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Sent via eFile

BCUC INDIGENOUS UTILITIES REGULATION INQUIRY
EXHIBIT A-13

Re: British Columbia Utilities Commission – Indigenous Utilities Regulation Inquiry – Project No. 1598998 – Daria Babaie, Ryezan Inc. – Jurisdictional Review of the Regulation of Indigenous Utilities in Canada

Good Afternoon:

Pursuant to Order in Council (OIC) No. 108, the British Columbia Utilities Commission (BCUC) is undertaking an Inquiry respecting the regulation of Indigenous utilities.[1] Section 3 of OIC No. 108 outlines the terms of reference for the Inquiry, whereby the BCUC must advise the Lieutenant Governor in Council on the appropriate nature and scope, if any, of the regulation of Indigenous utilities. The BCUC will be receiving evidence from Indigenous governments and community members, the provincial government, utility owners and operators, and interested members of the public, regarding the items in the terms of reference.

As part of the Inquiry, BCUC staff requisitioned a written report from an independent expert, Daria Babaie, Ryezan Inc., that will be added to the Inquiry's public evidentiary record. The BCUC stipulated that Mr. Babaie address the following scope items in his report:

1. **Regulation of Indigenous utilities[1]**
   - Are Indigenous utilities subject to regulation in other Canadian jurisdictions?
     - If so, what models of regulation exist?
   - Are Indigenous utilities subject to statutory exceptions or exemptions in other provinces?
   - Have other jurisdictions conducted reviews of the need to regulate or scope of regulation for Indigenous utilities?
2. **Characteristics of Indigenous utilities in other jurisdictions, with respect to:**
   - Nature of utility ownership and operations
     - e.g. partner organizations, transitional ownership arrangements, decision making structures
   - Types of services provided
     - e.g. electricity, gas, heat, cooling; generation and/or distribution; rate-paying structures
   - Types of customers served
     - e.g. community members only, other residential customers, commercial and industrial customers
   - Geographic service area of the utility, relative to the community area

Mr. Babaie's report is attached to this letter and will form part of the evidentiary record in this Inquiry. For clarity, while the contents of the report may inform the general discussion, it does not provide advice or recommendations to the BCUC or the Lieutenant Governor in Council on the specific subject matter of the Inquiry, nor is it intended to reflect the position of the BCUC with respect to any matter that it addresses.

[1] Using a definition of Indigenous Utilities aligned with the definition contained in OIC No. 108.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

PS/ad
Enclosure

Jurisdictional Review of the Regulation of Indigenous Utilities in Canada
July 2019

Prepared by:
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July 2019

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Acknowledgements

Ryezan Inc. would like to thank the Executive Director of the Canadian Association of Members of Public Utility Tribunals (CAMPUT) for assistance during this review by providing and facilitating contact information at the provincial and territorial energy regulators. Ryezan Inc. also thanks staff, board members, and commissioners from energy regulators who provided valuable information.

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Executive Summary

The British Columbia Utilities Commission (BCUC) is undertaking an Inquiry respecting the regulation of Indigenous (or First Nations) utilities in British Columbia (BC) pursuant to Order in Council (OIC) No. 108 (the "Inquiry").[1] The Inquiry requires the BCUC to advise on the appropriate nature and scope, if any, of the regulation of Indigenous utilities. The Inquiry also asks the BCUC to respond to several questions regarding the defining characteristics of Indigenous utilities, including ownership and operation, types of services provided, the persons to whom services are provided, and geographic areas served.

The BCUC has retained Ryezan Inc., as an independent consultant (the "Consultant") to provide a jurisdictional review regarding the regulation of Indigenous (or the "First Nations") utilities in Canada. The Consultant was asked to provide unbiased research into the regulation of the Indigenous utilities and their defining characteristics which would assist the Inquiry. The Consultant has not opined on the regulation of Indigenous utilities and their defining characteristics in British Columbia, however, parties to the Inquiry's proceeding may find the research report informative in considering the issues with respect to regulation of Indigenous utilities.

This review focuses on regulation of Indigenous utilities and their defining characteristics. The research findings, including concluding remarks are summarized in this section of report, and are tabulated in Appendix A. Specifically, the details related to regulation of Indigenous utilities and their defining characteristics, as well as statutory and regulatory exceptions or exemptions received, summary of applications filed with the boards or commissions, if any, for certain regulatory treatment and the related decisions and orders, are found in sections 4 to 8 of this report. Section 9 provides an overview of a number of Indigenous renewable energy projects which is an increasing trend across Canada. Specifically, it outlines the regulatory challenges arising from the ownership of microgrids.

In Canada, Indigenous Peoples are actively involved in the utility sector through owning and/or operating electricity transmission and distribution utilities and natural gas distributors (or utilities). Provincial and federal governments have introduced programs and offered financial incentives that facilitated building partnerships and joint ventures between the utilities and First Nations in the utility sector. This has promoted economic participation of First Nation communities in their region; especially with the electricity transmission companies. It has also enhanced the relationship between transmission utilities and First Nations. This research noted establishment of an increased number of joint partnership arrangements between First Nations and electricity transmission utilities in recent years in Alberta, Northwest Territories, and Ontario, which helped Indigenous Peoples pursue ownership interests in utilities. This trend is expected to increase in the future.

This report covers a jurisdictional review of the regulation of Indigenous utilities in twelve provinces and territories (BC was not part of the scope) across Canada. Specifically, several Indigenous utilities are found in Alberta, Northwest Territories, Nunavut, and Ontario. No other Indigenous utility exists in any other provinces or territories. In general, the utility model and defining characteristics for Indigenous utilities are unique to these provinces and territories, and therefore need to be considered

[1] http://www.bclaws.ca/civix/document/id/oic/oic_cur/0108_2019

in the historical context of their establishment and First Nation communities economic and geographical considerations.

The regulatory models with respect to the regulation of Indigenous utilities in the Canadian utility industry are unique to each province or territory. While there are several Indigenous utilities that are rate regulated and subject to regulation regardless of their ownership structure, there are some other Indigenous utilities that are not rate regulated by a commission or a board and are subject to certain statutory exceptions or exemptions. These Indigenous utilities are mostly found in Alberta and Ontario. The policy analysis and the rationale for some of these statutory exceptions and exemptions were not well documented, and the information is not publicly available. Lack of information and having access to the relevant information with regards to the regulation of Indigenous utilities and their defining characteristics have been one of the challenges throughout this research.[2] This research did not find any report or discussion paper undertaken, either by or for energy regulators, which addressed the question of the need to regulate Indigenous utilities.

Summary of Findings

Alberta

PiikaniLink Limited Partnership (PiikaniLink L.P.) is an Indigenous electricity transmission company that provides transmission services on Piikani Reserve. PiikaniLink L.P. is a joint partnership between AltaLink and Piikani Nation with Piikani Nation holding 51% equity portion of the PiikaniLink L.P.'s assets. KainaiLink Limited Partnership (KainaiLink L.P.) is an Indigenous electricity transmission company that provides transmission services on Blood Reserve. KainaiLink L.P. is a joint partnership between AltaLink and Blood Tribe with Blood Tribe holding 51% equity portion of KainaiLink L.P. AltaLink operates the transmission systems for PiikaniLink L.P. and KainaiLink L.P. PiikaniLink L.P. and KainaiLink L.P. are rate regulated by the Alberta Utilities Commission (the "AUC").

The three Indigenous communities of Ermineskin, Montana, and Peigan Indian wholly own their rural electricity distribution systems which are called Rural Electrification Associations (REAs). These REAs are not-for-profit, rural cooperatives that own their electricity distribution systems and distribute electricity to their members (or "customers") in rural regions of Alberta. These Indigenous REAs are owned and governed by the people (or members) within their communities. They contracted out the operation and maintenance of their distribution systems to FortisAlberta. The distribution rates for all REAs, including the Indigenous Peigan Indian REA, Ermineskin REA, and Montana REA, are not regulated by the AUC. While the rates for Peigan Indian REA and Montana REA are approved by their respective Chief and Council, the rates for Ermineskin REA is established by its board of directors on behalf of association members. The AUC has virtually no jurisdiction to hear customer complaints about rates that are being charged by a REA. Customers need to contact the REA's board or the Rural

[2] The OEB's Yearbook of Electricity Distributors publishes the financial and operational information collected from the Ontario's electricity distributors through the Reporting and Record-Keeping Requirements. The Yearbook does not provide any statistical information regarding the 3 Indigenous utilities Attawapiskat Power Corporation, Fort Albany Power Corporation and Kashechewan Power Corporation. It states, "*The following distributors have not filed RRR information: Attawapiskat Power Corporation, Fort Albany Power Corporation and Kashechewan Power Corporation*."

Utilities Branch of the government of Alberta regarding their complaints. However, the AUC has certain jurisdiction over REAs in the area of mergers and acquisitions. REAs are also exempt from Service Alberta's security deposit requirements. These exemptions apply equally to both Indigenous and non-Indigenous REAs.

The Indigenous rural natural gas co-operative associations (the "co-ops") are not-for-profit rural utilities that are wholly owned by First Nations. There are several Indigenous natural gas co-ops that own their natural gas distribution systems and provide natural gas services to their members. While some of these natural gas cooperatives operate their own assets, some others use investor-owned gas companies, e.g., ATCO Gas, or an adjacent co-op to operate and maintain their distribution systems. Similar to the REAs, the Indigenous natural gas cooperatives are not rate regulated by the AUC. The Chief and Council or the board of directors for the natural gas co-ops sets the rates. No specific statutory exceptions or exemptions exist regarding these Indigenous co-ops that would uniquely distinguish them from Alberta's non-Indigenous natural gas co-ops. However, in contrast to the REAs with respect to customer complaints, the AUC has certain authorities over natural gas co-ops. The AUC may hear complaints about terms of service, service charges, and rates if a customer believes they are discriminatory, improperly imposed, or fail to conform to the co-op's established rate structure.

Newfoundland and Labrador

The Mushuau Innu First Nation (the "Innu") owns the infrastructure necessary to supply electrical service to the community. Newfoundland and Labrador Hydro maintains the infrastructure based on an agreement with the federal government on a cost recovery basis. One may consider Innu as an "Indigenous utility" in the context of definition of a public utility under the *public utility* Act, and a recent Court of Appeal finding, which is discussed in detail in section 5 of this report. The Innu is not regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities.

Northwest Territories

Northland Utilities is a joint partnership between ATCO Ltd. and Denendeh Investments Inc., each holding 50% equity portion of Northland Utilities. Northland Utilities owns, operates and maintains its electrical infrastructure through its two operating companies: Northland Utilities companies (NWT) Limited and Northland Utilities (Yellowknife). Northland Utilities (NWT) Limited distributes electricity in Hay River. It also generates and distributes power in several other smaller communities. Northland Utilities (Yellowknife) Limited provides electricity distribution services to Yellowknife and N'Dilo. Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited are fully regulated by the Northwest Territories Public Utilities Board.

Nunavut

The Qulliq Energy Corporation (QEC) is a crown corporation, generation and distribution utility that is owned by the Government of Nunavut. The Minister Responsible for the QEC, along with the Executive Council, make the final decisions on power rates. The Minister is also a member of leadership team at QEC. By virtue of the fact that 85% of the population in Nunavut is Indigenous Peoples, QEC can be regarded as an "Indigenous utility". However, QEC is not comparable to any other conventional

Indigenous utility in Canada because of its very unique ownership and governance structure. Therefore, QEC may not prove relevant to the issues being examined by the BCUC.

Ontario

There are a number of licensed generators which are owned, either wholly or in part by Indigenous Peoples. However, the licensing is the only direct regulation by the OEB. There are four electricity transmitters, three electricity distributors, one natural gas distributor, and ten Independent Power Authorities (IPAs) that are owned or/and operated by First Nations in Ontario. In addition, 129 First Nations in the province hold 2.4% of Hydro One through OFN Power Holdings, which is a limited partnership owned by Ontario First Nations Sovereign Wealth (The Ontario government now holds about 47.4% of Hydro One).

Five Nations Energy Inc. (FNEI), B2M Limited Partnership (B2M L.P.), Wataynikaneyap Power LP (WPLP), and Cat Lake Power are the four Indigenous electricity transmission companies. These transmission companies are required to hold an electricity transmission licence by the Ontario Energy Board (OEB) in order to own and operate transmission facilities in Ontario.

FNEI is a non-profit, non-share capital that owns and operates transmission facilities in the western James Bay region of Ontario serving the remote First Nation communities of Attawapiskat, Fort Albany, and Kashechewan. B2M L.P. is an electricity transmitter that is a limited partnership between B2M GP Inc. and Saugeen Ojibway Nation Finance Corporation (SON FC) with a 66% and 34% partnership interest, respectively. B2M GP Inc. is a wholly owned subsidiary of Hydro One Inc. SON FC is jointly owned by the Chippewas of Saugeen First Nation and the Chippewas of Nawash First Nation. B2M L.P. owns and operates a section of electricity transmission line from the Bruce Nuclear Generation Complex to Hydro One's Milton Switching Station. WPLP is an electricity transmission company that is jointly owned by 24 First Nation remote communities in Ontario and FortisOntario. The participating First Nations hold a 51% interest in WPLP and FortisOntario holds the remaining 49% interest. The company is expected to connect 25 remote communities to the provincial grid by Q4 of 2023.

Cat Lake Power owns transmission assets in the community of Cat Lake. It is wholly owned by Cat Lake First Nation. In 2006, Cat Lake power requested the OEB have its licence relinquished. Hydro One Networks currently holds an interim licence to operate the transmission and distribution businesses serving the community.

Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation are non-profit, Indigenous utilities who provide electricity distribution services on reserves in Northern Ontario. They are wholly owned by Attawapiskat First Nation, Fort Albany First Nation, and Kashechewan First Nation, respectively. Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation have distribution licences with the OEB. These Indigenous utilities are rate-regulated by the OEB.

Six Nations Natural Gas Limited is a for-profit, natural gas utility that is owned by the Six Nations of the Grand River Territory. The utility is a limited partnership between Six Nations Natural Gas Limited and elected council of the Six Nations of the Grand River Territory. It distributes natural gas to customers on reserve. Although Six Nations Natural Gas is not regulated by the OEB, it is subject to a number of

non-OEB regulations, which also apply to all Ontario's natural gas utilities. For example, Six Nations Natural Gas must report when there has been damage to the system that results in a gas leak.
An Independent Power Authority (IPA) is a distributor that is owned and operated by a local First Nation community. There are ten IPAs in Ontario. They are not connected to the provincial grid, and rely on diesel generators to supply electricity to the communities. The IPAs are not regulated by the OEB.

A number of First Nations and their utilities are named under various regulations, and have received certain legislative exceptions or exemptions and specific different regulatory treatment with respect to the regulation of Indigenous utilities. For example, Cat Lake First Nation was named and specifically granted an exemption for Cat Lake Power to be not a rate-regulated utility. However, Cat Lake Power was required to hold a transmission licence with the OEB. As another example, the utilities for Attawapiskat, Fort Albany, and Kashechewan First Nations were granted an exemption with respect to the OEB assessment, which is related to covering expenses incurred and expenditures made by the OEB in exercising its powers and duties for a period until May 2004. In addition to naming the First Nation entities under certain schedules of regulations, the regulations use the following exemption criteria with respect to named First Nations:

1. The distributor must be a First Nation, or a corporation that is solely owned by a First Nation.
2. The distribution system owned by the distributor must not be connected to the Ontario grid.
3. The distributor must only distribute electricity within its geographic service territory as it existed on January 1, 2002.

Furthermore, the licences for these First Nations and their respective electricity distributors provide some limited exemptions from specific code requirements that are applicable to any other non-Indigenous licensed utility. In addition, the safety regulations that are governed by the Electrical Safety Authority and are applied to all Ontario's licensed electricity distributors, do not apply to these three First Nation utilities.

Conclusions

This review has identified a number of Indigenous utilities that exist in Canada, operating through different ownership structures and regulatory models. Specifically, there are Indigenous utilities operating in Alberta, Northwest Territories, Nunavut, and Ontario. These Indigenous utilities have a number of defining characteristics in common, whether or not being regulated. They are owned or/and operated, in full or in part, by a First Nation. They provide either electricity or natural gas utility services to customers or members on a reserve, either on their own or through a third-party. Compensation for the services is through rates charged to customers.

The report has identified statutory exceptions or exemptions respecting Indigenous utilities in Alberta and Ontario, which need to be considered in the historical context of the government's economic and energy policies in these provinces over the past decades. In addition, the unique regulatory treatment with respect to some of the statutory exemptions applicable to Indigenous utilities in Ontario, is due to

legislative and regulatory exemptions which the First Nations sought and/or applied for, and were subsequently granted.

Another finding is that it is not uncommon for regulatory models to be developed based on unique circumstances for regulation of each Indigenous utility. These circumstances include: Indigenous ownership in part or whole, the utility services provided, geographical area served be it rural or remote locations, service recipients, etc.

Lastly, there are new opportunities in distributed energy resources including renewable-based microgrids which may provide Indigenous Peoples who are living in the remote and rural areas of Canada with ownership and operational interests in unique, non-conventional renewable-based microgrid “utilities”. This will help address reliance on diesel generators. This may also lead to new regulatory challenges resulting from renewable-based microgrids and as such, regulators ought to be prepared to consider their regulatory treatment when operated by an Indigenous utility.

1. Introduction

On March 11, 2019, the Lieutenant Governor in Council, by Order in Council (OIC) No. 108, requested the BCUC, pursuant to section 5(1) of the *Utilities Commission Act (UCA)*, advise the Lieutenant Governor in Council respecting the regulation of Indigenous utilities in accordance with the terms of reference set out in the Inquiry.

On March 19, 2019 by Order G-62-19, the BCUC established an inquiry and appointed a panel respecting the regulation of Indigenous utilities (the "Indigenous Utilities Inquiry"), in response to the OIC No. 108. The BCUC will be receiving evidence from Indigenous governments and community members, government, utility owners and operators, and the public, to address the items in the OIC's terms of reference. Pursuant to OIC No. 108, "Indigenous nation" means any of the following:

a) a band within the meaning of the Indian Act (Canada);
b) the Westbank First Nation;
   i. the Sechelt Indian Band and the Sechelt Indian Government District established under the Sechelt Indian Band Self-Government Act (Canada);
c) a treaty first nation;
d) the Nisga'a Nation and Nisga'a Villages;
e) another Indigenous community within British Columbia, if the legal entity representing the community is a party to a treaty and land claims agreement within the meaning of sections 25 and 35 of *the Constitution Act, 1982* that is the subject of Provincial settlement legislation.

Pursuant to OIC No. 108, "Indigenous utility" is defined as a public utility that is owned or operated, in full or in part, by an Indigenous nation.

As part of the Inquiry, the BCUC has retained Ryezan Inc. to conduct a jurisdictional review respecting the regulation of Indigenous utilities (or First Nations) and their defining characteristics in Canada that will be added to the Inquiry's public evidentiary record. This review will address the following items:

1. Characteristics of Indigenous utilities in Canadian jurisdictions, with respect to:
   - Nature of utility ownership and operations
     - E.g. partner organizations, transitional ownership arrangements, decision making structures
   - Types of services provided
     - E.g. electricity, gas, heat, cooling; generation and/or distribution; rate-paying structures
   - Types of customers served
     - E.g. community members only, other residential customers, commercial and industrial customers
   - Geographic service area of the utility, relative to the community area

2. Regulation of Indigenous utilities[3]
   - Are Indigenous utilities subject to regulation in other Canadian jurisdictions?

[3] Using a definition of Indigenous utilities aligned with the definition contained in OIC No. 108

    - If so, what models of regulation exist?
  - Are Indigenous utilities subject to statutory exceptions or exemptions in other provinces?
  - Have other jurisdictions conducted reviews of the need to regulate or establish the scope of regulation for Indigenous utilities?

This jurisdictional review considered all Canadian provinces other than British Columbia, and the three territories with respect to Indigenous utilities and their defining characteristics. The mandates for these provincial and territorial regulators are found in Appendix B of this report.

The review determined if Indigenous utilities exist in different provinces and territories across Canada. Where the Indigenous communities are participating in a utility industry, e.g. natural gas or electricity, in a province or territory, the review provides information related to defining characteristics of the Indigenous utilities, including utility name, location, service territory and geographic areas served, ownership structure and governance, types of operation, number of customers, and types of services offered, among others.

Exceptions or exemptions, if any, from a relevant provincial or territorial Act or regulation that have been applied or applies to the Indigenous utilities are listed and discussed. For example, applications, if any, filed with a board or commission regarding (i) exemptions from regulation, (ii) and/or different regulatory treatment compared to non-Indigenous utilities within the jurisdiction of a board or commission, are outlined in a separate section. To provide context to the regulatory treatment of the Indigenous utilities by the boards and commissions, examples of the applications filed by Indigenous utilities, including a summary of details related to applications, arguments and submissions made by parties, and the rationale for the board or commission's decisions and orders, are provided. Specific sections of relevant Act and regulations, as well as guidelines, policies, and practices, if any, regarding the regulation of Indigenous utilities are stated. The review sets out any other provincial or territorial regulation that may apply to the Indigenous utilities if they are not regulated by a commission or a board. For each section, when it is applicable, general observations related to regulation of Indigenous utilities are stated. The report is organized in alphabetical order with respect to the provincial and territorial energy regulators in Canada.

Many Indigenous communities which are located in rural and remote areas of Canada are not connected to electricity grids, and instead rely on expensive and polluting diesel generation, as the sole energy source to produce electricity. For example, every community in Nunavut is isolated, and there is no territorial electricity grid at all. All communities in Nunavut rely on diesel generation. First Nations engagement in the utility industry and development of energy projects have increased in recent years by taking leadership, partnering in, and/or participating in the renewable energy sector. This is an increasing trend across all provinces and territories. This would reduce the Indigenous Peoples reliance on diesel generators. A brief discussion of Indigenous renewable energy projects in Canada is provided, as this may be of interest in considering the role Indigenous Peoples are playing in the renewable energy sector.

The new renewable related technologies are transforming the existing utility industry and creating new models of renewable-based "utilities" such as microgrids. Although this report primarily addresses regulation of Indigenous utilities and their defining characteristics, it also raises a set of questions with

respect to regulation of new "utility" models based on renewable energy resources and renewable-based microgrids.

2. Scope

This jurisdictional review covers Canadian provinces other than British Columbia, and the three territories. The review addresses the following five key questions:

1. Are there any utilities that are owned or operated in any province or territory, either wholly or in part by Indigenous peoples (referred to in this review report as "Indigenous utility" or "First Nation utility")?
   If so, what are the names of the Indigenous utility or Indigenous owner.

2. With respect to Indigenous utilities, has any board or commission received applications or undertaken reviews regarding:
   i. exemptions from regulation, and/or
   ii. different regulatory treatment compared to non-Indigenous utilities within the jurisdiction of board or commission?

3. If "yes" to question 2, were there written reasons? What conclusions were reached, and what principles or criteria (if any) did the board or commission apply in its decision?

4. Does any board or commission have any specific guidelines, policies, and practices for determining whether a current or future Indigenous utility would be regulated, and if so, what is the appropriate degree of regulation?

5. If Indigenous utilities are not regulated (or are exempt from regulation) by the board or commission, are they subject to regulation by other bodies or government? If so, what is the regulatory body?

This review primarily focuses on regulation of Indigenous utilities and their defining characteristics. It provides a summary of the different Indigenous utility models, and any significant trends that exist. The review does not cover in detail the Indigenous renewable energy projects across Canada.

Furthermore, the review does not provide any advice with respect to regulation of Indigenous utilities or any recommendations as to whether or not Indigenous utilities should be regulated in British Columbia under the *Act* or under another mechanism, as this was outside the scope of this report.

3. Approach

The Consultant contacted provincial and territorial boards and commissions responsible for the regulation of the electric and natural gas utilities in their respective province or territory. Inquiries were made of the boards and commissions' staff and the five questions related to the regulation of

Indigenous utilities that are listed in the scope section of this report were discussed. In addition, the Consultant conducted further research by reviewing the boards' and commissions' websites, and the statutory and regulatory authorities relevant to the boards and commissions.

Further inquiries were made with several other organizations across Canada, including Alberta Federation of Rural Electrification Associations, Federation of Alberta Gas Co-ops, Alberta Ministry of Energy, Alberta Ministry of Agriculture and Forestry, FortisAlberta, Peigan Indian REA, FortisOntario, Six Nations Natural Gas Limited, Hydro One, SaskPower, and the Quebec Office of Public Hearings on the Environment (the "Bape"), among others.

4. Alberta

The Alberta Utilities Commission (the "AUC" or the "Commission") regulates Alberta's investor-owned electric, gas, water utilities and certain municipally owned electric utilities to ensure that customers receive safe and reliable service at just and reasonable rates.[4]

In Alberta, First Nations participate in the electricity sector in different ways. Piikani Nation[5] and Blood Tribe[6] are two Indigenous communities that have recently secured majority ownership share (51%) of transmission assets in PiikaniLink Limited Partnership (PiikaniLink L.P.) and KainaiLink Limited Partnership (KainaiLink L.P.), respectively, through partnership with AltaLink. The transmission line facilities for PiikaniLink L.P. and KainaiLink L.P. cross the reserve lands for these two Indigenous communities. PiikaniLink L.P. is a transmission company that serves the 240 kilovolt (kV) transmission line between the Goose Lake Substation and the North Lethbridge Substation, and a portion of the Peigan 59S Substation located on Piikani Reserve No. 147. KainaiLink L.P. is a transmission company that serves the 240 kilovolt (kV) transmission line between the Goose Lake Substation and the North Lethbridge Substation located on Blood Reserve No. 148.

