AUC

Alberta Utilities Commission

Alberta Electric Distribution System-Connected Generation Inquiry

Final Report

December 29, 2017

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Final Report
Proceeding 22534

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Alberta Utilities Commission
Calgary, Alberta

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Executive summary

The Alberta Utilities Commission (AUC) is the province of Alberta's public utility regulator. On March 29, 2017, the AUC was requested by the Lieutenant Governor in Council, under Section 8 of the *Alberta Utilities Commission Act*, to inquire into and report to the Minister of Energy on matters relating to electric distribution system-connected generation in Alberta (Order in Council 120/2017 (OIC)). This OIC was revised by OIC 148/217 on April 11, 2017. The AUC issued its interim report to the minister on August 31, 2017.

This report follows the completion of the AUC's information gathering process, including public hearings held in Calgary and Edmonton in July of 2017, and provides the AUC's analysis and observations on the questions posed in the OIC. A description of the information gathering process is found in Section 2 of this final report.

The AUC first reviews Alberta's current electricity market design, including the legislation that enables this design, and provides a description of the delivery system, followed by descriptions of the entities that are involved in that system and the broader market (Section 3). This foundation is rounded out by a section describing the generation choices that are available in the current electricity market (Section 4). The remaining sections of the final report present the results of the AUC's inquiry.

Section 5 covers issues and questions related to the enablers and barriers to distribution-connected generation (DCG). Distribution wire owners confirmed that the distribution systems are capable of accommodating DCG at the current time, and into the foreseeable future at the current growth rates and at relatively little cost. However, the distribution wire owners were unable to predict when adding DCG to the distribution system in the future will require significant distribution system investment. The *Micro-generation Regulation* stood out as effective in supporting the interconnection of generation to the distribution system. Although no absolute barriers to developing alternative and renewable DCG were discovered, inquiry participants identified two prime areas for improvement. These were: (1) the sharing of distribution feeder capacity information to assist distribution-connected generators in locating DCG and (2) issues associated with the Alberta Electric System Operator's queuing process. Due to the broad range of parties consulted, unanimous consensus on all aspects of what constituted an enabler or a barrier was not obtained, particularly in the area of tariff design. Most inquiry participants agreed that the tariff structure should not be redesigned solely to enable growth of DCG and that grants or financial subsidies to stimulate increased DCG, if any, should be provided in a transparent manner and outside of the tariff rate structure.

Section 6 presents the concerns that inquiry participants expressed regarding the effect that other initiatives, such as the Renewable Electricity Program, the capacity market, and the regulated rate option rate cap could have on the further expansion of DCG. Participants indicated that if market prices were too low and significant growth in DCG is to contribute to the target of 30 per cent of electrical energy produced in Alberta to be generated from renewable sources by 2030, subsidies for DCG will be required.

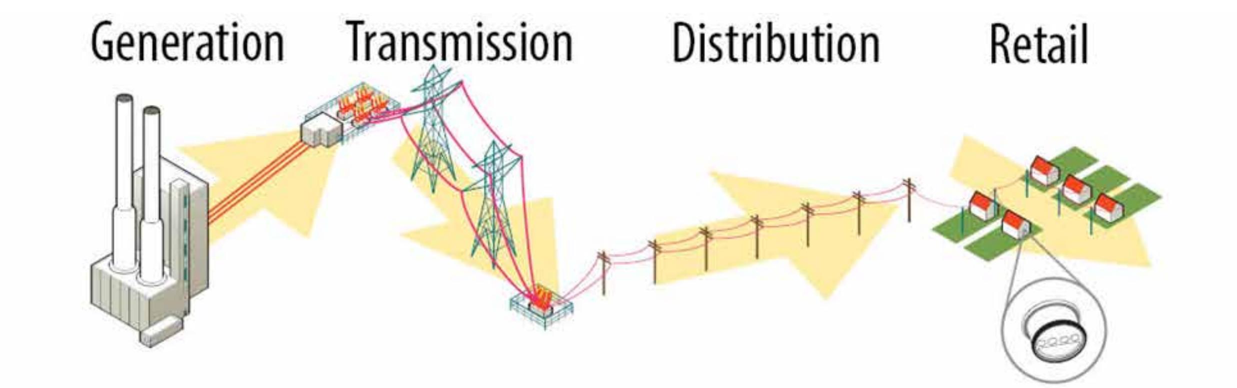
Technological changes are occurring in the electric utility industry and some of them are considered to be enablers to DCG growth. Improvements in measurement, control and monitoring technologies, cyber security considerations, the impact of the ability to store energy on the system and the development of blockchain technology are all discussed in Section 7.

Section 8 presents the two principal themes that emerged from the inquiry regarding future DCG growth: education and the need to plan in order to avoid ad-hoc measures. Stakeholders want to be engaged in an open and transparent planning process to make meaningful progress in Alberta. The section includes a summary of the effects of DCG in other jurisdictions, and concludes with the AUC's findings regarding community generation. Significantly, with respect to community generation, participants reported how individuals and organizations have successfully established what they described as community generation programs under the existing legislative framework. They did not support the introduction of additional legislation or rules to define community generation because doing so could place artificial boundaries and limits on possible opportunities to establish communities that meet their needs.

1 Introduction

1. Prior to the 1990s, all Alberta consumers of electricity received their electricity from the local electric utility and only industrial consumers were likely to generate any of their own electricity. Electricity was generated predominantly at large coal-fired generation plants and small hydro-electric developments. Transmission lines transported the electricity over long distances to substations which lowered the voltage to distribution levels and distribution lines transported the electricity to consumers. Rates charged for the electricity and the use of the transmission and distribution wires to get the electricity to consumers were regulated. For the most part, consumers did not play a role in the types of fuels used to generate the electricity, the way electricity was delivered to them, or the details of how their bills were developed or the billing system used. Electricity service was inexpensive and there were no choices. One could only get electricity from the monopoly supplier. This past industry model is represented in Figure 1.

Figure 1 - Electric Utility Model pre-1990



2. Many things have changed since then. In the 1990s, the Alberta government chose to open the market for electricity generators and allow market forces to set the prices for electricity through a power pool in which prices changed hourly. This change introduced a new entity to the marketplace. In addition to incumbent utility generators, independent power producers were added into the mix. This means that "Alberta currently has an 'energy-only' market. We're one of a few jurisdictions globally – and one of only two in North America – using this model."[1]

3. The Alberta government website explains an energy-only market as follows:

> "in an energy-only market, generators are paid for the electricity they produce based solely on the wholesale price of electricity, which fluctuates. These companies decide on the type of generation they produce and on the location of facilities. Electricity prices are based on supply and demand. Lowest-cost generators are dispatched first and the more expensive ones are only brought in as necessary to handle a higher load. These interconnected electric systems are known as a power pool. Power distributors take energy from the power pool and pay the declared hourly Pool price for the energy they

[1] Alberta government, Alberta's electricity market today. Retrieved from: https://www.alberta.ca/electricity-capacity-market.aspx.

> buy. Electricity retailers purchase wholesale blocks of energy and then repackage it into offers for Albertans."[2]

This means that both the capital costs of the generation plants and the cost of producing the energy are incurred by the generators and are recovered through the pool price.

4. Concurrent with the introduction of Alberta's energy-only market, the Alberta government also opened a competitive electricity retail market. Consumers were given the opportunity to select their supplier of electricity from among a number of competitive retailers, each of which offered different prices and price packages under contract. Since many Albertans were unfamiliar with this type of a competitive market, the government introduced a regulated rate option (RRO) rate available to those customers who did not wish to participate in the competitive market. Today, 52 per cent of residential customers and 40 per cent of small business customers remain on the RRO rate.

5. Circumstances have been changing again. No longer are there those who exclusively produce electricity and those who exclusively consume electricity. More and more industrial facilities have been installing their own generation sources (e.g., cogeneration) and smaller and smaller participants in the electricity marketplace are doing the same (e.g., solar panels (photovoltaics) on rooftops). This trend has created a new class of market participants who both produce and consume electricity.[3]

6. In 2008, in order to give small individual customers a better chance to participate as both a generator and consumer, the Government of Alberta passed the *Micro-generation Regulation*. The provisions of the *Micro-generation Regulation* made it possible for Albertans to generate their own electrical energy through various means, including solar panels and other renewable sources of electrical energy generated on their premises. Under the regulation, the size of the micro-generation generating unit was intended to meet all or a portion of the customer's total annual energy consumption at the customer's site. In addition, micro-generation customers could sell the electrical energy that they do not use into the power pool. The price they were paid was the same price they would pay for electrical energy from their retailer. In 2015, the Alberta government amended the *Micro-generation Regulation* to allow customers to generate more electrical energy from renewable resources (up to a limit of five megawatts) and to sell the difference into the market at the pool price (instead of the energy price charged by their retailer). The small micro-generators continue to be paid the same price they would pay for electrical energy from their retailer.

7. In just over a decade, things have changed considerably for Alberta residential and small business electricity customers – and more changes are coming. As part of the Alberta government's Climate Leadership Plan, coal-fired power plants are being phased out by 2030, and the government has set a target of 30 per cent of electrical energy produced in Alberta to be generated from renewable sources, like solar, wind and hydro by 2030. There are a number of initiatives designed to achieve this goal, and the government has created a new provincial agency, Energy Efficiency Alberta, to deliver programs to help families, businesses and communities become more energy efficient.

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2 Alberta government, Alberta's electricity market today. Retrieved from: https://www.alberta.ca/electricity-capacity-market.aspx.

3 Sometimes referred to as "prosumers." Prosumers can be large (e.g., industrial size) or small (e.g., an individual homeowner).

8. The government has also introduced a Renewable Electricity Program in which generators bid with the goal of being selected to provide renewable energy into the system under prices determined partly by the amount of subsidy provided by the government. This renewable energy may connect to either the transmission system or the distribution system. The program is run by the Alberta Electric System Operator (AESO) and will add 5,000 megawatts (MW) of renewable energy capacity to the system by 2030. Concurrently with these programs, the government has been supporting the development of renewable energy through various programs that provide grants to individuals so that they can invest in solar panels and other renewable energy sources for their homes and businesses and has instituted a grant program for First Nations and Metis communities.

9. As part of the plan to reform the province's electricity system to ensure that it meets the needs of the future, the government is also introducing a capacity market for electricity generation. This type of initiative is in part necessary because as reliance on renewable energy (such as wind and solar) increases, the risk of energy shortages on the system increases. Under the capacity market initiative, payments will be made to these companies that can assure the availability of energy when it is needed to ensure the reliability of electricity service.

10. In 2017, the Alberta government took another step to encourage the development of renewable energy in the province when, by way of Order-in-Council, it asked the Alberta Utilities Commission to conduct this inquiry. The AUC has been asked to inform the government on what it would take to encourage and roll out more renewable energy through interconnections to the distribution system so that more Albertans might have the chance to participate in the greening of the grid, either through direct involvement as a micro-generator or as a member of a group of users wishing to build renewable energy facilities or contract to purchase electricity from renewable energy producers, or both.

11. There are many issues raised by a decision to encourage interconnections of renewable energy sources to the distribution system. These issues fall into three categories. First, the distribution systems in the province (including measurement and billing) were initially designed and built to receive electricity from the transmission system and to deliver it to customers, and not to receive electricity from customers and deliver it on to a distribution system. Various changes to the distribution systems have been and continue to be required to accommodate this new reality. As the amount of distribution-connected generation[4] (DCG) grows, more changes will likely be necessary and these changes will be expensive, especially if the capacity of the distribution systems must be increased. All of these factors raise issues of cost allocation in order to ensure fairness of rates charged among and between customers who choose to participate in DCG and those that do not.

12. The second category of issues arises because the two principal types of renewable energy sources expected to be used for DCG (solar and wind) provide electrical energy intermittently.[5] That is, when the sun does not shine, there is no solar generation and when the wind does not blow, there is no wind generation. As noted above, this is one of the key reasons that the government decided to introduce a capacity market. But even apart from that, the introduction of

[4] The Order-In-Council used the terms: "Electric Distribution System-Connected Generation," "distribution system-connected generation," and "distribution-connected generation." For the purposes of this report, the AUC will use distribution-connected generation (DCG).

