased renewable penetration reduces fuel efficiency, some of the GHG benefits from renewable generation would be offset by reduced fuel efficiency as more fuel on average is required to generate each unit of energy.

Concurrent with this study, the GNWT has retained a consultant to examine the implications of increased renewable penetration on fuel efficiency.

2.3.4 Impact of Capacity Limits

Table 2-2 summarizes the intermittent renewable installed capacity and the remaining capacity available in each NWT community. The capacity limits are affected by both net metering customers and other community renewable generation projects. As of July 2020, nine of NTPC's isolated thermal communities[26] had reached or exceeded the capacity limits under the 20 per cent cap:

1) Aklavik;
2) Colville Lake;

[24] Rates effective September 1, 2020. NTPC website. Available: https://www.ntpc.com/customer-service/residential-service/what-is-my-power-rate. Accessed November 29, 2020.

[25] $1.277 per litre divided by a fuel efficiency of 3.580 kWh/litre per schedule 4.0.4 from NTPC's 2016/19 Phase I GRA compliance filing dated March 16, 2018.

[26] Dettah is connected to the Snare/Yellowknife hydroelectric system and does not have its own diesel generation or a defined community-specific capacity limit.

3) Fort Liard;
4) Fort Simpson;
5) Inuvik;
6) Jean Marie River;
7) Lutsel k'e;
8) Paulatuk; and
9) Tulita.

Concerns have been expressed about the ability of the utilities to enforce the current 20 per cent capacity limits in each community. These installations may occur entirely ‘behind the meter’ without subscribing to the program and delivering energy to the grid. However, these systems still result in reduced sales and therefore increase costs to utility customers.

Table 2-2: Intermittent Renewable Capacity in NWT Communities (kW) as of July 2020[27]

Utilities by Zones	Intermittent Renewable Energy Capacity Allowed	Current Solar Capacity Installed		Planned Projects	Current Available Capacity
		Net Metering Program (<15 kW)	Other Intermittent Renewable Generation (incl. Utility Owned)		
NTPC - Snare	183	22	25	0	136
NTPC - Taltson	659	1	5	0	653
NTPC - Thermal	1,813	483	691	272	520
NUL Yk	3,564	309	0	0	3,255
NUL NWT - Hydro	676	22	60	0	594
NUL NWT - Thermal	94	10	0	0	84
Total	**6,989**	**847**	**781**	**272**	**5,242**

[27] NTPC data from NTPC Renewable Microgrid Capacity by Community as of July 14, 2020. Available: https://www.ntpc.com/docs/default-source/customer-service-docs/net metering-capacity.pdf?sfvrsn=2. Accessed March 2, 2021; NTPC Snare zone includes intermittent renewable energy capacity estimated for Dettah based on 20% of average load from NTPC 2006/08 GRA Phase I Compliance filing Schedules; NUL estimates were prepared by InterGroup based on data from NUL. To date, intermittent renewable capacities include solely solar capacity installations.

3.0 ESTIMATED FINANCIAL AND RATE IMPACTS OF EXISTING NON-UTILITY GENERATION

3.1 METHODS AND APPROACH

The financial and rate impacts of renewable generation are different depending on which of the existing programs or models is used as shown in Table 3-1. For utility-owned generation (including generation purchased by the utility through a power purchase agreement or other contractual arrangement), the costs of renewable generation are already built into customer rates. For non-utility generation (including generation subscribed to the net-metering program and other generation that is not subscribed to the existing program), financial and rate impacts can arise from:

- Compensation for energy delivered to the grid being credited at a rate higher than the average cost of fuel (i.e., higher than the fuel savings to the utility). In the NWT this issue currently arises for the net-metering program. The NWT 2030 Energy Strategy notes payments for mid-scale renewables are intended to match the potential fuel savings.[28]
- Displacing sales and as a result reducing utility revenues that are eventually made up by increasing costs to all customers.

Both utility and non-utility intermittent renewable generation can reduce utility thermal generation fuel efficiency as a result of needing to keep larger or less efficient generating units running and can potentially drive new infrastructure costs to preserve system stability and reliability.

Table 3-1: Potential Financial and Rate Impacts of Different Types of Renewable Generation in the NWT

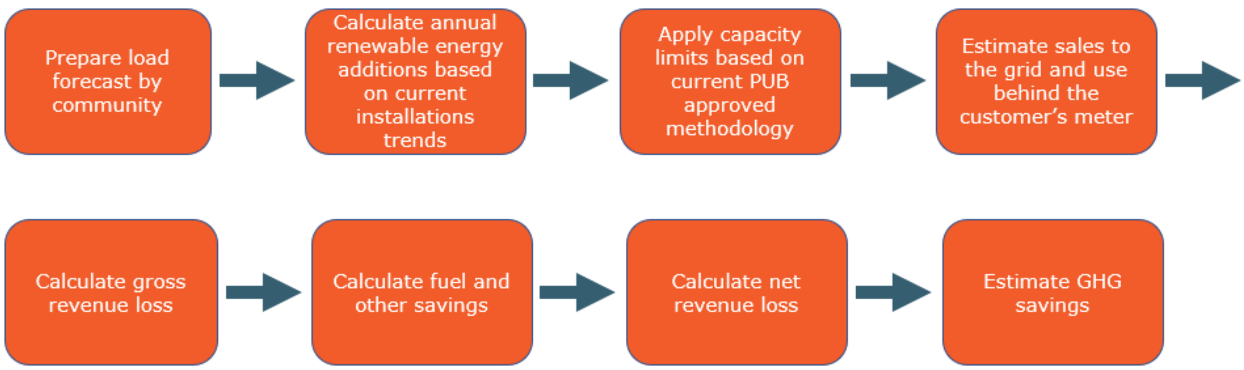
	Compensation for energy delivered higher than fuel savings	Displace electricity sales and reduce utility revenues	Potentially reduce utility generation fuel efficiency	Potentially driving stability and reliability costs
Net metering	Yes	Yes	Yes	Yes
Mid-scale renewable direct to grid	No – price intended to correspond to fuel savings	No	Yes	Yes
Behind the meter installations not subscribed to other programs	No. Energy not delivered to grid.	Yes	Yes	Yes
Utility-owned generation	No	No	Yes	Yes

[28] Page 18. GNWT 2030 Energy Strategy.

InterGroup prepared a model to better understand the potential impacts of the existing net metering program and other non-utility generation on utility revenues and the future availability of renewable energy under the existing 20 per cent cap for the period from 2020 through 2030.

The purpose of the model generally is to develop a base case against which future policy options can be evaluated. The model is not intended to provide precise estimates of future impacts on utility revenues, as these will be subject to a number of cost drivers outside of the ability of the utilities or the GNWT to control, including fuel prices and load growth. However, the model is anticipated to be a useful tool for understanding the general direction and magnitude of future outcomes based on the current programs and potential future program changes. Figure 3-1 provides a flow chart that illustrates the steps undertaken in the model. Further details are provided in Appendix A.

Figure 3-1: Flowchart Illustrating Modelling Steps



Four scenarios are examined in the model:

1. An estimate of 2030 revenue implications using existing 2019 installations.
2. A base case using recent average additions to renewable energy installations in each rate zone.
3. A low case scenario assuming lower than average uptake of new renewable generation.
4. A high scenario assuming higher than recent average uptake of new renewable generation.

The model estimates:

- Gross revenue loss to the utilities (i.e. the total revenues that are displaced by renewable generation).
- Net revenue loss (i.e. the gross revenues less fuel and other operating expense savings from avoided thermal generation).
- Accumulative rate increases over and above inflation needed to offset the net revenue loss. For example, a rate increase of 1 per cent in 2030 would indicate an additional increase of 1 per cent over and above inflation. The rate increase represents the total increase required over existing rates adjusted for inflation, it is not an average annual rate increase.
- GHG emissions reductions.

3.2 ASSUMPTIONS AND LIMITATIONS

Data sources, assumptions and inputs used in developing the model are documented in Appendix A. Key assumptions include:

- Annual cost inflation of 2 per cent based on the Bank of Canada long-term target for inflation. Revenue losses account for inflation.
- Annual load growth of 1 per cent in hydro zones and 0.5 per cent in thermal zones based on recent actual trends.
- Future installation of utility-connected renewable generation is capped at 20 per cent of average demand in each community (that is, once a community reaches the maximum capacity defined by the 20 per cent cap, it is assumed no future renewable generation can be connected). For communities that have already exceeded the cap, the model assumes all of the known existing generation remains, but no additional renewable generation can be installed.
- The calculation of net revenue loss to each utility from the net metering program is based on NTPC's current reporting structure to the PUB, including:
    - Credits for residential and general service customers are calculated based on the full retail energy rate for each utility and rate zone (i.e., credits for surplus generation delivered to the utility's grid). For NTPC the estimates are blended rates based on 2019 actuals. The retail energy rate includes adjustments for purchase power expense to NUL-Yk and NUL-NWT.
    - Estimated revenue loss from reduced consumption is based on 1,000 kWh of reduced consumption for each installed kW capacity excluding exported energy to the utility system consistent with the current PUB approved formula for calculating revenue losses.
- For existing known other non-utility owned generation that is not subscribed to the net metering program, revenue losses are calculated assuming 1,000 kilo-watt/hours of generation per installed kilo-watt consistent with the current PUB approved method for calculating revenue losses. These amounts are not metered by the utilities but are assumed to represent lost sales that would otherwise have been made.
- There is no turnover on solar PV stock. Solar PVs reaching their end of life before 2030 are assumed to be replaced with an equivalent capacity PV.

Known limitations on the model include:

- Some communities have already exceeded the 20 per cent generation cap and there are concerns about the ability to enforce the capacity limits.
- There are also concerns there may be customer-owned renewable generation installed on the system that is not subscribed to the net metering program or does not have a connection agreement with a utility.
- The model assumes generation is intermittent with no broad usage of battery or other storage technologies.

- The model does not account for potential power quality or generation efficiency implications of increased penetration of renewables. Those issues are currently being examined in a separate GNWT study.

Estimated greenhouse gas savings were calculated using the methods summarized inAppendix B. The following key assumptions are noted:

- GHG savings are calculated based on total generation, and as incremental savings over 2016 levels consistent with the GNWT policy to reduce GHG emissions compared to average historical levels.
- The model assumes no GHG savings arise from net metering generation in rate zones that are predominantly served by hydro-electricity.

3.3 INITIAL RESULTS

3.3.1 Net Metering Program

Results of the modelling for renewable installations subscribed to the net-metering program are summarized in the following tables:

- Table 3-2 summarizes the estimated lost revenues, accumulative rate increases that would be required to recover the lost revenues, estimated savings to existing subsidy programs, estimated GHG savings (measured in tonnes of CO2-equivalent gases (CO2e) and estimated lost revenue per tonne of GHG savings.
- Table 3-3 provides the estimated lost revenues and accumulative rate increases by rate zone.
- Figure 3-2 breaks out the components of the net revenue loss and the cost savings for each scenario.

Table 3-2: Net Metering Program Outcomes - 2019 Preliminary Actuals and 2030 Estimates

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	Low Case Scenario	High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$597,000	$742,000	$3,724,000	$2,643,000	$4,303,000
Net revenue loss	$330,000	$410,000	$1,968,000	$1,468,000	$2,390,000
Accumulative rate increase required to eliminate net revenue loss	0.3%	0.3%	1.3%	0.9%	1.5%
Net revenue loss over 2016 levels	$285,000	$365,000	$1,922,000	$1,422,000	$2,345,000
Community capacity limits					
Communities at or above capacity limit	6	3	27	17	31
Communities with capacity remaining	25	28	4	14	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$268,000	$211,000	$294,000
Avoided GREP costs	$1,000	$1,000	$10,000	$7,000	$10,000
Estimated GHG Savings					
Annual GHG Savings (tonnes of CO2e)	408	408	963	698	963
GHG Savings over 2016 levels (tonnes of CO2e)	300	300	855	590	855
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$810	$1,006	$2,043	$2,102	$2,482
Per tonne of GHG savings over 2016 levels	$1,102	$1,369	$2,302	$2,487	$2,796

Table 3-3: Net Metering Program Estimated Lost Revenues by Rate Zone - 2019 Preliminary Actuals and 2030 Estimates[29]

2019 Preliminary Actuals							
	NTPC Snare	**NTPC Taltson**	**NTPC Thermal**	**NUL Yk**	**NUL NWT Hydro**	**NUL NWT Thermal**	**Total**
Net Revenue Loss ($)	68,000	2,000	235,000	17,000	4,000	3,000	**330,000**
Electricity Sales Revenue ($)	40,634,000	10,010,000	57,319,000	9,748,000	4,768,000	3,544,000	**126,023,000**
Accumulative rate impact	0.2%	<0.1%	0.4%	0.2%	0.1%	0.1%	**0.3%**
2030 Estimates – Base Case Scenario							
	NTPC Snare	**NTPC Taltson**	**NTPC Thermal**	**NUL Yk**	**NUL NWT Hydro**	**NUL NWT Thermal**	**Total**
Net Revenue Loss ($)	1,022,000	3,000	630,000	265,000	5,000	43,000	**1,968,000**
Electricity Sales Revenue ($)	50,523,000	12,447,000	71,269,000	12,120,000	5,928,000	4,407,000	**156,694,000**
Accumulative rate impact	2.0%	<0.1%	0.9%	2.2%	0.1%	1.0%	**1.3%**

[29] Revenues for NUL-YK and NUL-NWT Hydro are net of revenues paid to NTPC for wholesale service.

Figure 3-2: Breakdown of Estimated Revenue Losses and Avoided Costs under Net Metering Program - 2019 Preliminary Actuals and 2030 Estimates

Description	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	2030 Estimates Low Case Scenario	2030 Estimates High Case Scenario
Gross Revenue Loss:	**$597,000**	**$742,000**	**$3,724,000**	**$2,643,000**	**$4,303,000**
1) Sales Exported to Utilities' System	$120,000	$149,000	$941,000	$659,000	$1,095,000
2) Own Consumption	$415,000	$515,000	$1,820,000	$1,387,000	$2,160,000
3) NTPC Wholesale Revenue Loss from NUL Net metering	$62,000	$77,000	$962,000	$598,000	$1,048,000
Cost Savings:	**$267,000**	**$331,000**	**$1,756,000**	**$1,176,000**	**$1,913,000**
1) Avoided Fuel or Purchase Power Cost	$243,000	$302,000	$1,581,000	$1,043,000	$1,690,000
2) Avoided Non-fuel Variable Cost	$24,000	$29,000	$174,000	$133,000	$223,000
Net Revenue Loss	**$330,000**	**$410,000**	**$1,968,000**	**$1,468,000**	**$2,390,000**
Net Revenue Loss over 2016 Levels	$285,000	$365,000	$1,922,000	$1,422,000	$2,345,000

Key findings from the modelling of the current net metering program include:

1. The majority of the gross revenue loss in 2019 arises as a result of displaced sales from generation used behind-the-meter (approximately $0.415 million of the total of $0.597 million). The remainder of the lost revenue arises from credits for generation delivered to the grid.[30]
2. The estimated net revenue loss for all utilities, including reduced wholesale revenues to NTPC as a result of NUL's net metering customers is approximately $0.330 million in 2019. The majority of this ($0.235 million) arises in NTPC's thermal zone. This is somewhat higher than reported by NTPC in its annual report of finances as a result of including the effect of reduced wholesale revenues due to NUL's net metering customers.
3. The estimated net revenue loss from the net metering program for NTPC is already higher than the 1 per cent threshold adopted by the PUB below which it indicated that in its view the revenue impact would be relatively immaterial and would not be unduly discriminatory to other customers. The current GNWT guidelines indicate the PUB may recommend funding by the GNWT if the PUB determines the amounts become material. In the event these costs continued to be recovered from other customers, accumulative rate increases required to recover the lost revenue are estimated to be 0.3 per cent in 2019 and 1.3 per cent by 2030.
4. The net revenue loss is estimated to increase to $1.968 million in 2030 in the Base Case Scenario. Approximately half of this revenue loss would arise in NTPC's Snare zone (including reduced wholesale revenues to NUL). Intermittent renewable generation in the Snare system primarily displaces existing hydro-electric generation, and therefore has no incremental reduction in GHG emissions.
5. The high scenario does not forecast any additional GHG savings over the base case scenario because the additional renewable generation is added to zones that are predominantly hydro-electric generation so there are no incremental GHG savings.

3.3.2 Other Renewable Generation

Some of the existing renewable generation subject to the capacity cap is not subscribed to the net metering program:

- Utility-owned generation where the costs are recovered through utility rates;
- Power purchase agreements where generation is sold to a utility at a price comparable to the variable cost of generation. These costs are also recovered through utility rates; and
- Other non-utility owned generation that is 'behind-the-meter' and does not deliver energy to the grid but does result in reduced utility revenues.

InterGroup prepared an estimate of the reduction in utility revenues as a result of known non-utility owned generation that is not subscribed to the net metering program or does not deliver

[30] Please see Appendix A, Table A-6.

energy to a utility through a purchase agreement. NUL did not identify any existing such projects in Yellowknife. The assumptions and methods used to estimate the impacts on revenues are provided in Appendix A. The results of the analysis are summarized in Table 3-4. Key assumptions and limitations used in preparing the estimates include:

- The estimates include existing and known-planned projects only.
- The model assumes these customers are general service customers in NTPC-served communities so there is no impact on TPSP or GREP.
- Estimated revenue losses from these types of projects are not currently reported to the PUB.

Projects in zones primarily served by hydro-electricity are assumed not to have incremental GHG savings.

Table 3-4: Estimated Revenue Losses and GHG Savings from Other Non-utility Renewable Generation for Base Case 2019 and 2030[31]

	2019 Preliminary Actuals						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Revenue and rate impacts							
Gross Revenue Loss ($)	10,000	7,000	240,000	0	15,000	0	272,000
Net Revenue Loss ($)	9,000	6,000	141,000	0	6,000	0	163,000
Electricity Sales Revenue ($)	40,634,000	10,010,000	57,319,000	9,748,000	4,768,000	3,544,000	126,023,000
Accumulative rate impact	<0.1%	0.1%	0.2%	0.0%	0.1%	0.0%	0.1%
Estimated GHG Savings							
Annual GHG Savings (tonnes of CO2e)	0	0	224	0	0	0	224
GHG Savings over 2016 levels (tonnes of CO2e)	0	0	166	0	0	0	166
Net revenue loss per tonne of GHG savings							
Per tonne of Annual GHG savings	0	0	$628	0	0	0	$726
Per tonne of GHG savings over 2016 levels	0	0	$850	0	0	0	$982
	2030 Estimates						
	NTPC Snare	**NTPC Taltson**	**NTPC Thermal**	**NUL Yk**	**NUL NWT Hydro**	**NUL NWT Thermal**	**Total**
Revenue and rate impacts							
Gross Revenue Loss ($)	12,000	8,000	508,000	0	18,000	0	547,000
Net Revenue Loss ($)	12,000	8,000	298,000	0	8,000	0	325,000
Electricity Sales Revenue ($)	50,523,000	12,447,000	71,269,000	12,120,000	5,928,000	4,407,000	156,694,000
Accumulative rate impact	<0.1%%	0.1%	0.4%	0.0%	0.1%	0.0%	0.2%
Estimated GHG Savings							
Annual GHG Savings (tonnes of CO2e)	0	0	386	0	0	0	386
GHG Savings over 2016 levels (tonnes of CO2e)	0	0	327	0	0	0	327
Net revenue loss per tonne of GHG savings							
Per tonne of Annual GHG savings	0	0	$365	0	0	0	$422
Per tonne of GHG savings over 2016 levels	0	0	$430	0	0	0	$497

[32] Hawaii solar integration study. 2013. National Renewable Energy Laboratory. Available: https://www.nrel.gov/docs/fy13osti/57215.pdf. Accessed March 2, 2021.

3.3.3 Incremental costs to integrate renewables and maintain system stability

InterGroup understands that at higher penetration levels, utilities may incur additional costs to integrate intermittent renewable generation. The 2013 Hawaii Solar Integration Study found that adding large amounts of new solar power to the electric grids on Maui and Oahu—enough to achieve roughly 20 per cent renewable energy penetration—will create operational challenges that could affect grid reliability.[32]

A 2017 study by Power Advisory found that wind integration costs could typically range between $0.50 to $6/MWh but that cost estimates are attributable to differences in methodologies, definitions, power system characteristics, fuel prices, wind output forecasts and the degree to which thermal plant cycling costs are considered.[33]

InterGroup also understands integration costs may include reduced fuel efficiencies as a result of operating generating units to support intermittent generation. InterGroup is not aware of any specific cost estimates prepared for the NWT or specific capital costs incurred by NWT utilities for such purposes to date. Conceptually however, the idea that there are costs associated with integrating intermittent renewables appears to be considered in a number of jurisdictions. Concurrently with this study, the GNWT retained CIMA+ to prepare an analysis of potential effects of increased renewable penetration on efficiency.

3.3.4 Summary of Findings

Table 3-5 summarizes the estimated impacts of non-utility owned renewable generation[34] for 2019 and 2030 based on the modelling completed to date. Key findings include:

- The estimated rate impact of the net metering program reported by NTPC in its 2019/20 annual report of finances exceeded the 1 per cent threshold established by the PUB. Under the current GNWT rate policy guidelines the PUB could request the GNWT provide funding to offset the net revenue losses. Net revenue losses for NUL are lower in 2019 as a result of fewer non-utility-generation customers.
- The net revenue loss reported by NTPC to the PUB is lower than calculated in this report, because NTPC does not report estimates of lost wholesale revenues as it does not have direct access to that data. NTPC's reporting is also limited to revenue losses related to the net metering program. It does not include lost revenues from other non-utility generation projects.

[32] Hawaii solar integration study. 2013. National Renewable Energy Laboratory. Available: https://www.nrel.gov/docs/fy13osti/57215.pdf. Accessed March 2, 2021.
[33] Page 14. Independent assessment of renewable generation costs and the relative benefits of these projects compared to Site C. Power Advisory LLC. Prepared for the Clean Energy Association of BC and the Canadian Wind Energy Association. 2017. Available: https://canwea.ca/wp-content/uploads/2014/01/PowerAdvisory-AssessmentGenerationCostsBenefitsReSiteC-web.pdf. Accessed March 2, 2021.

- The majority of the estimated revenue losses arise from the use of generation to displace consumption behind-the-meter.
- Estimates prepared in this report have assumed the 20 per cent cap on renewable generation in each community can be enforced and can limit installations for both net metering customers and customers who install their own generation without subscribing to the net metering program.
- It is understood there are concerns that utilities may not have complete visibility of all non-utility generation installations that are not subscribed to the net metering program. This limits the ability to prepare estimates of net revenue losses.

Table 3-5: Summary of Estimated Potential Rate Impacts of Non-Utility Owned Renewable Generation[35]

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	Low Case Scenario	High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$869,000	$1,289,000	$4,271,000	$3,191,000	$4,851,000
Net revenue loss	$493,000	$735,000	$2,293,000	$1,793,000	$2,715,000
Net revenue loss over 2016 levels	$410,000	$652,000	$2,210,000	$1,709,000	$2,632,000
Incremental capital costs	None specified	Under review in CIMA+ study			
Incremental fuel efficiency losses	None specified	Under review in CIMA+ study			
Accumulative rate increase required to eliminate net revenue loss	0.4%	0.5%	1.5%	1.1%	1.7%
Community capacity limits					
Communities at or above capacity limit	6	3	27	17	31
Communities with capacity remaining	25	28	4	14	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$268,000	$211,000	$294,000
Avoided GREP costs	$1,000	$1,000	$10,000	$7,000	$10,000
Estimated GHG savings					
Annual GHG savings (tonnes of CO2e)	632	794	1,349	1,084	1,349
GHG savings over 2016 levels (tonnes of CO2e)	465	627	1,182	918	1,182
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$780	$927	$1,700	$1,654	$2,013
Per tonne of GHG savings over 2016 levels	$1,060	$1,173	$1,939	$1,954	$2,296

[35] Excludes utility owned and power purchase agreements.

3.4 SENSITIVITY ANALYSIS

To understand the potential implications of higher penetration of renewable generation, InterGroup prepared a sensitivity analysis based on caps of 25 per cent, 30 per cent, and 35 per cent, assuming these limits are reached in 2030. Tables 3-6 through 3-8 present the results of the sensitivity analysis. The analysis should be interpreted with caution. The GNWT is undertaking additional analysis to understand the implications of increased penetration of renewables on fuel efficiency.

Table 3-6: Summary of Estimated Potential Rate Impacts of Non-Utility Owned Renewable Generation with 25% Cap[36]

	2019	2030	2030 Estimates		
	Preliminary Actuals	Estimates with Current Installations	Base Case Scenario	Low Case Scenario	High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$869,000	$1,289,000	$5,305,000	$3,519,000	$6,099,000
Net revenue loss	$493,000	$735,000	$2,840,000	$1,979,000	$3,412,000
Accumulative rate increase required to eliminate net revenue loss	0.4%	0.5%	1.8%	1.3%	2.2%
Net revenue loss over 2016 levels	$410,000	$652,000	$2,756,000	$1,895,000	$3,329,000
Community capacity limits					
Communities at or above capacity limit	6	3	25	15	31
Communities with capacity remaining	25	28	6	16	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$373,000	$288,000	$406,000
Avoided GREP costs	$1,000	$1,000	$12,000	$7,000	$12,000
Estimated GHG savings					
Annual GHG savings (tonnes of CO2e)	632	794	1,712	1,335	1,713
GHG savings over 2016 levels (tonnes of CO2e)	465	627	1,546	1,168	1,546
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$780	$927	$1,658	$1,483	$1,992
Per tonne of GHG savings over 2016 levels	$1,060	$1,173	$1,837	$1,694	$2,207

[36] Excludes utility owned and power purchase agreements.

Table 3-7: Summary of Estimated Potential Rate Impacts of Non-Utility Owned Renewable Generation with 30% Cap[37]

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	Low Case Scenario	High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$869,000	$1,289,000	$5,785,000	$3,848,000	$7,365,000
Net revenue loss	$493,000	$735,000	$3,110,000	$2,164,000	$4,118,000
Accumulative rate increase required to eliminate net revenue loss	0.4%	0.5%	2.0%	1.4%	2.6%
Net revenue loss over 2016 levels	$410,000	$652,000	$3,026,000	$2,080,000	$4,035,000
Community capacity limits					
Communities at or above capacity limit	6	3	25	14	31
Communities with capacity remaining	25	28	6	17	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$482,000	$366,000	$523,000
Avoided GREP costs	$1,000	$1,000	$14,000	$7,000	$14,000
Estimated GHG savings					
Annual GHG savings (tonnes of CO2e)	632	794	2,088	1,584	2,090
GHG savings over 2016 levels (tonnes of CO2e)	465	627	1,922	1,418	1,924
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$780	$927	$1,489	$1,366	$1,970
Per tonne of GHG savings over 2016 levels	$1,060	$1,173	$1,618	$1,526	$2,141

[37] Excludes utility owned and power purchase agreements.