There are currently three Indigenous communities who are the Rural Electrification Associations or REAs and own their rural electrical systems namely: Peigan Indian ERA, Ermineskin ERA, and Montana REA. Peigan Indian ERA is owned by Piikani Nation[7] with approximately 380 members or "customers" on reserve, as of January 2017[8], and is located in southern Alberta. Ermineskin ERA is owned by the

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[4] http://www.auc.ab.ca/Pages/who-we-regulate.aspx

[5] The Piikani Nation consists of roughly 3600 registered members. The Piikani Nation has a land mass of 46,677.8 Hectares and two reserves 147a where the town site is located and 147b which is the timber reserve. https://piikanination.wixsite.com/piikanination/about-us

[6] The Blood Tribe is the body of First Nations known as the Blood Indian Band. It has a population of 12,800 (2015) occupying approximately 549.7 square miles in the Rocky Mountains of approximately 7.5 square miles. It consists of Stand Off, Moses Lake, Levern, Old Agency, Fish Creek, Fort Whoop-Up and Bullhorn communities. http://bloodtribe.org/

[7] Piikani Nation owns and operates Peigan Indian REA. It is a non-profit organization and it currently serves rural consumers in the Piikani Nation. https://www.peiganrea.com/

[8] The AUC Decision 22320-D01-2017 - Peigan Indian REA, Varied Code of Conduct Regulation Compliance Plan January 27, 2017.

Ermineskin Cree Nation [9,10] with approximately 261 members or "customers" on reserve, as of December 2016[11], and is located in Maskwacis. Montana REA is owned by Montana Indian Reservation [12] with approximately 59 members or "customers" on reserve and is located in Maskwacis. These Indigenous communities own their distribution assets and can generate revenue from this REA ownership. Their distribution rates are not regulated by the AUC. The board of directors for the REA sets the rates. The Ermineskin REA, Montana REA, and Peigan Indian REA are serviced by FortisAlberta.[13] Section 4.2 below provides information regarding history of REAs in Alberta.

Similar to the REAs, there are several rural Indigenous natural gas co-ops who own their natural gas distribution assets and provide natural gas service to their members. Their distribution rates are not regulated by the AUC. The Chief and Council or the board of directors for the natural gas co-ops sets the rates. While some of these natural gas cooperatives operate their own assets, there are other co-ops that use investor-owned gas companies to operate and maintain their natural gas distribution systems.

To provide context to the regulatory treatment of the Indigenous utilities by the AUC, examples of the applications filed by Indigenous utilities, including a summary of details related to the applications filed by the Indigenous utilities, arguments and submissions made by parties, and the rationale for the AUC's decisions, are provided. Specific sections of the relevant Act and regulations regarding regulation of Indigenous utilities in Alberta, including any particular exceptions or exemptions granted, are also included in the next sections.

The following sections provide the details for the regulation of Indigenous utilities and their defining characteristics in Alberta.

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[9] The Ermineskin Cree Nation (Reserve #138) is one member of the Four Nations of Maskwacis, Alberta - located in Central Alberta about fifty miles south of Edmonton on Highway 2A, halfway between the towns of Ponoka and Wetaskiwin. The Ermineskin Cree Nations land base is approximately 25'000 acres. This area is traditionally known as the Bear Hills or Maskwacheesihk. The Ermineskin Reserve was established in 1885. The Ermineskin Cree Nation belongs to the Treaty Six Group of Indian Tribes in Western Canada. https://ermineskin.ca/history-culture/

[10] The Ermineskin is a non-profit organization and it currently serve 161 rural consumers in the Ermineskin area. It is member owned and member operated. https://www.ermineskin-rea.com/

[11] The AUC Decision 22200-D01-2016 - Ermineskin Rural Electrification Association Ltd., Varied Code of Conduct Regulation Compliance Plan, December 21, 2016.

[12] The Montana Indian Reservation, No. 139 is located approximately 90 kilometers south of Edmonton and 3 kilometers east of Highway No. 2A. It is the smallest First Nation that makes up the Four Nations of Maskwacis, Alberta.
http://www.montanafirstnation.com/about/

[13] FortisAlberta: Rural Electrification Associations https://www.fortisalberta.com/for-business-industry/rural-electrification-associations

4.1 Electricity Transmission Companies

4.1.1 PiikaniLink Limited Partnership

Background Information

PiikaniLink L.P. is a joint partnership between AltaLink and Piikani Nation. It was formed on March 6, 2017, allowing Piikani Nation with an option to purchase up to 51% of the PiikaniLink L.P.'s assets subject to approval from the AUC. On April 27, 2017, AltaLink applied to the AUC requesting for sale and transfer of the 240 kV Line and substation equipment on Piikani Nation reserve to PiikaniLink L.P. The limited partnership was approved by the AUC on November 13, 2018. Piikani Nation applied to the AUC on November 30, 2018 for an approval to purchase the equity portion of the PiikaniLink L.P. transmission assets. This required the AUC to approve Piikani Transmission Holding Limited Partnership and its financing arrangements to become 51% owner of PiikaniLink L.P. The AUC approved Piikani's application on April 18, 2019. On June 1, 2019, Piikani Nation completed the purchase of PiikaniLink L.P. shares to own 51% of the company.[14]

4.1.2 KainaiLink Limited Partnership

Background Information

KainaiLink L.P. is a joint partnership between AltaLink and Kainai Nation. The partnership discussion between AltaLink and Kainai Nation took place in 2006-2007. Project commitment and option agreement between parties were signed on May 27, 2010. The construction of AltaLink transmission line on the First Nation land started and the line was energized on October 2011. Purchase and sale agreement were signed on April 24, 2017.

On April 27, 2017, AltaLink applied to the AUC requesting for sale and transfer of the 240 kV Line on Kainai Nation reserve to KainaiLink L.P. The limited partnership was approved by the AUC on November 13, 2018. KainaiLink Nation applied to the AUC on November 30, 2018 for an approval to purchase the equity portion of the KainaiLink L.P. transmission assets. This required the AUC to approve KainaiLink Transmission Holding Limited Partnership and its financing arrangements to become 51% owner of KainaiLink L.P. The AUC approved KainaiLink's application on April 18, 2019.

Exceptions and Exemptions from the Act and Regulation

PiikaniLink L.P. and KainaiLink L.P. are not subject to any regulatory exceptions or exemptions. The discussion below demonstrates that the AUC treats these Indigenous utilities like any other non-Indigenous utilities that it regulates.

[14] http://piikaninationnews.ca/?p=674

Section 101(2)(d)(i) of the *Public Utilities Act* requires that an owner of a public utility, as designated under Section 101(1), obtain approval of the Commission to "*sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of them*."

On April 27, 2017, AltaLink, on behalf of the PiikaniLink L.P. and the KainaiLink L.P., filed applications for the sale and transfer of the 240 kV transmission assets to a new limited partnership and 2017-2018 general tariff applications with the Commission. The applications requested approval for sale and transfer of approximately $91.0 million of transmission assets located on reserve lands to the new limited partnerships, including debt financing and affiliate cross charging procedures for each new limited partnership. The applications of the new partnerships included revenue requests totaling $17.2 million for both partnerships for the two years. The transfers were part of the agreement which allowed AltaLink to route its Southwest Project on reserve lands.[15]

The applications sought approvals from the Commission with respect to:

i. transfer and sale of specific 240 kV transmission assets to PiikaniLink L.P. and KainaiLink L.P.
ii. create PiikaniLink L.P. and KainaiLink L.P. as new transmission facility operators in Alberta
iii. approve interim general tariffs for each of PiikaniLink L.P. and KainaiLink L.P.

AltaLink proposed that the acquisition by PiikaniLink L.P. and KainaiLink L.P. of the transmission assets referenced above would be financed by AltaLink Limited Partner (AltaLink L.P.). The amounts of the proposed loans are up to $40 million for PiikaniLink L.P. and $31 million for KainaiLink L.P. The Commission stated,

> The Commission conducts the no-harm test in two stages. First, the Commission assesses whether the transaction results in harm to ratepayers or, at the very least, leaves them no worse off than before the transaction in terms of financial impact or reliability of service. If the Commission concludes that ratepayers may be harmed, the Commission proceeds to the second stage and considers whether any identified harm can be mitigated by making approval subject to specified conditions.[16]

The Commission considered the no-harm test and the factors, as set out below that it had used in a prior Decision (2014-326) regarding the sale of AltaLink L.P.'s transmission assets and business to MidAmerican (Alberta) Canada Holdings Corporation. The Commission also referenced previous Commission decisions discussing each of those factors to guide the Commission's consideration of the proposed transfers. The no-harm test and the factors that were included in the Commission's decision regarding this case are as follows:[17]

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[15] AltaLink, L.P.,Management's Discussion and Analysis May 6, 2019, http://www.altalink.ca/files/pdf/news/Q1_2019_MDA.pdf
[16] AUC Decision dated November 13, 2018, AltaLink L.P. Transfer of Specific Transmission Assets to PiikaniLink L.P. and KainaiLink L.P. and the Associated 2017-2018 General Tariff Applications, page 2.
[17] Ibid., 8-9.

I. Whether there will be any impact to the rates and charges passed on to customers.
II. Whether any operational benefit or risk arises related to the acquiring party's utility experience. Whether the financial profile of the utility will be impacted for the purposes of attracting capital.
III. Whether the utility will remain sufficiently legally, financially and operationally separate from the acquiring party, which is, of course, the ring-fencing provisions, code of conduct, et cetera.
IV. Whether the Commission will maintain sufficient regulatory oversight of the utility.
V. Whether the management and operational expertise will remain in place post transaction.
VI. Whether the transmission (sic) (transaction) will result in any cost impacts for customers relating to such things as tax and pension funds.
VII. That the acquiring party wishes to be in the utility business in Alberta whereas the divesting party does not. That is in Decision 2005-118, Decision 2004-5 and Decision 2006-38.
VIII. Customers are, to the maximum extent possible, to be protected against any negative ramifications arising from the transactions.
IX. Customers are not entitled to a level of post-transaction regulatory certainty they would not have realized if the transaction had not been approved.
X. Customers are at least no worse off after the transaction is completed after consideration of the potential positive and negative impacts of the proposed share transactions.

The principles articulated in the cited decisions continued to guide the Commission and were applied in the Commission's consideration of the proposed transfers. The purpose of the no harm test is to ensure the proposed sale and transfer of the transmission assets to the new limited partnership does not result in harm to ratepayers.

The Commission determined that the no-harm test was not satisfied. The Commission found: (1) approval of the proposed transfers would result in ongoing incremental costs of $120,000 for 2017 to ratepayers for annual audit fees and for fees associated with hearing costs for each of PiikaniLink L.P. and KainaiLink L.P. that ratepayers were not previously obliged to pay, and (2) the repayment terms as set out in the loan agreements resulted in financial harm to ratepayers that, on balance, would leave ratepayers worse off than they otherwise would have been.[18]

Furthermore, the Commission found that the offsetting benefits claimed by AltaLink did not mitigate the financial harm. Nonetheless, The Commission was satisfied that the identified harm could be mitigated through the imposition of conditions. The Commission approved the applications with the conditions: (1) The incremental audit costs and hearing costs were to be removed from the KainaiLink L.P. and PiikaniLink L.P. tariffs and (2) any unreasonable or undue financial risk to ratepayers arising from the repayment terms in the financing of the proposed transfers may not be included within the AltaLink tariff.[19]

[18] Ibid., 9.
[19] Ibid., 10.

AltaLink claimed that the expected ongoing incremental costs to ratepayers were not significant in light of the $32 million in savings enjoyed by ratepayers, as a result of routing the transmission line through First Nations land. The Commission rejected the argument that alleged savings to ratepayers should be considered a benefit offsetting the ongoing incremental hearing and audit costs. The Commission stated what must be considered were the negative and positive effects of the proposed transfers themselves, and not of what preceded them.[20]

Regarding this case, the Commission relied on section 101(2)(d)(i) of the *Public Utilities Act* that requires that an owner of a public utility, as designated under Section 101(1), obtain approval of the Commission for the sale and transfer of the transmission lines. In deliberating its decision, the Commission applied and was guided by no-harm test and factors that are stated in this section of the report. The Commission had used the no-harm test and factors in its prior Commission's decisions regarding sale and transfer of transmission facilities. The Commission gave no consideration to the fact that the partnerships were involved with the Indigenous owners. But rather, it relied on actual evidence on the record, applied the same regulatory principles to this case, as it would to any other case. What guided the Commission was the interest of rate payers and the financial impact on them including "*the negative and positive effects of the proposed transfers*".

4.2 Rural Electrification Association (REA)

Background Information

The REA is a not-for-profit rural cooperative that owns an electricity distribution system and provides and distributes electricity to its member in a rural region of Alberta, as governed under the *Rural Utilities Act*.[21] The REAs own and operate electric distribution system and supply electric energy to their members on their land.

The Alberta Federation of Rural Electrification Associations is the provincial association that advocates for and represents REAs collectively.[22] The utility model under REAs is a unique model to Alberta, and it appears that it does not exist in any other jurisdiction in Canada. Not all REAs are members of the Alberta Federation of Rural Electrification Associations. For example, Peigan Indian REA and Montana REA are not members. Only Ermineskin REA is a member of Alberta Federation of Rural Electrification Associations.

The REAs set their Regulated Rate Option (RRO) rates independently of the AUC.[23,24] Each REA has an elected board of directors that have the oversights on the business operations of the REA. The REA's distribution rates are approved by the board of directors of the local REA's on behalf of association

[20] Ibid., 13-14.

[21] Retail Market Review Committee (RMRC), "Power for the People" pages 44 and 182.
[22] Alberta Federation of Rural Electrification Associations. http://www.afrea.ab.ca/rural-electric-program-grant
[23] "*In 2005 the Alberta government decided to prolong consumer access to a default rate, and phased in the current form of the Regulated Rate Option (RRO) over a five-year period starting in mid-2006*." - Ibid., 158.
[24] Market Surveillance Administrator - Regulated Rate Option in Alberta's Rural Electrification Associations and Municipalities, February 1, 2017. Page 4.

members and not by the AUC.[25] The REA boards set the "distribution tariffs" which include distribution, transmission and REA charges. Ermineskin REA and Peigan Indian REA set their own RRO rates. Montana REA contracts out this obligation to EPCOR, as a third party, who buys/sells energy (and sets the rate) to Montana members. EPCOR is a "regulated" RRO retailer (licensed by the AUC), and as such must file the RRO rates with the Commission.

History of REAs

In 1945, less than four percent of Alberta farms had electricity.[26] Alberta was far behind most other provinces and the American Midwest. The investor-owned utilities were not interested in providing and distributing electricity services to rural areas within Alberta due to high costs. The Rural Electric Program began in 1947. It is a cost-sharing program, which helps defray the high cost of electrical service to farmers.[27] In a 1948 plebiscite, the voters of Alberta rejected public ownership for rural electrification by the narrowest of margins (the 'no' side won by 151 votes out of a total of 279,831 cast).[28] Farmers across the province organized into cooperatives or co-ops to raise half the necessary money for electricity in their districts. The Government of Alberta provided loans for the remainder. By the late 1960s, a total of 416 co-ops (known as Rural Electrification Associations, or REAs) were established. 87% of rural Alberta had access to electricity by 1961. The REAs would own the power distribution system in their districts, while the power companies provided the electricity and the maintenance.[29]

The Indigenous communities in Alberta also showed interests in the REAs in order to have access to electricity. In 1955, the first Indigenous REA was established at Enoch just west of Edmonton. The Department of Indian Affairs and the power companies established agreements and built the systems. First Nations had not had a direct role in building the system and the project had to be undertaken by the local Indian agent, who served as secretary of the REA.[30]

The Ermineskin Band at Maskwacis and the Blood Tribe in southern Alberta formed REAs in 1958. This encouraged other bands to pursue the REAs. Four more reserves established REAs in 1960. By 1967, a total of 17 reserves throughout Alberta had access to electricity through REAs. Today, only three Indigenous REAs own their systems: Peigan Indian REA in southern Alberta, Ermineskin REA and Montana REA in Maskwacis. Other REAs owned by Indigenous communities sold their assets to the utility companies.[31] The REA boards may choose to operate and maintain (including construction of all distribution assets) or they may contract these functions out to a 3rd party. The REAs who perform these functions on their own systems are called "self-operating" while the REAs who contract these out

[25] Retail Market Review Committee (RMRC), "Power for the People", page 64.

[26] Alberta Culture and Tourism - Electricity & Alternative Energy. http://www.history.alberta.ca/EnergyHeritage/energy/electricity/the-early-history-of-electricity-in-alberta/rural-electrification-in-alberta.aspx#page-2
[27] Alberta Federation of Rural Electrification Associations. http://www.afrea.ab.ca/rural-electric-program-grant
[28] Alberta Culture and Tourism - Electricity & Alternative Energy.
[29] Ibid.
[30] Country Power: The Electrical Revolution in Rural Alberta, Frank and John Dolphin – The second edition published by Dream Write Publishing Ltd. 2013.
[31] Ibid.

are called "operating" REAs.

The three Indigenous Ermineskin REA, Montana REA, and Peigan Indian REA own their distribution assets, but contracted FortisAlberta to operate and maintain (including facilities construction) their distribution systems.[32] The distribution assets of these Indigenous REAs are subject to conventional asset management planning, e.g., pole testing every 7 years and tree brushing every 3 years that FortisAlberta also applies to its own distribution assets in other parts of Alberta. These REAs conduct their annual budgeting exercise including annual capital budget based on an annual report that FortisAlberta provides to each REA. The Montana REA and Peigan Indian REA are governed by the Chief and Council and Ermineskin REA is governed by a board of directors who are elected by the members.

Today, 41 REAs serve more than 43,000 members across Alberta. Seven REAs (representing 63% of REA members) are self-operating, where they own, operate and maintain their wires, and sell power to members through competitive contracts or regulated rates. The remaining REAs own their wires, but contract out maintenance and operations to an investor-owned utility that serves their part of the province.[33]

Exceptions and Exemptions from the Act and Regulation

No specific exceptions or exemptions from the *Rural Utilities Act*, or any other Act and associated regulations exist regarding the Indigenous REAs which would treat them differently and uniquely distinguish them from non-Indigenous REAs. All Indigenous REAs are subject to the same rules and regulations that would apply to any other non-Indigenous REAs.

Regulation of REAs under the Rural Utilities Act

The REA's board, and not the AUC, is the regulatory authority that is mandated under the *Rural Utilities Act* to approve RRO rates for the RRA's constituents. The *Rural Utilities Act* "*establishes the organization, governance, and makes provisions for the management of business and affairs, of rural utility associations. A rural utility association is an incorporated entity of five or more persons, of which its main purpose is to supply to its members utility services for electricity, natural gas, water that is used primarily for domestic purposes, and sewage. The Act enables rural utility associations to finance borrowings through a loan guarantee for provision of electrical services in rural areas*."[34] Under the *Rural Electrification Act and the Rural Electrification Long-term Financing Act,* the *Rural Utilities Regulation* outlines the specific operational requirements for a rural utility association. These include reserve requirements, association board by-laws, and the use of an amalgamation agreement for associations that intend to combine.

[32] https://www.fortisalberta.com/for-business-industry/rural-electrification-associations
[33] Retail Market Review Committee (RMRC), "Power for the People," page 45.
[34] Laws Online/Catalogue http://www.qp.alberta.ca/570.cfm?frm_isbn=9780779773565&search_by=link

Under section 21 of the the *Rural Utilities Act,* REAs are subject to filing an annual return with the Director of Rural Electrification Associations.[35] The Act specifies that the REA shall within 120 days after the close of each fiscal year send to the Director the annual return of the REA, being a general statement up to the end of the fiscal year last ended of the receipts, expenditures, funds and assets of the association as audited.

Section 26 of the *Rural Utilities Act* provides the Director of Rural Electrification Associations the power to investigate the affairs of the REA (i.e., the affairs are being mismanaged or are being conducted on an unsound basis).

The Rural Development Branch of the Alberta Ministry of Agriculture and Forestry provides regulatory oversight of the Alberta's rural utility cooperatives, including REAs, to ensure compliance with the *Rural Utilities Act*. The ministry works with REAs on matters of governance, providing advice on best practices and resolving disputes between members.[36] Service Alberta provides consumer protection services through its administration of the Energy Marketing and Residential Heat Sub-metering Regulation under the *Fair Trading Act*. The regulation only applies to retail electricity providers and not to the REAs where retailers must be licensed. REAs are also exempt from Service Alberta's security deposit requirements.[37] The exemptions apply equally to both Indigenous and non-Indigenous REAs. In addition, regulations have exempted all REAs, including Indigenous REAs, from some prudential requirements under the RRO Regulation. The regulation exempts REAs from the Alberta Electric System Operator (AESO) normal determination of whether a wholesale market participant should have access to unsecured credit limits.[38]

REAs are also governed under the *Hydro and Electric Energy Act,* as illustrated in the section below.

Regulation of REAs under the AUC

The AUC has limited jurisdiction to hear complaints about the REAs' distribution tariffs.[39] If a consumer has a concern or complaint about rates, tolls or tariffs that are being charged by a REA, the customer needs to contact the REA and its board. However, the AUC has certain jurisdiction over the REAs in the area of mergers and acquisitions. Sections 25, 29, 31, and 32 of the Alberta's *Hydro and Electric Energy Act* has granted the AUC with the oversight power over mergers and acquisitions related to the service areas of distribution systems.[40] In particular, section 32(1) and 32(2a) of the *Hydro and Electric Energy Act* names rural electrification association and states the following,

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[35] *The Rural Utilities Act* defines the "Director" with respect to rural electrification associations, the Director of Rural Electrification Associations and appointed by the Minister responsible for the *Act*.

[36] Retail Market Review Committee (RMRC), "Power for the People", page 45.
[37] Ibid. 46.
[38] Ibid. 111.
[39] Market Surveillance Administrator - Alberta Retail Markets for Electricity and Natural Gas - A description of basic structural features, July 17, 2014, page 11.
[40] *Hydro and Electric Energy Act, Chapter H-16 Current as of August 1, 2018 H*, Current as of August 1, 2018.

Rural electrification association

32(1) If a rural electrification association

(a) under an order made under section 29,

(i) has the size of its service area reduced, or

(ii) ceases to operate in a service area or part of it,

or

(b) on being authorized under section 30 to do so, discontinues the operation of its electric distribution system,

the Commission may, when in the Commission's opinion it is in the public interest to do so and on any notice and proceedings that the Commission considers suitable, **by order transfer to another person the service area or part of it served by the rural electrification association**. [Emphasis added in bold]

(2) When the Commission makes an order under subsection (1), it may

(a) for the purpose of ensuring the continued distribution of electric energy in the service area or part of it that was served by the rural electrification association, provide for

(i) **the transfer of any facilities associated with the electric distribution system from the rural electrification association to another party**, and

(ii) **the operation of the electric distribution system or part of it by any party that the Commission direct**s…. [Emphasis added in bold]

Under section 17(1) of the *Rural Utilities Regulation*, the Director of REAs must approve the amalgamation. The Director of REAs also needs to determine that the applicable resolutions and other documents are filed on the record of the proceeding and they are sufficient to satisfy the requirements contained in the *Rural Utilities Act*.

The AUC and the AESO have established quality standards with respect to the Tariff Billing Code and other standards for ensuring accuracy, correcting mistakes and speeding up the calculation processes. All distribution system owners are required to meet these quality standards and comply with the requirements. However, the REAs are exempted from the quality standards and are not bound to comply with the code, as the REAs are not under the jurisdiction of the AUC.[41]

The AUC has also certain regulatory jurisdiction over the REA's conduct compliance plan pursuant to the *Code of Conduct Regulation* and Rule 030: *Compliance with the Code of Conduct Regulation*. Section 37(1)(a) of the *Code of Conduct Regulation* authorizes the AUC to make a rule to vary the requirements of section 30(4) "in the case of a distributor with a small number of customers…". On March 31, 2016, the AUC issued Bulletin 2016-11 approving Rule 030, which came into effect on April 1, 2016. Section 3(1) of Rule 030 provides that a distributor that has 5,000 customers or less may file a varied compliance plan.

[41] Retail Market Review Committee (RMRC), "Power for the People", page 113.

The *Hydro and Electric Energy Act* states one of its purposes is "*to secure the observance of safe and efficient practices in the public interest in the development of hydro energy and in the generation, transmission and distribution of electric energy in Alberta*." This act also provides the AUC the power to establish service area boundaries for REAs. Section 18 provides the AUC the power to direct the owner of a distribution system "*to suspend the use of any connection if, in the opinion of the Commission, the continuation of a connection may seriously affect the operation of any interconnected electric system or communications system*".

Ermineskin REA Application with the AUC for A varied Code of Conduct Compliance Plan

On November 24, 2016, the Ermineskin REA filed an application with the AUC seeking approval of a varied code of conduct compliance plan. Section 3(3) of Rule 030 requires a varied plan to include at least the following:

a) A list of the distributor's affiliated providers.
b) A description of how the notice required by Section 34 of the Code of Conduct Regulation will be given to the public.
c) A description of the procedure that may be used for the voluntary resolution of complaints about non-compliance with the Code of Conduct Regulation or the compliance plan.