[5] Biomass is an example of a renewable energy source that is not intermittent.

the delivery of intermittent wind and solar electrical energy from DCG providers requires the distribution wire owners to introduce new tools to manage the balancing of the electrical energy delivered to and the electrical energy used by customers on the distribution system. As part of this, sometimes the distribution wire owners will have to deliver excess electrical energy to the transmission system or increase the amount of electrical energy being received from the transmission system. This intermittency issue is expected to be addressed in the future by new technologies such as improved energy storage systems.

13. The third category of issues deals with the need to educate Albertans about DCG opportunities. What the AUC heard in its inquiry was that there are already many options for how Albertans can form partnerships or many other types of communities to participate in the development of distribution system-connected renewable energy and many have already taken advantage of those opportunities. Participants stated that a well-developed education program is necessary and critical to promote the growth of DCG for Albertans who choose to engage in this initiative and to define and clarify expectations. Whether seeking to become a DCG provider themselves or to become a part of a community generation initiative, Albertans need to have a thorough understanding of the costs of participating in DCG initiatives and the options available to them as well as how to take advantage of those options. A well-developed education program will benefit Albertans and Alberta by providing Albertans with the tools and information they need to make informed decisions about their future electricity choices.

14. Participants agreed that stakeholder consultation on the development of a well-defined and detailed policy framework, or roadmap, should be the starting point to plan for the amount and the pace of the expected deployment of alternative and renewable DCG. This consultative work would be particularly useful with respect to learning from other jurisdictions with the goal of preventing the unintended consequences that arose in many of those jurisdictions.[6]

15. This report will address the issues raised by the government in the OIC and, while addressing the proposals of parties who participated in the inquiry, it will also seek to address the issues from the perspective of customers who wish to participate.

[6] Transcript, Volume 5, pages 621 and 760-761 for Germany’s program; Transcript, Volume 5, pages 590-591 and 734 for Nova Scotia’s COMFIT program.

2 Inquiry process

2.1 Scope

16. The starting point for the scope of the inquiry is the terms of reference provided in the Order-in-Council (OIC), which includes specific matters to be addressed.

17. The OIC directed that the AUC address the following matters:

(a) the current status of alternative and renewable distribution-connected generation in Alberta;

(b) the current state of Alberta's distribution systems, billing and settlement systems, and supporting Acts, Regulations and rules, to enable alternative and renewable distribution-connected generation;

(c) enablers and barriers to developing alternative and renewable distribution-connected generation, in Alberta; including but not be limited to:

(i) Alberta's electric distribution systems,

(ii) billing and settlement systems,

(iii) Acts, Regulations and rules governing distribution and retail,

(iv) rate design and tariff structures, including net metering,

(v) terms and conditions of service, and

(vi) the Alberta Interconnected Electric System;

(d) methods for assessing costs and benefits of infrastructure investments that may enable and facilitate broader deployment of alternative and renewable distribution-connected generation and efficient energy use; including but not be limited to:

(i) billing and settlement systems,

(ii) smart meters,

(iii) energy storage,

(iv) demand response,

(v) rate impacts to consumers, and

(vi) the potential for stranded infrastructure;

(e) current and potential regulatory approaches to consider alternative and renewable distribution-connected generation when planning the development of distribution networks;

(f) opportunities to improve processes for connecting alternative and renewable distribution-connected generation, not currently captured under the *Micro-generation Regulation*;

(g) the potential to align the planning and development of Alberta's distribution systems and broader deployment of alternative and renewable distribution-connected generation with the Government of Alberta's objectives of providing clean, affordable and reliable energy to Albertans.

18. The OIC did not require or ask the AUC to make recommendations or a decision on how to implement further penetration of electric distribution-connected generation. The mandate of the inquiry is limited to providing the information requested in the OIC.

19. The OIC, including the terms of reference is attached as Appendix 1 to this report.

2.2 Process

20. The AUC's process was divided into 2 phases: initial fact gathering through written questions and submissions and oral hearings conducted in Edmonton and Calgary, which concluded with the production of a interim report, and additional fact gathering and submissions concluding with the publication of this final report.

21. The OIC stated that "in conducting the inquiry, the AUC shall hear from interested stakeholders." The AUC interpreted this requirement in a broad sense and despite the limited time available, ensured as many opportunities as possible were provided to interested parties to provide input in the inquiry. In the interest of efficiency, the AUC accepted all submissions of data and analysis and considered each on its own merits in its deliberations on the matters posed in the terms of reference. Aspects of submission beyond the scope of the inquiry were not considered.

22. The AUC acknowledges the level of broad industry engagement and thanks all participants for the contributions provided.

23. In addition, the AUC considered materials obtained from its own research on the matters posed in the terms of reference. A list of these additional materials is set out in Appendix 2.

2.2.1 Initial fact gathering and interim report

24. During the initial fact-gathering phase, the AUC sought submissions, reviewed and analysed those submissions and prepared its interim report.

25. To ensure that the inquiry was open, transparent and accessible to the public, the AUC issued a filing announcement and created Proceeding 22534 in its public eFiling system for participants to register and provide their submissions. That same day, the AUC issued notice, provided information to parties regarding how to participate in the review and invited participation from the electricity industry, First Nations, and other members of the public. A copy of the issued notice is attached as Appendix 3 to this report.

26. Parties were requested to indicate their interest in participating in the review by filing a statement of intent to participate (SIP) on the AUC's public eFiling system. On the SIP filing deadline, 39 participants had registered to participate in the proceeding. A further 20 participants

registered to participate after the original SIP filing deadline. A list of the participants who registered to participate in the review is attached as Appendix 4 to this report.

27. On May 1, 2017, the AUC issued a letter establishing the process schedule that it intended to follow to complete the gathering of information from the participants who had registered in the proceeding. In the schedule, the AUC provided opportunities for parties to make submissions in writing and orally. The AUC also provided a detailed list of questions for participants to complete to the extent that they were able to do so. The questions followed the terms of reference attached to the schedule to the OIC and were provided to ensure that the AUC, in the course of conducting the review, gathered the information that the Government of Alberta sought. A copy of the questions issued is attached as Appendix 5 to this report.

28. The Commission issued a further set of supplemental questions to participants on June 16, 2017. A copy of the supplemental questions issued is attached as Appendix 6 to this report.

29. Of the 59 participants who filed a SIP, 35 provided responses to some or all of the written questions and 18 participants replied to the supplemental questions. All submissions are publicly available through the AUC's eFiling system.

30. The process schedule established by the AUC also provided participants with an opportunity to present oral submissions. The AUC allocated a number of days for hearings in areas of the province other than Calgary and Edmonton in order to facilitate receiving oral submissions from varied participants. It received no requests for such hearings. Consequently, oral submissions were presented in Edmonton and Calgary.

31. Five participants took part in the oral proceeding that occurred between July 4 and July 7, 2017, in Edmonton. Those participants were:

- The Alberta Federation of Rural Electrification Associations (AFREA) (association representing 23 rural electrification associations – distribution wire owners).
- The Canadian Solar Industries Association (CanSIA) (national trade association representing the solar energy industry across Canada).
- The Consumers' Coalition of Alberta (CCA) (coalition public interest group comprised of the Consumers' Association of Canada (Alberta Division) and the Alberta Council on Aging).
- EPCOR Utilities Inc. (EPCOR) (representing both a distribution wire owner and a retailer).
- SkyFire Energy Ltd. (SkyFire) (solar photovoltaic system developer).

32. Thirteen participants appeared in the oral proceeding held between July 17 and 20, 2017, in Calgary. Those participants were:

- The Alberta Electric System Operator (AESO) (Alberta independent system operator).
- AltaLink Management Ltd. (AltaLink) (electric transmission wire owner).

- ATCO Electric Ltd. (ATCO Electric) (electric distribution and transmission wire owner).
- Energy Storage Canada (ESC) (trade association representing the energy storage industry in Canada).
- ENMAX Corporation (ENMAX) (representing both a distribution wire owner and a retailer).
- FortisAlberta Inc. (FortisAlberta) (distribution wire owner).
- EQUS REA Ltd. (EQUS) (rural electrification association and distribution wire owner).
- Howell Mayhew Engineering Inc. (Howell Mayhew) (solar photovoltaic system developer).
- Lion’s Tooth Solutions Ltd. (Lion’s Tooth Solutions) (electric distributed generation project developer).
- The Office of the Utilities Consumer Advocate (UCA).
- The Pembina Institute for Appropriate Development (Pembina) (Alberta-based think tank).
- Teric Power Ltd. (Teric) (independent power producer).

33. Several participants also provided additional reports and research materials, including research and expert reports from other jurisdictions that have studied distributed generation or have embarked on pilot incentive programs to increase penetration of distributed generation on their electric wire systems. A list of these publications is provided in Appendix 7.

34. The final step of the initial fact gathering process was the production of the interim report. This was delivered to the Minister of Energy on August 31, 2017, 22 weeks after the start of the inquiry.

2.2.2 Additional fact gathering, consultation and the final report

35. During the course of the oral proceedings, a number of parties, having had the opportunity to make submissions and to consider matters raised by others, indicated that they would like to submit further comments and rebuttal comments. The AUC agreed that further information would be valuable and established a schedule to receive further submissions and rebuttal submissions on September 15, 2017, and September 29, 2017, respectively.

36. The AUC received supplemental submissions from the following parties:

- The AESO
- AFREA
- Aura Power Renewables Ltd. (Aura Power)

- The CCA
- ENMAX
- EPCOR
- FortisAlberta
- TransAlta Corporation (TransAlta)

37. The final step in the inquiry is the production of this report. In accordance with the OIC, the final report must be delivered to the Minister of Energy within nine months from March 29, 2017, being December 29, 2017. With the production and delivery of this report, the AUC has completed the work directed in the OIC. Specifically, within the terms of reference set out in the OIC, the AUC has submitted to the Minister as ordered: "The AUC's report:
(b) Must be submitted to the Minister of Energy within 9 months of the date on which the Order-in-Council to which this Schedule is attached was made, with an interim report submitted to the Minister of Energy no later than July 31, 2017."[7]

[7] The interim report deadline was changed to August 31, 2017 by Order-in-Council 148/2017.

3 Alberta's restructured electricity market

Key Observations:

The legislative framework that enables the provision of electrical energy in Alberta is complex and involves an intricate weaving of provincial and federal acts and regulations along with other legislative instruments. These acts, regulations, bylaws and rules currently enable DCG. Because the legislative framework is so integrated, changes to any part require analysis and consideration of the effects those changes may have on other legislative provisions.

Participants agreed that the current regulatory and legislative framework will support the continued growth of DCG and new regulations or legislation are not required.

The recent amendments to the *Micro-generation Regulation* significantly enabled small-scale DCG for individual Albertans.

There are four components to the electric delivery system: generation, transmission, distribution and retail. Multiple entities provide these services, each of which plays a unique and integrated role in the delivery of electricity services to Albertans.

38. The starting point for this inquiry requires an understanding of the components that make up Alberta's restructured electricity framework and the participants who provide those functions to deliver electrical energy to Albertans.

39. This section is intended to provide the reader with an overview of what the Alberta electric system looks like today and who the various entities in that system are. The purpose is for the reader to understand the current system and where distribution connected generation (DCG) fits into that system. In Section 3.1 the AUC first considers the legislative framework that enables the provision of electrical energy in Alberta. This is followed by a review of the various elements and functions of the delivery system in Section 3.2, and concludes with a discussion of the various entities that provide those functions in Section 3.3.

3.1 Legislative overview

40. Included within the terms of reference of the OIC is a direction to gather information regarding "the current state of Alberta's distribution systems, billing and settlement systems, and supporting Acts, Regulations and rules, to enable alternative and renewable distribution-connected generation."