Table 3-8: Summary of Estimated Potential Rate Impacts of Non-Utility Owned Renewable Generation with 35% Cap[38]

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	Low Case Scenario	High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$869,000	$1,289,000	$6,266,000	$4,134,000	$8,631,000
Net revenue loss	$493,000	$735,000	$3,379,000	$2,326,000	$4,825,000
Accumulative rate increase required to eliminate net revenue loss	0.4%	0.5%	2.2%	1.5%	3.1%
Net revenue loss over 2016 levels	$410,000	$652,000	$3,296,000	$2,242,000	$4,741,000
Community capacity limits					
Communities at or above capacity limit	6	3	25	8	31
Communities with capacity remaining	25	28	6	23	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$591,000	$433,000	$640,000
Avoided GREP costs	$1,000	$1,000	$17,000	$7,000	$17,000
Estimated GHG savings					
Annual GHG savings (tonnes of CO2e)	632	794	2,464	1,800	2,468
GHG savings over 2016 levels (tonnes of CO2e)	465	627	2,298	1,634	2,301
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$780	$927	$1,371	$1,292	$1,955
Per tonne of GHG savings over 2016 levels	$1,060	$1,173	$1,471	$1,424	$2,097

[38] Excludes utility owned and power purchase agreements.

4.0 LEGAL AND REGULATORY OPTIONS TO ENFORCE CAPACITY LIMITS

There are several reasons why the GNWT may wish to impose self-generation capacity limits as part of Territorial policy, and ensure utilities have the ability to track self-generators. These include:

1. Safety: to ensure the safety of utility employees utilities should know when customers are installing generation operating in parallel with utility service.
2. Operational efficiency: to maintain system stability and generation efficiency.
3. Rate and revenue impacts: to manage revenue reductions and minimize rate impacts on other customers.

This section examines the existing legal and regulatory tools that may be available to enforce standards and limits on customer-owned renewable generation.

InterGroup understands no current legislation or policies explicitly prohibit the installation of renewable generation where that generation is not connected to the electrical grid, subject to the requirements of electrical codes which are not directly within the scope of this assignment.

This section focuses on tools available to enforce or manage capacity limits on customers who install renewable generation that serves loads that are also connected to the electricity grid including:

- Customers who deliver energy to the grid, and customers who only consume the energy for their own use and do not deliver energy to the grid.
- Customers who are subscribed to the existing net metering program, as well as customers who do not subscribe to the program.

This section considers tools that are available under existing policies and those that could be implemented under new policies or legislation.

4.1 EXISTING LEGAL AND REGULATORY TOOLS

4.1.1 Utility Terms and Conditions of Service

NTPC and NUL currently have similar provisions requiring agreements to be in place where customers connect their own generation that state:

> A Customer must sign an agreement with the Corporation if the Customer wishes to use Service:
>
> a) in parallel operation with; or

> b) as supplementary, auxiliary or stand-by Service to any other source of Energy.[39]

NTPC's Terms and Conditions also indicate:

> The Corporation may, without notice, terminate Service to a Customer where, in the Corporation's opinion acting reasonably:
>
> a) the Customer's equipment or premises are unsafe or may become dangerous to life or property.
>
> b) the use of the Service may cause damage to the Corporation's Facilities, or interfere with, or disturb Service to any other Customer; or
>
> c) the Customer Facilities or any equipment of the Customer fail to comply with applicable statutes, regulations, standards and codes.[40]
>
> The Corporation will reconnect the Service when the safety problem is resolved, the Customer has provided the Corporation with an electrical inspection report of the Customer Facilities at the Customer's sole expense, the Corporation, acting reasonably, has approved such inspection report and the Customer has provided, or paid the Corporation's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

These sections appear to apply to any customer who installs generation connected to loads that are also capable of being supplied by utility electricity service, whether they subscribe to the existing net metering program or not. As such, any customer (not only net metering customers) installing renewable generation would be subject to these existing terms and conditions of service and would require an agreement with the utility.

In InterGroup's experience these terms are viewed to be industry-standard, and appropriate to maintain the safety and reliability of the system. Consideration should be given to ensuring NUL has reviewed its Terms and Conditions to ensure the same clarity regarding equivalent utility powers to those contained in Section 16.1 of the NTPC Terms and Conditions of Service. NUL presently has extensive terms related to safety and reliability, but it would be prudent to confirm these can be fully applied to customer self-generation.

It is understood there can be difficulties implementing these provisions, if customers install generation without telling the utility. This should be prevented. Not only do the utilities properly require this information to operate the system safely, but the ability to identify customers who self-generate is needed to manage policy options for the power system. Further consideration is needed of options to ensure this information is available to the utilities in a timely and comprehensive way.

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[39] Section 3.5 of NTPC's Terms and Conditions of Service and section 3.7 of NUL's Terms and Conditions of Service.
[40] Section 16.1 of NTPC's Terms and Conditions of Service.

4.1.2 Capacity Limits on Rate Options

The existing net metering program uses capacity limits designed broadly around maintaining system stability and efficiency. InterGroup understands the existing capacity limits are intended to apply to all intermittent generation, not only generation subscribed to the net metering program.

The existing net metering program uses both customer-specific and community-wide capacity limits to manage a number of potential concerns:

- Stability concerns relate to ensuring the collective self-generation in a community does not negatively affect power quality and stability throughout the community. This can arise when the utility's own generation is unable to respond to swings in the self-generation production.
- Efficiency concerns relate to the need for extra fuel consumption by diesel units running outside optimal operating loads to manage swings in intermittent generation.
- Availability concerns relate to individual customers taking up an excessive amount of the available self-generation potential in a community and preventing others from participating.

Capacity limits on access to rate options for customer owned renewable generation are a common tool by regulators in other jurisdictions. For example, Hawaiian Electric has program capacity limits for a number of its customer-owned solar generation rate options.[41] They are also consistent with InterGroup's experience in other jurisdictions, where regulators have capped access to net metering and other rate options in an approved tariff.

4.2 TOOLS THAT COULD BE IMPLEMENTED UNDER EXISTING LEGISLATION

4.2.1 Electrical Protection Act

Section 9 (1) of the *Electrical Protection Act* states:

> 9. (1) All plans and specifications for
>
> a. the installation of electrical equipment in a public, industrial or commercial building or in any other building where public safety is a concern,
>
> b. the installation of a generator, transformer, switchboard, large storage battery or large electrical equipment, or

[41] Hawaiian Electric Solar Programs Comparison. Available: https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/programs_bill_and_credit.pdf. Accessed February 28, 2021.

c. a prescribed installation, shall be submitted to an inspector by or on behalf of the owner of the premises in or on which it is proposed to make the installation.

To the extent there are concerns that some customers may have generation installed but do not have an agreement in place with the electric utility, it could be possible to make obtaining such an agreement part of the requirement for customers to submit plans and specification required under the *Electrical Protection Act.*

4.2.2 Public Utilities Act

Sections 48 (1) and 48 (2) of the *Public Utilities Act* state:

48. (1) No public utility shall in rates

a. make, demand or receive

i. an unreasonable, unjustly discriminatory or unduly preferential rate for a service provided by it, or

ii. a rate that otherwise contravenes this Act, the regulations, another enactment or an order of the Board;

b. subject any person or locality to an undue prejudice or disadvantage in respect of rates or services; or

c. extend to any person a form of agreement, facility or privilege, unless the agreement, facility or privilege is regularly and uniformly extended to all persons for service of the same description in substantially similar circumstances.

48. (2) It is a question of fact, of which the Board is of fact the sole judge, whether

a. a rate for service is unreasonable, unjustly discriminatory or unduly preferential;

b. there is undue prejudice or disadvantage in respect of a rate or service; or

c. a service is extended under substantially similar circumstances.

The issue of unjustly discriminatory and unduly preferential rates is of key importance in understanding the ability to design and implement rates (including associated terms and conditions of service). Regulators have typically considered the concepts of cost responsibility and materiality in assessing whether a proposed rate is unjustly discriminatory. To the extent a utility cost of service study shows a cost causation basis for charging a different fee or rate to a certain category of customer, regulators have typically found that charging rates that reflect those cost differences are not unjustly discriminatory.

As noted in section 2.3.1, utility net revenue losses associated with customer-owned renewable generation arise in large part because the existing rate design does not recover the fixed costs of providing service through existing fixed charges. Instead, in practice those fixed costs are recovered in substantial part through variable energy charges. Since customers with their own generation purchase less energy, the utility loses more in revenue than it saves through avoided fuel costs. In Decision 7-2016, the NWT PUB considered the potential impact on lost utility revenues of up to 1 per cent of earnings and determined that such a reduction being borne by NTPC's other customers would be relatively immaterial and not unduly discriminatory to the non-net metering customers. However, it could be argued that at some threshold higher than 1 per cent, charging higher rates to non-net metering customers to recover those losses could be unjustly discriminatory to the non-net metering customers.

Similarly, continuing to offer rates and terms and conditions of service to self-generation customer could be viewed as being unduly preferential. Specifically, if a customer can make extensive use of the utility's power system to deliver, receive, store, bill, and backup their power supply, it could be considered unduly preferential that they can achieve this without payment to the utility for these services. Such preference may be “duly” preferential if it is necessary to achieve other broad policy objectives, such as reducing GHG emissions, but at some point such preferences may require changes to the rate structure. The PUB must make a determination on the factual basis for preference versus undue preference.

Under the existing legislation it appears there is broad ability to address revenue loss impacts on other customers through modifications to the rate structures. This could include closing access to the exiting net metering program once capacity limits are reached. Other rate options to potentially manage cost and revenue impacts of customer-owned renewable generation are explored further in section 5.

These rate tools may not be able to explicitly prevent customers from installing their own renewable generation, as long as they comply with the requirements for customer agreements and safety and stability in the terms and conditions of service, but they could assist with managing the rate impacts on other customers.

4.3 TOOLS THAT COULD BE IMPLEMENTED UNDER NEW LEGISLATION

The existing legislation provides significant latitude to GNWT to adopt new policies, or direct the enforcement of existing policies, to the utilities or the PUB.

In the event the GNWT determined the existing legal and regulatory tools are not sufficient to address certain policy concerns, new legislation may be an option to provide clearer ability to enforce the requirements for utility agreements and absolute limits on customer-owned renewable generation. A review of other legislation in Canada identified precedent for some potential options.

4.3.1 Alberta Electric Utilities Act and Microgeneration Regulation

The *Electric Utilities Act* of Alberta[42] includes among the duties of electric distribution systems "to connect and disconnect customers and distributed generation in accordance with the owner's approved tariff and with principles established by the Commission regarding distributed generation".[43] This type of language could help clarify the right for utilities to disconnect distributed generation customers that do not comply with approved terms and conditions of service.

The Micro-Generation Regulation under the *Electric Utilities Act* of Alberta[44] is intended to allow the opportunity for customers to install their own micro-generation and deliver energy to the grid, within a framework defined in the regulation. Key elements of the microgeneration regulation include:

Sections 2 and 2.1 of the regulation require a customer to provide notice to their distribution company if they intend to install or modify a generating unit in a form approved by the Alberta Utilities Commission. If the distribution company believes the generating unit does not qualify as microgeneration there is a dispute resolution process available before the Alberta Utilities Commission.

Alberta Utilities Commission Rule 024 defines rules respecting micro-generation. The rules include requirements that distribution companies maintain records of all connected micro-generators and provide such information to the Commission upon request.[45]

To the extent there are concerns that customers may currently or at some time in the future install customer-owned generation without agreements in place with the utilities, these types of requirements.

4.3.2 Newfoundland and Labrador Electrical Power Control Act

The *Electrical Power Control Act* of Newfoundland and Labrador[46] sets out broad power policies for the province, including:

> All sources and facilities for the production, transmission and distribution of power in the province should be operated in a manner:
>
> - That would result in the most efficient production, transmission and distribution of power.
> - That would result in power being delivered to consumers at the lowest possible cost consistent with reliable service.[47]

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[42] Available; https://www.canlii.org/en/ab/laws/stat/sa-2003-c-e-5.1/latest/sa-2003-c-e-5.1.html
[43] Section 105(1) (k) of the *Alberta Electric Utilities Act*.
[44] Available; https://www.canlii.org/en/ab/laws/regu/alta-reg-27-2008/latest/alta-reg-27-2008.html
[45] Section 8. Alberta Utilities Commission Rule 024. Available: https://www.auc.ab.ca/Shared%20Documents/rules/Rule024.pdf
[46] Available: https://www.canlii.org/en/nl/laws/stat/snl-1994-c-e-5.1/latest/snl-1994-c-e-5.1.html
[47] Section 3 (b) (iii) of the *Electrical Power Control Act*.

For the NWT, including this type of language in legislation could clarify the GNWT's broad policy intentions and perhaps facilitate more prescriptive future policy directions to the PUB and utilities to implement and enforce measures to limit the impact of non-utility generation on the electric grid and other customers.

The *Electrical Power Control Act* also limits the ability of retailers and industrial customers to install their own generation:

> Notwithstanding another provision of this Act or another Act, a retailer or an industrial customer shall not develop, own, operate, manage or control a facility for the generation and supply of electrical power or energy either for its own use or for supply directly or indirectly to or for the public or an entity on the island portion of the province.[48]

InterGroup understands one of the broad objectives of this type of legislation in Newfoundland is to achieve efficiencies that arise from Newfoundland Hydro developing larger projects, and ensuring these projects (such as Muskrat Falls) are able to secure the needed revenue to operate.

The *Electrical Power Control Act* also provides certain exemptions from this provision, including:[49]

- The limitation does not apply to generation facilities used exclusively for emergency circumstances.
- Facilities that existing on December 31, 2011 are exempted, including refurbishment of those facilities.
- The Lieutenant-Governor in Council may, by order, exempt a retailer or industrial customer from the application of these limitations.

To be clear, the limits on customer-owned generation appear to apply narrowly to a small number of retailers and industrial customers in the province. Newfoundland and Labrador Hydro currently offers net metering service to customers consistent with a provincial government policy framework that includes a cap on total net metering in the province of 5 MW, as well as the ability for utilities to exercise discretion to limit the number of net metering customers where infrastructure and/or technical constraints exist.[50]

However, in the event other legal and regulatory tools are determined to be insufficient to address policy concerns related to increased penetration of customer-owned renewable generation, it may be possible to pass legislation to limit the ability of customers to install customer-owned IPGs. The key element of any such legislation could be modelled after section

[48] Section 14.1 (2) of the *Electrical Power Control Act*.
[49] Sections 14.1(4), 14.1 (5) and 14.1 (7) of the *Electrical Power Control Act.*
[50] Newfoundland and Labrador Net Metering Policy Framework. July 2015. Available: https://www.gov.nl.ca/iet/files/energy-electricity-net metering-framework.pdf

14.1 (2) of the *Electrical Power Control Act* but broadening it to ensure it applies to all customers (not just retailers and industrial customers).

4.4 SUMMARY

Key findings from this review include:

1. There are existing terms and conditions of service that require agreements with the utilities when customers install generation that operates in parallel with utility service. To the extent there are concerns that customers are currently or may in the future install generation without such agreements in place, specific requirements for such agreements could be strengthened and implemented under the *Electrical Protection Act* and the utility terms and conditions of service.
2. A number of rate options could be implemented under the existing *Public Utilities Act* that could help manage the rate impacts of customer-owned renewable generation. Indeed, rate changes may be required to ensure that rates to self-generators (whether in the Net Metering program or not) are not unjustly discriminatory nor unduly preferential.
3. Capacity limits could be used to limit or refuse access to rate options, including the existing net metering program. However, these options may not be able to explicitly prevent customers from installing generation, where that customer is not subscribed to an existing renewable energy rate program, except to the extent it interfered with safety and reliability.
4. In the event the GNWT wished to enforce absolute capacity limits on customer-owned renewable generation, it may be possible to implement legislation modelled after the Newfoundland and Labrador *Electrical Power Control Act.*

5.0 POLICY OPTIONS

5.1 POLICY OPTIONS TO ADDRESS RATE IMPACTS

A number of policy options are available that may help address rate impacts related to increased penetration of renewable energy. These options have been developed based on a review of programs in other jurisdictions in North America.

This section provides an overview of the potential options. Additional background and detail on each option is provided in Appendix C. Where possible, potential rate implications have been quantified and estimated. In some instances, descriptions of potential rate effects are qualitative.

5.1.1 Reduce value of credit for surplus generation

The credit net metering customer receive for surplus generation delivered to the grid could be reduced from the full retail energy rate to an amount that more closely reflects the variable cost of generation in each zone. SaskPower and Manitoba Hydro have recently implemented this change to their net metering programs.

This would reduce the value of the credit residential net metering customers receive in NTPC's thermal zone in 2030 from an estimated 97 cents/kWh[51] to approximately 39 cents/kWh based on average forecast diesel and natural gas prices and non-variable operations and maintenance expenses. Rates in the Snare and Taltson zones would be approximately 3 cents/kWh based on non-fuel variable operations and maintenance savings as these zones use very little fuel. However, this change would only affect the savings on energy delivered to the grid. Self-generation customers would still save at the full retail rate for their solar generation that they use to displace their own consumption behind the meter. In 2019, an estimated 70 per cent of generation from net metering customers was used to displace their own consumption. Customers who are not subscribed to the net metering program do not receive credits for surplus generation and would not be affected by this change.

This option would reduce the estimate net revenue loss for the utilities from $1.968 million in 2030 to $1.171 million in 2030 in the Base Case Scenario. If existing customers were grandfathered under the current rate structure, the net revenue loss would increase by approximately $0.109 million by 2030 (i.e. from $1.171 million to $1.280 million).

Implementing this option would require addressing the appropriate treatment of costs and revenues related to wholesale sales from NTPC to NUL.

5.1.2 Increase customer and demand charges to recover more fixed costs

The existing fixed charges (customer and demand charges) do not fully recover the fixed costs of operating the electricity systems. Increasing the proportion of total revenues recovered through the fixed charges would provide better cost-tracking. This option could be implemented over time as the utilities file rate applications with the PUB. The increases would then be reviewed and justified for approval in a public process before the PUB. This option would require changes to the existing GNWT policy guidelines to allow fixed charges to be increased. A number of other jurisdictions have been moving to rate structures that recover a higher proportion of distribution costs through fixed charges. This change would affect all customers, not just those who install their own generation.

If the existing fixed and variable charges were increased by approximately five per cent each year, the net revenue loss for the utilities in 2030 would decrease by an estimated $0.103 million annually. A five per cent increase on the existing $18 per month residential customer charge would be an increase of approximately $0.90 a month or $10.80 per year. A five per cent increase to the existing minimum billed demand for general service customers would be an increase of $2 per month or $24 per year. Variable energy rates would be lower in this scenario, such that some higher volume customers would see savings on the energy portion of the bill to offset the increase in fixed charges. Fixed charges are excluded from the calculation of TPSP but are included in GREP. Differences in fixed charges between utilities could result in changes to program spending on GREP.

[51] This is based on inflating a blended rate based on 2019 actual information.

5.1.3 Charge stand-by fee for renewable generation

NTPC currently has approved rates for stand-by service for general service customers. NTPC's terms and conditions of service state it will provide retail stand-by service to back-up customer self-generation where surplus capacity is available. Self-generation customers using intermittent renewable generation are currently exempt from paying the existing stand-by charge.[52] NTPC's charge of $24/kW was developed to recover the full cost of generation capacity. The stand-by charge has not been increased since it was originally approved in 2008. Some utilities, particularly in the United States, have implemented stand-by service charges that apply to customers who install renewable generation.

5.1.4 Implement new rate options and fees for customers with self-generation

Utilities could design rate options for customers with self-generation and implement rates or fees based on the costs to serve these customers. As long as the cost basis for the charges could be supported, such fees or rates would be consistent with existing legislation requirements not to implement rates that are unjustly discriminatory or unduly preferential. This option could significantly shape incentives and revenue loss for self-generation. Creating new classes or rate options would at first blush appear more complicated, but may make implementation of the needed changes simpler and cause fewer impacts on non-self generation customers if the changes were primarily restricted to just the new class.

As an example, the Public Utilities Commission of Hawaii closed the then-existing net energy metering program and approved new options for customers to interconnect distributed energy resources to the electric grid. The Hawaii Public Utilities Commission noted separate rate options for self-supply customers would allow those customers to be subject to an updated minimum bill (as an example of additional charges that could apply) and provide the flexibility to provide credits to those customers for grid-supportive benefits in the future.[53]

In the NWT, a separate rate option could be implemented for self-supply customers without additional fees at present. This, combined with strengthened requirements for customer agreements, could help improve the visibility of customer-owned generation to utilities and the PUB. This would also facilitate implementing additional charges or credits for these customers in the future.

5.1.5 Increase government rates to address lost revenue

The current GNWT rate policy guidelines allow government rates to be higher than non-government rates in the same zone and target revenue to cost ratios for government customers of between 100 per cent to 130 per cent. In NTPC's 2018/19 test year, government customer revenue to cost ratios were 124 per cent across all rate zones. In NTPC's thermal zone, revenues

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[52] Section 3.5. NTPC Terms and Conditions of Service.

[53] Pages 121-122, Order number 33258. Public Utilities Commission of the State of Hawaii. Available: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464. Accessed February 26, 2021.

from government customers were $32.3 million compared to costs of $24.7 million, meaning revenues from government customers in the thermal zone exceeded costs by $7.6 million for a revenue to cost ratio of approximately 130 per cent.[54]

NUL does not currently have different government and non-government rates, but does track revenues from government and non-government customers separately in order to administer the GREP. Government rates could be increased to recover the reductions in utility revenues from customer-owned generation. Alternatively, the GNWT could indicate that part of the reason government customers already pay higher rates is to offset lost revenue and direct the PUB to ensure that government rates at a minimum recover the lost revenue from customer-owned generation for each utility. This would require higher government rates to be implemented for NUL, but could be accommodated within the existing higher rates for government customers of NTPC.

Increasing government rates affects more than just territorial government customers, it would also affect federal government and tax-based and non-taxed based community government accounts and would require coordination with the Department of Municipal and Community Affairs.

5.1.6 Provide a subsidy to utilities to offset lost revenue

The GNWT could provide a subsidy to the utilities to offset the net impact on other customers. The cost of the program would be approximately $1.968 million by 2030 in the Base Case Scenario. However, the current net metering program is expected to save the GNWT approximately $0.277 million by 2030 in avoided TPSP and GREP costs, as a result of solar generation reducing customer electricity bills so the net impact to GNWT budgets would be approximately $1.691 million.

5.1.7 Replace existing programs with a feed-in tariff

A feed-in tariff is a procurement method for renewable energy. For example, Ontario's feed in tariff program was open to participants who generated renewable energy and sold it at a guaranteed price for a fixed contract term. Feed-in tariffs can be technology specific (e.g., wind may receive one price, solar may receive another).

The GNWT could transition to a feed-in tariff instead of a net metering program or other programs. Other jurisdictions in Canada have implemented or considered implementing feed-in tariffs for renewable generation. However, BC Hydro suspended the implementation of its feed-in tariff program in 2012 noting a need to minimize electricity rate increases[55] and Ontario ended its feed-in tariff program[56] and cancelled a number of renewable energy contracts. There is a risk that poorly designed feed-in tariffs can have a number of unintended effects.

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[54] Summary tab. NTPC 2018/19 COSA compliance filing.
[55] See BC Hydro website: https://www.bchydro.com/work-with-us/selling-clean-energy/closed-offerings/feed-in-tariff.html. Accessed January 24, 2021.
[56] IESO website on feed-in-tariff. Available: https://www.ieso.ca/sector-participants/feed-in-tariff-program/overview. Accessed March 11, 2021.

The current GNWT programs for mid-scale renewables delivered directly to the grid has some elements in common with a feed-in tariff and may be a more manageable way to deliver renewable energy to the grid given the small size of most communities in the NWT.

5.2 EVALUATION OF OPTIONS

The following criteria are proposed to evaluate the advantages and disadvantages of different policy options:

1. **Net cost to existing customers** – the changes in net costs of each option to existing customers as a result of lost revenue.
2. **Loss of existing benefits to non-utility generation customers –** the degree to which the option reduces the potential benefit of customer-owned generation to the customer installing the renewable generation.
3. **Impacts on government subsidies** – the changes to government subsidies including any potential new subsidies as well as impacts on existing subsidy programs such as TPSP and GREP.
4. **GHG emissions** – the ability to meet or exceed GNWT GHG emissions reduction targets.
5. **Regulatory and legal process considerations –** whether the policy could be implemented within existing legislative and regulatory frameworks or if changes to the frameworks would be required.
6. **Customer choice –** the degree to which the policy provides customers with choices in how they meet their electricity needs.
7. **Administrative efficiency** – the ease with which a particular option could be implemented.
8. **Consistency with other GNWT policy objectives** – whether or not the policy contributes to other GNWT policy objectives including affordability for consumers.
9. **Political feasibility and public acceptance -** an initial screening assessment of political or public acceptance concerns.

Table 5-1 summarizes InterGroup's preliminary policy evaluation of the different options.

Table 5-1: Preliminary Evaluation of Potential Policy Changes to the Net Metering Program

	Net costs to other customers	Reduced benefits to customers installing renewable generation	Impacts on government subsidies	GHG Impacts	Regulatory and legal process considerations	Effects on customer choice	Administrative Efficiency	Consistency with other GNWT policy objectives	Political feasibility and customer acceptance
Reduce credit for surplus generation for net metering customers	Would reduce net losses of utility revenue in the Base Case by $410,000 per year by 2030.	Would reduce credit to net metering customers for surplus energy. Would not affect customer savings on the 70% of self generation energy that is used to displace consumption behind-the-meter.	The GNWT subsidies for TPSP and GREP would be $45,000 lower per year by 2030 as compared to base case.	Would reduce the incentive for customers to install their own generation. However, an estimated 70% of the generation by net metering customers and 100% of the generation for non-net metering customers would not be affected.	Would require changes to rate policy guidelines and approval process with PUB. Likely desirable to implement as a joint process with all utilities for consistency across the territory.	Would likely be viewed as restricting customer choice.	Could be implemented in a similar manner to previous net-billing pilot project. Could likely be accommodated in existing utility billing systems.	Expected to reduce GHG savings relative to Base Case scenario as a result of lower uptake of renewable generation. However, would reduce need to recover lost utility revenue from other customers.	Reduction in credit rate would be unpopular with existing customers. However, customers still save at the full retail rate when they displace consumption behind-the-meter.
Increase Fixed Customer and Demand Charges for All Customers	Some customers would see bill increases of up to $10-$24 per year while other high volume customers could see bill decreases compared to the existing rate policies. Could reduce revenue losses to the utilities by	Could reduce savings to customers from installing renewable generation by $10-$24 per year, increasing over time.	Fixed charges are excluded from TPSP but are included in GREP. Differences in fixed charges between utilities result in changes to GREP spending. Small indirect effects on subsidies are expected	Could reduce uptake of renewable generation and therefore lower GHG savings.	Changes to existing fixed charges would require changes to rate policy guidelines and PUB application process.	Likely to be perceived as limiting customer choice by reducing incentives for self-generation and energy efficiency.	Utilities currently have fixed charges in the tariffs so increases could be implemented to existing charges.	Likely to reduce potential to achieve GHG savings from customer owned solar relative to existing programs.	A number of jurisdictions in Canada and the US have been increasing cost recovery through fixed charges. Changes would be reviewed in public processes before the PUB.