The AUC found the proposed compliance plan submitted by Ermineskin REA meet the requirements for a varied compliance plan, and therefore approved it effective January 1, 2017.[42]

Peigan Indian REA Application with the AUC for A varied Code of Conduct Compliance Plan

On January 9, 2017, the Peigan Indian REA filed similar applications. After its review, the AUC stated that it made a number of changes to the Pegan Indian REA's proposed compliance plan "to keep the records, accounts, records of financial transactions, reports and plans that are required under this Regulation or its compliance plan for at least 6 years.", a requirement under section 28 of the *Code of Conduct Regulation.*[43]

Similar to any other utilities in Alberta, both non-Indigenous REAs and Indigenous are subject to reporting to the AUC regarding any non-compliance with the *Code of Conduct Regulation.* In its decision regarding Peigan Indian REA related to its compliance plan, the AUC reminded Peigan Indian REA of the two reporting requirements: [44]

[42] The AUC Decision 22200-D01-2016 - Ermineskin Rural Electrification Association Ltd., Varied Code of Conduct Regulation Compliance Plan, December 21, 2016.
[43] The AUC Decision 22320-D01-2017 - Peigan Indian REA, Varied Code of Conduct Regulation Compliance Plan January 27, 2017.
[44] Ibid.

i. Under Section 4 of Rule 030, any non-compliance with the Code of Conduct Regulation or the compliance plan is to be reported to the Commission within 30 days of the Peigan Indian REA becoming aware of the non-compliance.
ii. Under Section 33(2) of the Code of Conduct Regulation, an annual compliance report is required and must be approved by the board of directors of the Peigan Indian REA and filed with the Commission within 90 days after the end of each calendar year.

Other Regulations

Alberta REAs, as rural electric distribution system owners, must follow all applicable national and for the underground systems, and *Alberta Electrical Utility Code*. The *Alberta Electrical Utility Code* is administered by the Safety Codes Council with mandate in regards to enforcement and sanctions.[45]

Through inter-operating agreements with REAs, the Investor Owned Utilities (IOUs) work on the majority of the REAs' infrastructure on their behalf, e.g., installations, tree brushing, etc. As the IOUs are subject to the AUC regulation, safety requirements are covered through these agreements in alignment with the requirements under the *Hydro and Electric Energy Act* and the *Alberta Utilities Commission Act*. Regarding safety requirements for the distribution systems owned by Peigan Indian ERA, Ermineskin ERA, and Montana REA, FortisAlberta must comply with all applicable national and provincial statutes when operating, maintaining and constructing these Indigenous utilities' electrical infrastructure.

4.3 Rural Natural Gas Co-operatives

The Rural Gas Program was started in 1973 by the Province of Alberta to help ensure Albertans could have access to natural gas.[46] Similar to the REAs, the rural natural gas co-operative associations (or the rural gas utilities) are not-for-profit rural utilities that own a natural gas distribution system under the *Rural Utilities Act* and provide natural gas service to their members. Natural gas co-ops are also governed by the *Gas Utilities Act*.

The Federation of Alberta Gas Co-ops is the provincial association that represents and advocates on behalf of a number of natural gas co-ops collectively, including seven First Nation members.[47,48] There are a number of Indigenous natural gas co-ops, including Ermineskin and Louis Bull who are not members of the Federation of Alberta Gas Co-ops.

[45] http://www.safetycodes.ab.ca/Public/Orders/Pages/default.aspx.

[46] The Federation of Alberta Gas Co-op Ltd. https://www.fedgas.com/
[47] The Federation of Alberta Gas Co-ops members: Dene Tha Natural Gas Utility, Goodfish Lake Gas Utility, Horse Lake Indian Band, Kehewin, Montana Indian Band, Onion Lake Gas, Samson Cree Nations. https://www.fedgas.com/data/documents/Federation_Members_Distribute_June_2019.pdf
[48] Ibid.

The natural gas co-ops are owned and governed by the people within their communities. They are run by a board of directors elected from the community.[49] However, the First Nation co-ops who are members of the Federation of Alberta Gas Co-ops are mostly governed by their respective Chief and Council. All members of the Federation of Alberta Gas Co-ops are shareholders in Gas Alberta[50], and purchase their gas exclusively from Gas Alberta. These members cooperate based on a zone agreement and support each other with respect to planning and operation of the natural gas distribution system. For example, while Samson natural gas co-op operates its natural gas facilities, it also provides operational assistance to Montana natural gas co-op. A number of co-ops contract out to the IOUs such as ATCO to operate and maintain their natural gas distribution systems.

Exceptions and Exemptions from the Act and Regulation

No specific exceptions or exemptions from the *Rural Utilities Act* or *Gas Distribution Act* and associated regulations exist regarding the Indigenous natural gas co-ops that would uniquely distinguish them from non-Indigenous natural gas co-ops. All Indigenous natural gas co-ops are subject to all rules and regulations that would apply to any other non-Indigenous natural gas co-ops.

The *Gas Distribution Act* grants an exclusive right and duty to offer and provide gas services to a franchise holder within a rural gas utility franchise area. Pursuant to section 28.1(3) of the *Gas Utilities Act,* a customer has the right to obtain gas services from a retailer or default supply provider. This is a key difference between the retail electricity and natural gas markets which does not permit dual-fuel contracts to be offered to many rural consumers.[51]

The AUC has authority over customer complains regarding natural gas co-ops. *"It may hear complaints about terms of service, service charges, and rates or tolls if a customer thinks they are discriminatory, improperly imposed, or fail to conform to the co-op's established rate structure*."[52]

Under section 2(1) of the *Gas Distribution Act*, the chief officer[53] at the Alberta Ministry of Agriculture and Forestry is responsible for the setting and enforcement of all standards related to the design, construction, operation, maintenance, quality assurance, plant records, surveys and as-built drawings for rural gas utilities and low-pressure distribution pipelines.[54] Under section 4(1) of the *Gas Distribution Act*, the chief officer or any other officer of the department, or an employee of the department is authorized to conduct inspections of a rural gas utility and examine any records of a distributor in connection with the operation of a rural gas utility if the distributor is a rural gas co-

[49] The Federation of Alberta Gas Co-op Ltd. https://www.fedgas.com/
[50] Gas Alberta Inc. is an exclusive supplier of natural gas to 74 gas distribution utilities in Alberta that are comprised of natural gas co-ops, towns, villages, counties and First Nation gas utilities. Its customers own and operate over 120,000 kilometers of distribution pipelines providing safe and reliable gas supplies to over 350,000 Albertans. Its shareholders are its customers. https://www.gasalberta.com/

[51] Market Surveillance Administrator - Alberta Retail Markets for Electricity and Natural Gas - A description of basic structural features, July 17, 2014, page 14.
[52] AUC, "Natural Gas Utilities," page 11.
[53] The *Gas Distribution Act* states that "chief officer" means the Deputy Minister of the Department or an employee of the Department designated by the Minister as chief officer.
[54] The *Gas Distribution Act,* Part 1 - Administration, Co-ordination of standards, page 4.

operative.[55] All Indigenous natural gas co-ops that are part of the Federation system are on a 1 in 3 year inspection cycle.

Similar to the REAs, under section 21 of the the *Rural Utilities Act,* the rural gas utilities are subject to filing an annual return with the Director of Natural Gas Co-operatives. [56] The Act specifies that the rural gas utility shall within 120 days after the close of each fiscal year send to the Director the annual return of the rural gas utility, being a general statement up to the end of the fiscal year last ended of the receipts, expenditures, funds and assets of the association as audited.

Contrary to the REAs, the rural gas utilities are subject to the AUC's certain jurisdiction under section 30 of the *Gas Distribution Act* - Jurisdiction of Alberta Utilities Commission. For example, with respect to customer complaints regarding terms of service, service charges, rates or tolls, the *Act* states[57],

> a consumer who is receiving gas service from a rural gas utility operated by a rural gas co-operative association or municipal gas utility and who has a grievance respecting terms of service, service charges, rates or tolls made to that consumer may, by application, appeal the matter to the Alberta Utilities Commission.

Section 30(1)(a) of the *Gas Distribution Act* also requires a rural gas co-operative association to file a copy of its schedule of rates, tolls and charges with the Alberta Utilities Commission.

Under section 30(2) of the *Gas Distribution Act,* the AUC may make an order varying, adjusting or disallowing the whole or any part of that term, charge, rate or toll if, on hearing an application made, the AUC is satisfied that the term, service charge, rate or toll,

a. does not conform to the utility rate structure established by the rural gas co-operative association or municipal gas utility,
b. has been improperly imposed, or
c. is discriminatory,

All natural gas co-ops, including Indigenous rural gas co-ops, use and follow the same standards and codes such as Natural gas and propane installation code CSA B149.

5. Newfoundland and Labrador

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") is responsible for the regulation of the electric utilities in the province to ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable.[58]

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[55] Ibid. Inspections, page 5.
[56] *The Rural Utilities Act* defines the "Director" with respect to natural gas associations, the Director of Natural Gas Co-operatives and appointed by the Minister responsible for the *Act*.
[57] Ibid. Jurisdiction of Alberta Utilities Commission, page 18.

[58] http://www.pub.nf.ca/mandate.htm

There are only two regulated utilities in the province of Newfoundland and Labrador:

1. Newfoundland and Labrador Hydro ("Hydro"), which is the primary generator in the province
2. Newfoundland Power Inc., which purchases the bulk of its power from Newfoundland and Labrador Hydro and is the primary distributor in the province.

The provincial government has amended the legislation to prohibit any utility but Hydro to supply and sell electrical power in the province. Both utilities are regulated by the Board. Neither of these utilities are Indigenous utilities.

In 2016, the Board, on its own motion, stated a case in writing for the Court of Appeal (the "Court") opinion on a question of law, namely whether the Board has jurisdiction pursuant to the *Public Utilities Act*, RSNL 1990 c. P-47 (Act) to make certain orders relating to the provision of electrical services that the Utility offers in the First Nation community of Natuashish, NL. The motion arose during the hearing of an application to the Board by the Mushauau Innu First Nation. The Board then decided that the separate proceeding with respect to issues relating to service in Natuashish would be to state a case for the opinion of the Court of Appeal. There were no further filings made by any parties to the Board following the decision of the Court of Appeal.

Section 5.1 below summarizes the Court of Appeal decision. The Court's opinion on the question of the Board's jurisdiction informs the BCUC's Inquiry with respect to regulation of Indigenous utilities. The importance of the Court's decision is that it provides insight into the question directed to the BCUC by the Province with respect to the regulation and characteristics of Indigenous utilities are.

5.1 Mushuau Innu First Nation

Background Information

Natuashish is an isolated community located on the north coast of Labrador. The Mushuau Innu First Nation (the "Innu") owns the infrastructure necessary to supply electrical service to the community. The facilities in Natuashish were built by the federal and provincial governments and then turned over to the Innu. The electrical assets, owned by the Innu, include the diesel generation plant, the power lines, and fuel tanks. Hydro maintains the infrastructure based on an agreement with the federal government on a cost recovery basis. All costs are charged at bill rates plus overhead to ensure full cost recovery. The Innu were not required to obtain a permit from the Board to own the electrical assets.

Hydro filed a rate application on July 30, 2013 requesting approval of, among other things, proposed rates to be effective January 1, 2014. The Innu intervened in the rate proceeding and applied to the Board for (i) a declaration setting aside Hydro's designation of its services to the community as a non-regulated business unit, (ii) an order requiring Hydro to provide electrical services to the community, and (iii) the inclusion of Natuashish electricity users in the rates charges in the Labrador isolated system. The Innu submitted that the Board has jurisdiction to order Hydro to purchase the electrical infrastructure in Natuashish from the Innu.

Hydro opposed these requests and filed a submission with the Board on August 26, 2015 setting out its position that the Board has no jurisdiction to make the declarations and orders requested. On September 4, 2015, the Board advised the parties that the issues relating to service in Natuashish would be addressed in a separate proceeding and would not form part of the evidence to be presented in the hearing of the application. On February 25, 2016, the Board filed a stated case with the Court of Appeal of Newfoundland and Labrador for its opinion and set out the three questions below.[59]

Stated case to the Court of Appeal of Newfoundland and Labrador – Three Questions

> Whether the Board of Commissioners of Public Utilities has jurisdiction pursuant to the Act to make the following orders relating to the provision of electrical services in Natuashish, NL:
>
> (i) A declaration that Hydro's current classification of its Natuashish operations as one of its "nonregulated business units" is incompatible with provincial electrical policy under the Act and the *Electrical Power Control Act, 1994*; or,
> (ii) An order requiring Hydro to provide regulated electrical services in Natuashish, NL; or
> (iii) An order requiring Hydro to acquire title to the Natuashish electrical assets from the Mushuau Innu First Nation.

The Court of Appeal released its decision on May 25, 2017.[60] The Court dealt with each of the jurisdictional questions noted above and, as set out in the headnote to the Decision, concluded:

> The Board would have explicit authority to require Hydro to provide electrical services to the community, if it determined that the extension of existing Hydro transmission lines would be feasible or reasonable. If the electrical service provided by the Innu to the community satisfied the definition of a public utility, a matter which the Board had authority to determine, the Board had jurisdiction to consent to the Innu's discontinuance of service. If the Innu's service did not satisfy the definition of a public utility, the Board would have jurisdiction to order Hydro to provide electrical service, only if power was not otherwise available to Natuashish residents. The Board lacked jurisdiction to order Hydro to provide regulated electrical services to Natuashish, so Hydro's designation of its Natuashish operations as a non-regulated business unit for accounting and reporting purposes was not problematic. There was no explicit authority provided to the Board to direct the means by which electrical service was to be provided, so the Board lacked jurisdiction to order Hydro to acquire title to the electrical assets from the Innu. [61]

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[59] The Newfoundland and Labrador Board of Commissioners of Public Utilities Decision and Order of the Board Order No. P.U. 49(2016), page 17
[60] Reference re: *Public Utilities Act (Nfld.), [2017] N.J. No. 194*.
[61] Newfoundland and Labrador Judgments - Newfoundland and Labrador Supreme Court - Court of Appeal, J.D. Green C.J.N.L., B.G. Welsh and C.W. White JJ.A., Heard: December 7 and 8, 2016, Judgment: May 25, 2017, Docket: 201601H0018 – Page 1.

The Court stated that it was convenient to begin with "Question Two" since the conclusions on that question would form the basis for determining the remaining questions.

Question Two: Does the Board have jurisdiction to require Hydro to provide regulated electrical services in Natuashish?

In analyzing this question, the Court considered both explicit and implicit powers that may be exercised by the Board. The explicit powers are found in the *Act* and they impose obligations on Hydro to provide electrical services in certain circumstances as set out in the *Act*.

Section 55 of the *Act* applies where the distance of a potential user of electricity is located more than 100 meters from an existing transmission line. The Court stated the purpose of section 55 is to authorize the Board to require Hydro to meet a request for electrical service by installing an "extension" to a transmission line, main supply-wire or cable suitable for carrying electricity.

The Innu, therefore, submitted that the Board has explicit authority under the Act to require Hydro to provide electrical service if the criteria in section 55 are met.

Alternatively, the Innu submitted the Board has implicit authority to make an order requiring the provision of electrical service by means of separate generating plant in Natashish. The Court considered this argument and noted that given the explicit authority found in sections 54 and 55 of the *Act*, if the legislature intended that the Board should exercise a broader authority over Hydro to provide services, "language to achieve that objective would have been expected."

The Court, however, also noted that there may be a legislative gap when it comes to isolated communities. The Court phrased the question as whether the legislative intention with isolated communities, where electricity is not available, would the Board have jurisdiction to order Hydro to provide power.

The Court turned to the *Electrical Power Control Act (ECPA)* and read it in conjunction with the *Act* with respect to rate regulation and access to power. Referencing section 4 of the *EPCA*, the Court stated the Board is required to implement the power policy set out in section 3 of the *Act*. Setting out section 3 of the *Act*, the Court considered section 3(1) which states that it is the policy of the province that the "rates to be charged" either generally or under specific contracts, for the supply of power within the province," should meet the requirements set out in section 3 (1) (i) – 3 (a)(iv). Section 70(1) of the *Act* states where "*a public utility shall not charge, demand, collect, or receive compensation for a service performed by it whether for the public or under the contract until the public utility has first submitted for the approval of the board a schedule of rates, tolls and charges and has obtained the approval of the board…. "*.

Public utility is defined in section 2(e) of the *Act*. The Court noted that whether the electrical service provided by the Innu with the assistance of Hydro to maintain the infrastructure satisfied the definition of a public utility was not before the Court. However, it stated that, "*That determination would properly be made by the Board based on the evidence."*

The following two paragraphs of the Court's decision, as to whether the Board would have jurisdiction to review rates in Natuashish and the Board's jurisdiction over rate regulation to any particular provider of electricity, are important considerations that inform the BCUC's Inquiry regarding regulation of Indigenous utilities:[62]

> **24** Section 70 would apply generally to any entity that satisfies the language of the definition and provides electrical service in the Province, subject to a possible constitutional impediment. For example, as applied to this case, provided there is no basis in federal jurisdiction over "Indians, and Lands reserved for the Indians" under section 91(24) of the *Constitution Act, 1867* to preclude the operation of section 70, and the provision of electricity by the ***Innu*** in Natuashish satisfies the definition of "***public*** utility", the ***Board*** would have jurisdiction to review rates in Natuashish under that provision. The legislation does not limit the ***Board***'s jurisdiction over rate regulation to any particular provider of electricity.
>
> **25** A similar result applies to the application of sections 16, 17 and 82 of the ***Public*** *Utilities Act* which are relied upon by the ***Innu***. Section 16 gives the ***Board*** authority for "the general supervision of all ***public*** utilities", section 17 permits the ***Board*** to inquire "into a violation of the laws or regulations in force in the province by a The Board decided that the separate proceeding would be to state a case for the opinion of the Court of Appeal. There was no further filing made by any parties to the Board following the decision of the Court of Appeal.

The Court then concluded that "*subject to the operation of section 91(24) of the Constitution Act, 1867 and satisfying the definition of a 'public utility', the Board would have jurisdiction to apply sections 16, 17, and 82 of the Public Utilities Act to the electrical services provided by the Innu in Natuashish*". Using the basic principles stated in Hogg, *Constitutional Law of Canada*, fifth edition, supplemented (Toronto, ON: Thomson Reuters Canada Limited, 2007), the Court stated[63],

> **54** As applied to this case, with exceptions not relevant here, the Province has authority generally over the development and provision of electrical power in the Province (sections 92(13), 92(16) and 92A of the *Constitution Act, 1867*). That jurisdiction would extend to Natuashish unless an exception to the general rule applies.

The Court's decision referenced the well-known "*doctrine of federal paramountcy*", as an exception to the general rule ousting provincial jurisdiction. It noted if any federal legislation, specifically with respect to provisions of the *Indian Act*, is inconsistent with the jurisdiction of the Board or the operation of the *Act* or the *ECPA*, the provincial law is rendered inoperative and the federal law would apply.

With respect to the submissions made involving possible constitutional impediments to the Board's jurisdiction in Natuashish, a reserve under the *Indian Ac*t, the Court stated the general rule is that provincial laws apply to Indians and land reserved for the Indians. As such the Province has authority

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[62] Ibid., 8.
[63] Ibid., 12.

generally over the development and provision of electrical power in the Province and that jurisdiction extends to Natuashish.

The Court also addressed the question "*whether the legislative intention was that rate regulation should be assessed on a Province-wide, regional or individual location basis.*" The Court noted that the cost of providing electrical service could vary, affecting the rate a public utility could charge in order to "*earn a just and reasonable return*". In determining the legislative intention, the Court provided a historical review of development of electrical service in the province to conclude the "*transition from rate oversight by government to the power of the Board to implement legislated policy*" on how the rates should be charged for the supply of the power within the province. The decision references to the Board's authority over all sources and facilities to be managed and operated for the (i) most efficient production, transmission, and distribution of power in the province, (ii) at the lowest possible cost consistent with reliable service, and (iii) consumers equitable access to supply of power.

Conclusion of the Court regarding Question Two

a) If the electrical service provided by the Innu in Natuashish satisfies the definition of a public utility, a matter which the Board has authority to determine, and assuming there is no constitutional impediment to the application of the *Public Utilities Act*, the Board would have jurisdiction to apply the relevant provisions of the *Act*. If the Innu wish to discontinue the service, section 38 of the *Act* would apply and the written consent of the Board would be required. (See brief discussion of constitutional issues below.)

b) If the electrical service provided by the Innu in Natuashish does not satisfy the definition of a public utility, the Board would have jurisdiction by necessary implication to order Hydro to provide electrical service in that community only if power is not otherwise available to the residents.

Question One: Does the Board have jurisdiction to declare that Hydro's current classification of its Natuashish operations as a "non-regulated business unit" is incompatible with provincial electrical policy under the *Public Utilities Act* and the *Electrical Power Control Act, 1994*?

The Court noted that the phrase "non-regulated business unit" is employed as a matter of accounting and reporting convenience when Hydro engages in business activities that are outside the scope of rate regulation overseen by the Board pursuant to the legislation. The Court also noted that maintaining the electrical infrastructure in Natuashish is a service that Hydro provides. It stated that, "*Designation as a non-regulated business unit is a means of separating Hydro's business of providing power to customers using infrastructure it owns and controls from its other business activities*".

Conclusion of the Court regarding Question One

The Court concluded that the Board would not have jurisdiction to order Hydro to provide regulated electrical services in Natuashish, the designation as a non-regulated business unit is not problematic;

the designation is an appropriate accounting and reporting mechanism. The issue would not arise if Hydro were the electrical service provider in Natuashish.

Question Three: Does the *Board* have jurisdiction to order Hydro to acquire title to the Natuashish electrical assets from the *Innu*?

The Court stated that this issue would arise only if the circumstances were such that the Board had jurisdiction to order Hydro to provide electrical services in Natuashish (Question Two). Assuming that the Board has jurisdiction, there is no explicit authority in the *Act* for the Board to direct the means by which electrical service is to be provided.

The Court noted that" both the *Public Utilities Act* and the *Electrical Power Control Ac* relate to rate regulation and access to electrical power". It stated that, "*Subject to compliance with the general principles stated in the provincial power policy, the manner in which a public utility provides electrical service is not controlled by the legislation*".

Conclusion of the Court regarding Question Three

The Court concluded that even if the Board has authority to order Hydro to provide electrical service in Natuashish, the Board does not have jurisdiction to order Hydro to acquire title to the electrical assets from the Innu.

Court of Appeal Decision Informs the BCUC Inquiry

The importance of the above decision is that it provides insight into the question directed to the BCUC by the Province with respect to what the characteristics of Indigenous utilities are, having regard to the nature of the ownership and operation, types of services provided, persons to whom services are provided and the geographic areas served by Indigenous utilities.

The Court's opinion on the question of the Board's jurisdiction informs the BCUC's jurisdictional review with respect to regulation of Indigenous utilities. While the Court did not specifically determine, if and to what extent, the electrical service provided by the Innu to the community satisfied the definition of the public utility, it appears that if one examines the definition of public utility defined in section 2(e) of the *Public Utility Act,* it may very well qualify as a public utility. In its analysis, the Court turned to a review of the *EPCA* and the *Act* and turned to the definition of public utility under section 2(e) of the *Act*:

Section 2(e) of the *Act* for that a "public utility" means a person, firm or corporation that owns, operates, manages or controls in this province equipment or facilities for
…

(ii) the production, generation, storage, transmission, delivery, or providing of electric power or energy, water or heat either directly or indirectly to or for the public or a corporation for compensation.

The language above is quite broad which seems to suggest that an Indigenous community such as the Innu who "*owns*" "*equipment or facilities for the production, generation, delivery, or providing of electric power*" to its community can be regarded as a public utility.

The Court noted that the question of whether the electrical service provided by the Innu with the assistance of Hydro to maintain the infrastructure satisfied the definition of a public utility was not before the court. However, it stated that, "*That determination would properly be made by the Board based on the evidence."* The Court then concluded that "*subject to the operation of section 91(24) of the Constitution Act, 1867 and satisfying the definition of a 'public utility', the Board would have jurisdiction to apply sections 16, 17, and 82 of the Public Utilities Act to the electrical services provided by the Innu in Natuashish*".

This is informative to the jurisdictional review because if it is found that an electrical service provided by an Indigenous utility satisfies the definition of a public utility, a matter which a provincial regulator has authority to determine, and assuming there is no constitutional impediment to the application of the legislation applicable to utility regulation in the respective province, in the case of British Columbia the *Public Utilities Act*, the Board would have jurisdiction to apply the relevant provisions of the *Act*. Therefore, it appears that the determination of whether an Indigenous utility can be defined as a public utility is very much dependent on the facts of each case.

The defining characteristics of an Indigenous utility would have to be both regulatory and in compliance with the governing *Act* for the provincial or territorial energy regulator. Other defining characteristics may relate to geography, ownership, service and other factors. There could be different types of ownership and operation arrangements to ensure viability and regulatory requirements. These are the matters which are considered in different sections of the report where information regarding Indigenous utilities and their regulation in other jurisdictions were provided. As set out in the Order in Council and confirmed in the BCUC's Notice, when looking at the characteristics of an Indigenous Utility, the BCUC need to consider the ownership and operation of the utility, the services provided, the service recipients and the area served by the utility.