41. In 1996, with the passing of the *Electric Utilities Act*, the electricity industry was restructured along functional lines, namely, generation, transmission, distribution and retail. As described in the Introduction, prices for generation and retail have largely been deregulated while the costs of transmission and distribution remain subject to regulatory oversight from the AUC. The legislative provisions that enable DCG touch on all of these functional lines.

42. The legislative framework that enables the provision of electrical energy in Alberta with this restructured model is complex and involves an intricate weaving of provincial and federal

acts and regulations along with other legislative instruments, many of which were developed in a piece meal fashion over time, thereby contributing to the challenges of planning for the future. For example, in this proceeding, the AESO identified more than 116 different provisions in legislation (from federal and provincial statutes to individual municipal bylaws) along with its own rules and those of the AUC.[8] The AUC identified additional legislative instruments. An appendix providing the identified provisions from the principal acts and regulations, bylaws and rules is attached to this report as Appendix 8. It includes the following:

<u>Provincial Acts and Regulations</u>

1. Alberta Utilities Commission Act, SA 2007, c A-37.2
2. Environmental Protection and Enhancement Act, RSA 2000, c E-12
    a. Environmental Assessment (Mandatory and Exempted Activities) Regulation, AR 111/93
    b. Activities Designation Regulation, AR 276/2003
3. Electric Utilities Act, SA 2003, c E-5.1
    a. Billing Regulation, 2003, AR 159/2003
    b. Distribution Tariff Regulation, AR 162/2003
    c. Fair, Efficient and Open Competition Regulation, AR 159/2009
    d. Independent Power and Small Power Regulation, AR 111/2003
    e. Isolated Generating Units and Customer Choice Regulation, Alta Reg 165/2003
    f. Liability Protection Regulation, Alta Reg 66/2004
    g. Micro-generation Regulation, AR 27/2008
    h. Regulated Rate Option Regulation, AR 262/2005
    i. Transmission Regulation, Alta Reg 86/2007
    j. Roles, Relationships and Responsibilities Regulation, 2003
4. Energy Efficiency Alberta Act, SoA, 2016 Chapter E-9.7
5. Hydro and Electric Energy Act, RSA 2000, c H-16
    a. Hydro and Electric Energy Regulation, AR 409/83

[8] Many other utilities also identified provisions in several acts and regulations and the AUC also acknowledges their contributions in assembling their legislative lists.

6. Municipal Government Act, RSA 2000, c M-26
    a. Extension of Linear Property Regulation, Alta Reg 207/2012
7. Post-Secondary Learning Act, SA 2003, c P-19.5
8. Public Utilities Act, RSA 2000, c P-45
9. Renewable Electricity Act, SA 2016, c R-16.5
10. Rural Utilities Act, RSA 2000 Chapter R-21
11. Small Power Research and Development Act, RSA 2000, c S-9
    a. Small Power Research and Development Regulation, AR 336/88
    b. Revenue Adjustment Regulation, AR 358/94
12. Water Act, RSA 2000, c W-3
    a. Water (Ministerial) Regulation, AR 205/98

<u>Federal Acts and Regulations</u>

1. Canadian Environmental Assessment Act, 2012, SC 2012, c 19, s 52
    a. Regulations Designating Physical Activities, SOR 2012-147
2. Electricity and Gas Inspection Act, RSC 1985, c E-4
    a. Electricity and Gas Inspection Regulations, SOR 86-131
    b. Specifications
3. Fisheries Act, RSC 1985, c F-14
4. Income Tax Regulations, CRC, c 945 pursuant to the Income Tax Act, RSC, 1985, c (5th Supp)
5. Navigation Protection Act, RSC, 1985, c N-22
6. Weights and Measures Act, RSC 1985, c W-6
    a. Weights and Measures Regulations, CRC, c 1605

<u>Rules</u>

1. Alberta Utilities Commission Rules
2. ATCO Rate 32 (Generator Interconnection and Standby Power)
3. FortisAlberta’s Option M (Distribution Generation Credit/Charge)

4. ISO rules, January 9, 2017

Section 201.1 Pool Participant Registration

Section 202.5 Supply Surplus

Section 202.6 Adequacy of Supply

Section 203.1 Offers and Bids for Energy

Section 203.3 Energy Restatements

Section 203.4 Delivery Requirements for Energy

Section 205.1 Offers for Operating Reserve

Section 205.2 Issuing Dispatches and Directives for Operating Reserve

Section 205.3 Restatements for Operating Reserve

Section 205.4 Regulating Reserve Technical Requirements and Performance Standards

Section 205.5 Spinning Reserve Technical Requirements and Performance Standards

Section 205.6 Supplemental Reserve Technical Requirements and Performance Standards

Section 301.2 ISO Directives

Section 302.1 Real Time Transmission Constraint Management

Section 304.4 Maintaining Network Voltage

Section 306.5 Generation Outage Reporting and Coordination

Section 306.7 Mothball Outage Reporting

Section 502.4 Automated Dispatch and Messaging System and Voice Communication System Requirements

Section 502.8 SCADA Technical Operating Requirements

<u>Municipal Bylaws</u>

A. Airdrie

a. The City of Airdrie Land Use Bylaw No B-01/2016

b. Bylaw B-27/2015

B. Brooks

a. The City of Brooks Land Use Bylaw No. 14/12 (Use to be 03/30)

b. Bylaw No. 14/14

C. Calgary

a. Land Use Bylaw 1P2007

D. Camrose

a. Land Use Bylaw 2880-16 and Amendments to May 1, 2017

E. Chestermere

a. Land Use Bylaw No. 022-10

b. Bylaw No. 022-13 Approving Electric Distribution System Franchise Agreement

F. Cold Lake

a. Land Use Bylaw #382-LU-10

b. Bylaw No. 486-FA-13

G. Edmonton

a. Edmonton Zoning Bylaw 12800

b. EPCOR Distribution Inc. Franchise Agreement Bylaw 13655

c. Edmonton Power Corporation Bylaw 11071

H. Fort Saskatchewan

a. Land Use Bylaw C10-13

b. Bylaw No. C21-13

I. Grande Prairie

a. Land Use Bylaw C-1260

b. Bylaw C-1311

J. Lacombe

a. Land Use Bylaw 400; Schedule A

b. Bylaw 388

K. Leduc

a. Land Use Bylaw 809-2013

b. Bylaw No. 819-2013

L. Lethbridge

a. Land Use Bylaw 5700

b. Electrical Utility Bylaw 6020 – Terms and Conditions of Electric Service

M. Lloydminster

a. The City of Lloydminster Land Use Bylaw No 05-2016

b. The City of Lloydminster Bylaw No 30-2007

N. Medicine Hat

a. The City of Medicine Hat Land Use Bylaw #4168

b. Electric Utility Bylaw #2244

O. Red Deer

a. Land Use Bylaw No 3357/2006

b. Electric Utility Bylaw 3272

P. Spruce Grove

a. Land Use Bylaw C-824-12

b. Bylaw No. C-835-12

Q. St. Albert

a. The City of St. Albert Land Use Bylaw 9/2005

b. Electric Distribution System Franchise Agreement Bylaw 17/2015

R. Wetaskiwin

a. The City of Wetaskiwin Land Use Bylaw 1804-13

b. Bylaw 1805-13

43. The provision of electricity service in Alberta is principally established through the provisions of the *Electric Utilities Act*, and the provisions of the *Hydro and Electric Energy Act*. These two pieces of legislation work as companion legislation with the former establishing the duties and obligations of utilities and the AESO to provide service to customers in the electricity market, and the recovery of expenditures through a tariff, while the latter focuses on the construction and operation of the physical assets used to deliver electrical energy. The *Transmission Regulation* further supplements the legislative framework as it pertains to the provision and costing of transmission services in Alberta.

44. Legislation regarding the provision of retail and billing services is primarily set out in regulations to the *Electric Utilities Act* and, in particular, in the *Regulated Rate Option Regulation* and in the *Billing Regulation, 2003.* Additionally, the provisions of the *Roles, Relationships and Responsibilities Regulation, 2003*, address, among other matters, the obligations of distribution wire owners to appoint default retail suppliers and the interaction between AUC-regulated distribution wire owners and Rural Electrification Associations (REAs), both of which provide distribution service in the same geographic area. REAs are also governed by provisions set out in the *Rural Utilities Act* and the *Cooperatives Act.* How they fit into the electricity system is unique to Alberta. Further, as discussed in the Introduction, the *Micro-generation Regulation* enables small-scale DCG.

45. In addition to the provincial legislation, there are also federal acts and regulations, such as the *Weights and Measures Act* and the *Canadian Environmental Assessment Act* that must be considered. For example, the *Weights and Measures Act* addresses requirements for electricity meters while provisions in the *Canadian Environmental Assessment Act* must be considered when constructing electric facilities. As well, numerous AESO rules, AUC rules and guidelines and municipal bylaws affect DCG.

46. Overall, parties generally agreed that the current regulatory and legislative framework will support the continued growth of DCG and did not consider that new regulations or legislation is required. In particular, many participants stated that the recent amendments to the *Micro-generation Regulation* (that increased the volume of electrical energy that could be generated by micro-generators as discussed further in Section 4.2) significantly enabled small-scale DCG for individual Albertans. Participants were particularly supportive of the convenience of the application, interconnection and dispute resolution processes established by the AUC through its Rule 024: *Rules Respecting Micro-Generation*.

47. Mr. Vonesch, of SkyFire, stated during the oral proceeding:

> We've seen tremendous growth since then, primarily driven by the drop in cost of similar modules, inverters, other technology, and -- and also I would say driven by the *Micro-generation Regulation*. That's been a very key piece of legislation as far as making it easier for these solar PV[9] systems to connect to the grid, providing easy, quick, access to -- you know, to participate that way.
>
> Overall, I think the *Micro-generation Regulation* is a really great piece of legislation, especially now as we look to other jurisdiction and some of the challenges that have

9 PV is a shortened reference to photovoltaic.

> arisen with other policies. I have a lot of respect for the way our regulation is structured here.
>
> [Hearing Transcript Vol. 2, pages 97-98]

48. Mr. Howell, of Howell Mayhew, a solar generator developer who has been at the forefront of the development of solar PV, stated:

> I think one of the key points that I would like to highlight is how much I like the *Micro-generation Regulation* and the way that it was set up because I think it gives the government a number of very important opportunities to facilitate the growth of micro-generation and potentially distribution-connection generation because of how the micro-gen regulation is already set up and implemented by the AUC.
>
> The key, I think, is its net billing concept and how the export payments are handled by the energy retailer and the AESO.
>
> [Hearing Transcript Vol. 8, page110]

3.2 The delivery system

49. The Alberta Interconnected Electric System (AIES) – often referred to as "the grid" – moves electrical energy from where it is generated to where it is used. The provincial grid has many components. The Alberta grid must operate as part of a larger North American interconnected electric system, and must be planned accordingly to comply with North American standards and practices.[10]

50. The costs charged to customers for the consumption of electrical energy include the cost of generating the electrical energy, the cost of delivering the electrical energy through the transmission and distribution systems and the cost for the retailer to manage and administer the customer's account.

51. The following paragraphs provide a very brief description of the basic components of the Alberta Interconnected Electric System.

3.2.1 Generation

52. Electrical energy generation is the process of generating electric power from primary sources of energy. It is the first stage in the delivery of electrical energy to end-use customers. Throughout the history of the electricity industry, the primary energy sources have been the burning of fossil fuels (coal, oil and natural gas) to produce steam to drive steam turbines, and the use of rivers to provide water to drive hydraulic turbines.[11] In Alberta, the primary sources of energy have historically included coal, natural gas, hydro, wind and biomass. As described in the Introduction, through the Climate Leadership Plan, Alberta is phasing out coal-fired generation and increasingly changing its sources of primary energy to renewable sources such as wind, hydro and solar.

[10] The Alberta Electric System Operator (AESO), About the AESO, How the grid is operated, posted February 8, 2017. Retrieved from https://www.aeso.ca/download/listedfiles/How-the-Grid-is-Operated.pdf.