	Net costs to other customers	Reduced benefits to customers installing renewable generation	Impacts on government subsidies	GHG Impacts	Regulatory and legal process considerations	Effects on customer choice	Administrative Efficiency	Consistency with other GNWT policy objectives	Political feasibility and customer acceptance
	$103,000 per year by 2030 compared to existing rate policies.		through lower energy charges than would occur under existing rate policies.						
Stand-by charges	Could increase utilities' revenues by $228,000 per year by 2030.	Could reduce savings to customers from installing renewable generation by 50%.	Current stand-by charges affect only NTPC general service customers. No impact expected on existing subsidy programs	Could reduce uptake of renewable generation and therefore lower GHG savings.	Changes to existing stand-by rate and removing renewable exemption would require PUB process.	Likely to be perceived as limiting customer choice.	NTPC has existing rate schedule. Charge could be designed on a kW or per customer basis for billing.	Likely to reduce potential to achieve GHG savings from customer owned solar relative to existing programs.	Stand-by charges for renewable generation are not common in Canada and have been controversial in the United States.
Implement new rate options for self-generation customers	Charging an access fee would reduce the revenue losses to utilities. A $20/month fee to all self-generation customers (lower than the existing stand-by charge) would result in an additional $207,000 in revenue and reduce the rate increases required to other customers.	A $20/month access charge would increase bills by $240 per year. Applying the access fee would reduce those savings by approximately 4 per cent.	Fixed charges are not included in the calculation of TPSP charges. There may be a small change to GREP subsidies, depending on how the charges are implemented across the utilities.	Access fees would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings.	Implementing an access fee would require a policy direction to the PUB and utility applications for PUB approval. The calculation of any access charges would need to be justified on a cost-causation basis.	Access charges would likely be perceived as inhibiting the ability of customers to install their own generation and reducing customer choice.	Implementing an access charge for customers with self-generation would require establishing and administering new rate options.	An access charge would be expected to reduce the uptake of customer owned renewable generation and reduce the potential GHG savings. However, it would reduce the net revenue loss to the utilities and the rate impact on non-adopting customers.	Higher charges for solar installations have been controversial when implemented in other jurisdictions.

	Net costs to other customers	Reduced benefits to customers installing renewable generation	Impacts on government subsidies	GHG Impacts	Regulatory and legal process considerations	Effects on customer choice	Administrative Efficiency	Consistency with other GNWT policy objectives	Political feasibility and customer acceptance
Increase government rates	Average for across all zones would be 1.3% rate increase by 2030.	No effect on non-government customers compared to existing policy scenario. Government customers would see higher rates and depending on whether those rates were applied to fixed or variable charges would see different bill impacts.	Government customers are not eligible for existing subsidies so no direct effects on existing subsidies expected.	Little direct effect on rates for non-government customers, so little impact on GHG emissions compared to current policy scenarios.	Policy direction would be required to implement higher government rates for NUL customers. A rate application and public PUB process required to implement rate increases.	Little effect expected on customer choice for non-government customers.	NTPC currently maintains different rates for government customers. NUL tracks government versus non-government customer to administer GREP but would need to implement rate classes with different rates for government customers.	Would have implications for GNWT budgeting and would require coordination with MACA.	Higher government rates would affect federal government and community government accounts and this may be an issue for relationships with other levels of government.
Subsidize lost utility revenue	Eliminate rate increases to recover lost utility revenues by 2030 of 1.3% rate increase in average for across all zones.	Not anticipated to affect benefits compared to existing policies.	Would require increasing annual subsidies by $1,968,000 annually by 2030.	Not anticipated to change installation of renewable generation compared to existing rate policies.	Direct subsidy would not require PUB approval but may need to be reflected as non-utility revenue in rate applications to PUB.	Not anticipated to have effects on customer choice relative to existing policies.	Would be an additional subsidy for utilities and the GNWT to administer.	Would maintain potential GHG savings of current renewable policies and eliminate rate impacts on other customers. Would divert funding available for other policy priorities.	Subsidy would reduce funds available for other policy priorities.

	Net costs to other customers	Reduced benefits to customers installing renewable generation	Impacts on government subsidies	GHG Impacts	Regulatory and legal process considerations	Effects on customer choice	Administrative Efficiency	Consistency with other GNWT policy objectives	Political feasibility and customer acceptance
Implement a feed-in tariff	A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on other customers compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.	A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on other customers compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.	A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on subsidies compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.	A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on GHG emissions compared to existing policies and programs.	Implementing a feed-in tariff would require policy direction to the PUB and the utilities would need to file an application to implement the tariff.	Some customers may view a feed-in tariff as improving customer choice.	Would likely require additional administration and management relative to existing programs.	A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.	Ontario cancelled a number of contracts under its feed-in tariff. This would likely reduce public support for a feed-in tariff.

5.3 RECOMMENDATIONS

5.3.1 Potential Future Policy Scenarios

Section 5.2 identified a number of policy options that could be implemented to manage the rate impacts of customer-owned renewable generation. Many of them could be implemented within the current legislative and regulatory framework, though some would require new policy directions to the PUB and a rate application to the PUB to implement them. However, some of the options would also likely reduce the incentives for customers to install their own renewable generation, thereby reducing incentives for future renewable generation uptake and reductions in GHG emissions. In evaluating the path forward for new policies, the GNWT will need to balance these considerations.

In InterGroup's view, three broad scenarios for future policies may exist:

<u>Incent continued customer installation of renewable generation</u>

This policy path may evolve by continuing the current renewable generation framework, including:

1. Providing full retail rate compensation for energy delivered to the grid under the net metering program.
2. Continuing to subsidize the installation of customer solar generation in thermal communities.
3. Maintaining existing rate policy restrictions on increasing fixed customer and demand charges.

Outcomes of this policy path are estimated to be similar to the Base Case scenario developed in Section 3. The GNWT could choose to subsidize the reduced utility revenue either directly by creating a new subsidy program or indirectly by permitting rates for government customers (including federal government and community government accounts) to increase to absorb the difference.

<u>Accommodate continued customer installation of renewable generation</u>

This policy path could involve some policy changes to reduce the current incentives available to customers who install renewable generation and the lost revenue to utilities through measures including:

1. Reducing the credit available to net metering customers for energy delivered to the grid to reflect the variable generation savings to the utility (primarily fuel savings, but also conceivably any non-fuel expenses that can be justified).
2. Removing incentives or limiting availability of rate options in hydro-electric zones where new renewable generation primarily displaces existing hydro-electric generation and does not result in addition GHG emissions savings.
3. Changing the existing rate policy direction to permit fixed customer charges and demand charges to increase for all customers over time. These changes would take effect slowly through utility rate applications.

4. Strengthening terms and conditions of service and permitting requirements to ensure utilities and the PUB have good visibility of all customer-owned renewable generation.
5. Creating a rate option for customers who install their own generation, but do not deliver energy to the grid. This rate option may not have any additional charges initially, but could provide the ability to implement specific charges in the future.

Outcomes of this policy path would be expected to result in somewhat lower installation of renewable generation by customers. This would reduce the anticipated GHG savings and also reduce the lost revenue to utilities. The GNWT could choose to subsidize the remaining reduction in utility revenue either directly by creating a new subsidy program or indirectly by permitting rates for government customers to increase to absorb the difference.

<u>Consolidate new renewable generation opportunities within utilities rather than individual customers.</u>

This policy path could involve some policy changes to substantially reduce or eliminate the current incentives available to customers who install renewable generation and consolidate the installation of renewable generation within the utilities or in partnership with the utilities. The Creating a Brighter Future Report noted the challenges of the limited opportunities for economies of scale in the territory and stated:

> The number of customers in the NWT is limited. Given the dispersed generation system required to serve the Territory, basic system costs are high. This situation impacts on utility company costs and is, ultimately, reflected in the prices paid by customers or the Government through subsidy programs. The Report recommends that the vision for the future be built on consolidating elements of the electricity system to increase the economies of scale in the system.[57]

Policy options involved in this scenario may include:

1. Closing the existing net metering program to new customers and reducing the credit available to existing customers to a rate more consistent with the variable cost of generation.
2. Creating a mandatory rate option for customers who install their own renewable generation and implementing stand-by charges, access charges or minimum bills to recover lost utility revenues.
3. Strengthening terms and conditions of service and permitting requirements to ensure utilities and the PUB have good visibility of all customer-owned renewable generation.
4. Implementing new legislation to explicitly permit utilities to enforce capacity limits on customer-installed renewable generation, whether or not they are subscribed to an existing rate option such as net metering.

[57] Executive summary. Creating a Brighter Future: A review of electricity regulation, rates and subsidy programs in the Northwest Territories. 2009. Available: https://www.ntassembly.ca/sites/assembly/files/09-11-05td52-164.pdf. Accessed February 28, 2021.

Outcomes of this policy path could result in materially reduced future GHG savings through customer installation of self-generation. It would also likely be viewed as substantially inhibiting consumer choice. However, it could also reduce utility revenue losses.

5.3.2 Potential Near-term Policy Options

In developing near-term policy options, the following considerations are noted:

- Capital costs of solar installations have fallen and are expected to continue to fall. Estimates prepared by the Canada Energy Regulator indicate the breakeven point for solar installations in the NWT are approximately 64 per cent of average electricity rates currently, and could decline to 53 per cent in the near future.[58] This suggests there could be room to reduce the credits available to net metering customers and still have customers realize bill savings.
- Estimates prepared for 2019 indicate customer owned intermittent renewable generation has saved approximately 465 tonnes of GHG emissions in that year over 2016 levels, including 300 tonnes from net metering customers and 166 tonnes from other customer-owned intermittent renewable self-generation.[59] This is already a substantial portion of the 700 tonnes of GHG savings targeted by 2030 in the GNWT 2030 Energy Strategy and excludes any utility-owned projects that could also contribute to GHG savings.
- The majority of savings to customers on net metering and all of the savings to customers who are not net metering customers arises from displacing the need to purchase energy from the utility. Customers continue to save at the full retail rate when they use their own generation to displace consumption behind-the-meter.
- Increasing fixed charges for all customers (not just those who install their own generation) is justifiable based on the cost of service studies prepared by the utilities as part of their rate applications and consistent with broader trends in the electricity sector in other jurisdictions.
- It is desirable to ensure utilities have good visibility of the customer-owned generation connected to the grid, even when that generation is not subscribed to the net metering program.

Based on the analyses conducted for this study, the GNWT may consider a path that balances the opportunity for customers to install their own generation and reduce GHG emissions while reducing the loss of utility revenues. This would be broadly consistent with the 'accommodate customer installation of renewable generation' scenario. Specific actions that may be considered as part of this path could include the following policy changes in the near term (within one to two years):

1. Adjust the credit for renewable generation delivered to the grid (by both net metering customers and mid-scale generators) to reflect the variable generation costs of each

[58] The Economics of Solar Power in Canada. Canada Energy Regulator. Available: https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/report/solar-power-economics/index.html. Accessed February 28, 2021.
[59] Total does not sum up due to rounding.

utility in each zone. In the short-run this value could be indexed to the cost of fuel and variable operations and maintenance costs. The credit could be modified as necessary to reflect:

   a) Additional costs incurred by utilities to integrate renewable generation (e.g., reductions in fuel efficiency or additional infrastructure needed to accommodate delivery of surplus intermittent generation.

   b) Additional long-run savings from avoided maintenance or capital costs or other benefits of intermittent renewable generation.

2. Revise the GNWT rate policy guidelines to permit utilities to increase their fixed charges.
3. Strengthening terms and conditions of service and permitting requirements to ensure utilities and the PUB have good visibility of all customer-owned renewable generation. This could also include creating a central registry to maintain records on renewable generation installed in the territory.
4. Creating a rate option for customers who install their own generation, but do not deliver energy to the grid. This rate option may not have any additional charges initially, but could develop the ability to implement specific charges or credits for grid services in the future.
5. Subsidize any remaining net revenue losses attributed to customer-owned generation net meter either through a direct subsidy to each utility or by allowing rates for government customers to be increased to recover the difference.
6. Re-evaluate the costs and benefits of the customer-owned generation policies in the medium-term (three to five years).

Table 5-2 summarizes the estimated rate and revenue effects as a result of these changes.

Table 5-2: Estimate of Rate Impacts of Potential Near-term Policy Changes

	2019 Preliminary Actuals	2030 Estimates
Net utility revenue loss before changes	$493,000	$2,293,000
Reduce value of credit and Fixed charges increase by 5%		$885,000
Remaining net cost	$493,000	$1,408,000

5.3.3 Implementation

Implementation of the near-term actions would require changes to the existing rate policy guidelines to the PUB and a PUB approval process. To ensure harmonization of rate changes to the net metering program a joint proceeding before the PUB that includes NTPC, NUL-NWT and NUL-YK is desirable. Table 5-3 summarizes the possible implementation mechanisms for each of the actions. It will be important to implement changes in a way that allows for transition for existing customers. A draft terms of reference for implementing the recommended changes is provided in Appendix D. It is expected these terms of reference would be revised and adapted based on policy decisions made by the GNWT and in consultation with the PUB, utilities and other stakeholders.

Table 5-3: Potential Implementation Mechanisms for Policy Changes

Potential Policy Changes	Potential Implementation Mechanisms
Adjust the credit for renewable generation delivered to the grid by both net metering customers and mid-scale generators) to reflect the variable generation costs of each utility in each zone.	1. Revise existing rate policy guidelines. 2. Joint PUB proceeding involving all utilities. 3. Instruct PUB to consider appropriate timelines to transition existing customers to the new credit rate.
Revise the GNWT rate policy guidelines to permit utilities to increase their fixed charges.	1. Revise existing rate policy guidelines. 2. Implement increases through regular utility Phase II rate applications.
Strengthen terms and conditions of service and permitting requirements to ensure utilities and the PUB have good visibility of all customer-owned renewable generation.	1. Revise existing rate policy guidelines. 2. Joint PUB proceeding involving all utilities. 3. Amendments to permitting requirements under the *Electrical Protection Act* if necessary to ensure customer agreements are in place for all customer-owned generation.
Create a rate option for customers who install their own generation, but do not deliver energy to the grid. This rate option would not have any additional charges initially, but could develop the ability to implement specific charges in the future.	1. Revise existing rate policy guidelines. 2. Joint PUB proceeding involving all utilities.
Subsidize any remaining net revenue losses attributed to the net metering program either through a direct subsidy to each utility or by allowing rates for government customers be increased to recover the difference.	1. Implement new GNWT subsidy (need not require PUB process). 2. Revise existing rate policy guidelines. 3. Implement higher rates for government customers as part of subsequent Phase II rate applications for each utility.

5.3.4 Communication with Customers

Existing customers have installed renewable generation based on current programs and rate structures. It will be important to provide advance notice to customers of changes to these programs. We recommend the following for communicating changes to customers:

1. The GNWT should publicly announce any policy changes in advance of implementing them and indicate a PUB process will be used to implement the changes.
2. Utilities should notify their customers in advance of any changes through bill inserts and providing information on their websites.
3. The PUB process will be undertaken consistent with the PUB's normal process for notifying customers and ensuring interested parties have the ability to participate in the application and review process.

The scope of the PUB application process should also consider appropriate transition processes for existing customers. This has been incorporated into the draft policy direction to the PUB in Appendix D.

5.3.5 Implications for TPSP and GREP

This section addresses potential implications of the potential near-term policy actions for the TPSP and GREP subsidy programs. In addition to these programs, the GNWT also administers the Housing Support Program (HSP). InterGroup understands there are no Housing Support Program customers who subscribe to the net metering program at present.

TPSP Summary

The Territorial Power Support Program (TPSP) is a subsidy provided by the GNWT to non-government residential electricity customers in communities across the Northwest Territories. In all NWT communities where non-government residential energy rates are higher than the residential rate in Yellowknife, the TPSP subsidizes that difference up to a maximum monthly consumption threshold.

From September 1 to March 31, non-government residential customers only pay the Yellowknife residential rate on the first 1,000 kWh of power consumed. After 1,000 kWh, each additional kWh is charged at the zone rate.

From April 1 to August 31 the threshold is reduced to the first 600 kWh per month and after that, each additional kWh, is charged at the zone rate.

The TPSP subsidy covers the full effective energy rate difference and the TPSP reference rate (i.e., Yellowknife residential rate) is calculated inclusive of all applicable riders, but excludes the customer charge.

Table 5-4 provides a sample TPSP eligible bill calculation for an NTPC thermal zone non-government residential customer with 1,300 kWh monthly consumption.

Table 5-4: TPSP Subsidized Bill Illustration

	Description	Sample February 2021 Bill (before GST) kWh		Rate		Amount
	TPSP Threshold	1000	KW.h			
1	Customer Charge			$18.00		$18.00
2	Energy Charge	1,300	KW.h @$	0.6837		$888.81
3	Rate Rider (Fuel Stab Fund)	1,300	KW.h @$	0.0090		$11.70
4	BASE BILL (add lines 1 through 3)					$918.51
5	Billed Customer Charge			$18.00		$18.00
6	Billed at TPSP Subsidized Rate	1,000	KW.h @$	0.3060	=	$305.99
7	Billed at Full Energy Rate	300	KW.h @$	0.6837		$205.11
8	Billed Rate Rider	300	KW.h @$	0.0090		$2.70
9	NET BILL (add lines 5 through 8)					$531.80
10	**TPSP Subsidy Amount**	**$918.51**	**-**	**$531.80**		**$386.71**
11	**TOTAL BILL before GST**					**$531.80**
	Savings to Customer					
	Base Bill					$918.51
	Net Bill to Customer					$531.80
	Savings to Customer					**$386.71**

Under the net metering program, customers are only billed for net power purchased from the utility. As such, customers do not pay for the power displaced through self-generation and receive credits for power exported to the grid (i.e., banked power credits).

Table 5-5 provides a sample TPSP eligible bill calculation for an NTPC thermal zone non-government residential net metering customer who displaces 400 kWh of their consumption with their own generation in the current month and has 200 kWh of credits for power previously exported to the grid. Note that generation consumed ‘behind the meter’ (i.e., that displaces the customer’s consumption) is not metered by the utilities. As such it is not included in the actual bill to a customer, but it is typically a significant portion of the self-generation for net metering customers and reflects savings to the customer compared to purchasing that power from the utility. Those amounts are shown in this sample table for illustration purposes.

Table 5-5: TPSP Subsidized Bill Illustration for Net Metering Customer

	Description	Sample February 2021 Bill with Net Metering				
		kWh		Rate		Amount
	TPSP Threshold	1000	KW.h			
1	Customer Charge			$18.00		$18.00
2	Energy Charge at Actual Consumption	1,300	KW.h @$	0.6837		$888.81
3	Rate Rider at Actual Consumption	1,300	KW.h @$	0.0090		$11.70
4	BASE BILL before net metering					$918.51
5	Self-generation in current month above TPSP (not part of bill)	300	KW.h @$	0.6927		$207.81
6	Self-generation in current month within TPSP (not part of bill)	100	KW.h @$	0.3060		$30.60
7	TPSP Savings to GNWT (not part of bill)	100	KW.h @$	0.3867		$38.67
8	Credit for power previously exported to grid (below TPSP)	200	KW.h @$	0.3060		$61.20
9	TPSP savings to GNWT for exported power	200	KW.h @$	0.3867		$77.34
10	Total Bill Offsets	600	KW.h			$415.62
11	BASE BILL after net metering	700	KW.h			$502.89
12	Billed Customer Charge			$18.00		$18.00
13	Billed at TPSP Subsidized Rate	700	KW.h @$	0.3060	=	$214.20
14	Billed at Full Energy Rate	0	KW.h @$	0.6837		$0.00
15	Billed Rate Rider	0	KW.h @$	0.0090		$0.00
16	NET BILL (add lines 9 through 12)					$232.20
17	**TPSP Subsidy Amount**	**$502.89**	-	**$232.20**		**$270.69**
18	**TOTAL BILL before GST**					**$232.20**
	Savings to Net Metering Customer					
	Base Bill					$918.51
	Net Bill to Customer					$232.20
	Direct Savings					*$299.61*
	Customer TPSP savings					*$270.69*
	GNWT avoided TPSP savings					*$116.01*
	Savings to Customer					**$686.31**

Under the current net metering program rules there are TPSP subsidy savings to the GNWT from net metering customers compared to non-net metering customers with the same total consumption. As illustrated in Tables 5-4 and 5-5, for the same amount of power consumed (1,300 kWh), the TPSP subsidy for a net metering customer would be $270.69 compared to $386.71 for a non-net metering customer.

The net amount saved through subsidies, net metering credits and displacing a portion of their own consumption for a net metering customer would be $686.31 compared to a non-net metering customer savings of $386.71.

If the net metering energy credit rate were changed from the retail energy rate to a lower rate (approximately the avoided cost of fuel), this would have implications for TPSP subsidy spending. This is because net metering customers would be compensated for the power exported to the grid at a lower rate than they would need to pay for the power consumed from the grid.

This is illustrated in Table 5-6, where a net metering customer has the same monthly consumption (1,300 kWh) offset by 400 kWh of their own generation behind-the-meter and a credit at the avoided cost of fuel (assumed at $0.33/kWh) for 200 kWh exported to the grid.

Table 5-6: TPSP Subsidized Bill Illustration for Net Metering Customer at Avoided Cost of Fuel Compensation

	Description	Sample February 2021 Bill with Net Metering				
		kWh		Rate		Amount
	TPSP Threshold	1000	KW.h			
1	Customer Charge			$18.00		$18.00
2	Energy Charge at Actual Consumption	1,300	KW.h @$	0.6837		$888.81
3	Rate Rider at Actual Consumption	1,300	KW.h @$	0.0090		$11.70
4	BASE BILL before net metering					$918.51
5	Self-generation in current month above TPSP (not part of bill)	300	KW.h @$	0.6927		$207.81
6	Self-generation in current month within TPSP (not part of bill)	100	KW.h @$	0.3060		$30.60
7	TPSP Savings to GNWT (not part of bill)	100	KW.h @$	0.3867		$38.67
	BASE Bill for TPSP Subsidy Determination	900	KW.h			$641.43
8	Billed Customer Charge			$18.00		$18.00
9	Billed at TPSP Subsidized Rate	900	KW.h @$	0.3060	=	$275.40
10	Billed at Full Energy Rate	0	KW.h @$	0.6837		$0.00
11	Billed Rate Rider	0	KW.h @$	0.0090		$0.00
12	NET BILL (add lines 6 through 9)					$293.40
13	**TPSP Subsidy Amount**	**$641.43**	**-**	**$293.40**		**$348.03**
14	Credit for power previously exported to grid	-200	KW.h @$	0.3300		($66.00)
15	**TOTAL EFFECTIVE BILL (10+12+13)**					**$227.40**
	Savings to Net Metering Customer					
	Base Bill					$918.51
	Net Bill to Customer					$227.40
	Direct Savings					*$304.41*
	Customer TPSP savings					*$348.03*
	GNWT avoided TPSP savings					*$38.67*
	Savings to Customer					**$691.11**

With the net metering compensation rate set at an avoided cost of fuel, the TPSP subsidy amount for this net metering customer increases from $270.69 to $348.03, whereas net savings to a net metering customer decreases from $686.31 to $691.11.

GREP Summary

The GNWT Rate Equalization Program (GREP) provides NUL thermal community customers with a financial contribution so that non-government residential and general service customers will have an equivalent energy charge (including rate riders) and customer charge to customers in NTPC thermal communities.[60]

For non-government residential customers, GREP is applied in combination with the TPSP subsidy such that up to a TPSP threshold limit a residential customer in NUL thermal communities is billed for the energy consumption per kWh at the subsidized TPSP rate. For power consumption over the TPSP threshold, residential customers are billed at NTPC's thermal zone non-government rate, and the GNWT compensates NUL for the difference between its full energy rate and NTPC's thermal zone non-government rate.

Application of the GREP subsidy is illustrated in Table 5-7 for residential customers and in Table 5-8 for general service customers.

[60] Northwest Territories Energy Report – May 2011, p.9. https://www.ntassembly.ca/sites/assembly/files/11-05-20td36-166.pdf.

Table 5-7: NUL Residential TPSP and GREP Subsidized Bill Illustration

	Description	Sample February 2021 Bill (before GST)				
		kWh		Rate		Amount
	TPSP Threshold	1000	KW.h			
1	NTPC Customer Charge			$18.00		$18.00
2	NTPC Energy Charge	1,300	KW.h @$	0.6837		$888.81
3	NTPC Rate Rider (Fuel Stab Fund)	1,300	KW.h @$	0.0090		$11.70
4	BASE BILL (add lines 1 through 3)					$918.51
5	Billed Customer Charge			$18.00		$18.00
6	Billed at TPSP Subsidized Rate	1,000	KW.h @$	0.3060	=	$305.99
7	Billed at NTPC Thermal Energy Rate	300	KW.h @$	0.6927		$207.81
8	NET BILL (add lines 5 through 8)					$531.80
9	**TPSP Subsidy Amount**	**$918.51**	**-**	**$531.80**		**$386.71**
10	NUL Customer Charge			$18.00		$18.00
11	NUL Full Energy Charge	1,300	KW.h @$	0.8415		$1,093.95
12	NUL Rate Rider (Fuel Stab Fund)	1,300	KW.h @$	-0.0202		($26.26)
13	FULL BILL at NUL Rates					$1,085.69
14	**GREP Subsidy Amount**	**$1,085.69**	**-**	**$918.51**		**$167.18**
15	**TOTAL BILL before GST**					**$531.80**
	Savings to Customer					
	Base Bill					$1,085.69
	Net Bill to Customer					$531.80
	Savings to Customer					**$553.89**

Table 5-8: NUL General Service GREP Subsidized Bill Illustration

	Description	Sample February 2021 Bill (before GST)			
		kWh		Rate	Amount
1	NTPC Demand Charge	10	kW @$	8	$80.00
2	NTPC Energy Charge	2,000	KW.h @$	0.5860	$1,172.00
3	NTPC Rate Rider	2,000	KW.h @$	0.0090	$18.00
4	BASE BILL (add lines 1 through 3)				$1,270.00
5	NUL Demand Charge	10	kW @$	14	$140.00
6	NUL Full Energy Charge	2,000	KW.h @$	0.6859	$1,371.80
7	NUL Rate Rider (Fuel Stab Fund)	2,000	KW.h @$	-0.0202	($40.40)
8	FULL BILL at NUL Rates				$1,471.40
9	**GREP Subsidy Amount**	**$1,471.40**	**-**	**$1,270.00**	**$201.40**
10	**TOTAL BILL before GST**				**$1,270.00**

Under the net metering program customers only get billed for net power purchased from the utility. As such, customers do not pay for consumption that is displaced through self-generation and receive credits at the full retail rate for the power previously exported to the grid. Similar to the implications for TPSP, this results in GREP subsidy savings to the GNWT as illustrated in Table 5-9.