6. Northwest Territories

The NWT Public Utilities Board (PUB) is an independent, quasi-judicial agency of the Government of the Northwest Territories. It is responsible for the regulation of public utilities in the Northwest Territories. The PUB obtains its authority from the *Public Utilities Act*. [64]

There are two Indigenous utilities namely: Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited, which are two operating companies of Northland Utilities. They are fully

[64] https://www.nwtpublicutilitiesboard.ca/about-us

regulated by the PUB. Section 6.1 below provides information regarding regulation and defining characteristics of Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

6.1 Electric Utilities

6.1.1 Northland Utilities (NWT) Limited

Northland Utilities (NWT) Limited serves over 9,000 residential and commercial customers. With its offices in Hay River, the utility distributes electricity in Hay River by purchasing power from NWT Power Corporation[65]. The utility also generates and distributes power in several other smaller communities including Kakisa, Dory Point, Fort Providence, Sambaa K'e, Wekweeti, Enterprise and the K'at'lodeeche First Nation.

6.1.2 Northland Utilities (Yellowknife) Limited

Northland Utilities (Yellowknife) Limited provides electricity distribution services to Yellowknife and N'Dilo. It is also fully regulated by the PUB.

Background Information

Northland Utilities is a joint partnership between ATCO Ltd. and Denendeh Investments Inc. It is governed by a five-member board of directors. For the last 30 years, Northland Utilities has been part owned by Denendeh Investments Incorporated, representing 27 Dene First Nations across the Northwest Territories. On March 18, 2015, Denendeh Investments Inc. and ATCO signed a Memorandum of Understanding that increased First Nations' ownership of Northland from 14 to 50 per cents.[66]

Northland Utilities owns, operates and maintains the power poles, power lines and other electrical infrastructure including five substations and five diesel plants.

Exceptions and Exemptions from the Act and Regulation

Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited do not receive any specific statutory exceptions or exemptions from the *Public Utilities Act*.

7. Nunavut

7.1 Crown Corporation Electric Utility

The Qulliq Energy Corporation (QEC) is the only utility in Nunavut, which is a crown corporation owned by the Government of Nunavut. QEC is the sole power utility, generating and distributing power in

[65] NWT Power Corporation is a crown corporation and100% owned by the Government of the Northwest Territories and is regulated by the PUB

[66] https://www.northlandutilities.com/en-ca/about-us.html

Nunavut. It delivers electricity to approximately 14,400 electrical customers across the territory by operating 25 stand-alone diesel power plants in 25 communities.[67]

QEC is governed by the *Utility Rates Review Council (URRC) Act*, which replaced the *Public Utilities Act* on March 29, 2001. The *URRC Act* was compiled using parts of legislation from across Canada, but it is a made-in-Nunavut solution to regulating utilities. The Utility Rates Review Council (URRC) is only an advisory body to the Minister Responsible for the QEC. Under the new Act, the Minister Responsible for the QEC, along with the Executive Council, make the final decisions on power rates.[68] The Minister Responsible for QEC, who is a member of the Legislative Assembly as well as a member of the Cabinet (or Executive Council) of the Government of Nunavut is a member of leadership team at QEC. [69]

By virtue of the fact that 85% of the population in Nunavut is Indigenous Peoples, the government-owned QEC can be regarded as an "Indigenous utility". However, it is not comparable to any other conventional Indigenous utilities that exist in Canada because of its ownership and governance structure. For this reason, QEC may not be relevant at all to the BCUC Inquiry.

Exceptions and Exemptions from the Act and Regulation

QEC does not receive any statutory exceptions or exemptions from the *URRC Act*.

8. Ontario

The Ontario Energy Board (the "OEB" or the "Board") is an independent regulatory body that makes decisions and provides advice to the government in order to contribute to a sustainable, reliable energy sector and to help consumers get value from their natural gas and electricity services.[70]

Five Nations Energy Inc. (FNEI), B2M Limited Partnership (B2M L.P.), Wataynikaneyap Power LP (WPLP), and Cat Lake Power are the four Indigenous electricity transmission companies. These transmission companies are required to hold an electricity transmission licence by the OEB in order to own and operate transmission facilities in Ontario. They are rate-regulated by the OEB.

There are an estimated 24,000 electricity customers on First Nations lands in Ontario, of which about 21,500 are residential users. Hydro One Networks Inc. (Hydro One) serves about 80% of these customers residing on First Nations lands in the province.[71] Other on-reserve customers are served by

[67] https://www.qec.nu.ca/home/
[68] http://www.urrc.gov.nu.ca/en/home.html
[69] https://www.qec.nu.ca/leadership-team

[70] https://www.oeb.ca/about-us
[71] Ontario Energy Board - Report to the Minister Options for an Appropriate Rate Assistance Program for On-Reserve First Nations Electricity Consumers December 29, 2016

ten Independent Power Authorities (IPAs) and the three First Nation Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation.

In Ontario's northwest, there are ten communities who are served by IPAs that rely on diesel generation. IPAs are owned or/and operated by First Nations. They are neither licensed, nor rate regulated by the OEB.

Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation are the only three Indigenous electricity distributors who provide distribution services in their respective First Nation communities in Northern Ontario. These three Indigenous utilities are licensed and rate-regulated by the OEB.

Six Nations Natural Gas Limited is an Indigenous natural gas distributor that is owned by the Six Nations of the Grand River Territory. It provides natural gas distribution services on reserve. The utility is not regulated by the OEB.

There are a number of licensed generators which are owned, either wholly or in part by Indigenous Peoples. However, the licensing is the only direct regulation by the OEB.
Although in general, rate-regulated Indigenous utilities are not treated differently from the rate-regulated non-Indigenous utilities in Ontario, the *Ontario Energy Board Act (the "OEB Act")* and supporting regulations include a number of exemptions and exceptions regarding Indigenous utilities. These exceptions and exemptions need to be considered in the historical context of the establishment of the Indigenous utilities and their economic and geographical considerations.

In addition, 129 First Nations in the province hold 2.4% of Hydro One through OFN Power Holdings, which is a limited partnership owned by Ontario First Nations Sovereign Wealth (The Ontario government now holds about 47.4% of Hydro One).

To provide context to the regulatory treatment of the Indigenous utilities by the OEB, examples of the applications filed by the Indigenous utilities, including a summary of details related to the applications filed by Indigenous utilities, arguments and submissions made by parties and the OEB staff, and the rationale for the OEB's decisions and orders, are provided in the following sections. Specific relevant sections from the OEB Act and regulations regarding regulation of Indigenous utilities in Ontario, including any particular exceptions or exemptions granted, are also stated.

The following sections provide the details for the regulation of Indigenous utilities and their defining characteristics in Ontario.

8.1 Electricity Transmission Utilities

8.1.1 Five Nations Energy Inc. ("FNEI")

Background Information

FNEI is an electricity transmitter that is licensed and regulated by the OEB. It is a non-profit, non-share capital, federally-incorporated corporation with its head office in Moose Factory, Ontario, and main operational office located in Timmins, Ontario. FNEI carries on the business of owning and operating electricity transmission facilities in the western James Bay region of Ontario serving the remote Communities of Attawapiskat, Fort Albany, and Kashechewan. It also supplies power to a line that connects to the De Beers Canada Victor Diamond Mine project north of Attawapiskat.[72]

Current facilities over which FNEI is authorized to transmit electricity in accordance with its electricity transmission licence (ET-2003-0074) with the OEB includes:

1. A 138 kV three-phase line approximately 270 km in length beginning at Moosonee and running northwest along James Bay by way of Fort Albany and Kashechewan and terminating at Attawapiskat.
2. Three step-down substations, one in each of Fort Albany, Kashechewan and Attawapiskat to supply the electrical distribution systems in these communities.
3. A second 138 kV three-phase line approximately 179 km in length beginning at Moosonee and running northwest along James Bay, parallel to the original 138 kV circuit terminating in Kashechewan.
4. A 138 kV switching station in Kashechewan where both 138 kV circuits run in parallel from Moosonee

FNEI was incorporated in 1997 by the three First Nation communities of Attawapiskat, Fort Albany and Kashechewan, who are equal members in FNEI. FNEI received $34,285,460 contribution in aid of construction funding from Indian and Northern Affairs Canada (INAC) for the acquisition and construction of station equipment, poles, and fixtures and overhead conductors.[73] In addition, FNEI made an agreement with De Beers Canada (De Beers). De Beers constructed a transmission line between Moosonee and Kashechewan which was completed in December 2009. Upon completing various legal and regulatory requirements, the line was transferred to FNEI. The cost of the asset borne by De Beers was approximately $37,300.00. De Beers reimbursed FNEI annually for incremental cost of operating the line during the life of the Victor Mine near Attawapiskat.

Since FNEI is a non-share capital corporation, it does not have shareholders. FNEI is governed by a board of directors. The FNEI's board includes representation from the three Indigenous utilities owned by the First Nation communities of Attawapiskat, Fort Albany and Kashechewan as well as

[72] https://www.fivenations.ca/index.php/about8/what-is-fnei

[73] Note 3 of the FNEI 2009 Audited Financial Statements on capital assets and asset amortization.

representation from Moose Cree First Nation and Taykwa Tagamou First Nation. Moose Cree First Nation and Taykwa Tagamou First Nation are members of the FNEI because the FNEI's assets pass through the traditional territories of these two First Nations. FNEI re-invests all of its revenues back into its transmission business.

Under the OEB's regulatory regime, FNEI recovers its approved revenue requirement through Ontario's Uniform Transmission Rates (UTRs). The OEB approves transmission utility revenues for recovery from ratepayers through the UTRs. The pooled revenue requirement for all rate-regulated transmitters across Ontario forms the basis of the UTR calculation. Given the small size of FNEI's revenue requirement in relation to the total revenue requirement for all rate-regulated transmitters, changes to FNEI's revenue requirement are not mathematically significant enough to change the UTRs on a standalone basis.

FNEI is required to file a cost of service rate application with the OEB seeking approval for its revenue requirement. Being a regulated transmission company, FNEI is subject to the OEB's approval in acquisition or expansion of new transmission assets. The following section provides examples of FNEI's applications with the OEB to acquire additional transmission assets. They clearly demonstrate that the OEB applied the same regulation and regulatory principles to FNEI, as it would to any other utility. The Indigenous nature of FNEI was not a consideration for the OEB in making its decision regarding the FNEI's applications.

Acquisition of Additional Transmission Assets

On October 22, 2009, FNEI commenced the commissioning of certain new transmission assets required to accommodate the mining operations of its customer De Beers Canada Inc. The assets consisted of:

(i) A 138 kV three-phase line approximately 179 km in length beginning at Moosonee and running northwest along James Bay, parallel to the original 138 kV circuit terminating in Kashechewan; and
(ii) A 138 kV switching station in Kashechewan where both 138 kV circuits in parallel from Moosonee.

The assets were originally constructed by De Beers Canada Inc. following the OEB's approval in its leave to construct Decision and Order of July 18, 2005 [EB-2004-0545]. The assets were required to enable De Beers to achieve full production at its Victor Mine. On November 3, 2009, FNEI filed an application with the OEB under section 74 of the *Ontario Energy Board Act, 1998* for an order of the OEB to amend the schedule of licensed facilities. The application sought amendment to its licence to own and operate the De Beers Canada Inc.'s assets as part of the FNEI transmission system to serve its four customers. FNEI advised the OEB that as a portion of the new assets was situated on reserve lands, a permit under section 28(2) of the *Indian Act (Canada)* was required from the Department of Indian and Northern Affairs (now Aboriginal Affairs and Northern Development Canada) and this was requested. On December 18, 2009, the OEB granted an interim approval of the proposed licence amendment subject to the receipt of permits by FNEI. On August 30, 2010 and September 30, 2010, FNEI advised the OEB that the section 28(2) permits were received.

Prior to 2015, the FNEI's transmission asset was a 138 kV three-phase line approximately 190 km in length beginning at approximately 80 km northwest of Moosonee. On April 6, 2015, FNEI filed an application under section 74 of the Act for an order amending its licence, in order to facilitate its acquisition and operation of approximately 80 km of Hydro One Networks Inc.'s transmission system in Northern Ontario. The 80 km transmission assets were situated on Crown Land. FNEI's Land Use Permit, as issued by the Ontario Ministry of Natural Resources pursuant to the *Public Lands Act*, did not extend over the lands relating to these assets. In its application, FNEI submitted that the desired amendment satisfied the OEB's objectives enumerated in the Act, particularly that of "*promot[ing] economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.*" The location of assets is remote and FNEI submitted that it made operational sense for one transmitter to own, operate and maintain the lines in the region.

On July 30, 2015, the OEB issued a Decision and Order (EB-2015-0127) which approved Hydro One's sale of the 80 km transmission assets to FNEI. On August 20, 2015, the OEB granted FNEI's request to amend it transmission licence in order to own and operate the additional 80 km of line, subject to:

(i) FNEI receipt of the requisite amendment to its Land Use Permit from the Ontario Ministry of Natural Resources, pursuant to the *Public Lands Act*, permitting FNEI to operate the Assets on Crown Land and
(ii) FNEI submission of a written confirmation of the Ontario Ministry of Natural Resources' approval to the OEB.

FNEI applied to the Ontario Ministry of Natural Resources for an amendment to the Land Use Permit, such that the permit would extend over the lands relating to new assets.

Exceptions and Exemptions from the Act and Regulation

FNEI does not have any specific exemptions under the *OEB Act, Electricity Act,* or any regulations. However, in its prior revenue requirement rate applications, FNEI requested that it be granted the ability to earn a ROE on the same basis as a for-profit utility. FNEI had requested approval to utilize some of its excess revenues to meet its other non-transmission corporate objectives, such as funding projects in the communities whose local distribution companies are members of FNEI. Although its requests in its first two rate applications were denied, FNEI was able to seek the OEB's approval in its third application to earn a return on FNEI's deemed equity that was the same return as that of for-profit utilities. Further, it sought approval to use the ROE to create opportunities for FNEI's board of directors to approve non-transmission spending, in a fashion similar to a board of a for-profit utility declaring shareholder dividends. The following sections provide the summary details of the FNEI's requests and the OEB's Decisions and Orders.

FNEI's 2001 Rate Application including A Request for Maximum Return on Equity (ROE)

On June 21, 2001, FNEI applied to the OEB for an Order pursuant to section 78 of the *1998 Ontario Energy Board Act*, to approve the revenue requirement of FNEI, and to fix just and reasonable rates for the transmission of electricity by FNEI. In its application, FNEI requested the maximum allowable return on equity, in accordance with the Rate Handbook, of 9.88 percent. FNEI indicated that the requested Return on Equity was to be used for one or more of the following purposes:

(i) to provide a cushion for unanticipated expenses (i.e. an operating reserve);
(ii) to create sufficient funds to enable FNEI to self-insure; and
(iii) to create sufficient funds for planned equipment replacements (i.e., a capital reserve).

FNEI also filed evidence to illustrate how non-profit utilities in U.S. jurisdictions were allowed, by their regulators, to accumulate funds in excess of their costs, through the application of a Times Interest Earned Ratio ("TIER") rate-making mechanism.

In its Decision with Reasons (RP-2001-0036) dated April 24, 2002, the OEB stated that it must make three decisions:

(i) Should a non-profit corporation, which is subject to the Board's regulation, be permitted to earn income in excess of its expenditures?

(ii) If a non-profit corporation is permitted to earn income in excess of its expenditures, how should the accumulated excess be described and accounted for, for regulatory purposes?

(iii) If a non-profit corporation is permitted to earn income in excess of its expenditures, by what method should the amount of this income be calculated?

The OEB found that FNEI's revenue requirement for the twelve months commencing November 1, 2001 should include an amount in excess of its projected expenditures given:

(i) the Canada Revenue Agency (CRA) permits a non-profit organization to earn income in excess of its expenditures under specific circumstances without jeopardizing its non-profit status; and
(ii) the precedents given by examples of non-profit utilities being permitted to earn income in excess of their expenditures.

The OEB determined that "*FNEI's revenue requirement for the twelve months commencing November 1, 2001 should include an amount in excess of its projected expenditures.*" [74] However, the OEB stated that it was concerned that "*any reserves are not reduced by expenditures that would otherwise be accounted for in FNEI's revenue requirement or rate base.*"[75] The OEB also stated that "*a non-profit*

[74] OEB Decision with Reasons (RP-2001-0036) dated April 24, 2002, page 15.
[75] Ibid.,16.

corporation that accumulates funds that are excess to its current expenditures must give careful consideration to maintaining its non-taxable status". [76]

The OEB directed FNEI to file, at its next rate case, a design for a reserve fund as the FNEI had indicated it was willing to develop. The OEB also directed FNEI to include in this report a description of the measures that would be taken to deal with the issue of maintaining its non-profit status. The OEB stated that given that FNEI did not, by its form of incorporation, have share capital, the OEB believed that it was inappropriate to describe amounts included in its revenue requirement that were in excess of its projected expenditures as a "return on equity". The OEB further directed FNEI to describe this excess of revenue over expenditures as "Internally Generated Funds", until such time as the OEB could consider and approve FNEI's proposal for one or more reserves. Finally, the OEB directed FNEI not to use this Internally Generated Funds account to charge against this account expenditures that would otherwise be charged to revenue requirement or rate base accounts.

In determining its decision, the OEB relied on the evidence and the FNEI's willingness to design and develop a reserve fund to be "*permitted to earn income in excess of its expenditures*" while maintaining its non-profit status. In informing its decision, the OEB used and was guided by a set of measures including FNEI's financial viability and maintaining its non-profit status, as it would with any other non-profit utility or any other non-Indigenous utility.

FNEI's 2010 Rate Application including A Request for Maximum ROE

On February 26, 2010, FNEI filed an application with the OEB under section 78 of *the Ontario Energy Board Act, 1998*, for 2010 transmission rates and related matters. In its application, FNEI requested OEB approval for a return on equity of 9.85% and proposed a design for the operating and capital reserves. FNEI requested that the operating and capital reserves not be capped and not be subject to restrictive rules respecting withdrawals. FNEI requested to earn revenues in excess of costs, not paid out as dividends, but rather to spend on activities that promoted the social, economic and civic welfare and development of its members, namely Attawapiskat, Fort Albany and Kashechewan First Nations.

Two parties to the proceeding (Energy Probe and Independent Electricity System Operator (IESO)), as well as the OEB staff submitted that the OEB should deny FNEI's request. They submitted that if FNEI wanted to earn a return on equity, in the same manner as other for-profit utilities, then it must reconsider its non-profit status and operate as a for-profit utility. They argued that a request for a return on equity assumed investor equity and FNEI as a non-profit utility without share capital did not have investors and should therefore not earn a return on equity.

FNEI argued that regardless of its non-profit, non-share capital structure, it could earn revenues in excess of costs, provided such excess revenues were not paid out as dividends, but rather were spent on activities that promoted the social, economic and civic welfare and development of the

[76] Ibid.

Attawapiskat, Fort Albany and Kashechewan First Nations. FNEI stated it had received professional advice on this point and was not concerned about losing its non-profit status merely by continuing to earn revenues in excess of costs. In the submissions of OEB staff and intervenors, the proposal was referred to as "the ROE approach".[77]

In its Decision and Order, the OEB referenced the appropriateness of FNEI earning a return on equity which was addressed by the OEB in the FNEI's previous rate case. The Board stated that it was not convinced it needed to vary its findings in this regard.[78]

The OEB referenced a similar issue in a prior OEB Decision and Order (EB-2005-0233) for a rate application by the Indigenous utility Attawapiskat Power Corporation ("APC"). It stated that the OEB determined that APC, a non-profit, non-share capital utility, sought the OEB approval to earn and retain revenues in excess of its expenditures in order to establish reserves. APC used the OEB's return on equity methodology (referred to as Internally Generated Funds) as a proxy to estimate the excess revenues needed to provide for reserves directly related to the reliable and sustainable operation of the utility.[79]
In the OEB Decision and Order for the APC, the OEB had noted that the cost of capital parameters relied on were really only appropriate for 'for-profit' utilities and were "*not directly applicable"* and were *"surrogates at best*".[80]

The OEB Decision and Order for the FNEI stated that, "*Having determined that it is not appropriate for FNEI to earn a return on equity per se, but also that it is crucial that the reserves be appropriately funded the issue is – How should the amounts in revenue requirement in excess of costs be determined?*" [81] It addresses this issue by stating that, "*In the Board's view, the appropriate methodology to manage excess revenues is the Reserve approach*."

The OEB rejected the FNEI's proposal to link "operating reserve" to capital reserve and stated that, "*The Board does not approve FNEI's proposal to link the 'Operating fund' and Capital reserve. Appropriating funds from the 'Operating fund' to the Capital reserve will make it impossible to build up the 'Operating fund' to its upper limit. The Board also finds that the 'Operating fund' as designed and proposed by FNEI is not a reserve in form or function. In order for a Reserve to operate as a Reserve it must be subject to specific, prescriptive rules governing withdrawals from the Reserve."* [82]

Finally, the OEB disapproved FNEI's proposal to use the Reserves or "excess earning" to support the social, economic and civic welfare and development activities in the three First Nations communities. It stated that,

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[77] The OEB Decision and Order (EB-2009-0387) dated November 1, 2010, FNEI Rate Application, page 18.
[78] Ibid., 20.

[79] Ibid.
[80] The OEB Decision and Order (EB-2005-0233) dated October 14, 2005, Attawapiskat Power Corporation and Attawapiskat First Nation Distribution Rate Application by, page 8.
[81] Ibid., 20.
[82] Ibid., 23.

> The Board stresses that amounts included in revenue requirement in excess of costs are for building reserves necessary to ensure the sustainable operation of the utility in its role as a transmitter of electricity pursuant to its license and for no other purpose. **The Company is specifically prohibited from using any funds to support the social, economic, and civic welfare and development activities in the First Nations communities.** As laudable as these activities may be, they are not the responsibility of the utility as a licensed electricity transmitter and the ratepayers of the utility should not be funding them. There are certain Board-approved charitable programs and the utility should inquire as to how they may be accommodated by the utility going forward.[83] [emphasis added in bold]

The OEB approved the recovery of revenue in excess of costs amounting to 9.50%, instead of the requested 9.85%, to fund the operating and capital reserves and directed FNEI to refer to these amounts as Internally Generated Funds. The OEB stated that when the reserves were fully funded, the utility had to make application for revised rates, and that under no circumstances it should collect any funds in excess of revenue requirement once the reserves are fully funded.

The above case demonstrates that the OEB gave no consideration to the fact that FNEI is an Indigenous utility whose stated goal is to be able to further community interests. But rather, the OEB applied the same regulatory principles to FNEI, as it would to any other utility.

FNEI's 2016 Rate Application including A Request A ROE on the same basis as a for-profit utility.

On July 27, 2016, FNEI filed a cost of service rate application with the OEB under section 78 of *the Ontario Energy Board Act, 1998*. FNEI sought approval for its proposed transmission revenue requirement effective January 1, 2016. In its application, FNEI requested that it be granted the ability to earn a ROE on the same basis as a for-profit utility. FNEI requested again approval to utilize some of its excess revenues to meet its other non-transmission corporate objects, such as funding projects in the communities whose local distribution companies are members of FNEI.

In the proceeding, the FNEI's evidence revealed that a reserves policy was never finalized and that the operating and capital reserves were never funded. The OEB staff and intervenors submitted that the OEB should not adopt the operating and capital reserves approach which was approved in the 2010 FNEI Decision, but should enable FNEI to earn revenue in excess of its costs to protect its financial viability, creditworthiness and ability to attract debt capital on reasonable terms. FNEI argued that the right of a utility to a fair return is not limited to for-profit utilities and the Fair Return Standard should apply to not-for-profit utilities. OEB staff submitted that the Fair Return Standard is informative for not-for-profit utilities, but did not apply to FNEI.

The OEB Decision and Order stated that "*The OEB has considered the need for operating and capital reserves going forward. All parties submitted that the requirement for the 2010 Capital and Operating Reserves directive would not be the best way to proceed. The OEB agrees. The OEB directs FNEI to close*

[83] Ibid.

its Capital and Operating Reserves as these accounts are no longer needed."[84] It further stated that, "*The OEB is not persuaded by the argument that the Fair Return Standard should not apply at all because FNEI has no equity investors. The OEB agrees with OEB staff that the Financial Integrity Standard applies to FNEI. While the OEB agrees that two of the three elements of the Fair Return Standard do not directly apply to FNEI, the OEB finds that the concepts of comparable investments and capital attraction are relevant considerations for FNEI*". [85]

In its Decision and Order, the OEB referred to the Fair Return Standard that sets out the principles to be used in the determination of the appropriate return on capital. The OEB approved a return on FNEI's deemed equity that was the same return applied to for-profit utilities. Further, the OEB stated that the approved ROE may create opportunities for FNEI's Board of Directors to approve non-transmission spending, in a fashion similar to a Board of a for-profit utility declaring shareholder dividends. The OEB directed FNEI to record the accounting entries related to non-rate regulated revenues and expenses in accordance with the OEB's Uniform System of Accounts when FNEI's Board of Directors approves non-transmission spending decisions.