[11] Donald G. Fink and H. Wayne Beaty, Standard Handbook for Electrical Engineers, 12th Edition, McGraw-Hill Book Company, 1987, pages 12-14.

53. The amount of generating capacity required is also affected by the amount of reserve capacity that is needed to provide a reliable energy supply. Reserve generating capacity is required to cover a number of items, such as: scheduled downtime for routine preventative maintenance, inadvertent forced outages caused by equipment malfunctions, extremely adverse weather conditions, actual load exceeding forecast, unexpected reduction in output capability of generating units due to equipment malfunctions, poor fuel condition, regulatory restrictions, etc., and delay of completion of new generating units.[12]

54. The Alberta electricity market is one of the smallest organized wholesale markets in North America: its current installed capacity is nearly 17,000 megawatts (MW). Its model for electrical energy supply is referred to as an energy-only market. In this model, generators recover their costs through payments from the power pool, the ancillary services market, the forward market,[13] or through bilateral contracts. This energy-only market design requires investors to rely on pool prices alone to provide a sufficient incentive to invest in new generation projects because Alberta does not have locational marginal pricing, limiting pricing signals to developers of new generation.

55. The pool price is set through economic dispatch of price and quantity offers by generators to the power pool.[14] These pairs are ranked by the power pool and placed in a merit order. The system controller calls on generators according to their place in the merit order to meet real-time demand. Every minute, the last generator dispatched in the merit order sets the System Marginal Price (SMP). At the end of the hour, the time-weighted average of the 60 one-minute SMPs is calculated and published as the settled pool price. As a simplistic example, if Generator A was dispatched for 30 minutes at $20 and Generator B was dispatched for 30 minutes at $30, the pool price would settle at $25 for the hour. The annual average hourly price is $22.11 per megawatt hour (MWh) for 2017[15] as compared to $18.28 per MWh in 2016 and $33.34 per MWh in 2015.[16]

56. A secondary market exists to procure operating reserves and ancillary services from generators. Generators and large industrial customers may also offer their capability (generation capacity or the ability to curtail load) to the AESO as reliability services or into an operating reserves market, to ensure that generation and load are continuously and instantaneously balanced.[17]

3.2.2 Transmission

57. Transmission systems deliver electrical energy from generating plants to industrial sites and to substations from which distribution systems supply residential and commercial service. Transmission systems also interconnect electric utilities, permitting power exchange when it is of

[12] Donald G. Fink and H. Wayne Beaty, Standard Handbook for Electrical Engineers, 12th Edition, McGraw-Hill Book Company, 1987, pages 12-14.

[13] Forward markets in Alberta include physical markets (where physical power is bought and sold ahead of production and consumption) and financial markets (where financial instruments such as forward or option contracts are used without the involvement of physical power).

[14] See ISO rules Section 201.6 – *Pricing*.

[15] Up to and including December 13, 2017.

[16] AESO 2016 Annual Market Statistics Accessed from https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/.

[17] See ISO rules Section 205 for more details on ancillary services markets for electricity in Alberta.

economic advantage and to assist one another when generating plants are out of service because of damage or routine repairs.[18]

58. The transmission system in Alberta consists of approximately 26,000 kilometres of transmission lines and over 580 substations. This system delivers electrical energy generated from coal-fired, natural gas-fired, hydro, wind and other renewable generation sources to substations located near to where the electrical energy is consumed by large industrial customers and through the distribution system to homes, offices and commercial sites. The transmission system covers a wide geographic area and is an integrated system of 500-kilovolt (kV), 240-kV, 144-kV and 72-kV transmission lines and substations across Alberta and is owned and operated by seven different entities.[19]

59. The Alberta transmission system was designed to transmit electrical energy from large centralized generation plants to homes, communities and businesses spread across great distances and did not contemplate the emergence of a competitive generation market or the large-scale integration of renewable generation. In general, the transmission system connects cogeneration and base-load electrical energy generation in the northern part of the province to major load centres in Edmonton and Calgary. Most peaking[20] generation is located in the central or the southern parts of the province, while existing hydro and wind generation is located primarily in the southern part of the province.

60. Alberta currently has three primary transmission system interconnections with other jurisdictions (interties); one each with British Columbia, Saskatchewan and Montana, in order to facilitate exchanges of electrical energy between jurisdictions. The interties are primarily used to import electrical energy into the province.[21]

3.2.3 Distribution

61. Electric distribution systems deliver electrical energy from the transmission grid through a substation to consumers in homes, offices and commercial sites. The purpose of the substation is to reduce (step down) the transmission voltage to a level that can be safely delivered to customers. Transformers perform the critical function of stepping down voltages throughout the distribution system. A distribution system may include medium-voltage (less than 25-kV) power lines, substations and pole-mounted transformers, low-voltage (less than one-kV) distribution wiring and electricity meters. Distribution substations typically contain switches, transformers and reclosers or circuit breakers to protect the distribution circuits as well as power factor correction capacitors and voltage regulators.

62. The distribution system has traditionally operated with a one-way delivery of electrical energy from centrally-located generation plants to end-use customers with relatively little or no monitoring and control automation.

[18] Donald G. Fink and H. Wayne Beaty, Standard Handbook for Electrical Engineers, 12th Edition, McGraw-Hill Book Company, 1987.

[19] The Alberta Electric System Operator, About the AESO, The basics of electricity transmission, posted January 13, 2017; Retrieved from https://www.aeso.ca/aeso/about-the-aeso/.

[20] Peaking generation is generation capacity that is normally used to produce electricity during peak-load hours.

[21] The Alberta Electric System Operator, About the AESO, An overview of the provincial grid, posted November 8, 2016. Retrieved from https://www.aeso.ca/download/listedfiles/FactSheet-AnOverviewOfThePowerGrid.pdf.

3.2.4 Retail and billing

63. A retailer provides retail services, such as billing and customer service, to Alberta customers. Retailers also obtain electrical energy to meet the needs of their customers through the Power Pool of Alberta, a market for the exchange of electrical energy.

64. Since 2001, Albertans have been able to obtain their electrical energy from a competitive retailer. When a customer chooses a competitive retailer, they may be required to sign a contract agreeing to a set price per kilowatt hour (kWh) of electrical energy for a set amount of time. The AUC does not regulate the rates or the service of competitive retailers.

65. Albertans also have the opportunity to receive their electrical energy from a regulated retailer[22] called the regulated rate option (RRO) provider. The charge for the services provided by the RRO provider is called the RRO rate. The RRO rate changes month-to-month. The provisions in the *Regulated Rate Option Regulation* set out the manner in which the RRO rate is determined. The RRO providers set their monthly RRO rate based on the monthly forward electricity prices and consumption volumes. The regulation allows RRO providers to purchase electrical energy in the forward market up to 120 days in advance of the start of what is referred to as the consumption month. For example, if December was the consumption month, then the RRO providers could purchase electrical energy from the forward market 120 days in advance of December 1, i.e., starting from August 3. It is the AUC's responsibility to review the RRO provider's energy charges under its jurisdiction to make sure that they are being passed along accurately to customers.

66. Retailer charges include the energy commodity charges, calculated by multiplying the amount of electrical energy used in the billing period by the applicable rate per kWh, and non-energy rates. Non-energy rates are charges that recover the retailer's costs of billing consumers for electrical energy and providing customer service.

67. Only registered pool participants can buy and sell electrical energy in the Alberta wholesale market. Therefore, all retailers must become a pool participant with the AESO.

68. There are three types of retailers who operate in the market: RRO providers, competitive retailers and self-retailers (customers who purchase electrical energy directly from the power pool).

69. The restructuring of the electricity market that provided for customer choice led to an increase in the number of transactions and participants involved in producing, exchanging and processing billing data.

70. The increased complexity in business processes made it crucial for data exchange and transaction rules to be standardized to the greatest extent possible so that customers could be billed in a timely and accurate manner. The current market rules and business processes, established and overseen by the AUC, are utilizing monthly meter reads as the basis for billing customers with cumulative meters for electrical energy consumption. The settlement, data

[22] The regulatory authorities being the AUC, the council of the municipality that owns an electric distribution system or the board of directors of a rural electrification association.

storage and communications systems necessary to support this market structure have been in place since 2001, while the billing system was introduced in 2006.

3.3 Who is involved?

71. Each of the above functions in the restructured market is delivered by different entities, some of which compete with each other, such as generators and retailers and others who provide monopoly services and are, therefore, regulated by the AUC. The AESO manages and operates the provincial power grid. The AESO has a crucial function in relation to the transmission system in that it forecasts electrical energy demand and plans the future of the transmission system accordingly. The AESO has additional roles (discussed in Section 3.3.1) such as monitoring and operating the grid to balance electrical energy supply and demand, as well as producing rules and parameters for the electricity industry participants to ensure the province's electricity market is fair, efficient and openly competitive.

3.3.1 AESO

72. The Independent System Operator (operating as the Alberta Electric System Operator or AESO), is a not-for-profit corporation established under the *Electric Utilities Act*. The AESO is independent of any industry affiliations and owns no transmission, distribution or generation assets. The AESO is responsible for overall coordination of grid operations, for planning and arranging for enhancements to the transmission system and for promoting a fair, efficient and openly competitive market for electrical energy in Alberta. The AESO is also responsible for managing and recovering the costs of transmission line losses, contracting with individual transmission facility owners to provide transmission services, and developing province-wide tariffs to provide for open and non-discriminatory access to the transmission system.[23]

73. The AESO manages and oversees a number of activities that contribute to the safe, reliable and economic operation of the interconnected electric and wholesale markets. These activities include: generation dispatch, system voltage control, procurement and management of ancillary services, generation and transmission outage coordination, intertie scheduling, and direction of system restoration during emergencies.

74. The AESO is responsible for assessing the current and future needs of market participants,[24] including planning[25] the capability of the transmission system to meet those needs, and arranging for necessary enhancements to the transmission system to maintain system reliability and support a fair, efficient and openly competitive market in Alberta. The AESO must also ensure that interconnections to neighbouring jurisdictions are capable of operating to

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[23] *Electric Utilities Act*, Section 17 – Duties of Independent System Operator.

[24] Both the AESO and *Electric Utilities Act* defines a market participant as any person that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services; or any broker, brokerage or forward exchange that trades or facilitates the trading of electricity, electric energy, electricity services or ancillary services.

[25] *Electric Utilities Act*, Section 17(i).

their path rating[26] to import and export electrical energy and to plan future interconnection capacity.

75. The AESO executes a crucial function in creating and managing the operation of a competitive power market. The large-scale integration of variable generation such as wind, ongoing evolution of the market structure and the need to continue to operate the system reliably and efficiently over a wide area, have added another layer of complexity to how the transmission system is planned and operated in Alberta.

76. All electrical energy entering the Alberta electricity market must be bought and sold through the power pool, which is operated by the AESO. To access the power pool, all market participants must have a system access agreement with the AESO, except for micro-generators. A micro-generator is not required under the *Micro-generation Regulation* to be a power pool participant. The AESO also carries out the financial settlement for all electric energy exchanged through the power pool.[27] There are over 200 participants in the Alberta power pool and the transactions of all electric energy bought and sold in the province totaled over five billion dollars in 2016.[28]

77. The AESO is responsible for procuring ancillary services and for managing and recovering the costs for the provision of ancillary services. Ancillary services are services required to ensure that electrical energy can be transmitted reliably, efficiently, and securely across the Alberta Interconnected Electric System. The AESO uses competitive processes to procure ancillary services except where there is a location-specific need. In these circumstances, only certain generators are eligible to provide these services. Ancillary services include operating reserves, transmission must-run services, black start, and load shedding services.[29]

78. Operating reserves are generating capacity that the AESO can dispatch, or load that can be reduced on short notice to continuously and instantaneously match supply and demand and maintain reliable operation of the power grid. The AESO manages a secondary market to procure and dispatch operating reserves. Generators and loads may offer their capability into the operating reserves market providing they comply with the rules and technical performance obligations established by the AESO.