Table 5-9: NUL Residential TPSP and GREP Subsidized Bill with Net Metering

	Description	Sample February 2021 Bill (before GST)				
		kWh		Rate		Amount
	TPSP Threshold	1000	KW.h			
1	NTPC Customer Charge			$18.00		$18.00
2	NTPC Energy Charge at Actual Consumption	1,300	KW.h @$	0.6837		$888.81
3	NTPC Rate Rider at Actual Consumption	1,300	KW.h @$	0.0090		$11.70
4	BASE BILL (add lines 1 through 3)					$918.51
5	Self-generation in current month above TPSP (not part of bill)	300	KW.h @$	0.6927		$207.81
6	Self-generation in current month within TPSP (not part of bill)	100	KW.h @$	0.3060		$30.60
7	TPSP Savings to GNWT (not part of bill)	100	KW.h @$	0.3867		$38.67
8	Credit for power previously exported to grid (below TPSP)	200	KW.h @$	0.3060		$61.20
9	TPSP savings to GNWT for exported power	200	KW.h @$	0.3867		$77.34
10	Total Bill Offsets	600				$415.62
11	BASE BILL after net metering	700	KW.h			$502.89
12	Billed Customer Charge			$18.00		$18.00
13	Billed at TPSP Subsidized Rate	700	KW.h @$	0.3060	=	$214.20
14	Billed at NTPC Thermal Energy Rate	0	KW.h @$	0.6927		$0.00
15	NET BILL (add lines 5 through 8)					$232.20
16	**TPSP Subsidy Amount**	**$502.89**	**-**	**$232.20**		**$270.69**
17	NUL Customer Charge			$18.00		$18.00
18	NUL Full Energy Charge	700	KW.h @$	0.8415		$589.05
19	NUL Rate Rider (Fuel Stab Fund)	700	KW.h @$	-0.0202		($14.14)
20	FULL BILL at NUL Rates					$592.91
21	**GREP Subsidy Amount**	**$592.91**	**-**	**$502.89**		**$90.02**
22	**TOTAL BILL before GST**					**$232.20**
	Savings to Customer					
	Base Bill					$1,085.69
	Net Bill to Customer					$232.20
	Direct Savings					*$299.61*
	Customer TPSP savings					*$270.69*
	Customer GREP savings					*$90.02*
	GNWT avoided TPSP savings					*$116.01*
	GNWT avoided GREP savings					*$77.16*
	Savings to Customer					**$853.49**

As illustrated in Tables 5-7 and 5-9, for the same amount of power consumed (1,300 kWh), the GREP subsidy for a net metering customer would be $90.02 compared to $167.18 for a non-net metering customer.

The net amount saved for a net metering customer would be $853.49 compared to a non-net metering customer savings of $553.89.

Tables 5-10 shows the GNWT GREP subsidy to NUL from a net metering general service customer consumption. The GNWT GREP subsidy in this case is $137.77 as compared to $201.40 for a non-net metering customer.

Table 5-10: NUL General Service GREP Subsidized Bill with Net Metering

	Description	Sample February 2021 Bill (before GST)			
		kWh		Rate	Amount
1	NTPC Demand Charge	10	kW @$	8	$80.00
2	NTPC Energy Chargeat Actual Consumption	2,000	KW.h @$	0.5860	$1,172.00
3	NTPC Rate Rider at Actual Consumption	2,000	KW.h @$	0.0090	$18.00
4	BASE BILL (add lines 1 through 3)				$1,270.00
5	Self-generation in current month (not part of bill)	600	KW.h @$	0.5950	$357.00
6	Credit for power previously exported to grid	300	KW.h @$	0.5950	$178.50
7	Total Bill Offsets	900			$535.50
8	BASE BILL after net metering	1,100	KW.h		$734.50
9	NUL Demand Charge	10	kW @$	14	$140.00
10	NUL Full Energy Charge	1,100	KW.h @$	0.6859	$754.49
11	NUL Rate Rider (Fuel Stab Fund)	1,100	KW.h @$	-0.0202	($22.22)
12	FULL BILL at NUL Rates				$872.27
13	**GREP Subsidy Amount**	**$872.27**	**-**	**$734.50**	**$137.77**
14	**TOTAL BILL before GST**				**$734.50**

If the net metering energy credit rate were changed from the retail energy rate to a lower rate (avoided cost of fuel), this would increase GREP subsidy amounts as compared to the current net metering program. This is because net metering customers would be compensated for power exported to the grid at a lower rate than they would need to pay for power consumed from the grid.

This is illustrated in Table 5-11, where a net metering customer has the same monthly consumption (1,300 kWh) offset by 400 kWh of own consumption displacement and also receives a compensation at avoided cost of fuel (assumed at $0.33/kWh) for 200 kWh exported to the grid.

Table 5-11: GREP Subsidized Bill Illustration for NUL Net Metering Residential Customer at Avoided Cost of Fuel Compensation

	Description	Sample February 2021 Bill (before GST)				
		kWh		Rate		Amount
	TPSP Threshold	1000	KW.h			
1	NTPC Customer Charge			$18.00		$18.00
2	NTPC Energy Charge at Actual Consumption	1,300	KW.h @$	0.6837		$888.81
3	NTPC Rate Rider at Actual Consumption	1,300	KW.h @$	0.0090		$11.70
4	BASE BILL (add lines 1 through 3)					$918.51
5	Self-generation in current month above TPSP (not part of bill)	300	KW.h @$	0.6927		$207.81
6	Self-generation in current month within TPSP (not part of bill)	100	KW.h @$	0.3060		$30.60
7	TPSP Savings to GNWT (not part of bill)	100	KW.h @$	0.3867		$38.67
8	BASE Bill for TPSP Subsidy Determination	900				$641.43
9	Billed Customer Charge			$18.00		$18.00
10	Billed at TPSP Subsidized Rate	900	KW.h @$	0.3060	=	$275.40
11	Billed at NTPC Thermal Energy Rate	0	KW.h @$	0.6927		$0.00
12	NET BILL (add lines 7 through 8)					$293.40
13	**TPSP Subsidy Amount**	**$641.43**	**-**	**$293.40**		**$348.03**
14	NUL Customer Charge			$18.00		$18.00
15	NUL Full Energy Charge	900	KW.h @$	0.8415		$757.35
16	NUL Rate Rider (Fuel Stab Fund)	900	KW.h @$	-0.0202		($18.18)
17	FULL BILL at NUL Rates					$757.17
18	**GREP Subsidy Amount**	**$757.17**	**-**	**$641.43**		**$115.74**
19	Credit for power previously exported to grid	-200	KW.h @$	0.3300		($66.00)
20	**TOTAL EFFECTIVE BILL before GST**					**$227.40**
	Savings to Customer					
	Base Bill					$1,085.69
	Net Bill to Customer					$227.40
	Direct Savings					*$304.41*
	Customer TPSP savings					*$348.03*
	Customer GREP savings					*$115.74*
	GNWT avoided TPSP savings					*$38.67*
	GNWT avoided GREP savings					*$51.44*
	Savings to Customer					**$858.29**

With the net metering compensation rate set at an avoided cost of fuel, the GNWT GREP subsidy amount for this residential net metering customer increases from $90.02 to $115.74, whereas net savings to a net metering customer decreases from $858.29 to $853.49.

For a general service net metering customer, the GNWT GREP subsidy amount increases from $137.77 to $158.98 as illustrated in Table 5-12.

Table 5-12: GREP Subsidized Bill Illustration for NUL Net Metering General Service Customer at Avoided Cost of Fuel Compensation

	Description	Sample February 2021 Bill (before GST)			
		kWh		Rate	Amount
1	NTPC Demand Charge	10	kW @$	8	$80.00
2	NTPC Energy Charge at Actual Consumption	2,000	KW.h @$	0.5860	$1,172.00
3	NTPC Rate Rider at Actual Consumption	2,000	KW.h @$	0.0090	$18.00
4	BASE BILL (add lines 1 through 3)				$1,270.00
5	Self-generation in current month (not part of bill)	600	KW.h @$	0.5950	$357.00
6	BASE BILL after net metering	1,400	KW.h		$913.00
7	NUL Demand Charge	10	kW @$	14	$140.00
8	NUL Full Energy Charge	1,400	KW.h @$	0.6859	$960.26
9	NUL Rate Rider (Fuel Stab Fund)	1,400	KW.h @$	-0.0202	($28.28)
10	FULL BILL at NUL Rates				$1,071.98
11	**GREP Subsidy Amount**	**$1,071.98**	**-**	**$913.00**	**$158.98**
12	Credit for power previously exported to grid	-300	KW.h @$	0.3300	($99.00)
13	**TOTAL EFFECTIVE BILL before GST**				**$814.00**

TPSP and GREP Implications Summary

Table 5-13 compares illustrative customer bills, TPSP, and utility revenue impacts for a NTPC non-net metering customer, as well as net metering customers under current program rules and under an energy credit set at the avoided cost of fuel.

Table 5-13: Sample Bill, TPSP and Utility Revenue Impacts Summary

	NTPC Residential Non-Government Customer		
	Non-Net Metering	Net Metering - Current	Net Metering - Credit at Avoided Cost of Fuel
Actual consumption, including own generation (kWh)	1,300	1,300	1,300
Own generation (kWh)		400	400
Export to Grid (kWh)		200	200
Customer Effective Bill, including compensation (before GST)	$531.80	$232.20	$227.40
GNWT TPSP Subsidy	$386.71	$270.69	$348.03
Utility Fuel Cost Savings		$198.00	$198.00
Utility Net Revenue Loss		$217.62	$145.08
Total Amount, including Lost Revenue	$918.51	$918.51	$918.51

Overall, the TPSP subsidy amount for a residential customer with a monthly consumption of 1,300 kWh, 400 kWh of consumption displaced behind the meter plus 200 kWh of credits for previous sales to the grid would be $270.69 under the current program rules as compared to $386.71 for a non-net metering customer resulting in the GNWT TPSP subsidy savings of approximately $116.

Note that in this example the effective bill to a net metering customer under the energy credit set at the avoided cost of fuel is slightly lower than to a net metering customer under the current rules. This is because at 1,300 kWh of monthly consumption and 400 kWh consumption displaced by the customer's own-generation behind-the-meter, all of the billed kWh for this residential customer would be eligible for the TPSP subsidized rate, which is currently lower than the assumed avoided cost of fuel ($0.306/kWh as compared to $0.330/kWh of avoided cost of fuel).

If the credits were set at an avoided cost of fuel, the GNWT would still see TPSP subsidy savings of approximately $39 ($348.03 as compared to $386.71 for a non-net metering customer), however the TPSP savings would be lower compared to the current net metering program.

Net metering customers under both the current program rules as well as at a reduced credit for exported energy would see bill savings estimated at approximately $300 (a bill of $232.20 and $227.40 as compared to $531.80 for a non-net metering customer).

Utility lost revenue is higher under the current net metering program rules as compared to a reduced credit for exported energy ($217.62 vs $145.08).

It is important to note that customer fixed charge changes resulting in lower required energy rate changes would be applicable to all customers, including non-net metering, and as such would have much wider TPSP implications. This however would also be impacted by the timing of such rate changes among utilities.

Table 5-14 provides a similar comparison for NUL non-government customers, including GREP subsidy impact to the GNWT.

Table 5-14: Sample Bill, GREP and Utility Revenue Impacts Summary

	NUL Non-Government Thermal Zone Customer		
	Non-Net Metering	Net Metering - Current	Net Metering - Credit at Avoided Cost of Fuel
Residential			
Actual consumption, including own generation (kWh)	1,300	1,300	1,300
Own generation (kWh)		400	400
Export to Grid (kWh)		200	200
Customer Effective Bill, including compensation (before GST)	$531.80	$232.20	$227.40
GNWT TPSP Subsidy	$386.71	$270.69	$348.03
GNWT GREP Subsidy	$167.18	$90.02	$115.74
Utility Fuel Cost Savings		$198.00	$198.00
Utility Net Revenue Loss		$294.78	$196.52
Total Amount, including Lost Revenue	$1,085.69	$1,085.69	$1,085.69
General Service			
Actual consumption, including own generation (kWh)	2,000	2,000	2,000
Own generation (kWh)		600	600
Export to Grid (kWh)		300	300
Customer Effective Bill, including compensation (before GST)	$1,270.00	$734.50	$814.00
GNWT GREP Subsidy	$201.40	$137.77	$158.98
Utility Fuel Cost Savings		$297.00	$297.00
Utility Net Revenue Loss		$302.13	$201.42
Total Amount, including Lost Revenue	$1,471.40	$1,471.40	$1,471.40

Overall, the GREP subsidy for a residential customer with a monthly consumption of 1,300 kWh, 400 kWh of own consumption displaced by behind-the-meter generation, plus 200 kWh of credits for previous exports to the grid would be $90.02 under the current program rules as compared to $167.18 for a non-net metering customer resulting in the GNWT GREP subsidy savings of approximately $77. For a general service customer with 2,000 kWh monthly consumption, the GNWT GREP subsidy savings would be approximately $63 ($137.77 as compared to $201.40 for a non-net metering customer).

If the credit for exported energy is set at the avoided cost of fuel, the GNWT would still see GREP subsidy savings of approximately $51 for a residential customer ($115.74 as compared to $167.18 for a non-net metering customer) and $42 for a general service customer ($158.98 as compared to $201.40 for a non-net metering customer). However, the GREP savings would be lower compared to the current net metering program.

The GNWT may wish to consider removing fixed charges from the calculation of the GREP, or providing policy directions to the utilities to maintain comparability between the fixed charges to reduce potential implications for the GREP subsidy.

6.0 SUMMARY OF FINDINGS

Key findings from the review of current net metering and customer-owned generation include:

Impact of current programs:

- The estimated net revenue loss to utilities related to the net metering program and customer-owned intermittent renewable generation in 2019 is $0.493 million. This is higher than the amounts reported by NTPC in its 2019/20 annual report of finances to the PUB because it includes lost revenue for NUL and lost wholesale revenues to NTPC.
- Estimated net revenue loss could increase to between $1.8 million and $2.7 million by 2030 assuming the 20 per cent cap on renewable generation is maintained and can be enforced. Net revenue loss could increase up to $3.4 million by 2030 in the Base Case Scenario if the cap is increased to 35 per cent.
- The majority of the estimated revenue loss by 2030 arises in hydro-electric zones where intermittent renewable generation primarily displaces existing renewable generation and therefore does not result in additional GHG emissions savings.
- Customer-owned generation has helped reduce GHG emissions by 465 tonnes of CO2e over 2016 levels. This could increase to an additional savings of up to 1,182 tonnes by 2030 under the existing policies.

Policy options to address revenue losses:

- There are a number of policy options available that could be implemented under existing legislation to help limit the lost revenue to utilities while maintaining the ability for customers to install their own renewable generation. These include reducing the credit for generation delivered to the grid, increasing fixed charges for all customers to better match cost causation and implementing cost based charges (such as stand-by charges, access fees or minimum bills) for customers who install their own generation.
- Additional options could be implemented but would require changes to existing legislation.

Potential near-term actions:

Near-term changes to limit the lost revenue to utilities and rate impacts to other customers, while still allowing customer to install their own generation and realize energy bill savings could include:

- Adjust the credit for renewable generation delivered to the grid (by both net metering customers and mid-scale generators) to reflect the variable generation costs of each utility in each zone. In the short-run this value could be indexed to the cost of fuel and variable operations and maintenance costs. The credit could be modified as necessary to reflect:
    a) Additional costs incurred by utilities to integrate renewable generation (e.g., reductions in fuel efficiency or additional infrastructure needed to accommodate delivery of surplus intermittent generation.
    b) Additional long-run savings from avoided maintenance or capital costs or other benefits of intermittent renewable generation.
- Revise the GNWT rate policy guidelines to permit utilities to increase their fixed charges.
- Strengthening terms and conditions of service and permitting requirements to ensure utilities and the PUB have good visibility of all customer-owned renewable generation. This could also include creating a central registry to maintain records on renewable generation installed in the territory.
- Creating a rate option for customers who install their own generation, but do not deliver energy to the grid. This rate option may not have any additional charges initially, but could develop the ability to implement specific charges or credits for grid services in the future.
- Subsidize any remaining net revenue losses attributed to customer-owned generation either through a direct subsidy to each utility or by allowing rates for government customers to be increased to recover the difference.
- Re-evaluate the costs and benefits of the customer-owned generation policies in the medium-term (three to five years).
- Implement the policy changes through a joint PUB process for all electric utilities and through regular rate applications.
- Consider removing fixed charges from the calculation of the GREP or providing policy directions to the utilities to maintain comparability between the fixed charges to reduce potential implications for the GREP subsidy.

7.0 GLOSSARY OF TERMS

Capacity

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

Consumption

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

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 customer.

Distribution

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

Distributed Generation

Customer-owned electric generation facilities connected to a utility's distribution systems.

Emissions

Greenhouse gas emissions produced by diesel generation. Methane (CH_4) and Nitrous Dioxide (N_2O) gases are converted into Carbon Dioxide (CO_2) equivalent.

Energy

a) Electricity;

b) Heat which 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 Northwest Territories Power Corporation Act.

Fixed Costs

Those costs which, in the short run, do not vary with kilowatt-hours produced or sold, or number of Customers served.

General Service

Customer Classification for service other than Residential, Industrial, Wholesale, or Street Lighting.

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 kilowatt-hours (kWh).

GNWT

The Government of the Northwest Territories.

Installed Capacity

The total Generation Capacity installed in a plant or facility.

Intermittent Power

Power, such as from solar or wind generation that cannot be dispatched on demand.

Kilowatt (kW)

The measure of electrical capacity required by the customer at any instantaneous moment. The kWh equates to power. 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.

Line Losses

Kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.

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.

NTPC

The Northwest Territories Power Corporation

NUL

Northland Utilities Limited.

O & M

Operating and Maintenance

Operating Expenses

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

Peak Load

The highest demand, measured over an interval of 15 or 30 minutes, on an electrical system during some period. As used in the forecast, peak load denotes the highest demand during the fiscal year.

Plant

Means a facility or facilities for the generation, transmission, 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).

PUB

The Public Utilities Boards of the Northwest Territories.

Rates

The prices at which regulated electricity services are provided.

Regulated

Aspects of a utility’s business subject to regulatory (PUB) approval.

Residential

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 Industrial, Wholesale or General Service purposes.

Transmission

The act or process of transferring electric energy in bulk from the point of generation to the point of transformation for distribution.

Variable Costs

Costs, such as fuel, that vary with the amount of electric energy supplied, or number of Customers served.

Wholesale

A customer, sales and revenue classification covering electric energy supplied to other electric utilities for resale to ultimate customer.

Net Metering and Community Self-Generation Policy Review

APPENDIX A

Net Metering and Community Self-Generation 10-year Rate and Financial Model Assumptions and Results based on Current Programs

This appendix provides information on the 10-year rate model (Model) prepared for the Government of the Northwest Territories (GNWT) Net metering Program and Community Self-Generation Policy Review.

The model includes preliminary actuals from 2019 and estimates to 2030. Net metering and community self-generation includes solar energy generation by net metering program customers and by other customers who are not subscribed to the net metering program.

I. Net Metering Program

1. Data Sources

The Model was designed based on information sources including the annual report of finances of the Northwest Territories Power Corporation (NTPC) and Northland Utilities (NUL) submitted to the Public Utilities Board, NTPC's renewable microgrid capacity by community information published on NTPC's website, and NTPC and NUL's general rate applications and rate schedules.

The model's report framework builds off NTPC's net metering cost report table from its annual report of finances, which is publicly available. Table A-1 presents NTPC's 2019-20 net metering cost report.

NTPC's net metering cost report does not include reduced wholesale revenues as a result of net metering customers served by NUL in Yellowknife and Hay River. The model was expanded to include an estimate of reduced wholesale revenues to NTPC from reduced sales in Yellowknife and Hay River.

Table A-1: NTPC 2019-20 Net Metering Cost Report[61]

Line No		Snare	Taltson	Thermal	Total
	Residential Net Metering Customers				
L1	Sales exported to NTPC's system (kWh)	535	0	36,610	37,145
L2	Residential Credit to Customer ($)	193	0	28,643	
	General Service Net Metering Customers				
L3	Sales exported to NTPC's system (kWh)	8,069	77	49,323	57,469
L4	General Service Credit to Customer ($)	3,233	15	38,309	
	Estimated Intermittent Generation for Own Consumption				
L5	Installed Capacity (kW)	22	1	538	
L6=L5x1000-(L1+L3)	Estimated Generation at Assumed Solar Potential (1,000 hours/year	13,446	923	452,547	
L7	Estimated revenue loss from reduced consumption ($)	5,387	183	351,490	
L8=L2+L4+L7	**Total Gross Revenue Loss ($)**	**8,813**	**198**	**418,442**	**427,453**
L9	Line Loss Adjustment (%)	3.0%	10.4%	5.8%	
L10=(L1+L3+L6)x(1+L6)	Avoided Generation (kWh)	22,712	1,104	569,712	593,527
L11	Thermal Generation Mix (%)	0.0%	0.0%	100.0%	
L12	Approved Zone Average Fuel Efficiency (kWh/l)	3.750	3.392	3.612	
L13	Approved Zone Average Fuel Price ($/l)	0.700	0.872	1.072	
L14=(L10xL11)/L12xL13	Avoided Fuel Cost ($)	0	0	169,084	169,084
L15	Estimated Non-fuel Variable Cost of Generation (cents/kWh)	2.5	2.5	2.5	
L16=L10xL15/100	Avoided Non-fuel Variable Cost ($)	568	28	14,243	14,838
L17=L14+L16	**Total Avoided Cost of Generation ($)**	**568**	**28**	**183,327**	**183,922**
L18=L8-L17	**Net Revenue Loss ($)**	**8,245**	**171**	**235,115**	**243,531**
	Net Metering Revenue Loss Recovery Test: Net Revenue Loss > 1% of Previous Years Net Income				
L19	1% of Net Income (NI) 2018-19 (if NI is negative, then value is $0)				**45,774**
L20=L18-L19	Loss Recovery Calculation: Net Revenue Loss less 1% of Net Income				**197,757**
	Eligible collection from the GNWT				**197,757**

Notes:
1. Credits to customers are based on the current non-government retail rates by rate class and rate zone
2. Line loss adjustment factors are for total line losses, as provided in Schedule 2 of Phase I GRA
3. Thermal generation mix values by rate zone are based on the load forecast by source of generation approved by the Public Utilities Board in the most recent GRA
4. The fuel efficiency rates used are those approved by the Public Utilities Board in the most recent GRA
5. The fuel prices used are those approved by the Public Utilities Board in the most recent GRA
6. Estimated revenue loss from own consumption is based on current non-government general service retail rate by zone

[61] NTPC 2019-20 Annual Report of Finances, Net Metering Cost Report, pdf page 11 of 12. Available: https://www.nwtpublicutilitiesboard.ca/sites/default/files/documents/2019-20%20NTPC%20Annual%20Report%20of%20Finances.pdf. Accessed February 18, 2021.

As well, NTPC annually publishes its renewable microgrid capacity by community. Table A-2 summarizes NTPC's renewable microgrid capacity by community as of July 14, 2020.

Table A-2: NTPC Renewable Microgrid Capacity by Community as of July 14, 2020[62]

	Community Average Load	Intermittent Renewable Energy Capacity Allowed (kW)	Current Solar Capacity Installed (kW)		Planned Projects (kW)*	Current Available Capacity (kW)**
			Net Metering Program (<15 kW)	Other (>15 kW)	(kW)*	(kW)**
Aklavik	363	73	21	55	0	0
Behchoko	814	163	7	25	0	131
Colville Lake	77	15	15	137	0	0
Déline	314	63	5	0	30	28
Dettah			15	0	0	0
Fort Good Hope	313	63	5	0	0	58
Fort Liard	259	52	0	60	0	0
Fort McPherson	397	79	5	0	0	74
Fort Resolution	293	59	0	0	0	59
Fort Simpson	867	173	55	118	0	0
Fort Smith	3,000	600	1	5	0	595
Gamètì	121	24	5	5	0	14
Inuvik	3,349	670	276	258	136	0
Jean Marie River	38	8	6	1	0	0
Lutsel k'e	170	34	0	35	0	0
Nahanni Butte	45	9	0	5	0	4
Norman Wells	1108	222	5	0	5	212
Paulatuk	166	33	26	7	5	0
Sachs Harbour	109	22	19	0	0	3
Tsiigehtchic	89	18	0	0	0	18
Tuktoyaktuk	481	96	15	0	51	30
Tulita	277	55	10	0	45	0
Ulukhaktok	235	47	0	0	0	47
Wha Ti	201	40	15	0	0	25
Wrigley	84	17	0	10	0	7
Total	**13,170**	**2,635**	**507**	**719**	**272**	**1137**

*** Includes solar projects in the planning stage.**
**** Includes all solar capacity installed whether under the Net Metering Program or not.**

NUL does not publish net metering reports similar to NTPC's. InterGroup obtained some historical net metering data from NUL to populate the model.

The model inputs are based on the following data sources and assumptions:

1. 2019 sales to grid information is from NTPC's Report of Finances and as provided by NUL.
2. 2019 installed capacity information from NTPC's Report of Finances and as provided by NUL.
3. 2019 estimated own generation is estimated based on assumed solar potential of 1,000 hours/year less the energy delivered to the utilities' grids for both NTPC and NUL.
4. Line loss percentages are from GRA filings:
    a. NTPC 2017-2019 GRA Phase I Compliance Filing, Schedule 2.1-1 to Schedule 2.1-3.
    b. NUL-NWT 2014-2015 GRA, Compliance filing, Schedule 4.1, 2015 Test Year.
5. GRA approved Zone Average Fuel Efficiency (kWh/l) from:
    a. NTPC 2017-2019 GRA Phase I Compliance Filing, Schedule 4.0.

[62] NTPC Renewable Microgrid Capacity by Community as of July 14, 2020. Available: https://www.ntpc.com/docs/default-source/customer-service-docs/net metering-capacity.pdf?sfvrsn=2. Accessed February 18, 2021.

    b. NUL-NWT 2014-2015 GRA, Compliance filing, Schedule 4.1, 2015 Test Year.
6. GRA approved Zone Average Fuel Price ($/l) from:
    a. NTPC 2017-2019 GRA Phase I Compliance Filing, Schedule 4.0.1.
    b. NUL-NWT 2014-2015 GRA, Compliance filing, Schedule 4.1, 2015 Test Year (approved).
7. NUL Yellowknife (NUL-Yk) and NUL-NWT purchase power prices are from NTPC's rate schedules.
8. Dettah average load is taken from 2006/08 GRA Phase I Compliance filing Schedules.

2. Base Case Scenario

A base case scenario was prepared using recent trends in customer installation of intermittent renewable generation.

2.1. Base Case Assumptions

Table A-3 shows assumptions used in the base case.

Table A-3: Base Case Assumptions

Annual Inflation	2%
Estimated Non-fuel Variable Cost of Generation	2.5 cents/kWh
Annual Load Growth* • Hydro Zone Communities • Thermal Zone Communities	 1.0% 0.5%
Intermittent Renewable Energy Capacity Allowed*	20%

*) For Annual Load Growth and Intermittent Renewable Energy Capacity Allowed assumptions the Model allows the user to select different values by community, if required.

Initial load growth estimates were developed based on the high end of recent actual load growth. Higher forecasts for load growth are considered appropriate for this modelling exercise as they provide a conservative estimate of the rate impact (i.e. the rate impacts are higher with higher load growth assumptions).