Again, this case shows the principles used by the OEB did not differentiate FNEI from any other utility regarding the fact that FNEI is an Indigenous utility.

8.1.2 B2M Limited Partnership (B2M L.P.)

Background Information

B2M Limited Partnership (B2M L.P.) is an electricity transmitter that is licensed and regulated by the OEB. B2M has an electricity transmission licence with the OEB to own and operate a section of electricity transmission line from the Bruce Nuclear Generation Complex to Hydro One's Milton Switching Station. B2M L.P. was established on December 17, 2014 to acquire a section of electricity transmission line owned by Hydro One Networks Inc. Hydro One continued to operate and maintain the transmission assets owned by B2M L. P. through a service level agreement.

B2M GP Inc., a wholly owned subsidiary of Hydro One Inc. B2M GP Inc. holds the general partner interest and substantially all of Hydro One Inc.'s partnership interests in B2M L.P. B2M GP Inc. is responsible for ensuring that the assets of the partnership are operated and maintained in accordance with all applicable regulatory standards and Hydro One Network's transmission maintenance and operating practices, through a comprehensive services agreement with Hydro One Networks.

SON FC is jointly owned by the Chippewas of Saugeen First Nation and the Chippewas of Nawash First Nation. SON FC was formed specifically as the vehicle for participation of the First Nations in B2M L.P. SON FC holds 34% partnership interest in B2M L.P. for the First Nations, but has no substantial assets or liabilities other than the financing arranged to fund the acquisition cost of its partnership interest.[86]

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[84] The OEB Decision and Order (EB-2016-0231) dated December 14, 2017, FNEI Rate Application, page 5.
[85] Ibid., 7.

[86] OEB Decision and Order, EB-2015-0026, B2M Limited Partnership, Application for an order approving revenue requirements for electricity transmission to be effective January 1, 2015 to December 31, 2019 - December 29, 2015

Exceptions and Exemptions from the Act and Regulation

B2M L.P. does not have any specific exemptions under the *OEB Act, Electricity Act,* or any regulations. The case below demonstrates that the OEB in determining its decision and order with respect to B2M LP gave no consideration to the fact that a SON FC was a part owner of B2M LP, as a First Nation entity. The OEB applied the same regulatory principles to B2M, as it would to any other utility.

B2M L.P., Hydro One, and SON LP Co. filed three separate but related applications dated March 28, 2013. B2M L.P. applied for an electricity transmission licence with the OEB. Hydro One applied for leave of the Board to sell certain electricity transmission assets (the Bruce to Milton assets) to B2M L.P. under section 86(1)(b) of the *Act*[87], and SON FC applied for leave of the Board to acquire up to a 34% partnership interest in B2M L.P.

The purpose of the applications was to give effect to a commercial transaction between Hydro One and the SON FC, allowing the SON FC to acquire up to a 34% ownership interest in the Bruce to Milton assets. Hydro One sought approval to sell the Bruce to Milton Assets to B2M L.P. B2M L.P. would become a licensed electricity transmitter for the purpose of owning and operating the Bruce to Milton assets. SON FC would acquire up to a 34% ownership interest in B2M L.P.

The OEB granted the requests in the applications filed by B2M L.P. and Hydro One. The OEB also determined that leave from the OEB was not required for the proposed acquisition of a 34% interest in B2M L.P. by SON FC. [88] In determining the applications, the OEB was guided by the principles set out in the OEB's prior decisions and applied the "no harm" test for the purposes of applications for leave to acquire shares or amalgamate under section 86 of the *Act*. The "no harm" test is a consideration of whether the proposed transaction would have an adverse effect relative to the status quo in relation to the OEB's statutory objectives. The factors to be considered are those set out in section 1 of the *Act*. According to the no-harm test, if the proposed transaction would have a positive or neutral effect on the attainment of the statutory objectives, then the application should be granted. Based on the presented evidence, the OEB found that the proposed transaction passed the "no harm test".[89]

The evidence on record further indicated that incremental transaction and operating costs of B2M L.P. would offset by the income tax benefits of the transaction over the long term. SON FC received advance tax rulings from the federal and provincial authorities regarding the taxable position of B2M L.P. and SON FC. The rulings indicated that it would receive the net profit from B2M L.P. without paying income taxes. The resulting reduction in income taxes in the revenue requirement decreased the cost to ratepayers over the life of the line.

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[87] Section 86(1)(b) of the Act states: No transmitter or distributor, without first obtaining from the Board an order granting leave, shall sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public;
[88] The OEB Decision and Order (EB-2013-0078, EB-2013-0079, and EB-2013-0080) dated November 28, 2013.
[89] Ibid.

8.1.3 Wataynikaneyap Power LP

Background Information

Wataynikaneyap Power LP (WPLP) is an electricity transmission company licensed by the OEB. It is a partnership between 24 First Nations communities (equally owned) and FortisOntario, a wholly-owned subsidiary of Fortis Inc. The participating First Nations hold a 51% interest in WPLP and FortisOntario holds the remaining 49% interest. The 24 First Nations communities will maintain their ability to increase their ownership to 100% over time. First Nations Limited Partnership also owns 100% of Opiikapawiin Services LP. FortisOntario also owns 100% of Wataynikaneyap Power PM Inc. (project management services) to provide services to WPLP. WPLP has already connected the community of Pikangikum First Nation Reserve to the provincial power grid by constructing the Red Lake remote connection line to the Pikangikum prior to constructing the remainder of its project. WPLP is currently participating in the environmental assessment process for phase 2 of the project, which is connecting 17 remote First Nation communities.

The participating First Nations have formed a partnership on the basis of their shared interest in developing, owning and operating approximately 1,800 kilometers of 230 kV, 115 kV, and 44 kV lines in northwestern Ontario to connect remote First Nation communities to the provincial electricity grid. The transmission lines will connect 16 of the 24 participating First Nation communities, and will allow for the future connection of an additional community. This will allow connection of 25 communities with population of approximately 15,000 and with a peak electricity demand of approximately 20 megawatts (MW) to the grid.

WPLP estimated that the cost of projects is $1.65B, including development, construction, contingency, capitalized interest, and Allowance for Funds Used During Construction (AFUDC).[90] On March 12, 2018, WPLP entered into a funding memorandum of understanding with the governments of Canada and Ontario with a total of $1.6 billion of federal funding to connect the remote communities. The funding is conditional on the finalization of definitive documentation and on appropriation of the funding by Parliament.[91] The Government of Canada will fund the Project in part as a capital contribution to WPLP, with the remainder placed in an independent trust (Trust) to offset the increase in Rural or Remote Electricity Rate Protection (RRRP) as a result of a transmission rate that WPLP proposes to charge to Hydro One Remote Communities Inc. (HORCI). WPLP's understanding is that the recipient of funds from the Trust will be the IESO.[92] Ontario Regulation 442/01 - Rural or Remote Electricity Rate Protection was amended effective July 1, 2016 "*to allow RRRP to be used to cover a portion of the costs required to build and operate the lines that would connect remote First Nations communities to the transmission grid*".[93] WPLP presented to the OEB that the total construction capital cost of $1,610 million ($620 million of equity was required from the owners of WPLP) would result in rate base before capital contribution of $1,747 million, an implied rate base of $1,550 million, and a $197 million capital

[90] Wataynikaneyap Power LP - Application Presentation, EB-2018-0190, November 2, 2018.
[91] OEB Decision and Order - EB-2018-0190 regarding Wataynikaneyap Power LP's Application for leave to construct transmission lines and associated facilities in northwestern Ontario, April 1, 2019, page 8.
[92] Ibid., 8-9.
[93] Environmental Registry, February 10, 2016.

contribution from the Government of Canada. The amount allocated to the Trust would be $1,353 million.[94,95]

In its application proceeding, WPLP stated the project is expected to start in Q1 of 2019, line to Pickle Lake will in service by Q4 of 2020, first community will be connected in Q1 of 2021, and all construction will be completed by Q4 of 2023.

Exceptions and Exemptions from the Act and Regulation

Exemptions for Licence Amendment without a Hearing and for the OEB's Needs Assessment for Leave to Construct

On July 29, 2016, the Minister of Energy provided the OEB with a transmission directive issued under section 28.6.1 of the *OEB Act* and approved by the Lieutenant Governor in Council.[96] Through an Order-in-Council No. 1158/2016 issued by the Lieutenant Governor in Council on July 20, 2016, the Province of Ontario declared the construction of electricity transmission lines as priority projects by First Nations, pursuant to section 96.1 of the *OEB Act*.[97] In its July 29, 2016 letter to the OEB, the Minister had stated that "*the connection of remote First Nation communities was **identified as a priority project** in the 2013 Long-Term Energy Plan. This project will reduce reliance on diesel generation and bring a number of environmental, social and economic benefits to these First Nation communities*".[98] [Emphasis Added in bold]

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[94] Wataynikaneyap Power LP - Application Presentation, EB-2018-0190, November 2, 2018.

[95] According to WPLP, the difference between $1,610M and the $1,650M project cost identified in the Application is that $1,610M reflects the total cost of the project before AFUDC, but including Pikangikum, fleet and facilities costs, which are not relevant to the Leave to Construct Application but will instead be considered as part of rate applications for the relevant facilities. The $1,650M excludes those items but includes AFUDC.

[96] **Directives, transmission systems**
28.6.1 (1) The Minister may issue, and the Board shall implement directives, approved by the Lieutenant Governor in Council, requiring the Board to take such steps as are specified in the directive relating to the construction, expansion or re-enforcement of transmission systems. 2016, c. 10, Sched. 2, s. 14.
Same
(2) Subsections 28.6 (2) and (3) apply with necessary modifications in respect of directives issued under subsection (1). 2016, c. 10, Sched. 2, s. 14.

[97] 96.1 (1) The Lieutenant Governor in Council may make an order declaring that the construction, expansion or reinforcement of an electricity transmission line specified in the order is needed as a priority project. 2015, c. 29, s. 16.

Effect of order
(2) When it considers an application under section 92 in respect of the construction, expansion or reinforcement of an electricity transmission line specified in an order under subsection (1), the Board shall accept that the construction, expansion or reinforcement is needed when forming its opinion under section 96. 2015, c. 29, s. 16.

Obligations must be followed
(3) Nothing in this section relieves a person from the obligation to obtain leave of the Board for the construction, expansion or reinforcement of an electricity transmission line specified in an order under subsection (1). 2015, c. 29, s. 16.

[98] The Minister of Energy's Directive to the OEB dated July 29, 2016.

The OIC stated that, "*AND WHEREAS the Government* ***has determined that the preferred manner of proceeding is to require 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP to undertake the development*** *of the Line to Pickle Lake and the· Remotes Connection Project, including any and all steps which are deemed to be necessary and desirable in order to seek required approvals;"* [Emphasis Added in bold]

Subsections 28.6 (2) and (3) of the *OEB Act* "*apply with necessary modifications in respect of directives issued under subsection (1)*" require the OEB to amend the licence conditions of a transmitter to require the transmitter to take the actions specified in the directive in relation to its transmission system, including enhancing, re-enforcing or expanding that system. In accordance with section 28.6(3) of the *OEB Act*, such a directive may specify whether the OEB is to hold a hearing for the purposes of giving effect to the directive.

The transmission directive required the OEB to amend, **without a hearing**, the transmission licence of 2472883 Ontario Limited on behalf of WPLP to require it to develop and seek approvals for certain transmission projects to connect certain named remote First Nation communities to the provincial electricity grid.[99] The projects were: a) the construction of a new 230 kV line to Pickle Lake and b) the construction of transmission lines extending north from Red Lake and Pickle Lake required to connect certain named remote First Nation communities to the provincial electricity grid.[100] [Emphasis Added in bold]

Since the province had declared the construction of electricity transmission lines by the First Nations as priority projects, pursuant to section 96.1 of the *OEB Act*, the OEB was required to accept that the construction of the proposed transmission facilities was needed.[101] Thus, the OEB stated that[102],

> By reason of section 96.1 of the OEB Act, the **OEB will not undertake a "needs" assessment as part of a leave to construct review of the transmission lines** comprising the Pickle Lake project and the Transmission Extension projects. I would ask that the preparation of the IESO's report take into account that, although the OEB will not be assessing "need" for the project, it will still examine cost related issues as it conducts its leave to construct review, and in doing so will consider the interests of consumers with respect to price, reliability and quality of service. [Emphasis Added in bold]

The requirement for WPLP to provide the OEB with reporting with respect to budget, timing and risks relating to the transmission projects had been identified in the transmission directive.

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[99] The OEB Decision and Order EB-2016-0258, dated September 1, 2016 regarding 2472883 Ontario Limited on Behalf of Wataynikaneyap Power LP Electricity Transmission Licence Amendment Further to Ministerial Directive, page 2.

[100] Ibid., 1.
[101] Ibid., 5.
[102] Letter from the OEB Chair to the Independent Electricity System Operator's President & Chief Executive Officer dated September 1, 2016.

The transmission directive required the OEB to amend the transmission licence "without a hearing" to require the applicant to develop and seek approvals for its transmission projects.

In response to a Ministerial Directive issued pursuant to section 28.6.1 of the *OEB Act*, the OEB amended WPLP's transmission licence on September 1, 2016 with a term of 20 years. Schedule 1 of WPLP's licence was also amended to include a reference to the transmission projects identified in the transmission directive. Consistent with the scope recommended by the IESO, the OEB ordered WPLP to proceed to:

a. Develop and seek approvals for a transmission line composed of a new 230 kV line originating at a point between Ignace and Dryden and terminating in Pickle Lake.
b. Develop and seek approvals for the transmission lines extending north from Red Lake and Pickle Lake required to connect the Remote Communities to the provincial electricity grid.

On June 8, 2018 (amended October 5, 2018 and January 28, 2019), Wataynikaneyap Power GP Inc., as the general partner on behalf of WPLP filed an application pursuant to section 92 of the *OEB Act*[103] for leave to construct a total of approximately 1,732 km of electricity transmission and interconnection facilities. The application stated that nine of the communities to be connected are served by HORCI and seven are served by an Independent Power Authority (IPA) which operates its local system. The IPA systems will ultimately be transferred to HORCI.

Exemption for Deeming the 44 kV and 25 kV Line Segments to be Transmission Facilities

In its application, WPLP stated that its proposed transmission facilities included a total of 22 stations (6 switching stations and 16 transformer stations) and 35 distinct line segments – running from one station to another or from a station to a Hydro One Remotes owned and operated distribution system serving a remote community – that will be operated at 230 kV, 115 kV, 44 kV or 25 kV. Since these segments operate at voltages of less than 50 kV, they will be a part of WPLP's transmission system from a functional perspective. Pursuant to section 84(b) of *the OEB Act*[104], WPLP sought an exemption of the OEB deeming the 44 kV and 25 kV line segments to be transmission facilities.[105]

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[103] **Leave to construct, etc., electricity transmission or distribution line**
92 (1) No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection. 1998, c. 15, Sched. B, s. 92 (1).

[104] **Distinction between transmission and distribution, determination**
84 In making a decision in any proceeding under this Part or under the Electricity Act, 1998, the Board may determine that,
(a) a system or part of a system that forms part of a transmission system is a distribution system or part of a distribution system; and
(b) a system or part of a system that forms part of a distribution system is a transmission system or part of a transmission system. 1998, c. 15, Sched. B, s. 84; 2003, c. 3, s. 53.

[105] WPLP Application - EB-2018-0190, Exhibit C, Tab 4, Schedule 1, page 1.

In its submission, OEB staff expressed no objection to this exemption request.

In its Decision and Order, the OEB granted the exemption and deemed the 44 kV and 25 kV line segments in both the Pickle Lake and the Red Lake remote connection networks to be transmission facilities.

Request for Transmission System Code (TSC) Exemptions

In its application, WPLP raised a number of concerns with respect to certain aspects of the TSC and stated,[106]

> Due to the unique nature of the Transmission Project as a large, new transmission system being developed as a priority transmission project for the primary or initial purpose of connecting remote communities to the provincial electricity grid, there are certain aspects of the TSC that are inconsistent or incompatible with, or are unsupportive of, the Transmission Project.

To address its concerns, WPLP requested a number of exemptions from certain requirements of the TSC apply to its entire transmission projects.[107] Some were related to cost responsibility provisions in the TSC and others were related to technical and connection requirements. In some instances, the exemptions were requested on a temporary basis until all of the initial 16 remote communities are connected or until WPLP files and obtains approval from the OEB for connection procedures. In other instances, the exemptions were requested on a longer-term basis.

In its application, WPLP stated that[108],

> However, due to the unique aspects of the Transmission Project, particularly as related to the Remote Connection Lines, the Transmission Project does not fit within the existing regulatory framework for cost responsibility or revenue recovery under the Transmission System Code (the "TSC"), thereby creating anomalous results and affecting the financial viability of the Transmission Project. As a result, WPLP is seeking licence amendments so as to exempt WPLP from parts of the TSC, including in relation to the recovery of a capital contribution for the Remote Connection Lines, which are line connections within the meaning given in the TSC. As a result of such exemptions, WPLP is seeking the approval of an alternative rate framework to ensure WPLP has sufficient revenue to operate the system in a financially viable, safe and reliable manner. Under the alternative rate framework, the implications for ratepayers are the same as under the existing TSC and uniform transmission rates ("UTR").

[106] WPLP Application - EB-2018-0190, Exhibit C, Tab 6, Schedule 1, Page 3.

[107] Ibid., 4-7

[108] WPLP Application - EB-2018-0190, Exhibit J, Tab 1, Schedule 1, Pages 1-2.

OEB staff did not object to the proposed temporary TSC exemptions. However, OEB staff submitted that, "*although exemptions from rules of general application such as the TSC may in some cases be warranted, they should be tailored as narrowly as possible to achieve the purpose of the exemption.*"[109] Specifically, the OEB staff argued that all of WPLP's TSC exemption requests were appropriate, but only in respect of the Remote Connection Lines – not the line to Pickle Lake. The proposed licence amendment by WPLP applied to both the Remote Connection Lines and the line to Pickle Lake and would exempt WPLP as a whole. In OEB staff's view, it was therefore too broad.

OEB staff agreed with WPLP that the line to Pickle Lake should be considered a transmission network facility, unlike the Remote Connection Lines which are transmission connection facilities and as such would normally trigger a capital contribution under the TSC. WPLP had requested cost recovery from the network pool per the normal course in relation to the line to Pickle Lake. OEB staff submitted that the Line to Pickle Lake is therefore not "unique" in the same sense that the Remote Connection Lines are. For this reason, OEB staff expressed the view that the exemptions should be limited to the Remote Connection Lines and should not apply to the Line to Pickle Lake.

In its reply submission, WPLP stated that after reviewing the OEB staff's submissions with respect to the proposed TSC exemptions, and subject to the assumption that the OEB agrees with WPLP and OEB staff that the Line to Pickle Lake is comprised of Network Facilities for which exceptional circumstances under section 6.3.5 of the TSC do not exist, WPLP agreed that the requested exemptions were not required in connection with the Line to Pickle Lake portion of the project and should therefore only applied to the Remote Connection Lines portion of the project. [110]

In the OEB Decision and Order - EB-2018-0190, the OEB approved the TSC exemptions in relation to the Remote Connection Lines portion of the project.

Exemption from Section 6.3.5 of the TSC

Section 6.3.5 of the TSC provides that a transmitter shall not require any customer to make a capital contribution for the construction of or modification to the transmitter's network facilities that may be required to accommodate a new or modified connection. In its application, WPLP stated that, "*WPLP would not be permitted to require any customer to make a capital contribution for the construction of the Line to Pickle Lake, including the Wataynikaneyap TS, since those facilities are 'network facilities'*".[111] WPLP requested exemptions from all sections relating to cost responsibility. WPLP proposed to affect the TSC exemptions by way of an amendment to its transmission licence.

In its submission, OEB staff agreed with WPLP that the Line to Pickle Lake should be considered a transmission network facility (unlike the Remote Connection Lines, which are transmission connection facilities). However, OEB staff noted that section 6.3.5 of TSC regarding cost responsibility, should

[109] OEB Staff Submission EB-2018-0190, February 1, 2019, page 21.

[110] Wataynikaneyap Power LP's reply submission EB-2018-0190 - February 15, 2019, Page 31.
[111] Ibid., 5.

apply to the line to Pickle Lake. That section of TSC requires a customer to pay a capital contribution in "exceptional circumstances" in relation to a network facility; e.g., where a specific customer triggers the need for a network investment. OEB staff argued that if such "exceptional circumstances" do arise, an exemption would result in all Ontario ratepayers paying. In OEB staff's view, that would not be appropriate. OEB staff proposed specific edits to WPLP's proposed licence amendment to restrict the scope of the exemption to the Remote Connection Lines and also tailor the scope to what is actually required in relation to cost responsibility.

In its submission, WPLP did not disagree that the Line to Pickle Lake should not be exempt from section 6.3.5 as long as the OEB agrees that the section would not be triggered by its project because, in this case, there are no exceptional circumstances.

In the OEB Decision and Order - EB-2018-0190, the OEB agreed that the Line to Pickle Lake is a network facility for which exceptional circumstances under section 6.3.5 of the TSC did not exist at this time. The OEB stated that the requested exemptions were not required in connection with the Line to Pickle Lake portion of the Project and should therefore only apply to the Remote Connection Lines portion of the Project. The OEB also stated that cost recovery for the Line to Pickle Lake would be through the UTR network charge as per the normal course. Therefore, the OEB approved the TSC exemptions in relation to the Remote Connection Lines portion of the project.[112]

Exemption from Section 6.5.3 of the TSC

OEB staff noted that the cost responsibility provisions related to capital contributions in the TSC included true-ups to ensure the customer pays based on actual consumption – not forecast consumption. OEB staff argued that an exemption from requiring a capital contribution should not also be construed to be an exemption from the need to undertake true-ups. OEB staff submitted that any rate charged by WPLP would need to be approved by the OEB and there should be true-ups to reflect actual HORCI customer consumption in order to achieve alignment with the OEB's beneficiary pay principle. OEB staff noted that such true-ups would result in rate adjustments to ensure HORCI (and its customers in the remote communities) are not exposed to forecast risk.[113]

WPLP disagreed with OEB staff's position on true-ups. WPLP referenced to the interrogatory responses and stated that the rate to be charged to HORCI would be a *fixed* monthly transmission rate, which would form part of HORCI's revenue requirement. WPLP noted that the fixed monthly rate would eliminate load forecast risk from a transmission perspective. It would be expected to decrease in future years as WPLP's rate base decreases through depreciation, but would not be subject to adjustments to account for any true-ups to reflect actual HORCI customer consumption, as suggested by OEB staff. WPLP further noted that the manner in which HORCI would recover its costs under the proposed cost recovery and rate framework insulates HORCI and its customers in the remote communities from forecast risk because the entire cost to HORCI will be added to its revenue requirement and recovered

[112] OEB Decision and Order - EB-2018-0190 regarding Wataynikaneyap Power LP's Application for leave to construct transmission lines and associated facilities in northwestern Ontario, April 1, 2019, page 23.
[113] OEB Staff Submission EB-2018-0190, February 1, 2019, page 21.

through the RRRP. Moreover, if the federal funding were appropriated, then Ontario ratepayers would be protected from volume risk as well through the RRRP offsets provided by the independent Trust. In its reply submission, WPLP asked the OEB to clarify in its decision that, under the proposed cost recovery framework and TSC exemptions requested in the Application, there would be no requirement for true-ups to the rates charged by WPLP to HORCI to reflect actual HORCI customer consumption.

In its Decision and Order, the OEB agreed with the WPLP's position. The OEB confirmed that there would be no true-ups related to consumption given the cost recovery and rate framework proposed. The OEB stated that WPLP would recover its approved costs through a fixed monthly charge, unrelated to forecast consumption.

Finally, the OEB approved the WPLP's request for approval of the TSC exemptions on a temporary basis; specifically, until the date when all the facilities are placed in service, or December 31, 2023, whichever is earlier. Accordingly, the WPLP's licence was amended pursuant to the OEB's Decision and Order.

The review of this case indicates that the OEB did not rely on the fact that WPLP is partially owned by Indigenous Peoples to make its decision and order. In contrast, the OEB deliberated its decision and order based on the evidence that was filed by WPLP on the proceeding, reasoning that was submitted by the applicant and the OEB staff, and the OEB's legislative mandate to regulate WPLP, as a transmission company.

Although one can conclude that WPLP had received certain exemptions related to the OEB's regulatory hearing process and the OEB needs assessment for leave to construct, for which a transmission line applicant would typically have been subject to, this was through government directive and not regulatory policy. WPLP was still required by the OEB to file an application with the OEB to develop and seek approvals for its transmission projects. The OEB relied on evidence on the record and examined submissions. In its Decision and Order, the OEB did not distinguish WPLP differently from any other applicant which would have been required to file an application to develop and seek approval for leave to construct.

8.1.5 Cat Lake Power Utility Ltd.

Cat Lake Power Utility Ltd. (the "Cat Lake Power") owns the transmission facility assets in the community of Cat Lake. It is 100% owned by the Cat Lake First Nation. Cat Lake Power was managing and operating the transmission line connected to the Hydro One Networks ("Hydro One") as well as distributing electricity to approximately 80 residential customers in the community from 2001 to 2006. In 2006, Cat Lake requested the OEB have their licence relinquished. The distribution assets in the Cat Lake community are owned by the Ontario Electricity Financial Corporation (OEFC). Hydro One currently holds an interim electricity distribution licence issued by the OEB under section 59(2) of the *Ontario Energy Board Act, 1998* under which Hydro One has possession and control of certain distribution businesses serving the Cat Lake community. Cat Lake Power's transmission licence which is posted on the OEB's website is valid until October 31, 2020. Although Cat Lake Power is no longer in

operation, the background information below related to this utility would be relevant to the BCUC's Inquiry with respect to the Indigenous utilities.