79. Load shedding services are services provided by large industrial customers to reduce demand instantaneously and automatically when an unexpected system event occurs. These services can be used by the AESO to respond to unexpected system events and to increase the transfer capability of transmission interconnections with other jurisdictions. The AESO contracts with large consumers of electrical energy to provide load shedding services.

80. The AESO has authority to make Independent System Operator (ISO) rules, as well as to set reliability standards, operating procedures, criteria and processes respecting power pool

[26] Path rating is defined in Section 1(1)(i) of the *Transmission Regulation* as the rating of capacity to transfer electric energy assigned to a transmission facility when it was placed in service and rated in accordance with reliability standards in effect at that time.

[27] *Electric Utilities Act*, Section 17(d).

[28] The Alberta Electric System Operator, the AESO 2016 annual market statistics, page 2. Retrieved from https://www.aeso.ca/download/listedfiles/2016-Annual-Market-Stats.pdf.

[29] The Alberta Electric System Operator, Ancillary services. Retrieved from https://www.aeso.ca/market/ancillary-services/.

operation, interconnection practices, coordination of outage schedules, and planning and arranging for upgrades to the transmission system. The AESO works with generation owners, transmission owners, distribution owners, market participants and customer groups on the development of these ISO rules, standards and procedures. Market participants must comply with ISO rules and reliability standards.[30] ISO rules are subject to regulatory oversight by the AUC on a complaint basis.[31] Market participants may also file complaints with the AUC regarding the conduct of the AESO.[32]

3.3.2 Transmission facility owners

81. Transmission facility owners (TFOs)[33] have specific obligations regarding the design, operation, maintenance, performance, integrity and capability of their transmission assets and the day-to-day operation of their portion of the transmission system. There are seven transmission facility owners in Alberta with the two largest being AltaLink and ATCO Electric. The remaining five are ENMAX Power Corporation (ENMAX Power), EPCOR Distribution & Transmission Inc., TransAlta, the City of Lethbridge and the City of Red Deer.[34]

82. In order to ensure that generators and market participants can access and supply electrical energy through the transmission system regardless of who owns the facilities, the AESO contracts with the TFOs to use their transmission assets to provide fair and open access to the system. The AUC approves the TFOs' terms and conditions of service. The *Electric Utilities Act* requires the TFOs to maintain their systems at a level suitable to ensure safe and reliable delivery of electricity[35] and they must comply with AESO reliability standards and ISO rules.[36]

3.3.3 Distribution wire owners

83. In Alberta, investor-owned and municipally-owned distribution utilities and Rural Electrification Associations (REAs) provide the electric distribution service.

3.3.3.1 Distribution utilities

84. The distribution tariffs for the cities of Lethbridge and Red Deer, and the towns of Cardston, Fort Macleod and Ponoka are approved by their local municipal governments and town councils. The cities of Calgary and Edmonton own their electric distribution systems. In Alberta's remaining communities, either FortisAlberta (southern and west-central Alberta) or ATCO Electric (northern and east-central Alberta) owns the distribution systems. ATCO Electric, ENMAX Power, EPCOR Distribution & Transmission Inc., and FortisAlberta serve

30 *Electric Utilities Act*, Section 20.8.
31 *Electric Utilities Act*, Section 25(1)(b).
32 *Electric Utilities Act*, Section 26(1).
33 The AESO and *Electric Utilities Act* define a transmission facility as an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25,000 volts to a nominal low voltage level of 25,000 volts or less.
34 Suncor also owns and operates transmission lines and substations for their own use and have an Industrial System Designation classification.
35 *Electric Utilities Act*, Section 39(1).
36 *Electric Utilities Act*, Section 39(3)(d).

over 90 per cent of distribution system customers in Alberta. The AUC regulates these companies' distribution service areas.[37]

85. Distribution wire owners are responsible for conducting load settlement calculations within their service area.[38] This responsibility is referred to as being a load settlement agent. The province is segmented into ten zones for the purpose of performing load settlement calculations.

86. The four largest distribution wire owners (ATCO Electric, ENMAX Power, EPCOR and FortisAlberta) act as their own load settlement agents. In the remaining six settlement zones, the distribution system owners have authorized one of the four large distribution wire owners or a third party to act as their load settlement agent. In total, there are six load settlement agents performing load settlement calculations in Alberta. AUC Rule 021: *Settlement System Code Rules* sets out how this information is provided in terms of format, content and timing.

87. Distribution wire owners are also responsible for providing usage and tariff billing information to the retailers serving the customers in the respective distribution wire owner's service area.[39] AUC Rule 004: *Alberta Tariff Billing Code Rules* likewise sets out how this usage and tariff billing information is provided in terms of format, content and timing.

88. The costs incurred by the distribution wire owner to provide these services are recovered through a distribution tariff, which is billed by the retailer on customer bills. Distribution tariff charges for the four major distribution wire owners remain fully regulated by the AUC through performance-based regulation.

3.3.3.2 Rural Electrification Associations

89. Rural Electrification Associations originated during the late 1940s and 1950s. They began as farmer owned co-operatives created to electrify the farms of Alberta. Each REA still provides service to its members, mainly in rural Alberta and within its designated service area. The distribution systems of the individual REAs intertwine with those of ATCO Electric and FortisAlberta in rural Alberta.[40] ATCO Electric and FortisAlberta are required to enter into an integrated operation agreement with each REA within its service area.[41] This integrated operation agreement ensures the two distribution wire owners (i.e., the REA and either ATCO Electric or FortisAlberta) work together to provide reliable and safe service to the customers and members within the overlapping service areas and that there is no duplication of distribution lines and service. The smaller REAs contract with either ATCO Electric or FortisAlberta to operate and maintain the REA's distribution system. There are six REAs,[42] referred to as self-operating

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37 Government of Alberta, Department of Energy, Statistics Information System Switching Percentage By Group‖ (January 21, 2011), Retrieved from: http://www.energy.alberta.ca/electricity/esi/Table1_Electricity_Alberta_ByGroup.pdf.

38 The distributor performs the function of calculating and reporting to the power pool (AESO in Alberta) how much electrical energy was allocated to each retailer in each hour of every day as set up in the AUC Rule 21: *Settlement System Code Rules.*

39 AUC Rule 004: *Alberta Tariff Billing Code Rules*.

40 In Alberta, most rural areas are radial networks. A radial distribution line may serve both the distribution entity customers and the REA members, and different parts of the same line may be owned by one or the other party.

41 Part 2 of the *Roles, Relationships and Responsibilities Regulation, 2003.*

42 Battle River Power Co-op, EQUS REA Ltd., Lakeland Rural Electrification Association Limited, North Parkland Power Rural Electrification Association Ltd., Rocky Rural Electrification Association Ltd. and Wild Rose REA Ltd.

REAs, who operate their distribution system and provide services such as power restoration, new construction, vegetation management, and billing themselves.

90. The REA's board of directors regulates and approves the distribution tariff charges for the REA.

3.3.4 Retailers

91. As stated in subsection 3.2.4, a retailer provides billing and customer service to consumers. Retailers also obtain electrical energy through the Power Pool of Alberta to meet the needs of their customers.

3.3.4.1 Regulated rate option

92. Each distribution wire owner must make available to eligible customers in the owner's service area the option of purchasing electricity services in accordance with a regulated rate tariff, the regulated rate option (RRO), instead of purchasing electricity services at a competitive retail energy rate.[43] Customers who consume less than 250,000 kilowatt hours of electrical energy per year and have not entered into a contract with a competitive retailer are eligible to receive electricity service under the RRO rate.

93. The distribution wire owner may provide the electricity service under its own regulated rate tariff or authorize another party to provide this service on its behalf. If the owner delegates the responsibility, this party is referred to as the RRO provider.

94. ATCO Electric, ENMAX Power, EPCOR Distribution & Transmission Inc. and FortisAlberta all delegated the responsibility of providing the RRO service within their service area. Direct Energy Regulated Services is the RRO provider in the ATCO Electric service area; ENMAX Energy Corporation provides the RRO service in the City of Calgary on behalf of ENMAX Power while EPCOR Energy Alberta GP Inc. is the RRO provider for the City of Edmonton as well as for FortisAlberta. The regulated rate tariffs of these RRO providers are approved by the AUC.

95. Electric distribution systems that are municipally-owned belong to the cities of Lethbridge and Red Deer, and the towns of Cardston, Fort Macleod, and Ponoka. All these owners, except the City of Lethbridge, appointed ENMAX Energy Corporation to be their RRO provider. The City of Lethbridge provides the RRO service to its customers. The regulated rate tariffs of the municipally-owned distribution utilities are approved by their respective municipal councils.

96. The board of directors of each rural electrification association that owns an electric distribution system approves the RRO rate on behalf of its members.

97. The calculation of the RRO rate is determined by using the monthly forward market electricity prices up to 120 days prior to when the RRO rate is in effect.[44] The RRO rate varies month-to-month, but remains fixed within a month. Thus, customers are not directly exposed to

[43] *Regulated Rate Option Regulation*, Section 2. A retailer provides these services.
[44] See Section 11 of the *Regulated Rate Option Regulation* AR262/2005.

the hourly spot market volatility and any associated large monthly price spikes. Currently the RRO rate is subject to a cap, which is discussed in Section 6.4.

98. Residential, farm and small commercial customers account for approximately 37 per cent of the total electrical energy consumed in the province. This percentage was lower when the economy was more robust. Approximately 52 per cent of the total number of residential customers and 40 per cent of the total number of eligible small commercial customers have elected to remain on the RRO rate.[45]

3.3.4.2 Competitive retailers

99. As explained subsection 3.2.4, competitive retailers offer electricity services to customers under an energy contract established by the retailer that states the price for the electrical energy as well as the terms and conditions of service. Some competitive retailers offer their services to customers throughout Alberta while others restrict their offerings to specific geographical areas.

100. The Government of Alberta licenses competitive retailers but does not regulate their prices. Customers can choose a retailer that offers various options including one-year, two-year, three-year and five-year fixed price contracts, floating rates, dual fuel (electrical energy and natural gas) services, seasonal plans and green energy products (electrical energy generated by renewable sources).

101. There are a number of competitive retailers offering electricity contracts for residential, farm and small business customers. They are Alberta Co-operative Energy, ATCO Energy Ltd., Direct Energy Partnership, ENMAX Energy Corporation., Encor by EPCOR, Fluent Utilities, Just Energy Alberta L.P., Leap Energy, Link Energy, PowerBill, and Xoom Energy. Two retailers, Sponsor Energy and Utility Network & Partners Inc. operate under multiple brand names. Direct Energy Marketing Limited, ENMAX Corporation and EPCOR Utilities Inc. provide competitive electricity services as well as the RRO service under separate business units. As of June 2017, 47.4 per cent of the eligible RRO residential customers, 27.1 per cent of eligible RRO farm customers and 59.2 per cent of eligible RRO small commercial customers were receiving electricity services from a competitive retailer.[46]

3.3.4.3 Self-retailers

102. Self-retailers are customers who procure electrical energy from the power pool for their own use. Most industrial customers and large commercial customers are self-retailers. A number of self-retailers use specialized service providers to manage the complex electrical energy billing processes, and for their energy settlement and billing data management requirements. Self-retailers can also be self-generators.

[45] The Market Surveillance Administrator, Retail Statistics, 2017-11-03 RetailStatistics.xlsx file, calculations done for June 2017. Retrieved from: http://albertamsa.ca/uploads/pdf/Archive/00000-2017/2017-11-03%20RetailStatistics.xlsx on November 29, 2017.

[46] Market Surveillance Administrator Retail Statistics, 2017-11-03 RetailStatistics.xlsx file, calculations done for June 2017. Retrieved from http://albertamsa.ca/uploads/pdf/Archive/00000-2017/2017-11-03%20RetailStatistics.xlsx on November 29, 2017.

4 Generation choice

Key Observations:

Although distribution-connected generation (DCG) has been in place in Alberta for decades, it provides a minor contribution to the electrical energy consumed by Albertans. Specifically, micro-generation represents 0.12 per cent of total Alberta installed generation capacity, and large-scale DCG served less than one per cent of the total provincial load and represents 2.5 per cent of the total installed generation capacity.