Average energy rates per kWh for residential and general service customers:

- NTPC: Average rate is a blend of government and non-government rates.
- NUL Yk and NUL NWT Hydro: Supply Charge, Fuel Charge, and Purchase Power Cost Adjustment Rider (Rider F).
- NUL NWT Thermal: Supply Charge and Fuel Charge.

Net metering capacity installation growth was calculated based on the following method:

- Average annual growth rates for 2017-2019 were calculated by community where available.
- Where communities did not have data to calculate growth rates available, the rate zone average was used.
- For NUL communities, growth rates were calculated based on similar NTPC rate zones:
    - NUL-Yk growth rate is assumed at NTPC Snare zone average growth rate;

    - NUL-NWT Hydro zone growth rate is assumed at NTPC Taltson zone average growth rate;
    - NUL-NWT Thermal zone growth rate is assumed at NTPC Thermal zone average growth rate.
- The model applies growth rates to the prior year installed capacity by community to estimate the installed capacity for the current year.
- If a community does not have any installed system under net metering program in 2019, then an initial value is assumed at 5 kW for thermal communities and 1 kW for hydro communities in the first forecast year.
- Capacity is capped at 20 per cent of the community's average load in the current year (i.e., the installed capacity by community cannot exceed the cap of 20 per cent of the average load in the community).

Table A-4 shows the calculation of the average growth rates by zone. In certain communities (Aklavik, Colville Lake, Fort Liard and Lutsel k'e) the current installed capacity already exceeds 20 per cent of the community's average load as of 2020. The model does not estimate any net metering capacity additions in those communities.

Table A-4: NWT Net Metering Capacity Growth by Zone

Zones	Current Solar Capacity Installed Net Metering Program (<15 kW)			Annual Growth		
	2017 (kW)	2018 (kW)	2019 (kW)	2018 vs. 2017	2019 vs. 2018	Average
NTPC - Snare	14	22	22	57.1%	0.0%	28.6%
NTPC - Taltson	1	1	1	0.0%	0.0%	0.0%
NTPC - Thermal	179	311	538	73.9%	72.9%	73.4%
NUL Yk			309			
NUL NWT - Hydro			22			
NUL NWT - Thermal			10			

Table A-5 summarizes the estimated net revenue loss resulting from the net metering program by utility with 2019 preliminary actuals and 2030 estimates in the Base Case Scenario.

Table A-5: Base Case Scenario Estimated Revenue Losses from Net Metering Program

	2019 Preliminary Actual							2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Net Metering Customers														
Sales exported to Utilities' system (kWh)	535	0	36,610	127,792	9,930	0	174,867	3,247	0	78,895	1,644,483	9,930	0	1,736,554
Average price per kWh (Cents)	36.12	24.25	78.24	31.03	34.90	84.15		44.91	30.15	97.28	38.58	43.39	104.63	
Residential Credit to Customer ($)	193	0	28,643	39,654	3,466	0	71,955	1,458	0	76,747	634,473	4,309	0	716,987
General Service Net Metering Customers														
Sales exported to Utilities' system (kWh)	8,069	77	49,323	20,805	0	2,340	80,614	48,973	154	106,291	267,728	0	22,891	446,037
Average price per kWh (Cents)	40.06	19.84	77.67	23.30	24.68	68.59		49.81	24.67	96.57	28.97	30.69	85.28	
General Service Credit to Customer ($)	3,233	15	38,309	4,848	0	1,605	48,009	24,396	38	102,647	77,562	0	19,522	224,166
Estimated Intermittent Generation for Own Consumption														
Under Net Metering Program (kW)	22	1	538	309	22	10	902	134	2	1,160	3,976	22	98	5,392
Estimated Generation at Assumed Solar Potential (1,000 hours/year)	13,396	923	452,367	161,308	12,320	7,660	647,974	81,305	1,846	974,850	2,064,135	12,070	74,934	3,209,141
Average price per kWh (Cents)	40.06	19.84	77.67	29.95	34.90	68.59		49.81	24.67	96.57	37.24	43.39	85.28	
Estimated revenue loss from reduced consumption ($)	5,367	183	351,350	48,308	4,300	5,254	414,762	40,501	455	941,433	768,606	5,238	63,906	1,820,140
Gross Revenue Loss from Net Metering ($)	**8,793**	**198**	**418,302**	**92,810**	**7,765**	**6,859**	**534,727**	**66,355**	**493**	**1,120,828**	**1,480,641**	**9,547**	**83,428**	**2,761,293**
Other Installed Capacity (kW)	25	5	691	0	60	0	781	25	5	908	0	60	0	998
Total Installed Capacity (kW)	**47**	**6**	**1,230**	**309**	**82**	**10**	**1,684**	**159**	**7**	**2,068**	**3,976**	**82**	**98**	**6,390**
Installation Cap (kW)	**183**	**659**	**1,813**	**3,564**	**676**	**94**	**6,989**	**204**	**735**	**1,915**	**3,976**	**754**	**98**	**7,682**
Line Loss Adjustment (%)	3.0%	10.4%	5.8%	3.4%	8.1%	9.0%		3.0%	10.4%	5.8%	3.4%	8.1%	9.0%	
Avoided Generation (kWh)	22,660	1,104	569,521	320,442	24,053	10,904	948,684	137,531	2,208	1,227,318	4,111,542	23,782	106,666	5,609,047
Thermal Generation Mix (%)	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%		0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	
Approved Zone Average Fuel Efficiency (kWh/l)	3.750	3.392	3.612			3.560		3.750	3.392	3.612			3.560	
Approved Zone Average Fuel Price ($/l) (for NUL Yk & NUL-NWT Hydro wholesale purchase price from NTPC $/kWh)	0.700	0.872	1.072	0.2127	0.1198	1.008		0.870	1.084	1.333	0.2645	0.1490	1.254	
Avoided Fuel or Purchase Power Cost ($)	0	0	169,027	68,158	2,882	3,089	243,156	0	0	452,904	1,087,362	3,543	37,574	1,581,382
Estimated Non-fuel Variable Cost of Generation (cents/kWh)	2.5	2.5	2.5	2.5	2.5	2.5		3.1	3.1	3.1	3.1	3.1	3.1	
Avoided Non-fuel Variable Cost ($)	567	28	14,238	8,011	601	273	23,717	4,275	69	38,150	127,805	739	3,316	174,354
Total Avoided Cost of Generation ($)	**567**	**28**	**183,265**	**76,169**	**3,483**	**3,362**	**266,873**	**4,275**	**69**	**491,054**	**1,215,166**	**4,282**	**40,890**	**1,755,736**
NTPC Wholesale Revenue Loss from NUL Net metering ($)	60,147	2,280					**62,427**	959,557	2,803					**962,360**
Net Revenue Loss from Net Metering ($)	**68,373**	**2,451**	**235,037**	**16,640**	**4,282**	**3,497**	**330,281**	**1,021,637**	**3,228**	**629,774**	**265,475**	**5,265**	**42,539**	**1,967,917**

2.2. Base Case Scenario GNWT TPSP and GREP Subsidy Savings Assumptions

The Territorial Power Support Program (TPSP) is designed to equalize NTPC and NUL NWT non-government residential energy rates to NUL-Yk residential rates up to thresholds 600kWh/month in summer months and for 1,000 kWh/month in winter months.[63]

The GNWT Rate Equalization Program (GREP) applies for both non-government residential and commercial customers in NUL NWT Thermal zone. The GREP is designed to equalize these customers' effective energy rates to rates in NTPC Thermal zone.[64]

TPSP subsidy savings estimates were calculated based on the following assumptions:

1. Residential sales are estimated based on the proportion of energy sold to utility grids by residential and general service net metering customers, except for NTPC Snare and NTPC Thermal zones.
    - NTPC Snare zone TPSP eligible sales are assumed at zero considering the very low level of residential net metering installations in the zone.
    - In NTPC Thermal zone, proportion of the energy sold to utility grip by residential and general service net metering customers is roughly in line, so residential sales are assumed at 50 per cent of total net metering generation.
2. 100 per cent of estimated residential sales are assumed for non-government customers and are TPSP eligible.

GREP subsidy saving estimates were calculated based on the following assumptions:

1. NUL-NWT Thermal general service sales are estimated based on the proportion of exports to utility grid by residential and general service net metering customers.
2. 100 per cent of estimated NUL-NWT Thermal general service sales are assumed as non-government general service sales.
3. It is assumed net metering general service customers do not cause for a demand increase, so GREP for demand charge is not calculated.
4. GREP calculation assumes that net metering generation does not offset any billed demand, taking into account that minimum demand charge is 5 kW per month as per NUL-NWT's rate schedule.

Table A-6 summarizes the estimated GNWT TPSP and GREP subsidy savings under the Base Case Scenario for 2019 and 2030.

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[63] NTPC webpage: https://www.ntpc.com/customer-service/territorial-power-support-program---tpsp. Accessed February 26, 2021; NWT PUB Decision 1-2016, paragraph 74. Available: https://www.nwtpublicutilitiesboard.ca/sites/default/files/supporting/1-2016%20DECISION%20NUL%20%28NWT%29%20Phase%20II%20GRA_0.pdf. Accessed February 26, 2021.

[64] Northwest Territories Energy Action Plan, A Three-Year Action Plan and a Long-Term Vision, December 2013, page 57. Available: https://www.inf.gov.nt.ca/sites/inf/files/northwest_territories_energy_action_plan_-_december_2013.pdf. Accessed February 27, 2021.

Table A-6: Base Case Scenario Estimated TPSP and GREP Savings

	2019 Preliminary Actual						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	269,150	N/A	22,000	0	291,150
100% of the these Lost Sales is assumed TPSP eligible	0	0	269,150	N/A	22,000	0	291,150
Avoided TPSP Subsidy Rate (Cents/kWh)	4.37	0.00	37.77	N/A	3.18	38.67	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	22,000	1,000	269,150	N/A	0	10,000	302,150
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**101,658**	**N/A**	**700**	**0**	**102,358**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	10,000	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	13.76	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	7.97	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	6.00	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**797**	**797**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**101,658**	**0**	**700**	**797**	**103,155**

	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	580,018	N/A	22,000	0	602,018
100% of the these Lost Sales is assumed TPSP eligible	0	0	580,018	N/A	22,000	0	602,018
Avoided TPSP Subsidy Rate (Cents/kWh)	5.33	0.00	46.04	N/A	3.88	47.14	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	133,525	2,000	580,018	N/A	0	97,825	813,368
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**267,049**	**N/A**	**853**	**0**	**267,901**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	97,825	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	16.77	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	9.72	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	7.31	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**9,504**	**9,504**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**267,049**	**0**	**853**	**9,504**	**277,405**

3. Low and High Estimate Scenarios

To address the uncertainty around future uptake of the net metering program, InterGroup also prepared low and high estimate scenarios to establish a range of possible outcomes.

3.1. Low Case Scenario

In the Low Case Scenario, annual growth for 2020-2030 is based on the average capacity increase in (kW) rather than the growth percentage. The Low Case Scenario results in 17 communities reaching the 20 per cent capacity limit by 2030. 14 communities remain below the maximum allowed capacity.

The kW annual increase values by community as calculated as follow:

- For communities with net metering installed capacity during 2017-2019, annual average kW increase is used.
- For communities without any net metering installed capacity currently, then used 5 per cent of Intermittent renewable energy capacity cap, which is currently 20 per cent of community average load.
- The 5 per cent of Intermittent renewable energy capacity cap was rounded up for all communities. Any value less than “1” (one) has been rounded up to “1” (one).

Table A-7 summarizes the estimated revenue loss for the net metering program in the Low Case Scenario. Table A-8 summarizes the estimated TPSP and GREP savings in the Low Case Scenario.

Table A-7: Low Case Scenario Estimated Revenue Losses from Net Metering Program

	2019 Preliminary Actual							2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Net Metering Customers														
Sales exported to Utilities' system (kWh)	535	0	36,610	127,792	9,930	0	174,867	2,856	0	57,868	937,555	178,740	0	1,177,019
Average price per kWh (Cents)	36.12	24.25	78.24	31.03	34.90	84.15		44.91	30.15	97.28	38.58	43.39	104.63	
Residential Credit to Customer ($)	193	0	28,643	39,654	3,466	0	71,955	1,282	0	56,293	361,727	77,562	0	496,864
General Service Net Metering Customers														
Sales exported to Utilities' system (kWh)	8,069	77	49,323	20,805	0	2,340	80,614	43,071	28,028	77,963	152,637	0	16,378	318,077
Average price per kWh (Cents)	40.06	19.84	77.67	23.30	24.68	68.59		49.81	24.67	96.57	28.97	30.69	85.28	
General Service Credit to Customer ($)	3,233	15	38,309	4,848	0	1,605	48,009	21,455	6,914	75,290	44,220	0	13,968	161,847
Estimated Intermittent Generation for Own Consumption														
Under Net Metering Program (kW)	22	1	538	309	22	10	902	117	364	851	2,267	396	70	4,065
Estimated Generation at Assumed Solar Potential (1,000 hours/year)	13,396	923	452,367	161,308	12,320	7,660	647,974	71,505	335,972	715,038	1,176,808	217,260	53,615	2,570,198
Average price per kWh (Cents)	40.06	19.84	77.67	29.95	34.90	68.59		49.81	24.67	96.57	37.24	43.39	85.28	
Estimated revenue loss from reduced consumption ($)	5,367	183	351,350	48,308	4,300	5,254	414,762	35,620	82,873	690,527	438,199	94,277	45,724	1,387,220
Gross Revenue Loss from Net Metering ($)	**8,793**	**198**	**418,302**	**92,810**	**7,765**	**6,859**	**534,727**	**58,357**	**89,787**	**822,111**	**844,145**	**171,839**	**59,692**	**2,045,932**
Other Installed Capacity (kW)	25	5	691	0	60	0	781	25	5	908	0	60	0	998
Total Installed Capacity (kW)	**47**	**6**	**1,230**	**309**	**82**	**10**	**1,684**	**142**	**369**	**1,759**	**2,267**	**456**	**70**	**5,064**
Installation Cap (kW)	**183**	**659**	**1,813**	**3,564**	**676**	**94**	**6,989**	**204**	**735**	**1,915**	**3,976**	**754**	**98**	**7,682**
Line Loss Adjustment (%)	3.0%	10.4%	5.8%	3.4%	8.1%	9.0%		3.0%	10.4%	5.8%	3.4%	8.1%	9.0%	
Avoided Generation (kWh)	22,660	1,104	569,521	320,442	24,053	10,904	948,684	120,955	401,856	900,219	2,344,078	428,082	76,319	4,271,509
Thermal Generation Mix (%)	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%		0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	
Approved Zone Average Fuel Efficiency (kWh/l)	3.750	3.392	3.612			3.560		3.750	3.392	3.612			3.560	
Approved Zone Average Fuel Price ($/l) (for NUL Yk & NUL-NWT Hydro wholesale purchase price from NTPC $/kWh)	0.700	0.872	1.072	0.2127	0.1198	1.008		0.870	1.084	1.333	0.2645	0.1490	1.254	
Avoided Fuel or Purchase Power Cost ($)	0	0	169,027	68,158	2,882	3,089	243,156	0	0	332,198	619,928	63,765	26,884	1,042,776
Estimated Non-fuel Variable Cost of Generation (cents/kWh)	2.5	2.5	2.5	2.5	2.5	2.5		3.1	3.1	3.1	3.1	3.1	3.1	
Avoided Non-fuel Variable Cost ($)	567	28	14,238	8,011	601	273	23,717	3,760	12,491	27,983	72,864	13,307	2,372	132,777
Total Avoided Cost of Generation ($)	**567**	**28**	**183,265**	**76,169**	**3,483**	**3,362**	**266,873**	**3,760**	**12,491**	**360,181**	**692,792**	**77,072**	**29,256**	**1,175,553**
NTPC Wholesale Revenue Loss from NUL Net metering ($)	60,147	2,280					**62,427**	547,064	50,459					**597,523**
Net Revenue Loss from Net Metering ($)	**68,373**	**2,451**	**235,037**	**16,640**	**4,282**	**3,497**	**330,281**	**601,662**	**127,754**	**461,930**	**151,353**	**94,767**	**30,436**	**1,467,902**

Table A-8: Low Case Scenario Estimated TPSP and GREP Savings

	2019 Preliminary Actual						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	269,150	N/A	22,000	0	291,150
100% of the these Lost Sales is assumed TPSP eligible	0	0	269,150	N/A	22,000	0	291,150
Avoided TPSP Subsidy Rate (Cents/kWh)	4.37	0.00	37.77	N/A	3.18	38.67	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	22,000	1,000	269,150	N/A	0	10,000	302,150
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**101,658**	**N/A**	**700**	**0**	**102,358**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	10,000	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	13.76	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	7.97	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	6.00	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**797**	**797**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**101,658**	**0**	**700**	**797**	**103,155**

	2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	425,435	N/A	396,000	0	821,435
100% of the these Lost Sales is assumed TPSP eligible	0	0	425,435	N/A	396,000	0	821,435
Avoided TPSP Subsidy Rate (Cents/kWh)	5.33	0.00	46.04	N/A	3.88	47.14	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	117,432	364,000	425,435	N/A	0	69,993	976,860
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**195,876**	**N/A**	**15,351**	**0**	**211,227**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	69,993	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	16.77	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	9.72	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	7.31	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**6,800**	**6,800**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**195,876**	**0**	**15,351**	**6,800**	**218,027**

3.2. High Case Scenario

The High Case Scenario assumes all 31 communities reach the 20 per cent capacity limit by 2030. The High Case Scenario results in 4 additional communities reaching the 20 per cent capacity limit by 2030.

Table A-9 and Table A-10 illustrate High Case Scenario results.

Table A-9 summarizes the estimated revenue loss for the net metering program in the High Case Scenario. Table A-10 summarizes the estimated TPSP and GREP savings in the High Case Scenario.

Table A-9: High Case Scenario Estimated Revenue Losses from Net Metering Program

	2019 Preliminary Actual							2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Net Metering Customers														
Sales exported to Utilities' system (kWh)	535	0	36,610	127,792	9,930	0	174,867	4,354	0	78,895	1,644,483	313,323	0	2,041,055
Average price per kWh (Cents)	36.12	24.25	78.24	31.03	34.90	84.15		44.91	30.15	97.28	38.58	43.39	104.63	
Residential Credit to Customer ($)	193	0	28,643	39,654	3,466	0	71,955	1,955	0	76,747	634,473	135,963	0	849,138
General Service Net Metering Customers														
Sales exported to Utilities' system (kWh)	8,069	77	49,323	20,805	0	2,340	80,614	65,675	56,193	106,291	267,728	0	22,891	518,778
Average price per kWh (Cents)	40.06	19.84	77.67	23.30	24.68	68.59		49.81	24.67	96.57	28.97	30.69	85.28	
General Service Credit to Customer ($)	3,233	15	38,309	4,848	0	1,605	48,009	32,715	13,861	102,647	77,562	0	19,522	246,308
Estimated Intermittent Generation for Own Consumption														
Under Net Metering Program (kW)	22	1	538	309	22	10	902	179	730	1,160	3,976	694	98	6,837
Estimated Generation at Assumed Solar Potential (1,000 hours/year)	13,396	923	452,367	161,308	12,320	7,660	647,974	109,033	673,586	974,850	2,064,135	380,847	74,934	4,277,386
Average price per kWh (Cents)	40.06	19.84	77.67	29.95	34.90	68.59		49.81	24.67	96.57	37.24	43.39	85.28	
Estimated revenue loss from reduced consumption ($)	5,367	183	351,350	48,308	4,300	5,254	414,762	54,314	166,151	941,433	768,606	165,264	63,906	2,159,674
Gross Revenue Loss from Net Metering ($)	**8,793**	**198**	**418,302**	**92,810**	**7,765**	**6,859**	**534,727**	**88,985**	**180,012**	**1,120,828**	**1,480,641**	**301,227**	**83,428**	**3,255,121**
Other Installed Capacity (kW)	25	5	691	0	60	0	781	25	5	908	0	60	0	998
Total Installed Capacity (kW)	**47**	**6**	**1,230**	**309**	**82**	**10**	**1,684**	**204**	**735**	**2,068**	**3,976**	**754**	**98**	**7,836**
Installation Cap (kW)	**183**	**659**	**1,813**	**3,564**	**676**	**94**	**6,989**	**204**	**735**	**1,915**	**3,976**	**754**	**98**	**7,682**
Line Loss Adjustment (%)	3.0%	10.4%	5.8%	3.4%	8.1%	9.0%		3.0%	10.4%	5.8%	3.4%	8.1%	9.0%	
Avoided Generation (kWh)	22,660	1,104	569,521	320,442	24,053	10,904	948,684	184,434	805,676	1,227,318	4,111,542	750,409	106,666	7,186,045
Thermal Generation Mix (%)	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%		0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	
Approved Zone Average Fuel Efficiency (kWh/l)	3.750	3.392	3.612			3.560		3.750	3.392	3.612			3.560	
Approved Zone Average Fuel Price ($/l) (for NUL Yk & NUL-NWT Hydro wholesale purchase price from NTPC $/kWh)	0.700	0.872	1.072	0.2127	0.1198	1.008		0.870	1.084	1.333	0.2645	0.1490	1.254	
Avoided Fuel or Purchase Power Cost ($)	0	0	169,027	68,158	2,882	3,089	243,156	0	0	452,904	1,087,362	111,778	37,574	1,689,618
Estimated Non-fuel Variable Cost of Generation (cents/kWh)	2.5	2.5	2.5	2.5	2.5	2.5		3.1	3.1	3.1	3.1	3.1	3.1	
Avoided Non-fuel Variable Cost ($)	567	28	14,238	8,011	601	273	23,717	5,733	25,044	38,150	127,805	23,326	3,316	223,374
Total Avoided Cost of Generation ($)	**567**	**28**	**183,265**	**76,169**	**3,483**	**3,362**	**266,873**	**5,733**	**25,044**	**491,054**	**1,215,166**	**135,104**	**40,890**	**1,912,991**
NTPC Wholesale Revenue Loss from NUL Net metering ($)	60,147	2,280					**62,427**	959,557	88,452					**1,048,009**
Net Revenue Loss from Net Metering ($)	**68,373**	**2,451**	**235,037**	**16,640**	**4,282**	**3,497**	**330,281**	**1,042,809**	**243,420**	**629,774**	**265,475**	**166,123**	**42,539**	**2,390,139**

Table A-10: High Case Scenario Estimated TPSP and GREP Savings

	2019 Preliminary Actual						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	269,150	N/A	22,000	0	291,150
100% of the these Lost Sales is assumed TPSP eligible	0	0	269,150	N/A	22,000	0	291,150
Avoided TPSP Subsidy Rate (Cents/kWh)	4.37	0.00	37.77	N/A	3.18	38.67	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	22,000	1,000	269,150	N/A	0	10,000	302,150
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**101,658**	**N/A**	**700**	**0**	**102,358**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	10,000	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	13.76	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	7.97	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	6.00	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**797**	**797**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**101,658**	**0**	**700**	**797**	**103,155**

	2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	580,018	N/A	694,170	0	1,274,188
100% of the these Lost Sales is assumed TPSP eligible	0	0	580,018	N/A	694,170	0	1,274,188
Avoided TPSP Subsidy Rate (Cents/kWh)	5.33	0.00	46.04	N/A	3.88	47.14	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	179,063	729,779	580,018	N/A	0	97,825	1,586,685
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**267,049**	**N/A**	**26,909**	**0**	**293,957**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	97,825	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	16.77	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	9.72	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	7.31	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**9,504**	**9,504**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**267,049**	**0**	**26,909**	**9,504**	**303,461**

4. Estimated based on the 2019 installed Net Metering capacities will remain by 2030

Additionally, InterGroup prepared an estimation based on the 2019 installed Net Metering capacities which will not increase until 2030. This estimation results only in 3 communities reaching the 20 per cent capacity limit by 2030. 28 communities remain below the maximum allowed capacity.

Table A-11 summarizes the estimated revenue loss for the net metering program based on the 2019 installed Net Metering capacities will remain by 2030.

Table A-12 summarizes the estimated TPSP and GREP savings based on the 2019 installed Net Metering capacities will remain by 2030.