Background Information

Prior to 1998, Cat Lake First Nation was serviced by Hydro One Remotes utilizing a diesel unit to generate power in the community. In March of 1997, mining operations ceased at Barrick Gold Golden Patricia mine site southwest of Cat Lake First Nation. The community planned to connect to the Ontario Hydro operated grid to replace the diesel generated power that required the hauling of fuel oil to the community over the winter road. This was not only costly, but posed an environmental risk to the community.[114]

The *Energy Competition Act, 1998* established the legislative framework for the electricity market in Ontario. As a result, the *Electricity Act, 1998* required the transfer of all assets and liabilities of the former Ontario Hydro on First Nations lands, including the Ontario Hydro's distribution assets in Cat Lake, to the OEFC. The distribution assets in Cat Lake are still held by the OEFC and transmission assets are owned by Cat Lake First Nation.

In 1998, the Cat Lake First Nation approached Hydro One to determine if they would be interested in constructing the transmission line to Cat Lake. Hydro One indicated they were not interested in constructing the proposed transmission line and extending it to the Cat Lake First Nation. In 1998, the community started the planning and design of a transmission line to the community. To finance the project, Indian and Northern Affairs Canada agreed to advance a portion of their capital funds to finance the project and committed additional funding. They also agreed to continue paying the Standard A rate for five years to assure the utility would be financially viable. Additional capital financing was provided by Northern Ontario Heritage Fund and commercial financing.

Cat Lake Power was registered as a federal non-profit business with the First Nation of Cat Lake being the single shareholder. In 2000, an operating agreement with Sioux Lookout Hydro allowed the company to receive approval from the Independent Market Operator (IMO) to connect to the provincial grid and purchase power on the wholesale market. Sioux Lookout Hydro, which is located in Sioux Lookout, was contracted by Cat Lake Power to operate the billing, maintenance, and connection services as well as provide some administrative support to the community.

After funding, licensing and construction the transmission line was commissioned in January of 2001. Cat Lake First Nation negotiated with Hydro One to purchase Ontario Hydro's distribution assets at the time of operational transfer to Cat Lake Power, but at the last moment Ontario Hydro did not agree to sell.

Cat Lake Power was operated and governed under a four-person board of directors with youth and community elder representatives. There was an elected chair and the board of directors had

[114] Cat Lake Power Proposal to Ontario Energy Board to Discontinue Distribution and Transmission Operations in Cat Lake First Nation, July 2006.

established the policies and procedures under which the utility operated. A manager reported directly to the board, while the board was accountable to its shareholder, the Cat Lake First Nation. The utility was able to set its own rates.

Cat Lake Power's transmission licence did not allow access to pooled rates with other transmitters. Cat Lake Power charged a bundled electricity rate for residential and commercial customers which included the cost of both electricity supplied and the cost for its delivery, which was not comparable to costs in an unbundled rate. All costs for the transmission line were borne by Cat Lake Power's ratepayers.

After five years of operation, Cat Lake Power stopped operating the distribution system and transmission line for the following reasons:[115]

I. Cat Lake Power was charging the Standard "A" Rate to the government funded organizations operating in the community such as Health Canada, schools and Ministry of Transportation. The Standard "A" rate was approximately ten times the residential rate subsidizing residential customers. After five years of operation, the subsidy that these organizations received from federal funding agencies was no longer available.

II. When the federal subsidy through the Standard "A" rate ended, Cat Lake Power was unable to operate without a subsidized rate and maintain a viable operation. Cat Lake Power was at the risk of default payments to the IESO for the purchase of power from the grid once Standard A rate was ended. There was no transmission revenue to offset the maintenance costs for the transmission assets. All costs for transmission assets were borne by Cat Lake ratepayers.

III. Cat Lake Power did not carry any insurance for its transmission assets because of high insurance cost. In 2003, a forest fire burned a number of poles along the transmission line to the community. The total cost of this repair was $500,000 which the Cat Lake First Nation was required to pay. There was a $500,000 contribution from INAC for the repairs due to the forest fire. Although the cost was recovered from Cat Lake First Nation and INAC, the inability to obtain insurance highlighted the risks of operating a transmission company.

In 2006, Cat Lake First Nation advised the OEB that Cat Lake Power was turning in its transmission licence as of April 1, 2006. It requested that Hydro One take over the operation of the transmission assets for which Cat Lake Power was licensed. The letter further stated that Cat Lake Power would no longer operate as a distribution company and indicated its intent to the Ontario Ministry of Energy to turn over operation of the distribution system to the owner of assets, the OEFC. On the same date, Cat Lake Power sent a separate letter to the Minister of Energy indicating that Cat Lake Power no longer wished to operate the distribution system that serves the Cat Lake community.[116]

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[115] Ibid.

[116] The OEB Decision and Order EB-2006-0180 issuing to Hydro One Network Inc. an interim distribution licence under subsection 59(2) of the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Schedule B), July 21, 2006.

In its proposal to the OEB with respect to discontinuing both its distribution and transmission operations, Cate Lake Power stated that,[117]

> It has become evident that a community the size of Cat Lake First Nation cannot operate a distribution and transmission company in the existing regulatory environment. The demands of the business require a level of expertise and training that cannot be supported by the small number of ratepayers. Raising the rates in the community is not reasonable as ratepayers will not be able to support the operation that has been created by the provincial government and it is recommended they exit both businesses.

In 2006, in order to meet its obligation of protecting the reliable supply of electricity to consumers in the Cat Lake community, the OEB took the following steps:[118]

I. Pursuant to section 84 of the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Schedule B) (the "Act"), the OEB deemed the transmission assets owned by Cat Lake Power to be distribution assets. These assets were listed in Schedule 1 of electricity transmission and wholesale licence No. ET-2002-0328 that was issued to Cat Lake Power on October 31, 2002.

II. Pursuant to section 59(2) of the Act, the OEB ordered Cat Lake Power to transfer possession and control over the transmission and distribution system to Hydro One. Cat Lake was required to continue to be responsible for meeting all requirements under its current licence until the transfer was complete.

III. Pursuant to section 59(2) of the Act, the OEB issued to Hydro One an interim distribution licence authorizing Hydro One to take possession and control of the deemed distribution assets owned by Cat Lake Power and the distribution assets in the Cat Lake community that were owned by the OEFC.

Hydro One currently holds an interim licence issued by the OEB under section 59(2) of the *Ontario Energy Board Act, 1998* under which Hydro One has possession and control over distribution assets that serve the Cat Lake community, specifically the deemed distribution assets owned by Cat Lake Power and the distribution assets in the Cat Lake community owned by the OEFC. The interim licence was issued by the OEB on July 21, 2006 (proceeding EB-2006-0180), and its term has since been amended and extended every three months. Hydro One has stated to the OEB that it plans to merge Cat Lake with Hydro One Remotes. It is not clear if and when such a merger would occur.

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[117] Cat Lake Power Proposal to Ontario Energy Board to Discontinue Distribution and Transmission Operations in Cat Lake First Nation, July 2006, page 22.

[118] The OEB Decision and Order EB-2006-0180 issuing to Hydro One Network Inc. an interim distribution licence under subsection 59(2) of the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Schedule B), July 21, 2006.

Exceptions and Exemptions from the Act and Regulation

Section 4.0.4 (1) of the *Ontario Regulation 161/99*, defines First Nation as,

> "First Nation" means a band as defined in the Indian Act (Canada), or a body of the aboriginal peoples of Canada who are treated by the Department of Indian Affairs and Northern Development (Canada) in the same manner as a body of the aboriginal peoples of Canada residing on a reserve as defined in the Indian Act (Canada). O. Reg. 72/02, s. 3.

Section 4.0.5 (1) of the *Ontario Regulation 161/99* named and granted an exemption to the Cat Lake with respect to certain sections of the *Ontario Energy Board Act*. The regulation states the following,

> 4.0.5 (1) The following provisions of the Act do not apply to a distributor who meets the conditions set out in subsection (2), and who distributes electricity in a reserve listed in Schedule 2:
>
> 1. Clauses 57[119] (a), (c), (d), (g) and (h).
> 2. Sections 71[120] and 72[121].
> 3. Section 78[122].

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[119] **Requirement to hold licence**

57 Neither the IESO nor the Smart Metering Entity shall exercise their powers or perform their duties under the Electricity Act, 1998 unless licensed to do so under this Part and no other person shall, unless licensed to do so under this Part,
(a) own or operate a distribution system;
(b) own or operate a transmission system;
(c) generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person;
(c.1) engage in unit sub-metering;
(d) retail electricity;
(e) purchase electricity or ancillary services in the IESO-administered markets or directly from a generator;
(f) sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer;
(g) direct the operation of transmission systems in Ontario;
(h) operate the market established by the market rules; or
(i) engage in an activity prescribed by the regulations that relates to electricity. 1998, c. 15, Sched. B, s. 57; 2002, c. 1, Sched. B, s. 6; 2004, c. 23, Sched. B, s. 10; 2006, c. 3, Sched. C, s. 4; 2010, c. 8, s. 38 (8); 2014, c. 7, Sched. 23, s. 4.

[120] **Restriction on business activity**
71 (1) Subject to subsection 70 (9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity. 2004, c. 23, Sched. B, s. 12.

[121] **Separate accounts**
72 Every distributor shall keep its financial records associated with distributing electricity separate from its financial records associated with other activities. 1998, c. 15, Sched. B, s. 72.

[122] **Orders by Board, electricity rates**
Order re: transmission of electricity
78 (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

4. Sections 80[123] and 81[124].
5. Section 86[125].
6. Section 92[126]. O. Reg. 72/02, s. 3.

(2) The distributor must meet the following conditions:
1. The distributor must be a First Nation, or a corporation that is solely owned by a First Nation.
2. The distributor must only distribute and generate electricity within its geographic service territory as it existed on January 1, 2002. O. Reg. 72/02, s. 3.

Section 2.5 of the *Ontario Regulation 160/99* which named and granted an exemption to the Cat Lake with respect to certain sections of *the Electricity Act, 1988* states the following,

> 2.5 (1) The following provisions of the Act do not apply to a distributor who meets the conditions set out in subsection (2), and who distributes electricity in a settlement or reserve listed in Schedule 2:

Order re: distribution of electricity
(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the Electricity Act, 1998 except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

[123] **Prohibition, generation by transmitters or distributors**
80 No transmitter or distributor or affiliate of a transmitter or distributor shall acquire an interest in a generation facility in Ontario, construct a generation facility in Ontario or purchase shares of a corporation that owns a generation facility in Ontario unless it has first given notice of its proposal to do so to the Board and the Board,
(a) has not issued a notice of review of the proposal within 60 days of the filing of the notice; or
(b) has approved the proposal under section 82. 1998, c. 15, Sched. B, s. 80.

[124] **Prohibition, transmission or distribution by generators**
81 No generator or affiliate of a generator shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario unless it has first given notice of its proposal to do so to the Board and the Board,
(a) has not issued a notice of review of the proposal within 60 days of the filing of the notice; or
(b) has approved the proposal under section 82. 1998, c. 15, Sched. B, s. 81.

[125] **Change in ownership or control of systems**
86 (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,
(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;
(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or
(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

[126] **Leave to construct, etc., electricity transmission or distribution line**
92 (1) No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection. 1998, c. 15, Sched. B, s. 92 (1).

1. Section 26.
2. Subsections 29 (4) to (6). O. Reg. 71/02, s. 2.

(2) The distributor must meet the following conditions:
   1. The distributor must be a First Nation, or a corporation that is solely owned by a First Nation.
   2. The distributor must only distribute electricity within its geographic service territory as it existed on January 1, 2002. O. Reg. 71/02, s. 2.

Cat Lake Power applied and received an exemption from requiring a distribution licence and from a number of other requirements of *the Electricity Act*. However, as a transmitter that was licensed by the OEB, Cat Lake Power had to comply with its regulatory licensing requirements. For example, Cat Lake Power was subject to the market rules that are established by the Independent Electricity System Operator (IESO formerly the IMO).[127]

The utility and its customers were not provided rate protection under the *Rural and Remote Rate Protection* offered under the regulatory regime.

8.2 Electricity Distribution Utilities

8.2.1 Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation

Background Information

Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation are non-for-profit electricity distribution companies. The are the only three Ontario electricity distributors who are wholly owned by their respective First Nation communities[128] that are

[127] Cat Lake Power Proposal to Ontario Energy Board to Discontinue Distribution and Transmission Operations in Cat Lake First Nation, July 2006, page 5.

[128] The Attawapiskat First Nation is an Indigenous community located in Kenora District in northern Ontario. It has approximately 3,000 members. The First Nation has a land area of 1.32 km and is located along the Attawapiskat River, 5 kilometers inland from the James Bay coastline. It is only accessible by air or by winter road. Mushkegowuk Council is its Tribal Council.

The Fort Albany First Nation is an Indigenous community located near James Bay in Northern Ontario. It has approximately 2,000 members. The community is located on southern shore of the Albany River. It is only accessible by air or by winter road. During the 1950's, old Fort Albany was abandoned and the people separated into two distinct communities: Fort Albany and Kashechewan. Mushkegowuk Council is its Tribal Council.

The Kashechewan First Nation is an Indigenous community located near James Bay in Northern Ontario. It has approximately 2,500 members. The community is located on the northern shore of the Albany River. Kashechewan First Nation is one of two communities that were established from Old Fort Albany in the 1950s. Mushkegowuk Council is its Tribal Council.

located in Northern Ontario. Each First Nation has a licence with the OEB to **own** the electrical distribution system in the service area described in its licence [emphasis added in bold]. The electricity distributors are licensed and regulated by the OEB to **operate** the distribution assets [emphasis added in bold].

These Indigenous distributors serve residential and general service customers (general service is a customer such as band office, school, or hospital with a monthly peak demand of 50 kW or less and an annual energy consumption equal to or below 150,000 kWh). Each of these Indigenous distributors is governed by a board of directors who are appointed by the Chief and Council of the respective First Nation.

The licences for Attawapiskat First Nation and Attawapiskat Power Corporation authorize them to distribute and sell electricity to the geographic area of the First Nation Community of Attawapiskat.

The licences for Fort Albany First Nation and Fort Albany Power Corporation specify their geographic service area to distribute and sell electricity:

A. Fort Albany Community Reserve within Fort Albany Indian Reserve No. 67 as follows:

    1. Part of Sinclair Island in the Albany River, District of Cochrane, being about 180 acres and designated as Location C.L.441 on the map comprised of Canada Lands Survey Record 51369 dated January 28, 1963.
    2. Lands located in the District of Cochrane, being about 30.26 acres and designated as Part 1 on the map comprised of Canada Lands Survey Record 55901 dated April 8, 1970.

B. **Four homes that are off-reserve** within one kilometer of the northern boundary of item 1. [Emphasis added in bold]

Kashechewan First Nation and Kashechewan Power Corporation are licensed and authorized by the OEB to distribute and sell electricity in Kashechewan Community Reserve within Fort Albany Indian Reserve No. 67, excluding the area served by Fort Albany First Nation.

Both the First Nation and the First Nation distributor have an obligation as a part of their licence requirements to ensure the distribution assets in the community are effectively and efficiently managed and maintained. These Indigenous utilities are connected through Indigenous Five Nations Energy Inc. (FNEI) transmission company to the Ontario's IESO-controlled grid.

Attawapiskat Power Corporation distributes electricity to 336 customers in the community of Attawapiskat First Nation. It has been distributing power to the community of Attawapiskat since the fall of 2003. Fort Albany Power Corporation distributes electricity to 225 customers in the community of Fort Albany First Nation. It has been distributing power to the community of Fort Albany since November 2001. Kashechewan Power Corporation distributes electricity to 280 customers in the community of Kashechewan First Nation. It has been distributing power to the community of

Kashechewan since December 2001. Each distributor is governed by a board of directors who are appointed by their respective First Nation.

These Indigenous distributors are licensed to retail electricity for the purposes of fulfilling their obligations under section 29 of the *Electricity Act*[129] in the manner specified in their licences. They are also licensed to act as a wholesaler for the purposes of fulfilling their obligations under the Retail Settlement Code[130] or under section 29 of the *Electricity Act*.

These three Indigenous electricity distributors have not filed any rate applications with the OEB since 2007. The reasons for not increasing rates and, thus not applying to the OEB appear to be related to a desire to keep rates low and affordable for the community. It may also be that the regulatory process may be overly cumbersome and time consuming for small-size distributors[131]; especially for small rate changes.

Exceptions and Exemptions from the Act and Regulation

The licences for the three Attawapiskat First Nation, Fort Albany First Nation, and Kashechewan and their respective electricity distributors have identical licensing terms and conditions, including compliance with the OEB's regulatory requirements. For example, section 4 of licence for each First Nation and its electricity distributor states,

> **4 Obligation to Comply with Legislation, Regulations and Market Rules**
>
> 4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance
> by regulation.

Section 5 of the licence states,

> **5 Obligation to Comply with Codes**
>
> 5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such

[129] Distributor's obligation to sell electricity
29 (1) A distributor shall sell electricity to every person connected to the distributor's distribution system, except a person who advises the distributor in writing that the person does not wish to purchase electricity from the distributor. 1998, c. 15, Sched. A, s. 29 (1).

[130] This code sets the minimum obligations that a distributor and retailer must meet in determining the financial settlement costs of electricity retailers and consumers and in facilitating service transaction requests where a competitive retailer provides service to a consumer. These obligations arise through sections 26 through 31, inclusive, of the *Electricity Act, 1998* and the conditions of distributions' licences and retailers' licences.

[131] According to the 2017 Yearbook of Electricity Distributors published by the Ontario Energy Board, the next small-size electricity distributor is Chapleau Public Utilities Corporation with 1,065 customers.

compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;
b) the Distribution System Code;
c) the Retail Settlement Code; and
d) the Standard Supply Service Code.

The licences for these First Nations and their distributors provide some limited exemptions from specific code requirements. For example, the licences stated that,

SCHEDULE 3 LIST OF CODE EXEMPTIONS

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

Section 4.0.4 (2) of the *Ontario Regulation 161/99* which granted an exemption for ten settlements and reserves operating under IPAs with respect to certain sections of the *Ontario Energy Board Act* states the following,

The following provisions of the Act do not apply to a distributor who meets the conditions set out in subsection (3), and who distributes electricity in a settlement or reserve listed in Schedule 1:

1. Section 57[132].

[132] **Requirement to hold licence**
57 Neither the IESO nor the Smart Metering Entity shall exercise their powers or perform their duties under the Electricity Act, 1998 unless licensed to do so under this Part and no other person shall, unless licensed to do so under this Part,
(a) own or operate a distribution system;
(b) own or operate a transmission system;
(c) generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person;
(c.1) engage in unit sub-metering;
(d) retail electricity;
(e) purchase electricity or ancillary services in the IESO-administered markets or directly from a generator;
(f) sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer;
(g) direct the operation of transmission systems in Ontario;
(h) operate the market established by the market rules; or
(i) engage in an activity prescribed by the regulations that relates to electricity. 1998, c. 15, Sched. B, s. 57; 2002, c. 1, Sched. B, s. 6; 2004, c. 23, Sched. B, s. 10; 2006, c. 3, Sched. C, s. 4; 2010, c. 8, s. 38 (8); 2014, c. 7, Sched. 23, s. 4.

2. Sections 71[133] and 72[134].
3. Section 78[135].
4. Sections 80[136] and 81[137].
5. Section 86[138].
6. Section 92[139]. O. Reg. 72/02, s. 3.

(3) The distributor must meet the following conditions:

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[133] **Restriction on business activity**
71 (1) Subject to subsection 70 (9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity. 2004, c. 23, Sched. B, s. 12.

[134] **Separate accounts**
72 Every distributor shall keep its financial records associated with distributing electricity separate from its financial records associated with other activities. 1998, c. 15, Sched. B, s. 72.

[135] **Orders by Board, electricity rates**
Order re: transmission of electricity
78 (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

Order re: distribution of electricity
(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the Electricity Act, 1998 except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

[136] **Prohibition, generation by transmitters or distributors**
80 No transmitter or distributor or affiliate of a transmitter or distributor shall acquire an interest in a generation facility in Ontario, construct a generation facility in Ontario or purchase shares of a corporation that owns a generation facility in Ontario unless it has first given notice of its proposal to do so to the Board and the Board,
(a) has not issued a notice of review of the proposal within 60 days of the filing of the notice; or
(b) has approved the proposal under section 82. 1998, c. 15, Sched. B, s. 80.

[137] **Prohibition, transmission or distribution by generators**
81 No generator or affiliate of a generator shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario unless it has first given notice of its proposal to do so to the Board and the Board,
(a) has not issued a notice of review of the proposal within 60 days of the filing of the notice; or
(b) has approved the proposal under section 82. 1998, c. 15, Sched. B, s. 81.

[138] **Change in ownership or control of systems**
86 (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,
(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;
(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or
(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

[139] **Leave to construct, etc., electricity transmission or distribution line**
92 (1) No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection. 1998, c. 15, Sched. B, s. 92 (1).

1. The distributor must be a First Nation, or a corporation that is solely owned by a First Nation.
2. The distribution system owned by the distributor must not be connected to the IESO-controlled grid.
3. The distributor must only distribute and generate electricity within its geographic service territory as it existed on January 1, 2002. O. Reg. 72/02, s. 3; O. Reg. 496/10, s. 4.

The electricity distributors for the Attawapiskat, Fort Albany, and Kashechewan First Nations who are connected to the IESO-controlled grid were excluded from the exemption granted to a number of First Nations under section 4.0.4 (2) of the *Ontario Regulation 161/99* since these three Indigenous utilities are connected to the IESO-controlled grid.

Section 2.4 (2) of the *Ontario Regulation 160/99* which granted an exemption for seven settlements and reserves with respect to certain sections of the *Electricity Act, 1988* states the following,

> The following provisions of the Act do not apply to a distributor who meets the conditions set out in subsection (3), and who distributes electricity in a settlement or reserve listed in Schedule 1:
>
> 1. Section 26.
> 2. Subsections 29 (4) to (6)[140]. O. Reg. 71/02, s. 2.
>
> (3) The distributor must meet the following conditions:
>
> 1. The distributor must be a First Nation, or a corporation that is solely owned by a First Nation.
> 2. The distribution system owned by the distributor must not be connected to the IESO-controlled grid.

[140] **Distributor's obligation to sell electricity**
29 (1) A distributor shall sell electricity to every person connected to the distributor's distribution system, except a person who advises the distributor in writing that the person does not wish to purchase electricity from the distributor. 1998, c. 15, Sched. A, s. 29 (1).

Exemptions
(4) The Board may exempt a distributor from any provision of this section if, after holding a hearing, the Board is satisfied that there is sufficient competition among retailers in the distributor's service area. 1998, c. 15, Sched. A, s. 29 (4).
Same
(5) An exemption under subsection (4) may be subject to such conditions and restrictions as may be specified by the Board. 1998, c. 15, Sched. A, s. 29 (5).
Same
(6) The Board shall not exempt a distributor entirely from all the provisions of this section unless, after holding a hearing, the Board is satisfied that consumers in the distributor's service area will continue to have access to electricity. 1998, c. 15, Sched. A, s. 29 (6).

3. The distributor must only distribute electricity within its geographic service territory as it existed on January 1, 2002. O. Reg. 71/02, s. 2; O. Reg. 294/14, s. 3.

Because the electricity distributors for the Attawapiskat, Fort Albany, and Kashechewan First Nations are connected to the IESO-controlled grid through Indigenous Five Nations Energy Inc. (FNEI) transmission company, they were excluded from the exemption granted to a number of First Nations under section 2.4 (2) of the Ontario Regulation 160/99. However, section 2.6 of the *Ontario Regulation 160/99* had granted an exemption to these three Indigenous utilities from section 26[141] of the *Electricity Act, 1998* with respect to the OEB assessment[142] for a period until May 2004. It had stated that,

> Section 26 of the *Act* does not apply to Attawapiskat Power Corporation, Fort Albany Power Corporation or Kashechewan Power Corporation until May 1, 2004. O. Reg. 71/02, s. 2.

Due to the exemption from the requirements of section 26 of the *Electricity Act 1998*, both the First Nation owners and their First Nation distributors were granted under their distribution licence an exemption to the requirements of the following sections of the Retail Settlement Code until May 1, 2004:

i. Section 2.3 - Implement Service Transaction Requests Involving Retailers[143]; and
ii. Section 2.7 - Establish Service Arrangements with Competitive Retailers[144].

Section 79 (1) of the *Ontario Energy Board Act* provides rate protection for all consumers who live in rural and remote areas in Ontario including those who live in Attawapiskat, Fort Albany, and Kashechewan First Nations.[145] These three First Nations communities who were named under the

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[141] **Assessment**
26 (1) Subject to the regulations, the Board's management committee may assess those persons or classes of persons prescribed by regulation with respect to all expenses incurred and expenditures made by the Board in the exercise of any powers or duties under this or any other Act. 1998, c. 15, Sched. B, s. 26 (1); 2003, c. 3, s. 24.