103. The OIC directed that the AUC inquire into "the current status of alternative and renewable distribution-connected generation (DCG) in Alberta." The AUC considers that any discussion of the status of alternative and renewable DCG must include an understanding of how DCG generally, and alternative and renewable DCG as a subset of DCG, operates within the overall generation market structure in Alberta.

104. As noted in subsection 3.2.1, Alberta's restructured electricity market has developed under a framework in which generators compete and the price that they receive for their product is determined in a market. In order for this to be effective, generators must be assured that if they build their generation that they will be able to deliver the electrical energy on to the provincial grid.

105. The AESO has responsibility for providing open and non-discriminatory transmission access to all forms of generation, wherever it is situated.[47] In addition, the AESO has the responsibility for planning and arranging for upgrades to the transmission system needed to connect generation to the market.[48] Generators make their own decisions about where to locate, what type of generation to build and the size of the generation facility. These decisions are informed by the power pool price that they project to receive.

106. Because it takes time to build the transmission system to connect to the generators, there is a generation queue that the AESO establishes based on the information it receives from the generators that want to operate in the province. Generators pay for the cost of local facilities that connect to the grid and pay an additional refundable contribution that varies depending where they locate in the system. The costs of transmission facilities and ancillary services are recovered from Albertans.[49]

107. This section first examines large-scale generation before delving into distribution system-connected generation, including large-scale distributed generation, large micro-generation, and small micro-generation.

[47] *Electric Utilities Act*, Section 29.
[48] *Transmission Regulation*, sections 15(1)(e) and (f).
[49] *Electric Utilities Act*, Section 30.

4.1 Large-scale generation

108. Large-scale generation that is traditionally connected to the transmission system includes generators using fuel sources such as coal, natural gas, wind, and hydro. Table 1 provides the breakdown of installed generation capacity and total electrical energy production by fuel type.

Table 1. Installed generation capacity in Alberta, by fuel type

Fuel Type	Installed Generation Capacity (MW)	Percentage	Total Electrical Energy Production (Percentage)
Coal	6,299	38	62
Natural Gas	7,348	45	27
Wind	1,445	9	7
Hydro	894	5	4
Other	437	3	N/A

Source: The AESO - Current Supply Demand Report, accessed October 2017.

109. Coal generation serves as base load[50] for Alberta and is the most common fuel source for generation of electrical energy. Natural gas-fired generation is the next largest source of generation.

110. Natural gas-fired generation in Alberta is generally of two distinct types: peaking and cogeneration. Peaking units typically have lower utilization rates as they generally only run during high demand or peak periods. Cogeneration is the simultaneous production of electrical energy and heat using a single fuel source. Cogeneration is typically used in Alberta to support bitumen production from oil sands projects or in upgrading facilities. These facilities tend to have a high utilization rate, as they operate to meet industrial steam requirements and to produce electrical energy. Approximately 64 per cent of the natural gas-fired capacity in Alberta is cogeneration units.

111. Wind generation supplied just over seven per cent of the total electrical energy produced in Alberta in 2016. The market share of wind generation has been increasing rapidly, as the majority of generating capacity from wind power in Alberta has been built in the past five years. Currently there is approximately 1,445 megawatts (MW) of wind generation installed, achieving, on average, a 35 per cent capacity factor in 2016.[51]

112. Hydro production in Alberta is very dependent on rain and snowfall, as these units are run-of-river with very little storage capacity. In addition to electrical energy production, these units also provide a large portion of total operating reserves required in Alberta.

113. Whereas electrical energy generation from gas and coal is typically obtained from large plants adjacent to the fuel source and required transmission lines to deliver the generated electrical energy to the load, electrical energy from wind, small hydro and solar tends to be smaller in size and more geographically distributed. Often, these new sources of generation can be small enough that they can be connected directly to the distribution system.

50 Base load is the minimum amount of electrical energy delivered or required over a given period of time at a steady rate.

51 The capacity factor is the ratio of net generation to installed capacity. Therefore, in 2016, 350 MWh of electrical energy was produced each hour for every 1,000 MW of installed wind capacity.

4.2 Distribution system-connected generation

114. Distribution system-connected generation (DCG) is not a recent or unknown development in the Alberta electricity system. When compared to transmission system-connected generation, DCG represents a small component of generation production in Alberta. The number of approvals for DCG that have been issued since the deregulation of the electricity market in 1996, by the AUC and its predecessor the Alberta Energy and Utilities Board, number in the hundreds.

115. DCG generates electrical energy from fuel sources such as hydro, wind, solar, fossil, solution gas and biomass. Generation technologies used in distributed generation include photovoltaics, microturbines, internal combustion reciprocating engines, combustion turbines, wind generators and fuel cells that may be situated at residential, commercial and industrial sites. Distribution system-connected generation can be used to generate a customers' entire electrical energy supply, to reduce peak demand (commonly referred to as "peak shaving"[52]) for standby or emergency generation; as a green power source or for increased reliability of the distribution system.

116. DCG in Alberta can be grouped based on fuel type. The three fuel types are alternative, renewable and conventional. The OIC defined alternative energy and renewable energy. Alternative energy is energy obtained from non-conventional energy resources (i.e., waste energy and fuel cells) or obtained from low-carbon intensity conventional sources of energy in a more efficient manner (e.g., combined heat and power applications). Renewable energy comes from a fuel source that is naturally occurring and replenishes within a human lifespan, such as solar, wind, hydro, geothermal and biomass. The AUC has adopted these definitions for the purposes of this report. Conventional sources are carbon-based such as natural and solution gas.

117. Regardless of fuel type, generators connected to the distribution system in Alberta are also distinguished by the size of their generation output. The *Micro-generation Regulation* has established two categories of micro-generation: small and large. A small micro-generation unit is defined as having a total nameplate capacity of less than 150 kW. Large micro-generation has a total nameplate capacity of between 150 kW and 5 MW (the maximum nameplate capacity eligible under the regulation).

4.2.1 Large-scale distribution-connected generation

118. DCG that does not meet the definition of a micro-generation unit is considered large-scale DCG. Large-scale distributed generation may be defined as generation, typically in the range of 5 to 20 megawatts that can connect to a distribution system, operate within distribution voltage levels and provide electrical energy close to the point of consumption. The distribution wire owner is responsible for installing the meter(s) and collecting the data. The distribution-connected generators are paid the hourly power pool price for electrical energy delivered to the distribution system.

119. In the industrial sector, distributed generation is a relatively mature technology and includes large amounts of cogeneration (hundreds of megawatts). Distribution-connected

[52] Peak shaving is a process in which you shift demand from peak times (e.g., noon) to times with lower demand (e.g., night).

generators use is to enhance the production processes. For instance, oil sands producers recapture the heat used in the oil upgrading process and use the heat to generate electrical energy. The excess electrical energy not used on site is sold to the power pool.

120. The following table provides the number of distribution system-connected generation sites with a nameplate capacity of more than 5 MW, the aggregate nameplate capacity and the aggregate average amount of electrical energy delivered to the distribution system on a monthly basis associated with each distribution wire owner that was in operation in Alberta in 2016.

Table 2. Distribution-connected generation in Alberta with nameplate capacity over 5 MW in 2016

Service Area	Number*	Aggregated nameplate capacity (MW)*	Aggregate amount of electrical energy delivered to the system (2016 monthly average) (MWh)
ATCO Electric Ltd.	11	97.8	6,715.7
ENMAX Power Corporation	7	74.4	5,895.9
EPCOR Distribution & Transmission Inc.	0	N/A	N/A
FortisAlberta Inc.	19	237.45	42,168.2
TOTALS	37	409.7	54,779.8

Source: Participant's written responses to Commission Question 2, Appendix B, Exhibit 22534-X0075.
* As of December 31, 2016

121. The AESO's Annual Market Statistics report indicated that the total Alberta internal load was 79,560 gigawatt hours in 2016.[53] Thus, DCG with nameplate capacity over 5 MW served less than one per cent of the total provincial load and it represented 2.5 per cent of the total Alberta installed generation capacity in 2016.

4.2.2 Large micro-generation

122. Unlike large-scale DCG, micro-generation units must produce electrical energy using a renewable, environmentally friendly fuel source such as solar panels, small-scale hydro, wind, biomass, micro-cogeneration and fuel cells. The electrical energy output is intended to meet all or a portion of the customer's electrical energy needs. Customers who generate their own electrical energy will be credited for any excess electrical energy delivered to the distribution system through a contract price, a regulated rate or a power pool price. Distribution wire owners are responsible to provide connection services for large micro-generators, to install the bi-directional interval meter,[54] as well as to collect the data from the meters.

123. On December 21, 2016, the definition of a large micro-generation generating unit in the *Micro-generation Regulation* was revised to a nameplate capacity from 150 kV to 5 MW (previously the maximum nameplate capacity was 1 MW). Table 3 provides the number of large micro-generation generating units connected to the distribution system.

53 The Alberta Electric System Operator, Annual market statistics report, February 21, 2017. Retrieved from https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports.
54 In Alberta, an interval meter records the consumption of electrical energy in 15 minute intervals.

Table 3. Distribution-connected generation in Alberta with nameplate capacity greater than or equal to 150 kW and less than or equal to 5 MW in 2016

Service Area	Fuel Source	Number of units*	Aggregated nameplate capacity (kW)*
ATCO Electric	Solar Wind Biomass Other (natural gas/propane)	1 1 1 9	320 600 3,600 16,600
ENMAX Power Corporation	Solar Other (fossil fuel)	3 46	716 30,393
FortisAlberta Inc.	Solar Wind Hydro Biomass Other (natural gas and co-generation)	6 28 3 3 11	3,995 28,140 8,700 8,908 14,395

Source: Participant's written responses to Commission Supplemental Question 1, Appendix B, Exhibit 22534-X0173.
*As of December 31, 2016

124. As shown in Table 4 below, there has been little growth, in terms of numbers and capacity in the large micro-generation category since 2012, based on the information provided by participants in response to Question 1 of the Commission's supplemental questions. For instance, ATCO Electric's statistics were unchanged throughout the five-year period, except for a decrease of one generating unit in the "other" category in 2015.[55] Likewise, FortisAlberta has seen a minimal increase in the number of generation units since 2012. However, the nameplate capacity has risen noticeably, especially in the other fuel source category. The nameplate capacity doubled from approximately seven megawatts in 2012 to 14 megawatts in 2016.[56] ENMAX Power has seen a growth in generating units that have fossil fuels as their source increasing from 27 units in 2012 to 46 units in 2016. The nameplate capacity increased from approximately 21 megawatts to 30 megawatts in that time.[57]

55 Exhibit 22534-X0205, ATCO Electric responses to Commission supplemental questions, PDF page 3.
56 Exhibit 22534-X0194, FortisAlberta responses to Commission supplemental questions, PDF page 2.
57 Exhibit 22534-X0201, ENMAX Power responses to Commission supplemental questions, PDF page 2.

Table 4. DCG units in Alberta with nameplate capacity greater than 150 kW and less than 5 MW

Service Area	Fuel Source	2012		2013		2014		2015		2016		As of June 2017	
		Number of units	Capacity	Number of units	Capacity	Number of units	Capacity	Number of units	Capacity	Number of units	Capacity	Number of units	Capacity
ATCO Electric Ltd.	Solar									1	320	1	320
	Wind	1	600	1	600	1	600	1	600	1	600	1	600
	Biomass					1	3,600	1	3,600	1	3,600	1	3,600
	Other	10	17,276	10	17,276	10	18,000	9	17,200	9	16,600	9	16,600
ENMAX Power Corporation	Solar							1	150	3	716	3	716
	Other*	27	20,625	34	25,435	34	25,435	45	30,088	46	30,393	54	35,361
EPCOR Distribution & Transmission Inc.	Solar							1	160				
FortisAlberta Inc.	Solar							2	1,620	6	3,995	6	4,114
	Wind	27	25,355	27	25,355	27	25,355	27	27,690	28	28,140	28	28,140
	Hydro	3	8,700	3	8,700	3	8,700	3	8,700	3	8,700	3	8,700
	Biomass	2	4,300	3	8,575	4	9,208	4	9,208	3	8,908	3	8,908
	Other**	7	6,945	7	6,945	10	8,155	11	14,755	11	14,395	13	22,095

Source: Participant's written responses to Commission Supplemental Question 1, Appendix B, Exhibit 22534-X0173.
* Other refers to other fossil fuels that are typically synchronous generators.
** Other Fuel Sources include gas and co-generation.