Table A-11: Estimated Revenue Losses from Net Metering Program with 2019 Installations Level

	2019 Preliminary Actual							2030 Estimate - with 2019 Installations						
	NTPC Snare	**NTPC Taltson**	**NTPC Thermal**	**NUL Yk**	**NUL NWT Hydro**	**NUL NWT Thermal**	**Total**	**NTPC Snare**	**NTPC Taltson**	**NTPC Thermal**	**NUL Yk**	**NUL NWT Hydro**	**NUL NWT Thermal**	**Total**
Residential Net Metering Customers														
Sales exported to Utilities' system (kWh)	535	0	36,610	127,792	9,930	0	174,867	535	0	36,610	127,792	9,930	0	174,867
Average price per kWh (Cents)	36.12	24.25	78.24	31.03	34.90	84.15		44.91	30.15	97.28	38.58	43.39	104.63	
Residential Credit to Customer ($)	193	0	28,643	39,654	3,466	0	71,955	240	0	35,614	49,305	4,309	0	89,467
General Service Net Metering Customers														
Sales exported to Utilities' system (kWh)	8,069	77	49,323	20,805	0	2,340	80,614	8,069	77	49,323	20,805	0	2,340	80,614
Average price per kWh (Cents)	40.06	19.84	77.67	23.30	24.68	68.59		49.81	24.67	96.57	28.97	30.69	85.28	
General Service Credit to Customer ($)	3,233	15	38,309	4,848	0	1,605	48,009	4,019	19	47,632	6,027	0	1,996	59,694
Estimated Intermittent Generation for Own Consumption														
Under Net Metering Program (kW)	22	1	538	309	22	10	902	22	1	538	309	22	10	902
Estimated Generation at Assumed Solar Potential (1,000 hours/year)	13,396	923	452,367	161,308	12,320	7,660	647,974	13,396	923	452,367	160,403	12,070	7,660	646,819
Average price per kWh (Cents)	40.06	19.84	77.67	29.95	34.90	68.59		49.81	24.67	96.57	37.24	43.39	85.28	
Estimated revenue loss from reduced consumption ($)	5,367	183	351,350	48,308	4,300	5,254	414,762	6,673	228	436,860	59,728	5,238	6,533	515,259
Gross Revenue Loss from Net Metering ($)	**8,793**	**198**	**418,302**	**92,810**	**7,765**	**6,859**	**534,727**	**10,933**	**247**	**520,106**	**115,060**	**9,547**	**8,528**	**664,420**
Other Installed Capacity (kW)	25	5	691	0	60	0	781	25	5	908	0	60	0	998
Total Installed Capacity (kW)	**47**	**6**	**1,230**	**309**	**82**	**10**	**1,684**	**47**	**6**	**1,447**	**309**	**82**	**10**	**1,901**
Installation Cap (kW)	**183**	**659**	**1,813**	**3,564**	**676**	**94**	**6,989**	**204**	**735**	**1,915**	**3,976**	**754**	**98**	**7,682**
Line Loss Adjustment (%)	3.0%	10.4%	5.8%	3.4%	8.1%	9.0%		3.0%	10.4%	5.8%	3.4%	8.1%	9.0%	
Avoided Generation (kWh)	22,660	1,104	569,521	320,442	24,053	10,904	948,684	22,660	1,104	569,521	319,506	23,782	10,904	947,477
Thermal Generation Mix (%)	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%		0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	
Approved Zone Average Fuel Efficiency (kWh/l)	3.750	3.392	3.612			3.560		3.750	3.392	3.612			3.560	
Approved Zone Average Fuel Price ($/l) (for NUL Yk & NUL-NWT Hydro wholesale purchase price from NTPC $/kWh)	0.700	0.872	1.072	0.2127	0.1198	1.008		0.870	1.084	1.333	0.2645	0.1490	1.254	
Avoided Fuel or Purchase Power Cost ($)	0	0	169,027	68,158	2,882	3,089	243,156	0	0	210,164	84,498	3,543	3,841	302,046
Estimated Non-fuel Variable Cost of Generation (cents/kWh)	2.5	2.5	2.5	2.5	2.5	2.5		3.1	3.1	3.1	3.1	3.1	3.1	
Avoided Non-fuel Variable Cost ($)	567	28	14,238	8,011	601	273	23,717	704	34	17,703	9,932	739	339	29,452
Total Avoided Cost of Generation ($)	**567**	**28**	**183,265**	**76,169**	**3,483**	**3,362**	**266,873**	**704**	**34**	**227,868**	**94,430**	**4,282**	**4,180**	**331,498**
NTPC Wholesale Revenue Loss from NUL Net metering ($)	60,147	2,280					**62,427**	74,567	2,803					**77,370**
Net Revenue Loss from Net Metering ($)	**68,373**	**2,451**	**235,037**	**16,640**	**4,282**	**3,497**	**330,281**	**84,795**	**3,016**	**292,238**	**20,630**	**5,265**	**4,348**	**410,293**

Table A-12: Estimated TPSP and GREP Savings with 2019 Installations Level

	2019 Preliminary Actual						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	269,150	N/A	22,000	0	291,150
100% of the these Lost Sales is assumed TPSP eligible	0	0	269,150	N/A	22,000	0	291,150
Avoided TPSP Subsidy Rate (Cents/kWh)	4.37	0.00	37.77	N/A	3.18	38.67	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	22,000	1,000	269,150	N/A	0	10,000	302,150
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**101,658**	**N/A**	**700**	**0**	**102,358**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	10,000	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	13.76	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	7.97	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	6.00	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**797**	**797**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**101,658**	**0**	**700**	**797**	**103,155**

	2030 Estimate - with 2019 Installations						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Residential Total Lost Sales (kWh)	0	0	269,150	N/A	22,000	0	291,150
100% of the these Lost Sales is assumed TPSP eligible	0	0	269,150	N/A	22,000	0	291,150
Avoided TPSP Subsidy Rate (Cents/kWh)	5.33	0.00	46.04	N/A	3.88	47.14	
General Service Total Lost Sales (General Service is not eligble for TPSP) (kWh)	22,000	1,000	269,150	N/A	0	10,000	302,150
Avoided TPSP Subsidy Amount ($)	**0**	**0**	**123,920**	**N/A**	**853**	**0**	**124,773**
Avoided GREP Residential (kWh)	N/A	N/A	N/A	N/A	N/A	0	
Avoided GREP General Service (kWh)	N/A	N/A	N/A	N/A	N/A	10,000	
GREP Residential Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	16.77	
GREP General Service Rate (Cents/kWh)	N/A	N/A	N/A	N/A	N/A	9.72	
Avoided GREP General Service Demand (kW)	N/A	N/A	N/A	N/A	N/A	0.00	
GREP General Service Demand Rate ($/kW)	N/A	N/A	N/A	N/A	N/A	7.31	
Avoided GREP Amount ($)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**972**	**972**
GNWT Savings from TPSP & GREP Subsidies ($)	**0**	**0**	**123,920**	**0**	**853**	**972**	**125,745**

5. Comparison of Scenarios

Table A-13 summarizes the results of each scenario estimates by 2030:

1) Net revenue loss:
    - The current estimated net revenue loss for all utilities is approximately $0.330 million in 2019. Most of this arise in NTPC's thermal zone.
    - The net revenue loss is estimated to increase by 2030:
        - Base Case Scenario: $1.968 million.
        - Low Case Scenario: $1.468 million.
        - High Case Scenario: $2.390 million.
        - Estimation with 2019 Installations Level: $0.410 million.
2) Installed renewable capacity:
    - In 2019, approximately 1,684 kW of renewable capacity has been installed out of a total potential of 6,989 kW under the existing cap (24 per cent of available capacity under the cap).
    - By 2030, it is estimated installed capacity will reach:
        - Base Case Scenario: 6,390 kW out of 7,682 of allowed capacity (83 per cent of available capacity is subscribed). NTPC thermal, NUL-Yk and NUL-NWT Thermal capacity limits are estimated to be fully subscribed or exceeded.
        - Low Case Scenario: 5,064 kW out of 7,682 of allowed capacity (66 per cent of available capacity is subscribed).
        - High Case Scenario: 7,836 kW out of 7,682 of allowed capacity (exceeds the allowed capacity by 2 per cent). The capacity excess reflects the installations already in place or known to be planned. The model does not otherwise assume additional increases in capacity beyond the cap.
        - Estimation with 2019 Installations Level: 1,901 kW out of 7,682 of allowed capacity (25 per cent of available capacity is subscribed).
3) Out of total 31 communities:
    - In 2019, 6 communities reached or exceeded their installed capacity limits.
    - By 2030:
        - Base Case Scenario: 27 communities would have reached or exceed their installed capacity limits.
        - Low Case Scenario: 17 communities would have reached or exceeded their installed capacity limits.
        - High Case Scenario: all 31 communities would have reached or exceeded their installed capacity limits.
        - Estimation with 2019 Installations Level: 3 communities would have reached or exceed their installed capacity limits.

Table A-13: Estimated Net metering Revenue Loss and Remaining Capacity by each Case Scenario

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	Low Case Scenario	High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$597,000	$742,000	$3,724,000	$2,643,000	$4,303,000
Net revenue loss	$330,000	$410,000	$1,968,000	$1,468,000	$2,390,000
Accumulative rate increase required to eliminate net revenue loss	0.3%	0.3%	1.3%	0.9%	1.5%
Net revenue loss over 2016 levels	$285,000	$365,000	$1,922,000	$1,422,000	$2,345,000
Community capacity limits					
Communities at or above capacity limit	6	3	27	17	31
Communities with capacity remaining	25	28	4	14	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$268,000	$211,000	$294,000
Avoided GREP costs	$1,000	$1,000	$10,000	$7,000	$10,000
Estimated GHG Savings					
Annual GHG Savings (tonnes of CO2e)	408	408	963	698	963
GHG Savings over 2016 levels (tonnes of CO2e)	300	300	855	590	855
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$810	$1,006	$2,043	$2,102	$2,482
Per tonne of GHG savings over 2016 levels	$1,102	$1,369	$2,302	$2,487	$2,796

II. Other Intermittent Non-Net Metering Self-Generation

Some of the existing installed renewable generation subject to the capacity cap is not subscribed to the net metering program:

- Utility owned-generation where the costs of the generation are recovered through utility rates
- Power purchase agreements where generation is sold to a utility at a price comparable to the variable cost of generation. These costs are also recovered through utility rates.
- Other non-utility owned generation that is 'behind-the-meter' and does not deliver energy to the grid but does result in reduced utility revenues.

The model estimates the reduction in utility revenues as a result of other non-utility owned generation that is not subscribed to the net metering program or does not deliver energy to a utility through a purchase agreement.

Table A-14 illustrates the known installed capacities in 2019. The model also incorporates planned projects identified in NTPC's 2020 capacity report (Table A-2)

Table A-14: Other Intermittent Non-Net Metering Self-Generation

	2019 Preliminary Actual						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Utility owned or power purchase price is based on avoided fuel cost (kW)	0	0	381	0	0	0	381
Customer owned (kW)	25	5	309	0	60	0	399
Total (kW)	**25**	**5**	**690**	**0**	**60**	**0**	**779**

Utility revenue reductions from other customer installed self-generation was estimated assuming 1,000kWh of generation per installed kW of capacity and the same rates and fuel prices used to estimate revenue losses from the net metering program.

Table A-15 summarizes the estimated utility revenue loss from other installed self-generation. The model estimates revenue losses of $0.163 million in 2019 and $0.325 million in 2030. These losses are the same for all three, base, low and high, scenarios because the model does not assume any estimate growth beyond known existing and planned projects.

Table A-15: Utility Revenue Loss from Other Intermittent Non-Net Metering Self-Generation

	2019 Preliminary Actual						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Other (>15 kW) Installed Capacity that Utilities have Revenue Loss (kW)	25	5	309	0	60	0	399
Avoided Generation at Assumed Solar Potential (1,000 hours/year)	25,000	4,500	309,430	0	60,000	0	398,930
Gross Revenue Loss ($)	10,016	893	240,332	0	14,808	0	**266,049**
Avoided Fuel or Purchase Power Cost ($)	0	0	91,835	0	7,188	0	99,023
Avoided Non-fuel Variable Cost ($)	625	113	7,736	0	1,500	0	9,973
Total Avoided Cost of Generation ($)	625	113	99,571	0	8,688	0	**108,997**
NTPC Wholesale Revenue Loss from NUL Other Capacity ($)	0	5,688					5,688
Net Revenue Loss from Other Capacity ($)	**9,391**	**6,468**	**140,761**	**0**	**6,120**	**0**	**162,740**

	2030 Estimates						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Other (>15 kW) Installed Capacity that Utilities have Revenue Loss (kW)	25	5	526	0	60	0	616
Avoided Generation at Assumed Solar Potential (1,000 hours/year)	25,000	4,500	526,430	0	60,000	0	615,930
Gross Revenue Loss ($)	12,453	1,110	508,384	0	18,412	0	**540,360**
Avoided Fuel or Purchase Power Cost ($)	0	0	194,263	0	8,937	0	203,200
Avoided Non-fuel Variable Cost ($)	777	140	16,364	0	1,865	0	19,146
Total Avoided Cost of Generation ($)	777	140	210,627	0	10,802	0	**222,346**
NTPC Wholesale Revenue Loss from NUL Other Capacity ($)	0	7,072					7,072
Net Revenue Loss from Other Capacity ($)	**11,676**	**8,042**	**297,758**	**0**	**7,609**	**0**	**325,086**

There is no impact to the GNWT TPSP and GREP savings from other intermittent non-net metering self-generation owned by customers based on following assumptions:

- All other installed capacities are assumed to be owned by non-residential customers that are not eligible for TPSP.
- GREP is designed only for NUL NWT Thermal zone and the model does not estimate another intermittent non-net metering capacity for NUL NWT Thermal zone.

III. Customer-owned Generation Net Metering and Non-Net Metering

Table A-16 sums up estimated utility total revenue loss from both net metering and other intermittent non-net metering self-generation installed self-generation. The model estimates the total net revenue loss of $0.493 million in 2019 and is estimated to increase by 2030:

- Base Case Scenario: $2.293 million.
- Low Case Scenario: $1.793 million.
- High Case Scenario: $2.715 million.
- Estimation with 2019 Installations Level and currently planned projects: $0.735 million.

Table A-16: Utility Total Revenue Loss from both Net metering and Other Intermittent Non-Net Metering Self-Generation

	2019 Preliminary Actuals	2030 Estimates with Current Installations	2030 Estimates Base Case Scenario	2030 Estimates Low Case Scenario	2030 Estimates High Case Scenario
Revenue and rate impacts					
Gross revenue loss	$869,000	$1,289,000	$4,271,000	$3,191,000	$4,851,000
Net revenue loss	$493,000	$735,000	$2,293,000	$1,793,000	$2,715,000
Net revenue loss over 2016 levels	$410,000	$652,000	$2,210,000	$1,709,000	$2,632,000
Community capacity limits					
Communities at or above capacity limit	6	3	27	17	31
Communities with capacity remaining	25	28	4	14	0
Impacts on existing subsidy programs					
Avoided TPSP costs	$102,000	$125,000	$268,000	$211,000	$294,000
Avoided GREP costs	$1,000	$1,000	$10,000	$7,000	$10,000
Estimated GHG savings					
Annual GHG savings (tonnes of CO2e)	632	794	1,349	1,084	1,349
GHG savings over 2016 levels (tonnes of CO2e)	465	627	1,182	918	1,182
Net revenue loss per tonne of GHG savings					
Per tonne of Annual GHG savings	$780	$927	$1,700	$1,654	$2,013
Per tonne of GHG savings over 2016 levels	$1,060	$1,173	$1,939	$1,954	$2,296

Net Metering and Community Self-Generation Policy Review

APPENDIX B

Net Metering and Community Self-Generation 10-year Model Assumptions and Results for Greenhouse Gas Emissions Savings

This appendix provides information on 10-year model (Model) for greenhouse gas (GHG) emissions reduction from avoided fossil fuel generation. Avoided fossil fuel generation from solar energy includes net metering and other non-net metering installed capacities.

The Government of Northwest Territories (GNWT) 2030 energy strategy has a strategic objective to reduce GHG emissions from electricity generation in diesel-powered communities by an average of 25 per cent.[65]

The Energy Strategy notes that small-scale and mid-scale generation are subject to the existing 20 per cent capacity limit on intermittent generation. The strategy has a target to reduce average GHG emissions from electricity generation in diesel communities from 72,000 tonnes to 54,000 tonnes by 2030 (a reduction of 18,000 tonnes or 25 per cent).[66] Of these 18,000 tonnes, approximately 700 tonnes is planned to be achieved through increased solar generation.[67]

1. GHG Emissions Reduction from Net Metering Program

This section discusses GHG emissions reduction from the Net Metering Program.

1.1. Assumptions to Estimate GHG Emissions Reduction from Net Metering Program

GHG emissions reductions were calculated for NTPC and NUL thermal zones only. The following assumptions were used to calculate GHG emissions reduction:

- Avoided generation from fossil fuel (kWh) comprises:
  - Own solar energy consumption (adjusted for utility line losses).
  - Solar energy exported to NTPC and NUL grids.
  - The avoided generation source is split into diesel and natural gas fuel:
    - 40 per cent of avoided generation from fossil fuel in Inuvik is assumed to be from natural gas source based on the mix approved in NTPC's most recent GRA.
    - All remaining avoided generation is assumed to be from diesel source.
- Avoided fossil fuel consumption (litre/Nm^3) is based on the approved fuel efficiencies from NTPC and NUL's most recent GRAs:
  - Natural gas efficiency is based on Inuvik natural gas efficiency.
  - Diesel efficiency assumes average of NTPC and NUL thermal zones fuel efficiency.

[65] GNWT 2030 Energy Strategy, page 1. Available: https://www.inf.gov.nt.ca/sites/inf/files/resources/gnwt_inf_7272_energy_strategy_web-eng.pdf. Accessed February 28, 2021.
[66] GNWT 2030 Energy Strategy, page 20.
[67] GNWT 2030 Energy Strategy, page 23.

- GHG emissions (tonne of CO_2e) were calculated separately for diesel and natural gas based on emission factors from Environment and Climate Change Canada and Government of Canada carbon equivalency factors.[68]
    - For diesel, sum of:
        - Carbon dioxide (CO_2) = [Avoided litres of Diesel x 2,681 grams of CO_2]/1,000,000.
        - Methane (CH_4) = [Avoided litres of Diesel x 0.078 grams of CH_4 x 25 times of Global Warming Potentials (GWP)]/1,000,000.
        - Nitrous Oxide (N_2O) = [Avoided litres of Diesel x 0.022 grams of N_2O x 298 GWP]/1,000,000.
    - For natural gas, sum of:
        - Carbon dioxide (CO_2) = [Avoided Nm^3 of Natural Gas x 1,901 grams of CO_2]/1,000,000.
        - Methane (CH_4) = [Avoided Nm^3 of Natural Gas x 0.49 grams of CH_4 x 25 GWP]/1,000,000.
        - Nitrous Oxide (N_2O) = [Avoided Nm^3 of Natural Gas x 0.049 grams of N_2O x 298 GWP]/1,000,000.

1.2. Estimation of GHG Emissions Reduction from Net Metering Program

Table B-1 illustrates calculation of GHG emissions and estimated GHG emission reductions for 2016 and 2019 from net metering program.

[68] Emission factors source: http://donnees.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/Emission_Factors.pdf. Accessed March 3, 2021; Carbon equivalency factors source: https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/quantification-guidance/global-warming-potentials.html. Accessed March 3, 2021.

Table B-1: GHG Emissions Saving from Net Metering Program for 2016 and 2019

Line	Description		2016 Actuals NTPC Thermal	2016 Actuals NUL-NWT Thermal	2016 Actuals Total	2019 Preliminary Actuals NTPC Thermal	2019 Preliminary Actuals NUL-NWT Thermal	2019 Preliminary Actuals Total
	Solar Generation under Net Metering							
L1	Own Solar Energy used	kWh	120,810	2,847	123,657	452,367	7,660	460,027
L2	Solar Energy Sold to NTPC and NUL	kWh	20,190	1,320	21,510	85,933	2,340	88,273
L3	**Total Solar Generation [L1+L2]**	kWh	**141,000**	**4,167**	**145,167**	**538,300**	**10,000**	**548,300**
L4	**Line Losses**	%	**5.8%**	**9.0%**		**5.8%**	**9.0%**	
L5	**Avoided Line Losses [L1/(1-L4)-L1]**	kWh	**7,438**	**283**	**7,721**	**27,853**	**761**	**28,614**
L6	**Avoided Generation from Fossil Fuel [L3+L5]**	kWh	**148,438**	**4,450**	**152,888**	**566,153**	**10,761**	**576,914**
	By fuel type, from:							
L8	Diesel [L7-L9]	kWh	119,521	4,450	123,971	455,753	10,761	466,514
L9	Natural Gas [Inuvik Installed Net Metering Capacity x 1000 x 40%]	kWh	28,918		28,918	110,400		110,400
	Fuel Efficiency							
L10	Diesel	kWh/L	3.612	3.560		3.612	3.560	
L11	Natural Gas (Inuvik)	kWh/Nm^3	3.530			3.530		
	Avoided Fossil Fuel Volume							
L12	Diesel [L8/L10]	Litre	33,090	1,250	34,340	126,177	3,023	129,200
L13	Natural Gas [L9/L11]	Nm^3	8,192		8,192	31,275		31,275
	GHG Emissions from Fossil Fuel Generation							
L14	Due to Diesel [(L12*2681+L12*0.078*25+L12*0.022*298)/1000000]	tonne of CO2e	89	3	92	339	8	347
L15	Due to Natural Gas [(L13*1901+L13*0.49*25+L13*0.049*298)/1000000]	tonne of CO2e	16		16	60		60
L16	**Net Metering GHG Emissions Subtotal [L14+L15]**	tonne of CO2e	**105**	**3**	**108**	**400**	**8**	**408**
L17	**Net Metering GHG Emissions change against 2016**	tonne of CO2e						**300**

Table B-2 illustrates annual GHG emissions reduction from Net Metering Program by 2030:

- Base Case Scenario: 963 tonne of CO_2e.
- Low Case Scenario: 698 tonne of CO_2e.
- High Case Scenario: 963 tonne of CO_2e.

Base Case and High Case scenarios achieve the same level of GHG emission reduction, because in both cases installed capacities in thermal communities are assumed to reach maximum intermittent renewable energy capacity allowed.

Table B-2: Annual GHG Emissions Saving from Net Metering Program by 2030

	2030 Estimates		
	NTPC Thermal	NUL-NWT Thermal	Total
Base Case Scenario (tonne of CO2e)	884	80	963
Low Case Scenario (tonne of CO2e)	641	57	698
High Case Scenario (tonne of CO2e)	884	80	963

2. GHG Emissions Reduction from Other Intermittent Non-Net Metering Self-Generation

This section presents GHG emissions reduction from other Intermittent non-net metering self-generation solar capacities, which are not part of the net metering program.

The GHG emissions reduction estimates are based on the same set of assumptions as in Section 1.1.

2.1. Assumptions for GHG Emissions Reduction from Other Solar Generation

The GHG emissions reduction estimates are based on the same set of assumptions as in Section 1.1.

2.2. GHG Emissions Reduction Estimate from Other Solar Generation

Table B-3 shows annual GHG emissions reductions from other solar generation by 2030. The scale of reduction is the same for all three cases (base, low, and high), because the model does not model any increase for other solar generations. By 2030, the annual GHG emissions reduction from other solar generation is estimated at 386 tonne of CO_2e.

Table B-3: Annual GHG Emissions Saving from Other Solar Generation by 2030

	2030 Estimates		
	NTPC Thermal	NUL-NWT Thermal	Total
GHG Emissions Saving (tonne of CO2e)	386	0	386

3. Total GHG Emissions Reduction from Net Metering and Non-Net Metering Self-Generation

Table B-4 shows annual total GHG emissions reductions from all solar generation by 2030:

- Base Case Scenario: 1,349 tonne of CO_2e or incremental reduction of 1,182 tonne of CO_2e over the 2016 levels.
- Low Case Scenario: 1,084 tonne of CO_2e or incremental reduction of 918 tonne of CO_2e over the 2016 levels.
- High Case Scenario: 1,349 tonne of CO_2e or incremental reduction of 1,182 tonne of CO_2e over the 2016 levels.

Table B-4: Annual GHG Emissions Saving from Net Metering and Non-Net Metering Self-Generation by 2030

	2016	2030 Estimates			2030 Estimates vs. 2016
		NTPC Thermal	NUL-NWT Thermal	Total	
2016 GHG Emissions Saving (tonne of CO2e)	167				
Base Case Scenario (tonne of CO2e)		1,269	80	1,349	1,182
Low Case Scenario (tonne of CO2e)		1,027	57	1,084	918
High Case Scenario (tonne of CO2e)		1,269	80	1,349	1,182

4. Total GHG Emissions Reduction from Net Metering, Non-Net Metering Intermittent Renewable and Utility Owned Generation

Table B-5 shows annual total GHG emissions reductions from all solar generation, including utility owned and power purchase agreement, by 2030:

- Base Case Scenario: 1,632 tonne of CO_2e or incremental reduction of 1,182 tonne of CO_2e over the 2016 levels.
- Low Case Scenario: 1,368 tonne of CO_2e or incremental reduction of 918 tonne of CO_2e over the 2016 levels.
- High Case Scenario: 1,632 tonne of CO_2e or incremental reduction of 1,182 tonne of CO_2e over the 2016 levels.

Table B-5: Annual GHG Emissions Saving from All Net Metering, Non-Net Metering and Utility Owned Generation by 2030[69]

	2016	2030 Estimates			2030 Estimates vs. 2016
		NTPC Thermal	NUL-NWT Thermal	Total	
2016 GHG Emissions Saving (tonne of CO2e)	450				
Base Case Scenario (tonne of CO2e)		1,553	80	1,632	1,182
Low Case Scenario (tonne of CO2e)		1,311	57	1,368	918
High Case Scenario (tonne of CO2e)		1,553	80	1,632	1,182

[69] Includes utility owned and power purchase agreement.

Net Metering and Community Self-Generation Policy Review

APPENDIX C

Net Metering and Community Self-Generation Background and Modelling of Potential Policy Options

This appendix provides background on policy options that could be implemented to reduce the impact of utility revenue losses due to customer self-generation on other customers. For each option, some background on the option is provided, and a preliminary assessment of the implications of the option are described. Where possible, effects have been quantified and the assumptions used to estimate impacts and the approach to modelling the results are summarized. The data used to estimate these results is the same as summarized in the Appendix A to the report except where otherwise noted in this appendix. In some cases only qualitative or directional estimates are possible.

I. Net Metering Renewable Self-Generation

1. Reduce value of credit for surplus generation

Net metering customers currently receive credit for surplus generation delivered to the grid at the full retail energy rate. This value is higher than the rate paid to mid-scale renewables delivering energy to the grid which is priced with reference to the variable cost savings, primarily fuel savings. The credits for net metering energy delivered to the grid could be revised to more closely reflect the variable cost of generation in each zone. SaskPower[70] and Manitoba Hydro[71] have recently implemented this change to their net metering programs.

<u>Estimated impact on net costs to other customers</u>

This option would reduce the net losses of utility revenue in the Base Case Scenario by $0.410 million by 2030.

<u>Estimated impact on benefits to existing net metering customers</u>

This would reduce the value of the credit residential net metering customers receive in NTPC's thermal zone in 2030 from an estimated 97 cents/kWh[72] to approximately 39 cents/kWh based on average forecast diesel and natural gas prices and non-variable operations and maintenance expenses. Rates in the Snare and Taltson zones would be approximately 3 cents/kWh based on non-fuel variable operations and maintenance savings as these zones use very little fuel. However, this change would only affect the savings on energy delivered to the grid. Self-generation customers would still save at the full retail rate for their solar generation that they use to displace their own consumption behind the meter. In 2019, approximately 70 per cent of generation from net metering customers was used to displace their own consumption. Customers who are not subscribed to the net metering program do not receive credits for surplus generation and would not be affected by this change.

[70] SaskPower states its rate of 7.5 cents/kWh is approximately its cost of generation. This compares to a retail rate of 14 cents/kWh. Available: https://www.saskpower.com/Our-Power-Future/Powering-2030/Generating-Power-as-an-Individual/Using-the-Power-You-Make/Net metering. Accessed February 28, 2021.

[71] Manitoba Hydro states its price for excess energy is 2.949 cents/kWh and is updated annually to reflect the market value of excess energy. The rate is not equal to electricity to recover costs for services Manitoba Hydro provides including transmission, distribution, safety and emergency restoration. Manitoba Hydro website. Available: https://www.hydro.mb.ca/accounts_and_services/generating_your_own_electricity/. Accessed February 28, 2021.

[72] This is a blended rate including government and non-government customers based on 2019 actual information.

Estimated impact on government subsidies

This option would reduce GNWT savings from TPSP and GREP subsidies in the Base Case Scenario by $0.049 million by 2030.

Estimated impact on GHG emissions

This change would reduce the incentive for customers to install their own generation. However, an estimated 70 per cent of the generation by net metering customers and 100 per cent of the generation for non-net metering customers would not be affected.

Regulatory and legal process considerations

Implementing this change would require changing the existing rate policy guidelines and a PUB approval process. It would likely be advantageous to implement this change as part of a joint proceeding with all the utilities to ensure consistency across the NWT.

Effects on customer choice

This change would likely be viewed as inhibiting the ability of customers to install their own generation and reducing customer choice.

Administrative efficiency

This option could be implemented in a similar manner to the previous net-billing pilot project, though there may be other ways to achieve the same outcome. It should be able to be implemented under existing utility billing systems.

Consistency with other GNWT policy objectives

Reducing the credit for net metering customers would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings. However it would reduce the net revenue loss to the utilities and the rate impact on non-adopting customers.

Political feasibility and public acceptance

The reduction in the credit rate would likely be unpopular with existing customers. However, customers would continue to save at the full retail rate when they displace consumption behind-the-meter.