[142] The majority of the OEB's revenue (the total of operating expenses excluding non-cash expenses and capital expenditures) is received through cost assessments issued under section 26 of the Act. Licence fee revenues are generated through the invoicing of all licensed entities.

[143] A distributor shall accept and process Service Transaction Requests (STRs) according to the rules and procedures described in Chapter 10. This Code prescribes rules associated with STRs when a consumer's electricity supply is already provided by a competitive retailer or when this STRs will be provided by a competitive retailer once the STR has been processed. Specific services covered by this Code are listed in section 10.1.

[144] A distributor shall enter into a Service Agreement with any licensed retailer who wishes to provide electricity services to consumers connected to the distributor's distribution system and to utilise retail settlement services offered by the distributor.

[145] **Rural or remote consumers**
79 (1) The Board, in approving just and reasonable rates for a distributor who delivers electricity to rural or remote consumers, shall provide rate protection for those consumers or prescribed classes of those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules. 1998, c. 15, Sched. B, s. 79 (1).

Ontario Regulation 442/01: Rural or Remote Electricity Rate Protection have been receiving rate protection under section 79 of the OEB Act. These First Nation communities are not treated differently and distinctively from other communities receiving rural or remote rate protection, since a number of other remote communities (not Indigenous) that are served by Hydro One Remote Communities Inc. are also included in the regulation.

Under regulation, the OEB is required to take reasonable steps to ensure that, for each month, the total amount of rate protection for consumers who live Attawapiskat, Fort Albany, and Kashechewan First Nations is the total monthly amount set out in the regulation. [146] The OEB is required to calculate the amount of rate protection for individual consumers on annual basis in a manner that ensures that the total amount of rate protection for those consumers is equal to the total amount of rate protection available for the year, as specified under the regulation. In this respect, the three Indigenous utilities are treated the same as any other utility eligible for rural and remote rate protection.

With respect to safety, the Electrical Safety Authority (ESA)[147] is the administrative regulatory authority in Ontario that is mandated by the Government of Ontario to enhance public electrical safety in the province. The ESA licenses the electrical contractors and mater electricians through Regulation 570/05, which sets requirements for those doing electrical work. Through Regulation 22/04, the ESA has safety oversight and accountability for Ontario's licensed distribution companies. However, the ESA does not have any electrical safety authority and jurisdiction for the Ontario's safety regulations and codes on First Nations land. The ESA safety services to the First Nation communities are provided upon request and on a voluntarily basis. As a good utility practice, these Indigenous utilities do not connect new customers unless the ESA performs the inspection and issues a safety certification.

Special case
(2) In setting rates under subsection (1), the Board shall ensure that the class of rural or remote consumers receiving assistance under section 108 of the Power Corporation Act on the day before this section comes into force shall receive rate protection while they continue to,
(a) occupy the same rural residential premises, as defined in section 108 of the Power Corporation Act, as they were occupying on that day; and
(b) live in a part of Ontario designated by regulation as a rural or remote area. 1998, c. 15, Sched. B, s. 79 (2).

[146] Under *Ontario Regulation 442/01: Rural or Remote Electricity Rate Protection*, the total monthly amount of rate protection is as follows: Attawapiskat: $53,333.33, Fort Albany: $30,000, and Kaschechewan: $50,000.

[147] In 2004, the Government of Ontario introduced the "*Ontario Regulation 22/04 - Electrical Distribution Safety Regulation"* (the "*O. Reg. 22/04*"). The Electrical Safety Authority (ESA) is responsible for administering *O. Reg. 22/04*" with respect to the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The ESA performs he Due Diligence Inspection (DDI) that is a field and physical inspection of the distributor's distribution system.

8.3 Natural Gas Distribution Utilities

8.3.1 Six Nations Natural Gas Limited

Background Information

Six Nations Natural Gas Limited (the "Six Nations Natural Gas") is a for-profit, natural gas utility that is owned by the Six Nations of the Grand River Territory[148,149]. The utility is a limited partnership between Six Nations Natural Gas Limited and elected council of the Six Nations of the Grand River Territory where the elected council is the limited or silent partner.

The utility was formed in 1989, when the council's then economic development manager put forth the idea of building a natural gas pipeline across the reserve. With a staff complement of 12, the utility distributes under 9,000,000 cubic meters of gas annually with the annual sales of approximately $2.8 million to 2,700 customers on reserve within First Nation community of Six Nations of the Grand River Territory and Mississaugas of New Credit First Nation in a 100-square-mile service area. Six Nations Natural Gas is an embedded gas distributor in the Enbridge Gas distribution franchise area by physically being connected to the Enbridge Gas distribution system (Enbridge Gas is the major rate-regulated natural gas distributor in Ontario, comprised of Enbridge Gas Distribution and the former Union Gas Company). Six Nations pays cost-based rates to Enbridge Gas for storage services. It currently purchases its gas from Shell North America.

Although Six Nations Natural Gas is not regulated by the OEB, it has interactions with the OEB when Enbridge Gas' connections to the Six Nations Natural Gas system require upgrades and changes.
Six Nations Natural Gas has established a Conditions of Service that includes quality of service, billing, customer care, among others. The Conditions Service also includes a three-step customer complaint process with the board of directors being the ultimate decision maker in addressing and resolving customer complaints. The complaints process does not involve the Six Nations of the Grand River Territory.

The utility is governed by a seven-member board of directors who are appointed by the Six Nations of the Grand River Territory, where the elected council can hold up to two elected members. The other seats are filled by members of the community. The rates are approved by its board of directors. The utility is a member of Ontario One Call[150] and the Ontario Regional Common Ground Alliance[151].

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[148] The Six Nations of the Grand River Territory consists of approximately 18,000 hectares of land. A small proportion of the land is held by the First Nations, while the majority of the land is held by individual band members through Certification of Possession.

[149] http://www.sixnatgas.com/about.html

[150] Ontario One Call is a not-for-profit organization that facilitates excavation locate requests to ensure homeowners, excavators and infrastructure owners are safe when digging. Established in 1996, Ontario One Call notifies infrastructure owners (members) of excavation requests. These members then deliver locates, minimizing the risk of infrastructure damage, loss of utilities, injury, and monetary consequences (https://www.on1call.com/about-us/).

[151] The Ontario Regional Common Ground Alliance works to foster an environment of safety throughout Ontario for all workers and the public. This is accomplished by offering practical tools while promoting public awareness and

Six Nations Natural Gas has some similarities with the two non-Indigenous, municipally-owned gas distribution utilities in the City of Kingston and City of Kitchener in Ontario, which are not regulated by the OEB. Utilities Kingston is a municipally-owned gas distribution utility owned by the City of Kingston in Ontario. It provides gas distribution services to nearly 15,000 customers in central Kingston. The City Council for the City of Kingston approves operating budget and capital budget for its municipally-owned gas utility. The City Council approves the schedules for natural gas local distribution rates and the charges for the appliance rental business. Kitchener Utilities is a municipally-owned gas distribution utility that is owned by the City of Kitchener in Ontario that provides natural gas to 66,000 of customers throughout Kitchener. It is a division of the Corporation of the City of Kitchener. The City Council for the City of Kitchener approves operating budget and capital budget for its municipally-owned gas utility.

Exceptions and Exemptions from the Act and Regulation

Nations Natural Gas is not regulated by the OEB.

In Ontario, no gas transmitter, gas distributor or storage company is permitted to sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the OEB. Section 36 (1) under PART III Gas Regulation - Order of Board required of the *Ontario Energy Board Act* states the following,

> No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 1998, c. 15, Sched. B, s. 36 (1).

However, the *Ontario Regulation 161/99* grants exemption from section 36 (1) of the *Ontario Energy Board Act* for the distributors who distribute less than 3,000,000 cubic metres of gas annually. Section 3 of the regulation states the following,

> Section 36 of the Act **does not apply** to the sale, transmission, distribution or storage of gas by a distributor who distributes less than 3,000,000 cubic metres of gas annually. O. Reg. 161/99, s. 3. [emphasis added in bold]

Section 36 (8) of the *Ontario Energy Board Act* also provides an exception to section 36 (1) of the *Ontario Energy Board Act* for a municipality or municipal public utility commission transmitting or distributing gas under the *Public Utilities Act*. Section 36 (8) states the following,

> This section does not apply to **a municipality** or **municipal public utility commission transmitting or distributing gas under the *Public Utilities Act*[152] on the day before this section comes into force**. 1998, c. 15, Sched. B, s. 36 (8). [emphasis added in bold]

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compliance of best practices in regards to underground infrastructure and ground disturbance practices (https://orcga.com/about-us/).

[152] Under the *Public Utilities Act*, R.S.O. 1990, c. P.52, "public utility" means water, artificial or natural gas, steam or hot water. 2001, c. 25, s. 482 (1).

Six Nations Natural Gas, Utilities Kingston and Kitchener Utilities are the only three natural gas utilities in Ontario that are exempted from the *Ontario Energy Board Act* with respect to rate regulation under section 36(1) by being a municipality or municipal public utility commission transmitting or distributing gas under the *Public Utilities Act*. Six Nations Natural Gas has not been treated differently from any other natural gas distributor in the province when it comes to regulation by virtue of being an Indigenous natural gas distributor. Similar to the Utilities Kingston and Kitchener Utilities, Six Nations Natural Gas has been operating prior to 1998. In fact, Six Nations Natural Gas has been operating since 1989, which was prior to the date 1998 when section 36 (8) of the *Ontario Energy Board Act* came into force.

The *Ontario Energy Board Act* refers to a number of other Acts to ensure gas supplies to buildings in Ontario. For example, Section 42(2) under Duties of gas transmitters and distributors of the *Ontario Energy Board Act* states the following,

> **Duty of gas distributor**
> (2) Subject to the *Public Utilities Act*, the *Technical Standards and Safety Act, 2000* and the regulations made under the latter *Act*, sections 80, 81, 82 and 83 of the *Municipal Act, 2001* and sections 64, 65, 66 and 67 of the *City of Toronto Act, 2006*, a gas distributor shall provide gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building. 2006, c. 32, Sched. C, s. 42.

Other Regulations

A number of other non-OEB regulations apply to Ontario natural gas utilities, including Six Nations Natural Gas. For example, *Ontario Regulation 210/01, Oil and Gas Pipeline Systems*, requires that Six Nations Natural Gas report when there has been damage to the system that results in a gas leak. As part of a Technical Standards and Safety Authority audit, mandated under the *Electricity and Gas Inspection Act*, Six Nations Natural Gas conducts inspections of customer-owned appliances, piping and fittings to identify hazards.

8.4 Independent Power Authority (IPA)

An Independent Power Authority (IPA) is a distributor that is owned and operated by a local First Nation community. There are ten IPAs in Ontario. They are not connected to the provincial grid, and therefore they are neither licensed, nor are rate regulated by the OEB. The IPAs include Keewaywin First Nation, Muskrat Dam First Nation, North Spirit First Nation, Nibinamik First Nation, Wawakapewin First Nation, Weenusk First Nation, Pikangikum First Nation, Wunnumin Lake First Nation, Poplar Hill First Nation, and Eabametoong First Nation.

Exceptions and Exemptions from the Act and Regulation

The ten First Nations owning and operating the IPAs are specifically named under Schedule 1 of the Ontario Regulation 161/99, and thus they are not regulated by the OEB.

9. Renewable Energy Projects Across Canada

Although this report primarily addresses regulation of Indigenous utilities and their defining characteristics, it raises a set of questions with respect to regulation of new "utility" models based on renewable energy resources and renewable-based microgrids (the "Microgrids"). A brief discussion of Indigenous renewable energy projects in Canada is provided, as this may be of interest in considering the role Indigenous Peoples are playing in the renewable energy sector.

Many Indigenous communities which are located in rural and remote areas of Canada are not connected to electricity grids, and instead rely on expensive and polluting diesel generation, as the sole energy source to produce electricity. For example, every community in Nunavut is located in an isolated area, and there is no territorial electricity grid at all. All communities in Nunavut rely on diesel generation.

First Nations engagement in development of energy projects have increased in recent years, as Indigenous Peoples are taking leadership in their role in the renewable energy sector. This is an increasing trend across all provinces and territories. A number of key factors have contributed to the First Nations engagement including the following, among others:

1. Energy policies implemented by the Government of Canada and some provincial and territorial governments in promoting renewable energy solutions including solar, wind, and geothermal.[153]
2. First Nations desire towards achieving self-sufficiency, self-reliance and self-determination in meeting their energy needs within First Nation communities.
3. First Nations goal of economic development.

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[153] In January 2019, the Government of Yukon announced that it has fully implemented the Independent Power Production policy, allowing First Nation governments, communities and entrepreneurs to generate renewable energy and feed it into the electrical grid to help meet local demands.

The government announced that "*the implemented policy provides clarity and regulatory certainty for the utilities and independent power producers while ensuring rates remain stable for utility consumers*." https://yukon.ca/en/news/government-yukons-independent-power-production-policy-implemented

Support for renewable energy projects has been recently changed by a number of provincial governments in Canada. In July 2018, Ontario's new government announced that it was cancelling 758 renewable energy contracts in what it stated was an effort to reduce electricity bills in the province. In October 2018, the Quebec government announced that it wanted out of the contentious Apuiat wind farm project and has tapped Hydro-Québec to come up with an exit strategy, Radio-Canada has learned. On June 10, 2019, the new Government of Alberta advised the AESO that it would not be continuing with the REP and thus did not intend to proceed with additional competition rounds. The government provided direction moving forward that the AESO should continue to oversee the projects and contracts awarded under previous REP rounds.

4. First Nations influence on the government policies to reduce reliance on diesel generation and bring a number of environmental, social and economic benefits to the First Nation communities.

The fact that First Nations are undertaking initiatives to reduce reliance on diesel generators in their communities, coupled with the financial incentives and grants provided by provincial/territorial and federal government, will facilitate the development of Microgrids on First Nations reserve; especially in remote and rural areas across Canada. In addition, collaboration approach and partnership relationships between Indigenous communities and industry have expedited the implementation of renewable generation projects across provinces and territories. For example, Gull Bay First Nation[154], which is a remote community in Ontario and is not connected to the provincial grid, implemented an integrated renewable-based microgrid project that is first of its kind in Canada. Gully Bay First Nation developed its microgrid system by receiving funding support from various government and private sources and in collaboration with Hydro One Remotes, the Ontario Power Generation (OPG), and the Independent Electricity System Operator. In Alberta, the private-sector partnerships with Kainai First Nation, Sawridge First Nation, and Paul First Nation led to development of approximately $1.2 billion in utility scale wind projects over 5 MW which include a minimum 25 per cent Indigenous equity component. British Columbia, which has a number of remote Indigenous communities who rely on diesel generation, as supplied by BC Hydro, may not be an exception from this increasing trend in development of community-based, utility-scale renewable energy resources.

Furthermore, as a number of First Nations across Canada have been undertaking initiatives towards self-governance in health care and education, they have also increased their participation in the utility industry towards meeting their energy needs while achieving "energy sovereignty" and self-reliance and self-determination for energy. Gul Gay First Nation in Ontario calls its Microgrid project as "*Canada's Game Changer: Off-grid diesel reduction to energy sovereignty*".

The current regulatory structure that is built around historical model of electric utility, as a traditional "natural monopoly" model, is being challenged and is evolving by the introduction of emerging distributed energy resources and advanced innovative renewable solutions.[155] These advanced renewable energy solutions served as as disruptive technologies that have imposed challenges for "traditional" regulatory models. These technologies that are transforming the existing utility industry and creating new models of "utilities" such as Microgrids may require energy regulators develop, adopt, and implement the "rules of the road" for microgrid development.[156]

The degree of involvement for the energy regulators in Canada with respect to the regulation of renewable energy resources varies across provinces and territories depending on particular provincial

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[154] Kiashke Zaaging Anishinaabek – Gull Bay First Nation is an Ojibway Nation located on the western shores of Lake Nipigon and the surrounding territory. It is roughly a 200km drive north from the closest urban city of Thunder Bay, Ontario and has a registered population of approximately 1,375 Citizens residing on and off reserve. http://www.gullbayfirstnation.com/

[155] Microgrids: A Regulatory Perspective - California Public Utilities Commission Policy & Planning Division April 14, 2014.

[156] Ibid., 22.

or territorial government's energy policy. In Yukon, the director of the Energy Branch in the Department of Energy, Mines and Resources must approve the applications to supply electricity generated by a micro-generation facility to the electrical system of a public utility. In Ontario, the OEB has issued 16 electricity storage licences to the entities seeking developing electricity battery energy storage facilities in Ontario. However, depending on the government's energy policy direction, a number of regulators are responding to the new development of renewable solutions by developing policies related to solar, battery storage devices, distributed generation, net energy metering, and behind-the-meter microgrids. In November, 2018, the OEB's Advisory Committee on Innovation issued its report regarding actions that the OEB can take to advance innovation in Ontario's energy sector.

The development of renewable energy resources by Indigenous Peoples is an important consideration for regulators given many Indigenous communities that are located in isolated rural and remote areas and are not connected to electricity grid may develop "utility" scale Microgrids instead of continuing on reliance for diesel generation. From a regulatory perspective, the regulators are challenged to respond to development of distributed energy resources including Microgrids (the "New Utility"). They need to address a number of issues, among others, including:

1. Should the renewable-based microgrids treated differently from traditional diesel-based microgrids from a regulatory perspective?
2. Should the owners of the New Utility be regulated?
3. Should the operator of the New Utility be regulated?
4. Should there be any exemption, in part or in full, for producing/distributing certain amount of power before the New Utility are regulated?
5. How should the cost for development of the New Utility be recovered from its users or customers if the New Utility is not publicly funded, i.e., government grants?
6. Who should approve the allocation of cost for the New Utility among different customer classes if there is such allocation?
7. How should the tariff of rates, if any, for the New Utility customers be designed and structured?
8. Who should approve the tariff of rates, if applicable, for the New Utility customers?
9. How should the stranded cost, if any, of natural monopoly distribution system be recovered? Who should pay for it?
10. What should be the stand-by rates charged by the regulated distribution system providing emergency and/or back-up power supply to the New Utility?
11. Who should have the oversights to ensure quality and reliability of supply for customers?
12. What role, if any, should the regulator play in development and implementation of the New Utility?

Alberta

Private sector companies have partnered with First Nations to invest approximately $1.2 billion in renewable energy projects in Alberta's Renewable Electricity Program (REP) round 2.[157] In December 2018, the Government of Alberta announced that the three "*wind projects are private-sector*

[157] Government of Alberta -Wind projects create jobs, Indigenous partnerships, December 17, 2018. https://www.alberta.ca/release.cfm?xID=6225465E583D7-C8A6-0844-D9754D497BA00D68

partnerships with First Nations, which include a minimum 25 per cent Indigenous equity component that will help create jobs and new economic benefits. Additional opportunities may include skills training and educational opportunities."[158]

Kainai First Nation, Sawridge First Nation, and Paul First Nation have participated in Alberta's Renewable Electricity Program (REP) round 2, as partners in utility scale projects over 5 MW. The requirement for the REP round 2 was that all proponents had to have an Indigenous partner at 25% equity. EDF Renewables Canada Inc. (subsidiary of France-based company) will build the 202-megawatt Cypress Wind Power project near Medicine Hat in partnership with the Kainai First Nation. Capstone Infrastructure Corporation (Ontario-based) will build the 48-megawatt Buffalo Atlee wind farms near Brooks in partnership with the Sawridge First Nation. Potentia Renewables Inc. (Ontario-based) will build the 113-megawatt Stirling Wind project near Lethbridge in partnership with the Paul First Nation, as well as Calgary-based Greengate Power Corporation. Each of these projects are expected to begin construction in 2020 and be fully operational by mid-2021.[159]

Manitoba

AKI Solutions Group is a non-profit, First Nations managed social enterprise. Aki Energy has installed over 3 million dollars in renewable energy technologies in partnership with Manitoba First Nations. For example, it developed geothermal energy partnerships with Peguis First Nation and Fisher River Cree Nation.[160]

Northwest Territories

On November 17, 2018, the Government of Northwest Territories and federal government announced $40 million to build the Inuvik Wind Generation project, which will include turbines, a grid controller and a large battery to store energy when wind speed slows.[161]

Ontario

In Ontario, First Nation communities are engaged in numerous renewable energy projects. One project of particular interest is the fully-integrated renewable-based microgrid project by Gull Bay First Nation. Gull Bay First Nation is a remote community in Ontario. Currently, it is not economic to connect this community to the provincial grid. The Giizis Energy microgrid is owned 100% by Gull Bay First Nation through its ownership of Ma'iingan Development and it is expected to be operational in August 2019. Gull Bay First Nation calls the project as, "Canada's Game Changer: Off-grid diesel reduction to energy sovereignty".[162] According to the Ontario's Independent Electricity System Operator (IESO), it is "fully-

[158] Ibid.
[159] Ibid.
[160] http://www.akienergy.com/overview-1
[161] https://www.cbc.ca/news/canada/north/wind-power-andrew-stewart-q-and-a-1.4907876
[162] http://www.gullbayfirstnation.com/mashkawiziiwin-energy/

integrated microgrid" with battery storage and "first of its kind in Canada".[163] The project is an integration of solar photovoltaic power using more than 1,000 ground-mounted solar panels, battery energy storage, and a microgrid controller. Since the microgrid generates 360 kW power to the community, pursuant to section 57(c) of the *Ontario Energy Board Act, 1998*, the community is subject to an exemption from the requirement to hold an electricity generation licence with the OEB.[164] The system is connected to the existing Hydro One Remotes diesel generating station is partially displacing the traditional diesel-based distribution system through its microgrid system, and thus off-setting diesel use.

Saskatchewan

On May 31, 2019, SaskPower and First Nations Power Authority signed an agreement and announced 85 million First Nations-led solar projects partnership. The projects will generate 20 megawatts of power to the provincial gird. The project, which is expected to be stretched over the next 20 years, is part of SaskPower's goal to add 60 megawatts of solar power across the province by 2021.[165]

10. Conclusions

In Canada, Indigenous Peoples are actively involved in the utility sector through owning and/or operating electricity transmission and distribution utilities and natural gas distributors. This jurisdictional review has identified that a number of Indigenous utilities exist across Canada, specifically, in Alberta, Northwest Territories, Nunavut, and Ontario. These Indigenous utilities have a number of defining characteristics in common, whether or not they are regulated. They are owned or/and operated, in full or in part, by an Indigenous nation. They provide either electricity or natural gas utility services to customers or members on a reserve, either on their own or through a third-party. They charge their customers through rates for the services that they provide.

Different ownership structures result from historical context for the establishment of these Indigenous utilities, as well as the economic and geographical considerations of First Nations communities. The utilities that are owned wholly by Indigenous Peoples are only found in Alberta and Ontario. Indigenous Peigan Indian REA, Ermineskin REA, and Montana REA are wholly owned by First Nation communities located in rural areas of Alberta. These REAs are not-for-profit, rural cooperatives that

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[163] The IESO, "Fully-integrated microgrid at Gull Bay First Nation first of its kind in Canada", June 20, 2018 http://www.ieso.ca/en/Powering-Tomorrow/Efficiency/Fully-integrated-microgrid-at-Gull-Bay-First-Nation-first-of-its-kind-in-Canada

[164] The OEB's Electricity generation licence (includes Feed-in Tariff program)
Section 57(c) of the *Ontario Energy Board Act, 1998* provides that no person is permitted to generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person without a licence. There are certain exemptions from the requirement to hold an electricity generation licence. One of those exemptions is that a person who owns or operates one or more facilities each with a total name plate capacity of 500 kilowatts or less is exempt from the need to obtain an electricity generation licence.

[165] https://leaderpost.com/news/local-news/saskpower-first-nations-power-authority-announce-solar-project-partnership

own their electricity distribution systems and distribute electricity to their members within their communities. Similar to the REAs, there are several Indigenous rural natural gas co-operatives in Alberta that are not-for-profit rural utilities and are wholly owned by First Nations. These natural gas co-ops provide natural gas services to their members on the First Nation reserve lands. The non-for-profit, electricity transmission utility FNEI and the three non-for-profit, electricity distributors Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation are wholly owned by the Indigenous Peoples in Northern Ontario. Six Nations Natural Gas is wholly owned by the Six Nations of the Grand River Territory to distribute natural gas services to its customers on the reserve.

Furthermore, the review noted an increased number of joint partnership arrangements between First Nation communities and electricity transmission utilities. These are mostly found in recent years in Alberta, Northwest Territories, and Ontario. These partnerships helped Indigenous Peoples pursue ownership interests in utilities. This trend is expected to increase in the future. For example, PiikaniLink L.P. is a joint partnership between AltaLink and Piikani Nation. Piikani Nation owns 51% of the PiikaniLink L.P.'s assets. WPLP is an electricity transmission company that is jointly owned by 24 First Nation communities in Ontario and FortisOntario. The participating First Nations hold a 51% interest in WPLP and FortisOntario holds the remaining 49% interest.

An important finding through this review is that it is not uncommon for regulatory models to be developed based on unique circumstances for regulation of each Indigenous utility and their defining characteristics in the provinces and territories. The regulatory models with respect to the regulation of Indigenous utilities in Alberta, Northwest Territories, Nunavut, and Ontario are also unique to each of these provinces and territory.