125. Overall, participants considered the *Micro-generation Regulation*, and the recent changes made to it,[58] to be a success in allowing individual Albertans and small businesses to meet their electrical energy needs by generating electrical energy from renewable or alternative energy sources. Respondents commented that the streamlined application and connection process as well as the micro-generation guideline established by the AUC made it convenient for customers to install micro-generation.

4.2.3 Small micro-generation

126. The introduction of the *Micro-generation Regulation* in 2008 has enabled the growth of small-scale generation for Albertans. Distribution wire owners are responsible to provide connection services for small micro-generators, to install the bi-directional cumulative meter, as well as to collect the data from the meters.

127. The AESO's *Micro-generation in Alberta* report, which was provided in response to a Commission question, indicates there were 1,908 micro-generation sites, of which 1,803 were solar PV, as of May 10, 2017.[59] The total installed micro-generation capacity was 18.7 MW, with solar PV representing 17.3 MW of that total. Micro-generation represents 0.12 per cent of total installed generation capacity in Alberta. The majority of this solar PV installed micro-generation has a nameplate capacity of less than 150 kW.

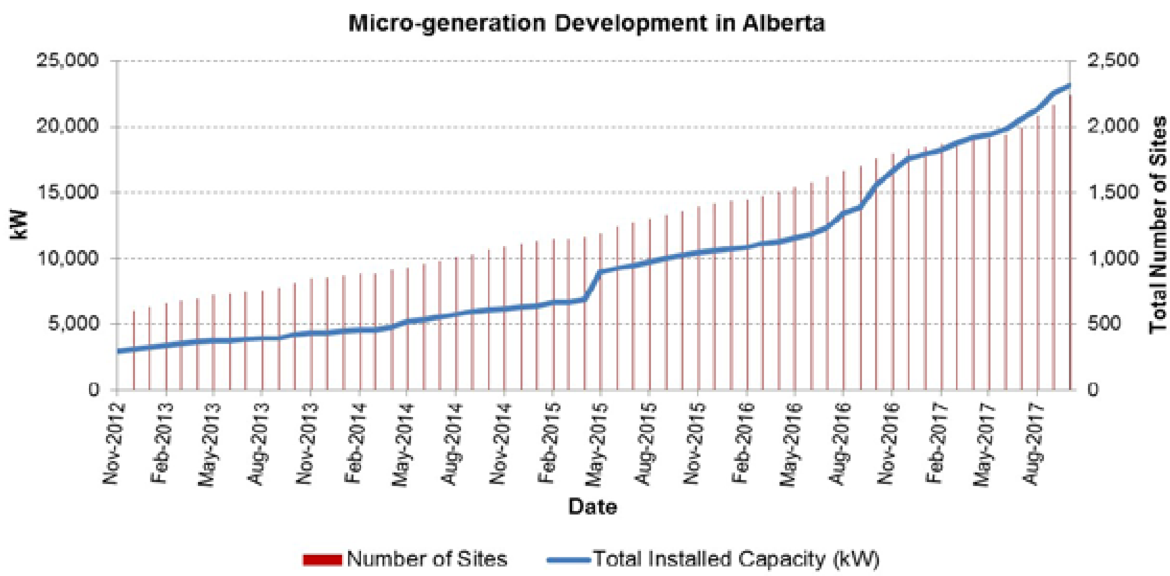
58 On December 21, 2016, the regulation was amended to increase the size limit of a micro-generation system to five megawatts from one megawatt and allow a micro-generating system to serve adjacent sites.

59 Exhibit 22534-X0130, AESO responses to Commission questions, PDF page 217.

128. Figure 2 shows the growth, in terms of number of sites and generating capacity since August 2012. The growth has been accelerating in recent years; attributed to steadily declining material costs, especially for solar PV systems.[60]

129. Year-over-year growth in terms of number and installed kilowatt (kW) of capacity of micro-generation, as set out in the AESO's report *Micro-generation in Alberta*[61] is shown in the graph below.

Figure 2 - Micro-generation development in Alberta



60 Transcript Volume 2, page 231, PDF page 97.

61 The Alberta Electric System Operator, Micro-generation in Alberta report, November 2017. Retrieved from: https://www.aeso.ca/market/market-and-system-reporting/micro-generation-reporting/.

5 Enablers and barriers to developing alternative and renewable DCG

Key Observations:

The data and analysis reviewed by the AUC during its information gathering processes suggests that there are no absolute barriers to developing alternative and renewable DCG in Alberta however, participants identified areas for improvement. Overall, participants expected that alternative and renewable DCG would contribute towards meeting the government's 30-30 target.

Section 5.1

Distribution wire owners generally agreed that although their distribution systems were designed for one-way delivery of electrical energy, with the exception of ENMAX's secondary distribution system, they can and are accommodating growth of DCG and they do not foresee continued gradual organic growth as being a problem. However, no distribution wire owner could predict at what point growth would cause operational issues on its system that would require significant distribution system investment or where on their systems those issues might arise. This could be considered as a barrier to the development of alternative and renewable DCG.

Micro-generators considered that the connection process for them enabled the development of alternative and renewable DCG and no issues regarding the connection process were identified as barriers. Proponents were particularly supportive of the efficiency resulting from the changes to the *Micro-generation Regulation* and the AUC Micro-Generation Notice Application guideline was perceived as working very well.

Large-scale DCG generators considered that the connection process could be improved and potentially standardized but the absence of these improvements does not operate as a barrier to the development of alternative and renewable DCG at this time. Although not identified as a barrier, large-scale DCG generators were concerned about the absence of readily available system capacity information. The distribution wire owners acknowledged that this information would be valuable and would assist in enabling the development of alternative and renewable DCG, however, obtaining this information and then maintaining these records would be a time-consuming and expensive endeavour. It was unclear to all participants who would be responsible to maintain this information and who would or should pay for the gathering and maintaining of this information.

Proponents suggested that improvements could also be made to the AESO's queuing process to prioritize community-scale and small-scale DCG.

Section 5.2

The AUC observed that participants agreed that alternative and renewable DCG would contribute to meeting the 30-30 target and that there were no barriers to facilitating the current organic levels of growth. There was general consensus that a "build in advance of need" model, similar to the one that was mandated in legislation for transmission, is not advocated for the distribution system, and is not needed to enable the development of alternative and renewable DCG.

Section 5.3

The way in which a tariff is structured can both enable the development of DCG and act as a barrier to its development. With regard to tariff structures and assessing the costs and pricing attributable to enabling and growing DCG, most participants acknowledged that the reliability provided through an interconnection to the distribution system was not cost-free. This is particularly critical given the intermittent nature of renewable and alternative DCG sources such as solar and wind.

Although some proponents suggested that adoption of rate design proposals such as net metering or virtual net metering may enable further DCG development, most proponents rejected these proposals because the allocation of the DCG customer's reliability costs to non-DCG customers was considered to be unfair. It is usually more affluent people who can afford to install DCG (e.g., solar rooftop panels). If they do not have to pay for all their costs to be connected to and to use the distribution system, as would be the case if net metering or virtual net metering were adopted, those costs would have to be paid for by Albertans who do not have DCG.

Section 5.4

Distribution wire owners are concerned that future investment in the assets and technology on the distribution system that would be necessary to achieve the government's renewable energy goals could result in stranded assets and their associated costs.

Section 5.5

Overall, most participants asserted that the tariff structure should not be redesigned solely to enable growth in DCG. Rather, grants or financial subsidies to stimulate increased DCG should be provided in a transparent manner and outside of the tariff rate structure. Finally, some participants identified the ability to recover the remaining asset value of assets that may be prematurely retired due to DCG growth as a potential barrier to growth.

130. Included within the terms of reference of the OIC was a direction to gather information regarding:

(c) enablers and barriers to developing alternative and renewable distribution-connected generation, in Alberta; including but not be limited to:

(i) Alberta's electric distribution systems,

(ii) billing and settlement systems,

(iii) Acts, Regulations and rules governing distribution and retail,

(iv) rate design and tariff structures, including net metering,

(v) terms and conditions of service, and

(vi) the Alberta Interconnected Electric System.

131. In this section, the AUC reviews the enablers and barriers to enhancing alternative and renewable distribution-connected generation (DCG) that were raised and discussed by participants during the inquiry. The AUC's review of the enablers and barriers is not organized as set out in the OIC because these factors are intertwined. Rather, the AUC begins by considering the current capacity of the distribution system and the manner in which DCG is currently integrated into the distribution system. The AUC then examines the capability of the distribution system to absorb further growth of DCG as well as the pace of that growth. Finally, the AUC reviews the effect of costs and pricing and the effect that technological advances have made on the viability of DCG.

5.1 Capability of the system to accommodate DCG

132. In this subsection, the AUC examines whether there are any features unique to Alberta that would act as barriers or enable the development of DCG. The AUC then reviews the operational aspects of the distribution systems, such as the ease in which distribution-connected generators can connect and the information available to potential distribution-connected generators to locate on the distribution systems. The capacity or lack of capacity on different portions of the distribution system can enable or create a barrier for the development of DCG. For example, growth of renewable and alternative DCG is affected by the ability of the distribution systems' existing facilities and the distribution wire owner's processes to accommodate requests to connect DCG. This capability will vary across the distribution systems in the province. This is because external factors such as wind or sun, create uneven demand for connection service across the province. Some distribution systems, or parts of distribution systems, may have insufficient capacity to accommodate all of the DCG requested, while other systems may be able to easily accommodate increased DCG growth. For example, the southern rural part of Alberta is exposed to the most favourable weather conditions for solar and wind projects; consequently, many of the DCG projects are proposed for this area.[62]

133. This examination reveals that there are some unique features in Alberta that may be barriers to the development of alternative and renewable DCG. It also reveals that the connection process for micro-generation enables the development of DCG. In addition, the AUC heard from large-scale DCG proponents that improvements to the connection process could be made.

5.1.1 Unique electricity features

134. The AUC invited submissions from the distribution wire owners to identify any unique features generally or on their distribution systems (such as locational or system issues) that might be considered to be barriers to the enhanced development of alternative and renewable DCG. It also invited other participants to provide their perspectives. Three features were identified as barriers: (1) ENMAX's secondary network, (2) the intertwined nature of REA and investor-owned distribution systems, and (3) the ownership mix of distribution systems.

[62] Exhibit 22534-X0105 FortisAlberta responses to Commission questions, PDF pages 5 and 6.

135. First, ENMAX indicated that it operates a low voltage secondary network[63] in its downtown core, and ENMAX does not allow DCG to deliver into this secondary network "for technical reasons related to reliability and safety." ENMAX explained that "in order to maintain system performance and reliability, the protection systems in the Secondary Network do not accommodate generation export. DCG designed for non-export, intended to offset customer load, can be used within the secondary network system with no anticipated consequence to system stability."[64] Because of this particular design, micro-generation and large-scale DCG generators cannot connect their generation projects on this secondary network in Calgary's downtown core.[65] This is a barrier to the development of large-scale DCG development in Calgary's downtown core.