Assumptions for modelling the effects of reducing the credit for surplus generation

The following assumptions were used to estimate the rate impacts of this option. The credit rate for surplus energy would be calculated as follows:

- For NTPC and NUL hydro zones: avoided non-fuel variable cost of the generation. InterGroup understands the previous net-billing program for NUL hydro zone customers provided a credit at the purchase power rate, not the non-fuel variable cost of generation. For consistency purposes in the modelling an equivalent credit was assumed for NTPC and NUL hydro customers.
- For NTPC and NUL Thermal zones: avoided fuel plus non-fuel variable costs of the generation.

This option is applied only to surplus energy delivered to the grid and does not affect self-generation used to displace consumption behind the meter for net metering customers and for customers not subscribed to the net metering program.

Results of the option to reduce value of credit for surplus generation

Table C-1 and Table C-2 present estimates for all three case scenarios by each zone compared to the net revenue losses to utilities and the impacts on TPSP and GREP subsidy programs under current renewable generation programs.

Annual net revenue losses are estimated to decrease by 2030 (Table C-1):

- Base Case Scenario: $0.797 million, or $0.410 million excluding the negative net revenue loss in NUL-Yk.
- Low Case Scenario: $0.556 million, or $0.336 million excluding the negative net revenue loss in NUL-Yk.
- High Case Scenario: $0.939 million, or $0.552 million excluding the negative net revenue loss in NUL-Yk.

Table C-1: Utility Net Revenue Loss Reduction as a Result of Reducing Value of Credit for Surplus Generation

Utility Net Revenue Loss	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	1,021,637	3,228	629,774	265,475	5,265	42,539	1,967,917
Reduce Value of Credit ($)	997,406	3,195	524,472	(387,120)	1,265	31,792	1,171,009
Variance ($)	**(24,230)**	**(33)**	**(105,301)**	**(652,595)**	**(4,000)**	**(10,747)**	**(796,908)**

Utility Net Revenue Loss	2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	601,662	127,754	461,930	151,353	94,767	30,436	1,467,902
Reduce Value of Credit ($)	580,352	121,712	384,693	(220,706)	22,761	22,747	911,558
Variance ($)	**(21,310)**	**(6,042)**	**(77,237)**	**(372,059)**	**(72,006)**	**(7,690)**	**(556,344)**

Utility Net Revenue Loss	2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	1,042,809	243,420	629,774	265,475	166,123	42,539	2,390,139
Reduce Value of Credit ($)	1,010,315	231,306	524,472	(387,120)	39,899	31,792	1,450,663
Variance ($)	**(32,494)**	**(12,114)**	**(105,301)**	**(652,595)**	**(126,223)**	**(10,747)**	**(939,475)**

Under this option, as stated, the credit rate for surplus energy in the hydro zones is set at avoided non-fuel variable cost of generation, which is lower than current wholesale price of energy to NUL NWT and NUL Yk. Surplus energy purchased by NUL from net metering customers in hydro zones will replace equivalent amount of wholesale purchase power units from NTPC. Given that the credit rate for surplus energy in NUL's hydro zone is lower than NTPC wholesale energy price, this would result in net savings to NUL from the energy purchased from net metering customers in hydro zones. With significant net metering program uptake in NUL hydro zones, which is forecast to take place by 2030, this is estimated to result in negative net revenue loss for NUL Yk.

The GNWT savings from TPSP and GREP annual subsidies are estimated to decrease relative to the existing policies by 2030 (Table C-2):

- Base Case Scenario: $0.045 million.
- Low Case Scenario: $0.040 million.
- High Case Scenario: $0.057 million.

Table C-2: Estimated TPSP and GREP Subsidy Savings Reduction as a Result of Reducing Value of Credit for Surplus Generation

Savings from TPSP and GREP Subsidies	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	267,049	0	853	9,504	277,405
Reduce Value of Credit ($)	0	0	224,417	0	468	7,280	232,166
Variance ($)	**0**	**0**	**(42,631)**	**0**	**(385)**	**(2,224)**	**(45,240)**

Savings from TPSP and GREP Subsidies	2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	195,876	0	15,351	6,800	218,027
Reduce Value of Credit ($)	0	0	164,607	0	8,422	5,209	178,238
Variance ($)	**0**	**0**	**(31,269)**	**0**	**(6,929)**	**(1,591)**	**(39,789)**

Savings from TPSP and GREP Subsidies	2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	267,049	0	26,909	9,504	303,461
Reduce Value of Credit ($)	0	0	224,417	0	14,763	7,280	246,461
Variance ($)	**0**	**0**	**(42,631)**	**0**	**(12,146)**	**(2,224)**	**(57,001)**

2. Increase customer and demand charges for all customers

Current electricity rates in the NWT do not fully recover the fixed costs of operating the electricity system through fixed charges. The majority of electricity utility revenues are recovered through variable energy charges. When energy sales volumes decrease, the utilities lose more revenue than they reduce their costs. This also means that customers who displace energy purchases by using their own generation realize savings on their bill that are higher than the savings to the utility and other customers. The rate effect is sometimes characterized as incenting 'uneconomic bypass' – that is, providing a price signal that is higher than the actual value of the new generation and therefore incenting more customer-owned generation than economic efficiency would indicate. Over time this puts upward pressure on rates for other customers.

A report by the Brattle Group prepared on behalf of ATCO noted:

> Rates are not merely a blunt tool for recovering costs. They provide customers with proper price signals that enable adoption of the emerging energy technologies that

> are most beneficial to the grid, while still fully recovering the costs that they impose on the grid from those customers. Ultimately, this alignment of customer incentives with the optimal operation of the power grid will reduce costs for all customers. Given the rapid pace of technological change, it is important to modernize rates in a proactive rather than reactive manner.[73]

A number of utilities and regulators have recognized this issue with existing electricity rate design.

The Council of European Energy Regulators (CEER) has noted the need for rates and tariffs to be cost-reflective, that is, the costs a user imposes on the distribution system should be reflected by the distribution tariff. In particular, the CEER paper states:

> The costs related to all historic investment in the network are a large part of the total distribution cost, but are not dependent on the network users' consumption, and are basically sunk costs. In this paper sunk costs are referred to as *residual* cost. How residual costs are covered by the tariff structure is a matter of economic efficiency (minimising economic distortions) and a collective and fair remuneration from all users. This basically implies an optimal lump-sum charge, i.e. a fixed rate paid collectively by all users of the network (e.g. some kind of subscription fee), in cases where costs cannot be linked with a specific network user.[74]

Table C-3 summarizes CEER's description of the cost categories for a distribution system and how those costs would ideally be reflected in a distribution tariff.

Table C-3: Distribution Service Costs and Tariff Designs[75]

	Present cost			Future cost
Cost categories	**Short-run marginal costs**	**Customer specific costs**	**Residual (sunk) costs**	**Long-run marginal costs**
Description	Network losses and variable payment related to DSR	Metering and data processing	Other costs for coverage according to the regulation	Cost for increasing capacity (wire and non-wire option)
Preferred tariff design	Marginal pricing (Energy Time of Use)	Cost-based (Fixed)	Cost-based (capacity, Fixed)	Semi-marginal pricing (Energy Time of Use, capacity peak pricing)

The Alberta Utilities Commission (AUC) recently completed an inquiry into the future of the distribution system and noted that while distribution system costs are predominantly fixed and sunk, a significant

[73] Page 6. Modernizing Distribution Rate Design. Brattle Group. 2020. Exhibit 24116_X0570 to the Alberta Utilities Commission Distribution System Inquiry.

[74] Council of European Energy Regulators Paper on Electricity Distribution Tariffs Supporting the Energy Transition. 2020. Pages 10- 11. Available: https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0. Accessed March 1, 2021.

[75] Council of European Energy Regulators Paper on Electricity Distribution Tariffs Supporting the Energy Transition. 2020. Page 11. Available: https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0. Accessed March 1, 2021.

portion of these costs are recovered through variable charges.[76] Four experts who participated in a technical workshop before the AUC agreed at a conceptual level that distribution rates should involve both (i) non-avoidable charges to recover the embedded costs of the existing infrastructure; and (ii) variable, avoidable charges to send a forward-looking price signal capable of affecting future system costs by altering current behaviour. In tandem these help incent customers to make economically efficient decisions in their consumption of electricity, including the choice between electricity drawn from the grid and self-supplied.[77] One of the experts who presented to the AUC stated that "…rates should accurately reflect costs, and policy goals such as promoting clean energy are ideally accomplished through initiatives independent of rate design, in order to avoid distorting the incentives that customers have to make economically efficient decisions."[78]

However, experts participating in the proceeding before the AUC also noted that other rate design principles remain important, including customer understandability.[79] The AUC noted finding a balance between competing rate design criteria "…is particularly important before a large number of customers make significant investments in self-generation, guided by the existing price signals from utility rates encouraging self-supply and uneconomic bypass. If a significant amount of DER investment is premised on tariff avoidance, moving to cost-based rates could result in considerable customer frustration in the short term despite promoting efficient outcomes longer-term."[80]

The AUC acknowledged that technical limitations on metering and data processing may inhibit the full transition to a fully-cost-reflective tariff for some time. Some parties to the inquiry before the AUC recommended developing a roadmap through a stakeholder process to identify trigger points to guide steps to a more fully integrated and transparent tariff system.[81]

Currently, there is a substantial gap between the portion of fixed utility costs that are fixed in the short-run, and the revenues that are based on fixed charges. Based on the findings of the CEER and AUC processes, it is justifiable to begin to increase the proportion of electricity costs that are recovered through fixed charges for all customers. This would help improve the cost-reflectivity of electricity rates and reduce the lost utility revenues that occur when customers install their own generation. Currently NTPC's fixed

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[76] Paragraph 283. Distribution System Inquiry Final Report. February 2021. Available: https://www.auc.ab.ca/regulatory_documents/Lists/eFiling%20Documents/DispForm.aspx?ID=9471&e=zzAhBw. Accessed March 1, 2021.

[77] Paragraph 315. Distribution System Inquiry Final Report. February 2021. Available: https://www.auc.ab.ca/regulatory_documents/Lists/eFiling%20Documents/DispForm.aspx?ID=9471&e=zzAhBw. Accessed March 1, 2021.

[78] Paragraph 321. Distribution System Inquiry Final Report. February 2021. Available: https://www.auc.ab.ca/regulatory_documents/Lists/eFiling%20Documents/DispForm.aspx?ID=9471&e=zzAhBw. Accessed March 1, 2021.

[79] Paragraph 320. Distribution System Inquiry Final Report. February 2021. Available: https://www.auc.ab.ca/regulatory_documents/Lists/eFiling%20Documents/DispForm.aspx?ID=9471&e=zzAhBw. Accessed March 1, 2021.

[80] Paragraph 323. Distribution System Inquiry Final Report. February 2021. Available: https://www.auc.ab.ca/regulatory_documents/Lists/eFiling%20Documents/DispForm.aspx?ID=9471&e=zzAhBw. Accessed March 1, 2021.

[81] Paragraph 417. Distribution System Inquiry Final Report. February 2021. Available: https://www.auc.ab.ca/regulatory_documents/Lists/eFiling%20Documents/DispForm.aspx?ID=9471&e=zzAhBw. Accessed March 1, 2021.

charges are frozen pursuant to a GNWT policy direction. Removing this policy direction would allow fixed charges to increase over time. However, this transition would likely need to be phased-in slowly over time. For modelling purposes, InterGroup considered the potential implications of a 5 per cent increase in revenues from fixed charges could be phased in over time, with a resulting decrease to variable charges such that the total revenues are unchanged, and only the proportion of revenues recovered through fixed and variable charges is altered.

Estimated impact on customers without self-generation

Increasing NTPC's existing customer charge of $18/month by five per cent would be an additional $0.90 per month or $10.80 per year. This would result in an increase to bills that customers cannot avoid through managing their energy consumption. However, the variable energy rates would be lower compared to the existing rate policy scenario such that higher volume users may see a decrease in their total bill.

Increasing NTPC's existing minimum demand charge for general service customers of $40/month by five per cent would be an additional charge of $2 per month or $24/year. This would result in an increase to bills that customers cannot avoid through managing their energy consumption. However, the variable energy rates would be lower compared to the existing rate policy scenario such that higher volume users may see a decrease in their total bill.

Overall, increasing fixed charges by 5 per cent per year would reduce the lost revenues for utilities by $0.103 million annually by 2030 compared to the Base Case Scenario under the current rate policies.

Estimated impact on benefits to existing net metering customers

Increasing NTPC's existing customer charge of $18/month would be an additional $0.90 per month or $10.80 per year. This would result in an increase to bills that self-generation customers cannot avoid and would reduce their savings by approximately this amount each year.

Increasing NTPC's existing minimum demand charge for general service customers of $40/month by five per cent would be an additional charge of $2 per month or $24/year. This would result in an increase to bills that self-generation customers cannot avoid and would reduce their savings by approximately this amount each year.

Estimated impact on government subsidies

Increasing fixed charges would not have a direct effect on the current TPSP and GREP programs as fixed charges are not subsidized under those programs. There would be a small net increase in spending on subsidy programs as variable charges would be reduced compared to the existing rate policy scenarios. The estimated changes are approximately $0.010 million increase by 2030 compared to the existing rate policy scenarios.

Estimated impact on GHG emissions

Increasing fixed charges would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings.

Regulatory and legal process considerations

Fixed charges for NTPC are currently frozen pursuant to a GNWT policy direction. Increasing fixed charges would require changing the policy direction and would also require rate applications to the PUB.

Effects on customer choice

Increasing fixed charges could be perceived by customers as inhibiting customer choice, both to install their own generation and take other actions (such as energy efficiency improvements) to manage their electricity bills.

Administrative efficiency

Both utilities currently have fixed charges as part of their tariffs. Increases to the fixed charges could be accomplished within the current billing structures.

Consistency with other GNWT policy objectives

Increasing fixed charges would be expected to reduce the uptake of customer owned renewable generation and potentially other energy efficiency investments and could therefore reduce the potential GHG savings. However, it would reduce the net revenue loss to the utilities and the rate impact on non-adopting customers. If the fixed charges are increased slowly over time it would still allow customers to realize savings on the variable portion of their bill from installing self-generation and energy efficiency improvements.

Political feasibility and public acceptance

A number of jurisdictions and regulators are moving toward increasing fixed charges for all customers. When done gradually, the impact on customers bills would be done in small increments and reviewed through public proceedings before the PUB.

Modelling assumptions for the option to increase customer and demand charges higher than variable charges

The following assumptions were used to estimate impacts of this option:

- Fixed charges increase annually by 5 per cent.
- Utilities revenue requirements increase by annual inflation rate, 2 per cent as discussed in Appendix A.
- Variable charges increase at lower rates to balance the revenue requirements. The model shows the variable rates need to increase approximately by 1.6 per cent to keep up with 2 per cent annual inflation.

Results of the option to reduce value of credit for surplus generation

Table C-4 and Table C-5 present the estimates of the impacts of increasing fixed charges for all customers on the net revenue losses to utilities and the impacts on TPSP and GREP subsidy programs under the current customer self-generation programs.

Annual net utility revenue losses are estimated to decrease by 2030 (Table C-4):

- Base Case Scenario: $0.103 million.
- Low Case Scenario: $0.076 million.
- High Case Scenario: $0.122 million.

Table C-4: Estimated Changes to Utility Net Revenue Loss as a Result of Increasing Fixed Charges to All Customers

Utility Net Revenue Loss	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	1,021,637	3,228	629,774	265,475	5,265	42,539	1,967,917
Fixed charge increases by 5% ($)	1,019,158	3,210	587,909	210,170	4,908	39,423	1,864,778
Variance ($)	**(2,478)**	**(18)**	**(41,865)**	**(55,305)**	**(357)**	**(3,116)**	**(103,139)**

Utility Net Revenue Loss	2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	601,662	127,754	461,930	151,353	94,767	30,436	1,467,902
Fixed charge increases by 5% ($)	599,482	124,400	431,222	119,823	88,349	28,207	1,391,482
Variance ($)	**(2,180)**	**(3,354)**	**(30,707)**	**(31,530)**	**(6,419)**	**(2,230)**	**(76,419)**

Utility Net Revenue Loss	2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	1,042,809	243,420	629,774	265,475	166,123	42,539	2,390,139
Fixed charge increases by 5% ($)	1,039,485	236,696	587,909	210,170	154,871	39,423	2,268,554
Variance ($)	**(3,324)**	**(6,724)**	**(41,865)**	**(55,305)**	**(11,251)**	**(3,116)**	**(121,585)**

The GNWT savings from TPSP and GREP annual subsidies are estimated to decrease by 2030 compared to the existing customer self-generation policies (Table C-5):

- Base Case Scenario: $0.010 million.
- Low Case Scenario: $0.008 million.
- High Case Scenario: $0.011 million.

Table C-5: TPSP and GREP Subsidy Savings Reduction as a Results of Fixed Charges Higher Increase than Variable Charges

Savings from TPSP and GREP Subsidies	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	267,049	0	853	9,504	277,405
Fixed charge increases by 5% ($)	0	0	257,074	0	821	9,149	267,044
Variance ($)	**0**	**0**	**(9,975)**	**0**	**(32)**	**(355)**	**(10,362)**

Savings from TPSP and GREP Subsidies	2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	195,876	0	15,351	6,800	218,027
Fixed charge increases by 5% ($)	0	0	188,560	0	14,777	6,546	209,883
Variance ($)	**0**	**0**	**(7,316)**	**0**	**(573)**	**(254)**	**(8,144)**

Savings from TPSP and GREP Subsidies	2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	267,049	0	26,909	9,504	303,461
Fixed charge increases by 5% ($)	0	0	257,074	0	25,904	9,149	292,127
Variance ($)	**0**	**0**	**(9,975)**	**0**	**(1,005)**	**(355)**	**(11,335)**

3. Stand-by Charge for Customers with Renewable Generation

NTPC currently has approved rates for stand-by service for general service customers. NTPC's terms and conditions of service state it will provide retail stand-by service to back-up customer self-generation where surplus capacity is available. Self-generation customers using intermittent renewable generation are exempt from paying the existing stand-by charges.[82]

NTPC's existing stand-by charge of $24/kW was developed to recover the full-cost demand charge related to the generation function in thermal communities. NTPC's original application for the stand-by charge noted NTPC must plan to have sufficient capacity to serve the full capacity of the customer-owned generation during the system peak. NTPC also not a significant amount of generation demand-related

[82] Section 3.5. NTPC Terms and Conditions of Service.

costs are recovered through the energy charge to general service customers under the existing rate structures. In approving the stand-by rate, the PUB noted that it considered the proposed standby charge to be a reasonable proxy for the cost of peaking generation.[83] The stand-by charge has not been increased since it was originally approved in 2008. InterGroup understands there are very few customers that currently pay the stand-by rate. Further, the stand-by charge does not currently apply to NTPC's residential customers and NUL does not have an approved stand-by charge.

Some utilities in North America have developed stand-by charges that apply to some types of renewable generation installed by customers. For example:

- Virginia Electric and Power maintains a standby charge for certain residential net metering customers. Where the alternating current capacity of a renewable fuel generator exceeds 15 kW, the customer is billed a distribution standby charge of $2.62 pe kW of demand, minus any amounts billed under the distribution energy charge, but not less than zero.[84]

- Santee Cooper in South Caroline charges a stand-by fee for residential solar generation of $4.40/kW and a monthly meter fee of $2.00. The stand-by fee is designed to collect the fixed costs embedded in the energy charges that solar customers continue to use when their solar system is not producing enough to supply their needs. [85]

- Alabama Power charges a rate rider for supplementary, back-up or maintenance power capacity reservation where the customer obtains any portion of its electric requirements from installed on-site, non-emergency electric generating capacity that operates in parallel with the utility's system. The current charge is $5.41/kW added to the applicable rate schedule.[86]

Estimated impact on net costs to other customers

This could increase utilities' revenues by $0.228 million per year by 2030.

Estimated impact on benefits to existing net metering customers

Applying the existing $24/kW stand-by charge to a non-government general service customer in NTPC's thermal zone with a 10 kW installation would increase their bill by $240/month or $2,880/year. At existing rates the customer would be expected to save approximately $5,860/year.[87] Applying the stand-by charge would reduce those savings by approximately 50 per cent.

Estimated impact on government subsidies

The current stand-by rate applies only to general service customers in NTPC's thermal zone. As such a stand-by charge would not be expected to directly affect existing subsidy programs.

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[83] Pages 39 and 40. Decision 26-2008. Northwest Territories Public Utilities Board.

[84] Page 99. Virginia Electric Power Company Tariff. Available: https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/shared-rates/entire-filed-tariff.pdf?la=en&rev=4f8d794a30c14ad0b54d079cb6e40e22&hash=6D8CA6DB531C5AD6CE894ED4B9D7B636. Accessed February 27, 2020.

[85] Santee Cooper website. Available: https://www.santeecooper.com/Save-Energy-Money/For-My-Home/Solar/Index.aspx.

[86] Alabama Power Rate Rider RGB – Supplementary, Back-up or Maintenance Power. Available: https://www.alabamapower.com/content/dam/alabamapower/Rates/RGB.pdf. Accessed February 27, 2021.

[87] Assuming 1,000 kWh/year/kW of installed generation at the current energy rate of 58.60 cents/kWh.

Estimated impact on GHG emissions

A stand-by charge would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings.

Regulatory and legal process considerations

Currently the stand-by charge has only been approved for NTPC's general service customers. Customers using intermittent generation are also currently exempted from the existing stand-by charge. Expanding the stand-by charge to remove the exemption and apply to more customers would require applications to the PUB. It is likely the charge would need to be adjusted as it has not been changed since 2008.

Effects on customer choice

A stand-by charge would likely be perceived as inhibiting the ability of customers to install their own generation and reducing customer choice.

Administrative efficiency

NTPC currently maintains a stand-by charge on its rate schedules so has the ability to implement such charges. A stand-by charge could be developed as a per kW charge or a per customer charge which could facilitate billing.

Consistency with other GNWT policy objectives

A stand-by charge would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings. However, it would reduce the net revenue loss to the utilities and the rate impact on non-adopting customers.

Political feasibility and public acceptance

Stand-by charges for renewable generation are not typical in Canada and have been controversial when implemented in the United States.

Assumptions for estimating the effects of a Stand-by Charge

The following assumptions were used to estimate the effects of a stand-by charge:

- Stand-by Charge is currently applicable only to NTPC general service customers because NUL-Yk and NUL-NWT rate schedules do not include the stand-by charge and NTPC's stand-by charge is not currently applicable to residential customers.
- Stand-by Charge, $24 per kW, remains unchanged until 2030.

Estimated impacts of Stand-by Charge option

Table C-6 presents estimates of potential revenues from a stand-by charge for all three scenarios by each zone. This revenue could be used to offset losses to utility revenue through lower variable energy sales to customers with their own generation. This option does not have any effect to the GNWT TPSP and GREP subsidies compared to the existing policy scenarios because fixed charges are not subsidized through these programs.

Additional annual revenue for NTPC from general service customers with renewable generation installations from a stand-by charge by 2030 are estimated at:

- Base Case Scenario: $0.228 million.
- Low Case Scenario: $0.277 million.
- High Case Scenario: $0.450 million.

Table C-6: Additional Revenue from Stand-by Charge Option

Revenue from Stand-by Charge	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Base Case Scenario ($)	36,064	576	191,758	N/A	N/A	N/A	**228,398**
Low Case Scenario ($)	31,717	104,832	140,652	N/A	N/A	N/A	**277,201**
High Case Scenario ($)	48,363	210,176	191,758	N/A	N/A	N/A	**450,298**

Implement new rate options and fees for customers with self-generation

Utilities could design rate options for customers with self-generation and implement rates or fees based on the costs to serve these customers. As long as the cost basis for the charges could be supported, such fees or rates would be consistent with existing legislation requirements not to implement rates that are unjustly discriminatory or unduly preferential. This option can significantly shape the situation with respect to incentives, revenue loss, fairness and equity. Creating new classes or rate options would at first blush appear more complicated, but may make implementation of the needed changes simpler and cause less adverse effects on non-self generation customers if the changes were primarily restricted to just the new class.

As an example, in Order 33258, the Public Utilities Commission of Hawaii closed the then-existing net energy metering program and approved new options for customers to interconnect distributed energy resources to the electric grid.[88] In explaining the rationale for establishing the new options the Commission noted:

> After review of the record in this docket, the commission finds a self-supply option to be reasonable and in the public interest, and thus will approve the HECO Companies proposed self-supply tariff, with certain modifications as discussed herein. While some Parties assert that a tariff to enable a self-supply option is not needed, and that a customer self-supply option can be established by revising provisions of Rule 14H to allow for expedited interconnection of qualifying systems, the commission finds and concludes that a self-supply tariff is superior

[88] Page 1, Order number 33258. Public Utilities Commission of the State of Hawaii. Available: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464. Accessed February 26, 2021.

to simply writing the requirements for a self-supply system directly into the interconnection standards in Rule 14H.

Without a new tariff, customers interconnecting a self-supply system would be subject to the existing applicable rate schedule. This would not allow the flexibility to allow customers with self-supply systems to be subject to an updated minimum bill, for example, nor would it enable self-supply systems to offer (and be compensated for) grid-supportive benefits in the future. Flexibility and adaptability to evolving technology and grid requirements are fundamental aspects of the self-supply option.[89]

The new rate options include:

- **Customer Grid-Supply (CGS)** participants receive a PUC-approved credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid. The program remains open until the installed capacity has been reached.
- **Customer Grid-Supply Plus (CGS Plus)** systems must include grid support technology to manage grid reliability and allow the utility to remotely monitor system performance, technical compliance and, if necessary, control for grid stability.
- **Customer Self-Supply (CSS)** is intended only for private rooftop solar installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy.
- **Smart Export** customers with a renewable system and battery energy storage system have the option to export energy to the grid from 4 p.m. – 9 a.m. Systems must include grid support technology to manage grid reliability and system performance.

All of the rate options are subject to a minimum bill that is higher than the basic customer charge and three of the programs have capacity limits on their availability. The customer self-supply option does not have a capacity limit on availability.

There may be many types of such charges that could be implemented including minimum bills, access fees (charged either on a per kWh basis or as a fixed customer or demand charge each month) or combination of several of these.

[89] Pages 121-122, Order number 33258. Public Utilities Commission of the State of Hawaii. Available: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464. Accessed February 26, 2021.