There are several Indigenous utilities in these provinces and territories that are rate regulated and subject to regulation, e.g., PiikaniLink L.P. in Alberta, Northland Utilities (NWT) Limited in Northwest Territories, and FNEI in Ontario. Furthermore, there are some other Indigenous utilities that are not regulated by a commission or a board and are subject to certain statutory exceptions or exemptions. The Indigenous utilities that are not rate regulated are only found in Alberta and Ontario.

The Indigenous REAs and Indigenous natural gas co-ops in Alberta are not regulated by the AUC. Six Nation Natural Gas and the ten IPAs in Ontario are not regulated by the OEB. The Chiefs and Council or the board of directors for these utilities set and approve the rates that these Indigenous utilities charge to their customers. The statutory exceptions or exemptions for these Indigenous utilities need to be considered in the historical context of the government's economic and energy policies in Alberta and Ontario over the past decades. In addition, the unique regulatory treatment with respect to some of the statuary exemptions related to Indigenous utilities in Ontario, is due to legislative and regulatory exemptions which the First Nations sought and/or applied for, and were subsequently granted.

Finally, the demonstrated interest of Indigenous Peoples in pursuing new renewable projects and ownership interests in utilities, suggests that regulatory treatment in the future could also result in unique, non-conventional utility models or exemptions. The current regulatory structure that is built around the historical model of the electric utility, as a traditional "natural monopoly" model is being challenged by the introduction of emerging distributed energy resources and advanced innovative renewable solutions such as microgrids. These technologies are transforming the existing utility industry and creating new models of renewable-based "utilities" such as Microgrids. First Nations are

undertaking initiatives to reduce reliance on diesel generators in their communities. This coupled with the financial incentives and grants provided by provincial/territorial and federal government as well as partnership opportunities with both public and private sectors will expedite the development of microgrids on First Nation reserves across Canada. From a regulatory perspective, the regulators must be prepared to address the regulatory challenges and issues arising from the development of renewable-based microgrids.

11. Appendices A – Regulations and Defining Characteristics of Indigenous Utilities

Province or Territory: Alberta
Board/Commission: Alberta Utilities Commission (AUC)

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by Board or Commission?**	**Subject to Partial or Full Regulation by Board or Commission?**	**Statutory Exemptions or Exceptions Granted?**	**Application Related Regulatory Exception Granted?**
PiikaniLink L.P.	Electricity Transmission	Piikani Nation (51%) and AltaLink (49%)	Limited Partnership	For-profit	Self-operating (AltaLink)	Transmission customers	Piikani Nation reserve	Yes	Full regulation	No	No
KainaiLink L.P.	Electricity Transmission	Blood Tribe (51%) and AltaLink (49%)	Limited Partnership	For-profit	Self-operating (AltaLink)	Transmission customers	Blood Tribe reserve	Yes	Full regulation	No	No
Ermineskin ERA	Electricity Distribution	Ermineskin Cree Nation	Rural Electrification Associations - cooperatives	Not-for-profit	Self-operating REA	Members	Ermineskin Cree Nation Reserve	No. A board of directors sets the rates	Partial, very limited regulation	Yes	Yes
Peigan Indian REA	Electricity Distribution	Piikani Nation	Rural Electrification Associations - cooperatives	Not-for-profit	Operating REA - Operation contracted out to FortisAlberta	Members	Piikani Nation Reserve	No. Chief and Council sets the rates	Partial, very limited regulation	Yes	Yes
Montana REA	Electricity Distribution	Montana Indian Reservation	Rural Electrification Associations - cooperatives	Not-for-profit	Operating REA - Operation contracted	Members	Montana Indian Reservation	No. Chief and Council sets the rates	Partial, very limited regulation.	Yes	Yes

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by Board or Commission?**	**Subject to Partial or Full Regulation by Board or Commission?**	**Statutory Exemptions or Exceptions Granted?**	**Application Related Regulatory Exception Granted?**
					out to FortisAlberta						
*Rural Natural Gas Co-operatives (several co-ops)	Natural Gas Distribution	**Individual Indigenous Community	Cooperatives	Not-for-profit	It varies among co-ops. Self-operating and Operating Cooperatives (Contracted out to a neighboring Indigenous co-op or an investor-owned gas utility)	Members	Reserve	No. It varies among co-ops While Chief and Council sets the rates for a number of natural gas co-ops, the board of directors for other co-op establishes the rates.	Partial, limited regulation	Yes	Yes

Notes:
*There are several Indigenous natural gas co-ops in Alberta. While a number of co-ops such as Dene Tha Natural Gas Utility, Goodfish Lake Gas Utility, Horse Lake Indian Band, Kehewin, Montana Indian Band, Onion Lake Gas, Samson Cree Nations are members of the Federation of Alberta Gas Co-ops members, there are other co-ops such as Ermineskin and Louis Bull who are not members of the Federation of Alberta Gas Co-ops.
** Each natural gas cooperative is owned by its First Nation owner, and is governed by the Indigenous Peoples within the community.

Province or Territory: Northwest Territories
Board/Commission: Northwest Territories Public Utilities Board

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by Board or Commission ?**	**Subject to Partial or Full Regulation by Board or Commission ?**	**Statutory Exemptions or Exceptions Granted?**	**Application Related Regulatory Exception Granted?**
Northland Utilities (NWT) Limited	Electricity Generation and Distribution	Denendeh Investments Inc. (27 Dene First Nations 50%) and ATCO Ltd. (50%)	Limited Partnership	Not-for-profit	Self-operating - ATCO Ltd.	Various class of customers, e.g. residential, commercial	Hay River, and several other smaller communities including Kakisa, Dory Point, Fort Providence, Sambaa K'e, Wekweeti, Enterprise and the K'at'lodeeche First Nation.	Yes	Full regulation	No	No
Northland Utilities (Yellowknif) Limited	Electricity Distribution	Denendeh Investments Inc. (27 Dene First Nations 50%) and ATCO Ltd. (50%)	Limited Partnership	For-profit	Self-operating - ATCO Ltd.	Various class of customers, e.g. residential, commercial	Yellowknife and N'Dilo	Yes	Full regulation	No	No

Province or Territory: Nunavut
Board/Commission: No board or commission exists. The Utility Rates Review Council (URRC) is only an advisory body to the Minister Responsible for the Qulliq Energy Corporation

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by Board or Commission?**	**Subject to Partial or Full Regulation by Board or Commission?**	**Statutory Exemptions or Exceptions Granted?**	**Application Related Regulatory Exception Granted?**
Qulliq Energy Corporation (QEC)	Electricity Generation (25 stand-alone diesel power plants in 25 communities) and Distribution	Government of Nunavut	Crown Corporation	Not-For-profit	Self-operating	Various class of customers, e.g. residential, commercial	25 communities in Nunavut	Yes. The Minister Responsible for the QEC, along with the Executive Council make the final decisions on power rates	No. Government regulation. The Utility Rates Review Council (URRC) is only an advisory body to the Minister Responsible for the QEC	Government regulation	Not applicable.

Province or Territory: Ontario
Board/Commission: Ontario Energy Board (OEB)

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by the Board or Commission?**	**Subject to Partial/ Full Regulation by Board or Commission?**	**Statutory Exemption or Exception Granted?**	**Application Related Regulatory Exception Granted?**
Five Nations Energy Inc. ("FNEI")	Electricity Transmission	Members: Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation	Corporation	Not-for-profit	Self-operating	Attawapiskat Power Corporation, Fort Albany Power Corporation, and Kashechewan Power Corporation, and De Beers Canada Victor Diamond	Attawapiskat First Nation reserve, Fort Albany First Nation reserve, and Kashechewan First Nation reserve, De Beers Canada Victor Diamond	Yes	Full regulation	No	Yes (Maximum ROE granted in its 2016 rate application – similar to the for-profit utilities)
B2M Limited Partnership (B2M L.P.)	Electricity Transmission	B2M GP Inc., a wholly owned subsidiary of Hydro One Inc. (66%) and SON FC owned by the Chippewas of Saugeen First Nation and the Chippewas of Nawash First Nation (34%)	Limited Partnership	For-profit	Operation contracted out to Hydro One	Transmission customers	Chippewas of Saugeen First Nation and the Chippewas of Nawash First Nation reserves	Yes	Full regulation	No	No

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by the Board or Commission?**	**Subject to Partial/ Full Regulation by Board or Commission?**	**Statutory Exemption or Exception Granted?**	**Application Related Regulatory Exception Granted?**
Wataynika -neyap Power LP (WPLP)	Electricity Transmission	24 participating First Nations (51%) and FortisOntario (49%)	Limited Partnership	For-profit	Operation contracted out to FortisOntario	Transmission customers - remote First Nation communities	25 First Nation communities Reserve	Yes	Full regulation	Yes (Order-in-Council No. 1158/2016 - July 20, 2016). An exemption included for Licence Amendment without a Hearing and an exemption from for the OEB's Needs Assessment for Leave to Construct.	Yes (Certain sections of the Transmission System Code).
* Cat Lake Power - from 2001 to 2006	Electricity Transmission	Cat Lake First Nation	Corporation	Not-for-profit	Operation contracted out to - Sioux Lookout Hydro from 2001 to 2006	Residential and general	Cat Lake First Nation Reserve	No. A board of directors set the rates from 2001 to 2006	Regulation was limited to only licensing and meeting its license	Yes	No

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by the Board or Commission?**	**Subject to Partial/ Full Regulation by Board or Commission?**	**Statutory Exemption or Exception Granted?**	**Application Related Regulatory Exception Granted?**
									requirements.		
Attawapiskat Power Corporation	Electricity Distribution	Attawapiskat First Nation	Corporation	Not-for-profit	Self-operating	Residential and general service customers	Attawapiskat First Nation reserve	Yes	Full regulation	Yes	No
Fort Albany Power Corporation	Electricity Distribution	Fort Albany First Nation	Corporation	Not-for-profit	Self-operating	Residential and general service customers	Fort Albany First Nation reserve and Four homes that are off-reserve within one kilometer of the northern boundary.	Yes	Full regulation	Yes	No
Kashechewan Power Corporation	Electricity Distribution	Kashechewan First Nation	Corporation	Not-for-profit	Self-operating	Residential and general service customers	Kashechewan First Nation reserve	Yes	Full regulation	Yes	No
Six Nations Natural Gas Limited	Natural Gas Distributor	Six Nations of the Grand River Territory	Limited Partnership	For profit	Self-operating	Residential and general service customers	The reserve within First Nation community of Six Nations of the Grand River Territory and Mississaugas of New Credit First Nation in a 100-square-mile service area	No. A board of directors sets the rates	No	Yes	Not applicable. OEB does not regulate.

	Defining Characteristics of Indigenous Utilities							Regulation of Indigenous Utilities			
Utility Name	**Type of Services**	**Owner(s)**	**Ownership Type**	**Type of Organization**	**Operating Structure**	**Type of Customers Served**	**Geographic Service Area**	**Rate Regulated by the Board or Commission?**	**Subject to Partial/ Full Regulation by Board or Commission?**	**Statutory Exemption or Exception Granted?**	**Application Related Regulatory Exception Granted?**
** Independent Power Authority (IPA)	Diesel Generation and Electricity Distribution	***Individual Indigenous Community	Corporation	Not-for-profit	Self-operating	Residential and general service customers	Reserve	No	No	Yes	Not applicable. OEB does not regulate.
**** Generators	Generation	Wholly or in part by Indigenous Peoples	Corporation	Not-for-profit/For profit	Self-operating	Generation customer	Reserve	No	Regulation is limited to only licensing and meeting license requirements.	Yes	Not applicable. OEB does not regulate.

Notes:
* Cat Lake First Nation still owns its transmission assets in the community of Cat Lake. In 2006, Cat Lake power requested the OEB have its licence relinquished. Hydro One Networks currently holds an interim licence to operate the transmission and distribution businesses serving the community.
** There are ten IPAs in Ontario. They are not connected to the provincial grid, and therefore they are neither licensed, nor are rate regulated by the OEB.
*** They include Keewaywin First Nation, Muskrat Dam First Nation, North Spirit First Nation, Nibinamik First Nation, Wawakapewin First Nation, Weenusk First Nation, Pikangikum First Nation, Wunnumin Lake First Nation, Poplar Hill First Nation, and Eabametoong First Nation.
**** There are a number of licensed generators which are owned, either wholly or in part by Indigenous Peoples. However, the licensing is the only direct regulation by the OEB.

12. Appendices B - Mandate of Canadian Provincial and Territorial Energy Regulators

Province/ Territory	Regulator	Mandate
1. Alberta	Alberta Utilities Commission	The Alberta Utilities Commission (AUC) regulates Alberta's investor-owned electric, gas, water utilities and certain municipally owned electric utilities to ensure that customers receive safe and reliable service at just and reasonable rates. The AUC also regulates the routes, tolls and tariffs of energy transmission through utility pipelines and electric transmission and distribution lines. Companies who propose to construct or rebuild electric generation, transmission or distribution facilities in Alberta, must apply to the Commission for siting approval. When reviewing the utility's application, the Commission considers the social and environmental impacts, as well as any economic implications for the ratepayers. Furthermore, the AUC also provides an adjudicative function for issues arising in Alberta's electric and natural gas markets. Source: http://www.auc.ab.ca/pages/who-we-regulate.aspx

Province/ Territory	Regulator	Mandate
2. British Columbia	British Columbia Utilities Commission	We are a regulatory agency of the Provincial Government, operating under and administering the *Utilities Commission Act*. As a quasi-judicial body, the BCUC has the power to make legally binding rulings on matters within our jurisdiction, such as a regulated entity's: • Rate or premium applications • New facility construction plans • Issuance of securities Our areas of oversight include: • Natural Gas utilities • Electricity utilities • Intra-provincial pipelines. Under the Oil and Gas Activities Act, the BCUC establishes tolls and conditions of service for intra provincial oil pipelines. • Universal compulsory automobile insurance We are responsible for ensuring customers receive safe, reliable services at fair rates from the entities we regulate. We balance that responsibility against the need to ensure utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. In addition to our regulatory responsibilities, the BCUC reviews ratepayers' complaints and inquiries about regulated entities within our jurisdiction. Source: https://www.bcuc.com/about/our-role.html

Province/ Territory	Regulator	Mandate
3. Manitoba	Manitoba Public Utilities Board	The PUB has a specific mandate based on its enabling legislation. We act as a rate setting tribunal for various public utilities. The PUB establishes just and reasonable rates for the provision of electricity by Manitoba Hydro, for natural gas supplied by Centra Gas, for propane supplied by Stittco Utilities Ltd, rate bases and premiums charged for compulsory driver and Basic vehicle insurance provided by Manitoba Public Insurance and rates charged by water and wastewater utilities outside the City of Winnipeg. The PUB regulates private natural gas brokers and monitors the construction and operation of gas pipelines that are subject to provincial jurisdiction. We make recommendations to government on a triennial basis regarding the regulation of payday lenders and payday loans including the maximum chargeable rate. The PUB also sets the maximum allowable fee charged for cashing a government cheque. As a quasi-judicial administrative tribunal, we hear appeals on behalf of the Water Services Board and from individuals who have been disconnected from water and wastewater utilities or natural gas or propane service (other than in the winter). The PUB fulfills its mandate through public hearings, paper reviews and when required direct intervention. Our processes involve enquiry, research, consultation, careful deliberation, and public dissemination of decisions and notices of upcoming Board activities including rate applications. When considering a rate application, the Board reviews the financial requirements of the utility as well as the impact on the consumer. While the Board is sensitive to customer reaction to increases, it must consider the sustainability of the utility. Source: http://www.pubmanitoba.ca/v1/about-pub/what-we-do.html

Province/ Territory	Regulator	Mandate
4. New Brunswick	New Brunswick Energy and Utilities Board	The New Brunswick Energy and Utilities Board regulates aspects of electricity and natural gas utilities as well as motor carriers, to ensure that customers receive safe and reliable service at just and reasonable rates. In addition, the Board sets weekly retail prices for petroleum products sold within the province. The Board's regulatory functions are carried out through both written and oral proceedings, and representative groups are encouraged to participate in the process. Participation helps to ensure that the Board is informed of the issues, and that decisions are made in the public interest. Board hearings, which resemble court proceedings, are conducted by a panel of three or more Board members. The panel hears evidence about the need for a rate increase or a change in service. Unlike courts, much of the evidence is filed prior to the actual hearing. The Board members then deliberate and issue a written decision. The Board must balance the needs of consumers for fair rates with a utility's right to have a reasonable opportunity to earn a fair return on its investment. Source: http://www.nbeub.ca/what-we-do

Province/ Territory	Regulator	Mandate
5. Newfoundland & Labrador	Newfoundland & Labrador Board of Commissioners of Public Utilities	The Board is an independent, quasi-judicial regulatory body appointed by the Lieutenant Governor in Council, and operates primarily under the authority of the Public Utilities Act, R.S.N. 1990. The Board was established in 1949. The Board is responsible for the regulation of the electric utilities in the province to ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable. In 2004, the Board has received the added responsibility for ensuring fairness in marketing of petroleum products throughout the province in accordance with the *Petroleum Products Act*. The Board is also responsible for the supervision of rates charged by automobile insurers for the various automobile insurance coverages, limited regulation of the motor carrier industry in relation to certain passenger and ambulance operations as well as conducting hearings and other required activities under the *Expropriation Act*. The Board conducts Public Hearings of a quasi-judicial nature, in accordance with the provisions of the *Public Enquiries Act* and the Board's regulations -Newfoundland Regulations 39196. The Orders issued by the Board as a result of Public Hearings have the force of law and can only be appealed to the Supreme Court of Newfoundland, Court of Appeal. The Board's jurisdiction is defined by the following legislation which it administers: • *Public Utilities Act, R.S.N. 1990* • *Electrical Power Control Act* • *Petroleum Products Act* • *Automobile Insurance Act* • *Motor Carrier Act* • *Expropriation Act* • *Act to Amend the Electrical Power Control Act* • *Motor Vehicle Transport Act* • *Public Utilities Acquisition of Lands Act* Source: http://www.pub.nf.ca/mandate.htm

Province/ Territory	Regulator	Mandate
6. Northwest Territories	Northwest Territories Public Utilities Board	The NWT Public Utilities Board (PUB) is an independent, quasi-judicial agency of the Government of the Northwest Territories. It is responsible for the regulation of public utilities in the NWT. The PUB obtains its authority from the *Public Utilities Act*. The PUB deals with issues using an application and decision process. Any organization or individual seeking PUB approval on a given matter must prepare and submit a written application specifying the orders it is seeking from the PUB. The application should contain all materials and evidence necessary to enable the PUB to assess the merits of the application. Source: https://www.nwtpublicutilitiesboard.ca/about-us

Province/ Territory	Regulator	Mandate
7. Nova Scotia	Nova Scotia Utility and Review Board	The following mandates are all responsibilities of the NSUARB: • Auto Insurance • Criminal Injuries • Electricity • Expropriation Compensation • Film Classification • Fire Safety • Gaming • Gasoline & Diesel Pricing • Halifax-Dartmouth Bridge Commission • Liquor Licensing • Motor Carrier Passenger • Municipal & School Board Boundaries • Natural Gas • Payday Loans • Planning • Property Assessment Appeals • Railways • Wastewater & Stormwater • Water Source: https://nsuarb.novascotia.ca/mandates

Province/ Territory	Regulator	Mandate
8. Nunavut	Nunavut Utility Rates Review Council	The *Public Utilities Act* was inherited from the Northwest Territories when Nunavut was created in 1999. On March 29, 2001, it was replaced by the *Utility Rates Review Council (URRC) Act*. The *URRC Act* was compiled using parts of legislation from across Canada. It is a made-in-Nunavut solution to regulating utilities. Previously, the Nunavut Public Utilities Board was a decision-making body with full power to make more than recommendations. Under the *URRC Act* however, the Council is now an advisory body to the Minister Responsible for the Qulliq Energy Corporation (QEC). Under the new Act, the Minister Responsible for the QEC, along with the Executive Council, make the final decisions on power rates. The latest change to the *URRC Act* was in 2010 when the Nunavut Legislative Assembly approved amendments to the Act. The main change is with the process of a Fuel Stabilization Rider (FSR). Now, the Minister Responsible for *URRC* no longer requires the approval for the Executive Council for an *interim*. FSR. This was changed so that the process can happen expeditiously to benefit the ratepayer. Source: http://www.urrc.gov.nu.ca/en/home.html

Province/ Territory	Regulator	Mandate
9. Ontario	Ontario Energy Board	The Ontario Energy Board is an independent regulatory body that makes decisions and provides advice to the government in order to contribute to a sustainable, reliable energy sector and to help consumers get value from their natural gas and electricity services. We do this by: • Establishing rates and prices that are reasonable to consumers and that allow utilities to invest in the system • Encouraging higher performance from natural gas and electricity utilities and measuring progress • Making the consumer's own usage, and the broader energy issues, easier to understand • Looking out for consumer interests, investigating complaints and applying penalties, where appropriate • Thinking about the long-term needs of the energy sector and developing regulatory policy to meet emerging challenges. Source: https://www.oeb.ca/about-us/mission-and-mandate

Province/ Territory	Regulator	Mandate
10. Saskatchewan	Saskatchewan Rate Review Panel	The Saskatchewan Rate Review Panel advises the Government of Saskatchewan on rate applications proposed by SaskEnergy, SaskPower and the SGI Auto Fund. The Panel reviews each application and provides an independent public report stating its opinion about the fairness and reasonableness of the rate change, while balancing the interests of the customer, the Crown corporation and the public. Source: https://www.saskratereview.ca/

Province/ Territory	Regulator	Mandate
11. Yukon	Yukon Utilities Board	The Board receives its mandate from the *Public Utilities Act* and Regulations. The Board's mandate, in summary, includes the following: • issuing orders fixing rates of a public utility • prohibiting or limiting any proposed rate change • fixing proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any public utility • fixing standards, classifications, regulations, practices, measurements or services to be observed, provided or followed by a public utility, and • determining areas that services of a public utility shall provide The Board also requires the public utility to establish, construct, maintain, and operate any reasonable expansion of its existing services as well as determining the conditions that may be imposed by a public utility to establish, construct, maintain or operate an expansion of its existing services. Source: http://yukonutilitiesboard.yk.ca/about/mandate-of-the-board/

Province/ Territory	Regulator	Mandate
12. Québec	Régie de l'énergie du Québec	**Electricity** The Régie has the authority to fix the rates and conditions for the supply, transmission, delivery and storage of natural gas by a distributor, after holding public hearings. It also monitors the operations of natural gas distributors to ascertain that consumers are adequately supplied and are charged fair and reasonable rates. It approves their supply plans and commercial programs. The Régie also approves investment projects, the construction of immovables or the acquisition of assets intended for the distribution of natural gas. The Régie has sole authority to examine consumer complaints about a decision rendered by a natural gas distributor concerning the application of the rates or conditions of service. The distributors are required to apply an internal complaint examination procedure approved by the Régie. **Natural gas** The Régie has the authority to fix the rates and conditions for the supply, transmission, delivery and storage of natural gas by a distributor, after holding public hearings. It also monitors the operations of natural gas distributors to ascertain that consumers are adequately supplied and are charged fair and reasonable rates. It approves their supply plans and commercial programs. The Régie also approves investment projects, the construction of immovables or the acquisition of assets intended for the distribution of natural gas. The Régie has sole authority to examine consumer complaints about a decision rendered by a natural gas distributor concerning the application of the rates or conditions of service. The distributors are required to apply an internal complaint examination procedure approved by the Régie. **Petroleum products** The Régie monitors petroleum product prices and can provide the consumers with information on this regard. With respect to gasoline and diesel fuel, the Régie has the authority to determine, every three years, an amount per litre representing the operating costs borne by a gasoline or diesel fuel retailer, and to assess the expediency of excluding the amount from or including the amount in the operating costs borne by a retailer. **Steam** The Régie monitors steam prices and can provide the consumers with information on this regard. Source: http://www.regie-energie.qc.ca/en/faq.html

Province/ Territory	Regulator	Mandate
13. Prince Edward Island	Prince Edward Island – Island Regulatory and Appeals Commission	The Commission is an independent tribunal that hears appeals on issues relating to land use, property and revenue (sales) tax and unsightly premises. It administers land ownership legislation in Prince Edward Island and regulates the petroleum industry and automobile insurance rates. The Commission regulates electric utilities and certain water and wastewater utilities in Prince Edward Island and hears and considers appeals from decisions or orders of the *Director of Residential Rental Property* (Rentalsman). The Commission also has limited jurisdiction over the rates charged by Island Waste Management Corporation. The Commission also advises the Minister of Communities, Lands and Environment with respect to the disposition of applications to establish or restructure a municipality under the *Municipal Government Act*. The Island Regulatory and Appeals Commission, or "IRAC" as it is commonly known in Prince Edward Island, was established in 1991 following the amalgamation of the former Public Utilities Commission, Land Use Commission and the Office of the Director of Residential Rental Property (Rentals man). The Commission operates at arms-length from the Provincial Government. It has three full-time and up to five part-time Commissioners and a staff complement of 20. The Commission reports to the Legislative Assembly of Prince Edward Island through the Minister of Education and Lifetime Learning. Source: http://www.irac.pe.ca/aboutirac/