Table C-7: Hawaii Private Rooftop Solar Options[90]

OAHU	CGS	CGS Plus	CSS	Smart Export
Export Allowed	Yes	Yes	No	Yes
Export Restrictions	No	No	N/A	Solar Day
Reconciliation	Monthly	Annual	N/A	Annual
Minimum Bill	$25	$25	$25	$25
Credit rate (c/kWh)* **	$0.15	$0.10	N/A	$0.15
Program Cap	51.3 MW	35 MW	N/A	25 MW
Inverter Requirements	Advanced with Volt Var and Frequency Watt activated; Fixed Power Factor deactivated.*	Advanced with Volt Var and Frequency Watt activated; Fixed Power Factor deactivated.	Advanced with Volt Var and Frequency Watt activated; Fixed Power Factor deactivated.	Advanced with Volt Var and Frequency Watt activated; Fixed Power Factor deactivated.
Controls	N/A	Yes: Utility or Aggregator	Customer	Yes: Economic
Communications	N/A	N/A	Yes	N/A
Hypothetical Bill Comparison: **	$93.28	$118.38	$169.09	$93.79

**Prior to 3/10/2018 CGS Customers were required to program their advanced inverters to include TROV-2, Full ride-through and Fixed Power Factor. They must now be re-programmed to current requirements as noted in Rule 14H.*

***Assumes a residential bill with Delivered (DEL) energy of 503 kWh, Received (REC) energy of 907 kWh, with a NET of 404 kWh and the application of the monthly bill credit for Oahu. Does not reflect any benefit from accrued credits. Calculation is based on rates effective October 2018. Some rates vary monthly. Non-residential customers subject to different rate schedules and higher minimum bill.*

****Credit rate shown is rounded to the nearest whole value. Standard retail rates applied for energy delivered/used when rooftop solar or other renewable system is not in use or exporting to the grid. Customers on rates other than retail should contact us to verify whether those options will apply in coordination with these programs.*

Customer Grid-Supply remains open until installed capacity is reached. New applications are placed into queue for processing when space in the program becomes available. There is no guarantee that space will become available. New applications may be submitted via mail and are not supported in the Customer Interconnection Tool.

NEM and NEM Plus are not shown in this table. The NEM program is closed and NEM Plus is only available to customers already enrolled in the NEM program.

Estimated impact on net costs to other customers

Charging an access fee would reduce the revenue losses to utilities and the impact on other customers. A nominal $20/month fee to all self-generation customers (lower than the existing stand-by charge) would result in an additional $0.207 million in revenue and reduce the rate increases that would otherwise flow to other customers.

[90] Comparison of rooftop solar options. Available: https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/programs_bill_and_credit.pdf. Accessed February 28, 2021.

Estimated impact on benefits to existing self-generation customers

Applying a $20/month access charge would increase bills by $240 per year. A 10 kW installation at existing non-government general service rates would be expected to save approximately $5,860/year.[91] Applying the access fee would reduce those savings by approximately 4 per cent.

Estimated impact on government subsidies

Fixed charges are not included in the calculation of TPSP charges. There may be a small change to GREP subsidies, depending on how the charges are implemented across the utilities.

Estimated impact on GHG emissions

Access fees would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings.

Regulatory and legal process considerations

Implementing an access fee would require a policy direction to the PUB and utility applications for PUB approval.

Effects on customer choice

Access charges would likely be perceived as inhibiting the ability of customers to install their own generation and reducing customer choice.

Administrative efficiency

Implementing an access charge for customers with self-generation would require establishing and administering new rate options. It may not require cost of service rate class changes but would require the calculation of any access charges to be justified on a cost-causation basis.

Consistency with other GNWT policy objectives

An access charge would be expected to reduce the uptake of customer owned renewable generation and could therefore reduce the potential GHG savings. However, it would reduce the net revenue loss to the utilities and the rate impact on non-adopting customers.

Political feasibility and public acceptance

Higher charges for solar installations have been controversial when implemented in other jurisdictions.

Assumptions for modelling the access fee option

The following assumptions were used to estimate this option:

- Number of net metering customers for 2019 as provided by NTPC and NUL.
- Estimates for further years are based on the net metering installed capacity of the forecast year and the ratio of customer numbers in 2019 by each zone.
- Access Fee is applicable for both residential and general service customers of all utilities.
- Illustrative access fee of $20 per customer per month (lower than the existing stand-by service charge) and remains unchanged until 2030.

[91] Assuming 1,000 kWh/year/kW of installed generation at the current energy rate of 58.60 cents/kWh.

Estimate of additional revenue from an access fee option

Table C-8 presents additional revenue estimates from a $20/month access fee for all three case scenarios by each zone. This option does not have any effect to the GNWT TPSP and GREP subsidies.

Additional annual revenue for utilities from new imposed Access Fee by 2030:

- Base Case Scenario: $0.207 million.
- Low Case Scenario: $0.233 million.
- High Case Scenario: $0.420 million.

Table C-8: Estimated Additional Revenue from Access Fee Option

Revenue from Access Fee	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Base Case Scenario ($)	4,320	480	34,560	163,680	1,200	2,400	**206,640**
Low Case Scenario ($)	3,840	87,360	25,440	93,360	21,600	1,680	**233,280**
High Case Scenario ($)	5,760	175,200	34,560	163,680	37,920	2,400	**419,520**

Increase Government Rates to Recover Utility Revenue Losses

The current GNWT rate policy guidelines allow government rates to be higher than non-government rates in the same zone and target revenue to cost ratios for government customers of between 100 per cent to 130 per cent. In NTPC's 2018/19 test year, government customer revenue to cost ratios were 124 per cent across all rate zones. In NTPC's thermal zone, revenues from government customers were $32.3 million compared to costs of $24.7 million, meaning revenues from government customers in the thermal zone exceeded costs by $7.6 million for a revenue to cost ratio of approximately 130 per cent.[92]

NUL does not currently have different government and non-government rates, but does track revenues from government and non-government customers separately in order to administer the GREP. Government rates could be increased to recover the reductions in utility revenues from customer-owned generation. Alternatively, the GNWT could indicate that part of the reason government customers already pay higher rates is to offset this lost revenue and direct the PUB to ensure that government rates at a minimum recover the lost revenue from customer-owned generation for each utility. This would require higher government rates to be implemented for NUL, but could be accommodated within the existing higher rates for government customers of NTPC.

Increasing government rates affects more than just territorial government customers, it would also affect federal government and community government accounts and would require coordination with the Department of Municipal and Community Affairs.

[92] Summary tab. NTPC 2018/19 COSA compliance filing.

Estimated impact on net costs to other customers

NTPC's thermal zone has the most substantial forecast revenue loss by 2030, approximately $0.700 million. Revenue from government customers in NTPC's thermal zone is approximately $32 million per year. Eliminating a net revenue loss of $0.700 million would require a cumulative rate increase to government customers in the thermal zone of approximately two per cent as shown in Table C-XXX. This would eliminate the rate increases to non-government customers over this time period.

Estimated impact on benefits to existing self-generation customers

No effect anticipated on non-government customers compared to the existing policy scenario. Government customers would see higher rates and depending on whether those rates were applied to fixed or variable charges, could see rate impacts compared to the existing policy scenario.

Estimated impact on government subsidies

Government customers are not eligible for the subsidies so there would be little effect anticipated on existing subsidies.

Estimated impact on GHG emissions

Little effect on rates for non-government customers, so little impact on GHG emissions compared to the current policy scenario.

Regulatory and legal process considerations

Current rate policy directives permit government rates to be higher than non-government customers in the same zone. Policy direction would be required to direct the PUB to ensure government rates are sufficiently higher than non-government rates to recover lost revenue from customer-owned generation. A rate application and public process before the PUB would be required to implement the changes.

Effects on customer choice

Little effect expected on customer choice for non-government customers.

Administrative efficiency

NTPC currently maintains different rates for government customers. NUL tracks government versus non-government customers in order to administer GREP but would need to create rate classes with different rates for government customers.

Consistency with other GNWT policy objectives

Implementing increases for government rates would require coordination with the Department of Municipal and Community Affairs and affect budgeting for government utility accounts.

Political feasibility and public acceptance

Higher government rates would affect federal government and community government accounts as well as territorial government accounts and this may be an issue for relationships with other levels of government.

Table C-9: Rate Increase for Government Customers in NTPC Thermal Zone to Cover Utilities Net Revenue Losses from Net Metering Customers[93]

	2020*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NTPC Thermal Net Revenue Loss ($)	**293,230**	**325,099**	**357,620**	**401,410**	**462,732**	**506,689**	**564,756**	**580,280**	**596,221**	**612,756**	**629,774**
Incremental change ($)		**31,869**	**32,521**	**43,790**	**61,321**	**43,957**	**58,067**	**15,524**	**15,941**	**16,535**	**17,018**
Average Annual Increase in Percentage											
Growth due to load growth	1.0%										
Government Sales Energy-Related Revenue ($)	31,510,860	32,764,574	33,786,895	34,840,763	35,938,066	37,086,569	38,251,868	39,466,895	40,674,789	41,919,589	43,202,595
Annual increase needed, average (%)	0.9%	0.1%	0.1%	0.1%	0.2%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%
Cumulative increase		1.0%	1.1%	1.3%	1.4%	1.5%	1.7%	1.7%	1.8%	1.8%	1.9%
Average Annual Increase in Cents											
Government Sales Energy-Related (kWh)	30,966,000	31,275,660	31,588,417	31,904,301	32,223,344	32,545,577	32,871,033	33,199,743	33,531,741	33,867,058	34,205,729
Annual increase needed, average (cent/kWh)	0.95	0.10	0.10	0.14	0.19	0.14	0.18	0.05	0.05	0.05	0.05
Cumulative increase (cent/kWh)	0.95	1.05	1.15	1.29	1.48	1.61	1.79	1.84	1.89	1.93	1.98

[93] Government Sales Energy-Related Revenue is from NTPC 2016/19 Phase II GRA Compliance Filing, Revised Schedule 3.2.2, 2018/19 Proof of Revenue at Proposed Rates.

Subsidize lost utility revenue

The GNWT could choose to subsidize lost utility revenue as a result of customer self-generation. NTPC currently calculates the lost revenue from the net metering program. That calculation could be expanded in to include customers who install self-generation that is not subscribed to the net metering program (to the extent utilities are aware of such installations). A direct government subsidy would not need PUB approval, but for rate application purposes it may be desirable to report the subsidy as a non-utility revenue in order to reconcile revenues to the approved regulated revenue requirement.

<u>Estimated impact on customers without self-generation</u>

A direct government subsidy would eliminate the revenue loss for the utilities and could avoid the 1.3 per cent increase by 2030 in the base case scenario that would otherwise be recovered from non-self generation customers.

<u>Estimated impact on benefits to existing self-generation customers</u>

A direct subsidy for lower utility revenues would likely not affect the benefits to existing self-generation customers.

<u>Estimated impact on government subsidies</u>

This new subsidy would increase the subsidies paid to the electric utilities by approximately $1.968 million annually by 2030.

<u>Estimated impact on GHG emissions</u>

The direct subsidy would not be expected to change the installation of renewable energy compared to the base case scenario and therefore would not change the GHG emissions savings.

<u>Regulatory and legal process considerations</u>

A direct subsidy to the utilities would not require approval by the PUB, but likely should be reflected as a non-utility revenue for ratemaking purposes to ensure total revenues reconcile to the approved revenue requirement.

<u>Effects on customer choice</u>

A direct subsidy would likely not materially affect customer choice.

<u>Administrative efficiency</u>

Both utilities currently administer existing subsidy programs. This would add an extra program to be administered.

<u>Consistency with other GNWT policy objectives</u>

A direct subsidy would maintain the potential GHG reductions from the Base Case Scenario and reduce the rate impact on non-adopting customers. However, the subsidy would reduce the funds available to support other GNWT policy objectives.

<u>Political feasibility and public acceptance</u>

The subsidy would reduce funds available for other policy priorities.

Replace existing programs with a feed-in tariff

A feed-in tariff is a procurement method for renewable energy. For example, Ontario's feed in tariff program was open to participants who generate renewable energy and sell it at a guaranteed price for a fixed contract term.[94] Feed-in tariffs may be technology specific (e.g. wind may receive one price, solar may receive another). A nu

The current GNWT programs for mid-scale renewables delivered directly to the grid has some elements in common with a feed-in tariff.

<u>Estimated impact on net costs to other customers</u>

A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on other customers compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.

<u>Estimated impact on benefits to existing self-generation customers</u>

A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on other customers compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.

<u>Estimated impact on government subsidies</u>

A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on subsidies compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed.

<u>Estimated impact on GHG emissions</u>

A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact on GHG emissions compared to existing policies and programs.

<u>Regulatory and legal process considerations</u>

Implementing a feed-in tariff would require policy direction to the PUB and the utilities would need to file an application to implement the tariff.

<u>Effects on customer choice</u>

Some customers may view a feed-in tariff as improving customer choice.

<u>Administrative efficiency</u>

Would likely require additional administration and management relative to existing programs.

<u>Consistency with other GNWT policy objectives</u>

A feed-in tariff that operated similarly to the existing mid-scale renewable program would not be expected to have a substantial impact compared to existing policies and programs. There may be added risk of higher costs from a feed-in tariff if it is not well designed relative to existing program options.

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[94] Government of Ontario website. Available: https://www.ontario.ca/document/renewable-energy-development-ontario-guide-municipalities/40-feed-tariff-program. Accessed March 1, 2021.

Political feasibility and public acceptance

Ontario's feed-in tariff program resulted in a number of contracts being cancelled and higher costs for customers. This would likely reduce public support for a feed-in tariff.

Combined Rate Impacts of Reducing Credit for Surplus Generation and Increasing Fixed Charges For All Customers

This option assumes combination of two following options:

- Reduce value of credit for surplus generation.
- Increase customer and demand charges higher than variable charges.

Assumptions for combined option

The following assumptions were used to estimate the rate impacts of this option:

- Reduce value of credit for surplus energy:
  - For NTPC and NUL hydro zones: avoided non-fuel variable cost of the generation.
  - For NTPC and NUL Thermal zones: avoided fuel and non-fuel variable costs of the generation.
- Fixed charges increase:
  - Fixed charges annually increase by 5 per cent.
  - Utilities revenue requirements increase by annual inflation rate, 2 per cent as discussed in Appendix A.
  - Variable charges increase at lower than inflation (1.6 per cent) to balance revenue requirements.

Results of combined option

Table C-10 and Table C-11 present results of the combined for all three scenarios by each zone and compares to the utilities' net revenue losses and the GNWT savings from TPSP and GREP subsidies under current renewable generation policies.

Utility annual net revenue losses are estimated to decrease by 2030 (Table C-10):

- Base Case Scenario: \$0.865 million, or \$0.449 million excluding the negative net revenue loss in NUL-Yk.
- Low Case Scenario: \$0.608 million, or \$0.371 million excluding the negative net revenue loss in NUL-Yk.
- High Case Scenario: \$1.020 million, or \$0.604 million excluding the negative net revenue loss in NUL-Yk.

Table C-10: Utility Net Revenue Loss Reduction as a Results of Consolidated Option

Utility Net Revenue Loss	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
	2030 Estimate - Base Case Scenario						
Under Current Program Conditions ($)	1,021,637	3,228	629,774	265,475	5,265	42,539	1,967,917
Consolidation of two options: Reduce value of credit and Fixed charges increase by 5% ($)	995,894	3,178	489,308	(415,829)	1,069	29,405	1,103,024
Variance ($)	**(25,743)**	**(50)**	**(140,466)**	**(681,304)**	**(4,196)**	**(13,134)**	**(864,893)**

Utility Net Revenue Loss	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
	2030 Estimate - Low Case Scenario						
Under Current Program Conditions ($)	601,662	127,754	461,930	151,353	94,767	30,436	1,467,902
Consolidation of two options: Reduce value of credit and Fixed charges increase by 5% ($)	579,021	118,616	358,900	(237,073)	19,240	21,039	859,743
Variance ($)	**(22,641)**	**(9,138)**	**(103,029)**	**(388,426)**	**(75,527)**	**(9,397)**	**(608,159)**

Utility Net Revenue Loss	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
	2030 Estimate - High Case Scenario						
Under Current Program Conditions ($)	1,042,809	243,420	629,774	265,475	166,123	42,539	2,390,139
Consolidation of two options: Reduce value of credit and Fixed charges increase by 5% ($)	1,008,286	225,100	489,308	(415,829)	33,726	29,405	1,369,996
Variance ($)	**(34,523)**	**(18,320)**	**(140,466)**	**(681,304)**	**(132,396)**	**(13,134)**	**(1,020,143)**

Under this option, as stated, the credit rate for surplus energy in the hydro zones is set at avoided non-fuel variable cost of generation, which is lower than current wholesale price of energy to NUL NWT and NUL Yk. Surplus energy purchased by NUL from net metering customers in hydro zones will replace equivalent amount of wholesale purchase power units from NTPC. Given that the credit rate for surplus energy in NUL's hydro zone is lower than NTPC wholesale energy price, this would result in net savings to NUL from the energy purchased from net metering customers in hydro zones. With significant net metering program uptake in NUL hydro zones, which is forecast to take place by 2030, this is estimated to result in negative net revenue loss for NUL Yk.

The GNWT savings from TPSP and GREP annual subsidies are estimated to decrease by 2030 compared to the current policy scenarios (Table C-11):

- Base Case Scenario: $0.054 million.
- Low Case Scenario: $0.046 million.
- High Case Scenario: $0.066 million.

Table C-11: TPSP and GREP Subsidy Savings Reduction as a Results of Consolidated Option

Savings from TPSP and GREP Subsidies	2030 Estimate - Base Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	267,049	0	853	9,504	277,405
Consolidation of two options: Reduce value of credit and Fixed charges increase by 5% ($)	0	0	216,035	0	450	7,008	223,494
Variance ($)	**0**	**0**	**(51,013)**	**0**	**(402)**	**(2,496)**	**(53,912)**

Savings from TPSP and GREP Subsidies	2030 Estimate - Low Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	195,876	0	15,351	6,800	218,027
Consolidation of two options: Reduce value of credit and Fixed charges increase by 5% ($)	0	0	158,459	0	8,107	5,014	171,580
Variance ($)	**0**	**0**	**(37,418)**	**0**	**(7,243)**	**(1,786)**	**(46,447)**

Savings from TPSP and GREP Subsidies	2030 Estimate - High Case Scenario						
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL Yk	NUL NWT Hydro	NUL NWT Thermal	Total
Under Current Program Conditions ($)	0	0	267,049	0	26,909	9,504	303,461
Consolidation of two options: Reduce value of credit and Fixed charges increase by 5% ($)	0	0	216,035	0	14,212	7,008	237,255
Variance ($)	**0**	**0**	**(51,013)**	**0**	**(12,697)**	**(2,496)**	**(66,206)**

Summary of the Options and Results

Table C-12 illustrates summary of impacts of the options on utility revenue losses.

Table C-12: Summary table for Policy Options Impacts to the Utilities' Revenue Losses from Net Metering Customers

	2030 Estimates		
	Base Case Scenario	Low Case Scenario	High Case Scenario
Net revenue losses under current net metering program conditions	**$1,968,000**	**$1,468,000**	**2,390,000**
Impacts of options to reduce the net revenue losses from combined two options: (i) Reduce value of credit for surplus generation (ii) Increase customer and demand charges higher than variable charge	$865,000	$608,000	$1,020,000
Net cost to the GNWT	**$1,103,000**	**$860,000**	**$1,370,000**

Table C-13 illustrates summary of impacts of the options on the GNWT savings from TPSP and GREP.

Table C-13: Summary table for Policy Options Impacts to the GNWT savings from TPSP and GREP from Net Metering Customers

	2030 Estimate		
	Base Case Scenario	Low Case Scenario	High Case Scenario
GNWT savings from TPSP and GREP under current net metering program conditions	**$277,000**	**$218,000**	**$303,000**
Impacts of options to subsidies from combined two options: (i) Reduce value of credit for surplus generation (ii) Increase customer and demand charges higher than variable charge	$54,000	$46,000	$66,000
Subsidy savings with impact of the recommended option	**$223,000**	**$172,000**	**$237,000**

II. Other Intermittent Renewable Generation by Customers

Some of the existing installed renewable generation subject to the capacity cap is not subscribed to the net metering program:

- Utility owned-generation where the costs of the generation are recovered through utility rates.
- Power purchase agreements where generation is sold to a utility at a price comparable to the variable cost of generation. These costs are also recovered through utility rates.
- Other non-utility owned generation that is 'behind-the-meter' and does not deliver energy to the grid but does result in reduced utility revenues.

As illustrated in Appendix A, utilities' annual revenues loss from other Intermittent customers owned self-generation by 2030 is $0.325 million.

From the policy options discussed in Part I of this appendix, following options will have impact to revenue loss from other intermittent self-generation owned by customers.

- Increase customer and demand charges for all customers.
- Consolidated option that includes Increase customer and demand charges for all customers.

Tables C-14 shows utilities annual revenue loss changes from increasing the fixed charges by 5 per cent. By 2030 net revenue loss change from other installed self-generation is estimated to be $0.020 million and this will be the same for all three, base, low, and high, scenarios, because the model does not assume any growth for other intermittent renewable generation.

Table C-14: Estimated Changes to Utility Net Revenue Loss from Other Intermittent Renewable Generation

Utility Net Revenue Loss	2030 Estimates - Base Case Scenario				
	NTPC Snare	NTPC Taltson	NTPC Thermal	NUL NWT Hydro	Total
Under Current Program Conditions ($)	11,676	8,042	297,758	7,609	325,086
Fixed charge increases by 5% ($)	11,211	8,001	278,769	6,922	304,903
Variance ($)	**(465)**	**(41)**	**(18,989)**	**(688)**	**(20,183)**

There is no impact to the GNWT TPSP and GREP savings from other intermittent renewable self-generation owned by customers based on following assumptions:

- All other intermittent renewable generation capacities are owned by non-residential customers which are not eligible for TPSP.
- GREP is designed only for NUL NWT Thermal zone and the model does not estimate another intermittent renewable generation capacity for NUL NWT Thermal zone.

III. Combined effect of Net Metering and Non-Net Metering Self-Generation

Table C-15 illustrates summary of impacts of the options on utility total net revenue losses from net metering and non-net metering self-generations, excluding utility related installed capacities.

Table C-15: Summary Table for Policy Options Impacts to the Utilities' Total Net Revenue Losses

	2030 Estimate		
	Base Case Scenario	Low Case Scenario	High Case Scenario
Total net revenue losses under current net metering program conditions	**$2,293,000**	**$1,793,000**	**2,715,000**
Impacts of options to reduce the total net revenue losses from combined two options: (i) Reduce value of credit for surplus generation (ii) Increase customer and demand charges higher than variable charge	$885,000	$628,000	$1,040,000
Net cost to the GNWT	**$1,408,000**	**$1,165,000**	**$1,675,000**

Because the model assumes other intermittent non-net metering self-generation does not have any impact to the GNWT savings from TPSP and GREP, impacts of the options on the GNWT savings from TPSP and GREP are remaining the same as shown in Table C-13.

Net Metering and Community Self-Generation Policy Review

APPENDIX D

Net Metering and Community Self-Generation Review Draft Terms of Reference for Implementation

This appendix provides draft terms of reference that could be used to implement recommendations contained in the review of net metering and community-self generation. It is anticipated these would be revised based on policy decisions made by the GNWT and input from the PUB, utilities and other stakeholders.

Draft Terms of Reference

Under Subsection 14(1) of the *Public Utilities Act,* the Executive Council of the Government of the Northwest Territories (GNWT) has the authority to issue directives to the Public Utilities Board (PUB or Board).

The GNWT supports the optimization of electricity resources in the NWT in a way that maximizes the use of cost-effective renewable electricity and reduction of GHG emissions, while sending fair and appropriate economic price signals to customers and minimizing the overall cost of power to all ratepayers. As renewable generation has evolved in the NWT it is important to ensure rates, policies and terms and conditions of service are adapted to support the efficient allocation of resources.

Customer-owned Intermittent Renewable Generation

The Board should initiate a joint proceeding involving all of the electric utilities in the NWT to review the existing rate structures and terms and conditions of service applicable to customers who install customer-owned intermittent renewable generation. Specifically, the following items should be reviewed by the Board:

a. For application to all customers who own and operate intermittent renewable generation serving loads connected to the distribution system (not only those customers currently subscribed to specific rate options such as net metering), the Board is to recommend any necessary changes to the utility terms and conditions of service to ensure safety, reliability, and the efficient operation of the utility-owned generation. This must include at minimum the following provisions:

    i. The requirement for all utility-served (connected to the utility system) self-generation customers to notify the utility of their self-generation equipment and specifications, and to have a signed agreement with the utility before such equipment begins operation.

    ii. A requirement for self-generation customers to notify the utility if they make changes to the capacity of their self-generation equipment.

    iii. Transition provisions and timelines to implement part (i) to existing customer self-generation.

    iv. The imposition of a 20 per cent combined capacity limit on intermittent renewable generation in thermal communities, whether owned by the utility or customers.

    v. The capacity limit indicated in (iii) above does not apply to projects which are either utility-owned generation or large-scale community government-owned generation under a Power Purchase Agreement with the utility, and are either (a) appropriately converted from intermittent generation to reliable firm generation by way of connected storage, such as batteries, or (b) considered by the utility to be at a scale that can be installed without impacting, safety, reliability or system stability.

b. For all customers whose self-generation is able to deliver power to the utility grid at any time, recommend changes to how customers are compensated for surplus energy delivered to the grid to reflect the value of that energy. In setting this value, the Board should consider that the rate should meet standard tests of economic efficiency and value-for-money for the utility system, and be feasible for the utilities to implement, notably, the rate should reflect:

    i. The short-run marginal cost savings to the utilities from the self-generation, which may be different by rate zone.

    ii. Any incremental capital or operating costs incurred by the utilities to integrate the renewable generation.

    iii. Any incremental operating benefits to the utilities arising from the renewable generation.

    iv. An appropriate treatment of system generation costs and wholesale revenues from NUL to NTPC in determining the compensation rates.

    v. Consideration of the impacts on customers who own their own intermittent generation and customers who do not own their own generation. This includes ensuring that any rate, new rate class, or other program offering meets the standards of the Public Utilities Act, section 48(1) that the rate be neither unjustly discriminatory (to self-generating customers or to non-self-generation customers) nor unduly preferential (to self-generating customers or to non-self-generation customers).

    vi. How the resulting credits should be calculated and updated over time.

    vii. Maintaining existing provisions that the credits will not be paid out as cash and expire annually.

c. In reviewing options under part (b), the Board may decide to close the existing net metering program, replace the existing program with a net billing program, or other options to align the compensation customers receive for surplus generation with the value to the utilities and all customers. This choice may differ by zone, and by rate class.

d. Recommend a rate design for customers who own their own intermittent generation, are connected to the grid but do not deliver electricity to the grid. Such rate options may or may not involve the creation of new class(es), and may or may not have increased or additional charges associated with them at this time.

e. Recommend any charges to customers who own their own intermittent renewable generation (whether or not they deliver energy to the grid) that may include stand-by charges, access fees, or minimum bills necessary to promote fair cost recovery from those customers.

f. Recommend a mechanism for utilities to report to the Board on the number of customers with intermittent renewable generation and the size of that generation, inclusive of those who deliver surplus energy to the grid and those that do not.

g. Recommend any necessary changes to utility reporting on lost revenue due to customer-owned intermittent renewable generation to include:

    i. lost revenue from all customer-owned intermittent renewable generation, not only those customers who subscribe to a specific rate option such as net metering.

    ii. lost Wholesale revenues to NTPC as a result of intermittent renewable generation from NUL retail customers.

h. Establish an implementation process including transition provisions, notice to existing customers and public notices to implement the recommended changes.

Fixed Customer Charges and Demand Charges

Fixed customer charges and demand charges are permitted to change over time to reflect rate design objectives, including cost causation and gradualism. Monthly customer and demand charges should be comparable across zones and utilities to the extent practical to ensure no undue disparity between customers. These changes can be implemented as part of Phase II General Rate Applications for each utility.

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