136. Second, parties identified the concurrent operation of REAs and investor-owned distribution systems, which is unique to Alberta, as a potential barrier to developing alternative and renewable DCG because the necessary integration of the operations between the distribution systems increases the cost and complexity to operate these systems. Further, AFREA expressed concern that any increases in REA costs to accommodate DCG on the integrated distribution systems will make the REAs uncompetitive.[66] AFREA noted that investments made by an REA on its distribution system could only be recovered from the members of the REA and on a not-for-profit basis. Therefore, any REA investment to accommodate DCG, if not recovered from the distribution-connected generator, will be borne by other REA members who do not receive any benefit from the generation. In addition, the number of members to collect from is small. In contrast, the investor-owned distribution wire owners, ATCO Electric and FortisAlberta, can recover the investment from all ratepayers within their service area and earn a profit on the investment. Consequently, for some REAs, they may not be willing to connect DCG unless they can be assured that their costs would be recovered from the distribution-connected generator.

137. Third, although not unique to North America, unlike most other provinces, the distribution systems in Alberta are owned and operated by a mix of entities, none of which is a Crown corporation or is a vertically integrated utility. There are two investor-owned, eight[67] municipally-owned and 32 member-owned (i.e., REAs) distribution wire owners. This mix of ownership structures might be considered a barrier to the growth of DCG due to the planning and coordination required among the distribution wire owners. Compounding this challenge is the restructuring of the generation and retail sectors to enable competition.

63 Low voltage secondary network systems – known for ensuring high reliability - are designed for areas with high electrical energy use and high customer density. Several transformers are connected together underground so that the electrical energy can be supplied to a customer by more than one transformer. This design is different than the distribution system in the rest of Calgary, where there is typically one transformer used to supply electrical energy to a group of customers.

64 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 23.

65 EPCOR also operates a secondary network. For system performance, reliability and safety reasons (primarily arc flash fault energy considerations), EPCOR does not allow DCG to export onto its downtown secondary network. DCG designed for non-export, intended to entirely offset customer load, could be used within the secondary network system with no anticipated consequence to system stability. However, large-scale DCG generator proposals in the downtown Edmonton area would need to be reviewed on a case by case basis with EPCOR's system planning specialists, with a basic prerequisite that the generation output would need to be connected to a non-network distribution circuit.

66 Exhibit 22534-X0095, AFREA Submission, PDF page 6.

67 The cities of Calgary, Edmonton, Lethbridge, Medicine Hat and Red Deer and the towns of Cardston, Fort Macleod and Ponoka.

5.1.2 Connections and queuing

138. The ease with which a DCG proponent can connect to the distribution system can be considered either as an enabler or a barrier to the development of alternative and renewable DCG in the province. Factors such as easing the administrative burden to connect, reducing the time to process applications and shortening the queue can all enable the development of DCG.

139. In addition to identifying enablers and barriers, Section 1 (f) of the terms of reference in the OIC requests the AUC to gather information regarding "opportunities to improve processes for connecting alternative and renewable distribution-connected generation, not currently captured under the *Micro-generation Regulation*."

140. The AUC invited participants to provide submissions, both in writing and orally, regarding the ease with which DCG can be connected to the distribution systems. The AUC then requested participants to provide their views as to whether process improvements were required and, if so, to identify these improvements.

141. As set out in Section 4.2 above, there are three classes of distribution-connected generators in Alberta: large micro-generators, small micro-generators and large-scale distribution-connected generators. Given the distinction between these three classes and the correspondingly distinct connection processes attributable to each, the AUC considered that to address this matter fully, responses should not be limited to the connection processes of micro-generation generators.

142. Overall, the connection process for micro-generation was considered to enable the development of renewable and alternative DCG. Although no absolute barriers were identified to prevent the development of renewable and alternative DCG for large-scale distribution-connected generators, some improvements were proposed to further enable DCG growth.

5.1.2.1 Micro-generators

143. DCG proponents consider that the provisions of the current *Micro-generation Regulation* and the processes established under the AUC's micro-generation rule enable small-scale renewable projects to be built and connected in a timely manner. One of the reasons why this is the case is because the costs of metering and connecting a micro-generation unit to the distribution system are borne by the distribution wire owner. In turn, the distribution wire owner will recover these costs from the other ratepayers in its service area.

144. Given their overall satisfaction with the connection process at the micro-generation level and their experience with that connection process for projects up to one megawatt (MW), representatives of micro-generators did not offer further comment regarding process improvements at this level.

145. With the recent changes to the *Micro-generation Regulation* that increased the maximum capacity of eligible generating units from 1 MW to 5 MW, those generators may expect to experience similar review treatment because the same application process now applies. However, ENMAX stated that this expectation may be unrealistic because larger-sized projects require more review time to assess operational effects; therefore, the interconnection of these larger-sized projects will not be as prompt as for the smaller-sized projects.

5.1.2.2 Large-scale DCG

146. DCG proponents stated that the process to connect large-scale DCG is complex and time-consuming and does not easily enable the development of alternative and renewable DCG. The reasons for this are three-fold: (1) the distribution systems were not built to accommodate the bi-directional flow of electrical energy for commercial sale, and, therefore, the technical connection requirements are more complex; (2) visibility of the system is limited; and (3) the application processes vary.

5.1.2.2.1 Design of distribution systems

147. Accommodating large-scale DCG on the distribution systems is a complex exercise. This is because the distribution systems were not designed for electrical energy to flow from customers back on to the distribution systems. Rather, they were designed to receive electrical energy from the transmission system and deliver it to the customers (typically referred to as "load"). Distribution systems were not designed to have generation of any kind connected to them. Because of this historical design, as noted by ENMAX, these large-scale DCG projects, compared to the micro-generation projects, have a greater impact on the distribution system and require a more thorough technical assessment. Consequently, the review timelines are longer and the technical connection requirements are often more stringent for these DCG projects as compared to 1 MW micro-generation projects.

5.1.2.2.2 Visibility

148. Because distribution systems were not designed to have generation connected to them, distribution wire owners have limited ability to control, monitor and detect operational issues. For example, ATCO Electric explained that it has no control mechanisms in place for renewable or alternative DCG on its system.[68] It stated that its ability to control DCG units is limited to direct transfer trip for anti-islanding protection[69] and only for DCG units having synchronous generation.[70]

149. Likewise, the AESO and transmission facilities owners, such as AltaLink, stated they also have limited visibility of DCG.[71] [72] The AESO advised that it only becomes aware of a DCG unit either when the owner of the DCG unit registers as a market participant[73] or when a distribution wire owner informs the AESO that a proposed interconnection of a generator to the distribution system would have an operational effect to the transmission system that requires

68 Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 5.

69 Islanding refers to the situation when a DCG unit continues to deliver electrical energy to the distribution system after the distribution wire owner shut off the flow of electrical energy from its end. Islanding can pose a dangerous threat to workers, who may not be aware that electrical energy continues to flow while attempting to do work on the line. When islanding is detected, the delivery of electrical energy from the DCG unit must immediately stop. This is known as anti-islanding.

70 Synchronous generating units convert the mechanical power output of steam turbines, gas turbines, reciprocating engines and hydro turbines into electrical energy, and delivers this electrical energy to the grid.

71 Exhibit 22534-X0130, AESO responses to Commission questions, PDF pages 1-2.

72 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 3.

73 ISO rules, Section 203.1, *Offers and Bids for Energy*, requires all source assets with a maximum capability of 5 MW or greater to submit an offer in the energy market. The AESO receives real-time visibility of distributed generation 5 MW or greater in accordance with ISO rules, Section 502.8, *SCADA Technical and Operating Requirements*.

upgrades to substation equipment. Specifically, the AESO indicated that for large-scale DCG units that are configured to deliver electrical energy to the transmission system, the AESO receives site information and hourly net-to-grid[74] output data, whereas for large-scale DCG not covered by the *Micro-generation Regulation* and not configured to deliver electrical energy to the distribution system, the AESO typically does not receive any data.

150. Distribution wire owners, transmission facility owners and the AESO all stated that upgrades to their systems involving monitoring, control and communication devices and associated software would be required once the penetration level of DCG begins to have an operational effect on safety and reliability. Further discussion of both the operational levels and system upgrades is provided in Section 8.3.

5.1.2.2.3 Non-standardized interconnection processes

151. The distribution wire owner conducts an assessment for each connection application. Each distribution wire owner has its own policies, practices and processes in place to review and approve connection applications. In some cases, these policies, practices and processes are incorporated into the wire owners' terms and conditions of service[75] and in other cases, they are incorporated in various other documents. The AUC approves the terms and conditions of service for ATCO Electric, ENMAX, EPCOR, and FortisAlberta as a part of their tariffs. REA terms and conditions of service are approved by the respective REA Boards. For municipally-owned distribution wire owners (other than ENMAX and EPCOR), terms and conditions of service are approved by municipal councils.

152. DCG proponents and potential large-scale distribution-connected generators stated improvements to the distribution wire owners' application and review processes should focus on three areas: (1) standardization of the application process (2) providing more transparency, certainty and information to assist in determining optimal locations and (3) improvements to the AESO's queuing process to prioritize community-scale DCG where demand to connect exceeds the locational capacity.

(1) Standardization of the application process

153. Some DCG proponents proposed that all the timelines, technical and information requirements and steps (including dispute resolution) in the application process be standardized to make it easier for distribution-connected generators to interconnect to different systems. Distribution wire owners[76] also acknowledged that the standardization of certain aspects of the review and interconnection process (e.g., connection, communication and system protection requirements) could be beneficial to enable expected growth in DCG. They also pointed to the implementation of grid modernization equipment and systems and the introduction of smart DCG technologies such as advanced inverters as examples of standardization that can enable

[74] Net to grid refers to the amount of electrical energy delivered to the transmission grid by a DCG unit, not the total amount of electrical energy generated by the DCG unit. For example, a DCG unit may generate 5 MW of electrical energy, of which 4 MW was consumed at the site and 1 MW delivered to the transmission system. The net-to-grid amount reported to the AESO would therefore be 1 MW, not the actual 5 MW generated.

[75] Section 1(c)(v) of the terms of reference in the OIC requests the AUC in identifying enablers and barriers to consider the terms and conditions of service.

[76] Distribution wire owners responses to Commission question 26, specifically.

growth in DCG.[77] Some proponents stated that a consultation process would be the most effective and efficient manner of establishing standards for the application process. For example, AltaLink suggested that a consultative approach led by the AUC would be the most effective means to establish the standards.

(2) System Information

154. Access to system information was identified by many distribution-connected generators as necessary to efficiently enable growth in large-scale DCG. This information is not available today, and its absence was perceived as a barrier. Many stated the hosting capacity[78] of the distribution system at the feeder line level was the most beneficial information that distribution wire owners could provide. They stated the provision of, and access to, more system capacity information early in the process and mechanisms to resolve disputes in a timelier manner were areas for improvement. For example, SkyFire stated information from the distribution wire owners on where capacity exists on its distribution system would ensure developers are siting projects at the optimal locations. According to SkyFire, this information would result in significant savings in project development and interconnection costs and assist in the integration of the DCG project into the distribution system.[79]

Distribution wire owners considered that their review and information processes were able to serve the requirements of distribution-connected generators today but acknowledged that the provision of hosting capacity information would help in the review process. However, they explained that the process of compiling and regularly updating this hosting capacity would be data and labour intensive and that this additional cost would have to be paid for by their customers. While distribution wire owners have started to provide additional information, activities currently being undertaken to make hosting capacity information available are limited in scope. For example, ATCO Electric posts service area maps on its website showing the location and characteristics of its line segments, but these characteristics are limited (e.g., single phase, three phase)[80] and, although EPCOR[81] has engaged with researchers at the University of Alberta to perform a detailed hosting capacity analysis, this analysis is only on a segment of its service area.

(3) AESO queue

155. The AESO's website[82] explains the connection process it uses to provide system access to customers and the role of its connection queue (called the Connection Queue Business Practices) in managing the flow of information and activities. There are six stages in the AESO's queuing

77 The Institute of Electrical and Electronics Engineers (IEEE) has written a standard that addresses all grid-connected distributed generation including renewable energy systems. IEEE 1547-2003 provides technical requirements and tests for grid-connected operation. This information along with other examples of standards were provided by FortisAlberta in its response to Commission's question 26 in Exhibit 22534-X0105, PDF pages 63-64.

78 Hosting capacity is a measure of the ability for a distribution system to accommodate the integration of the generation without threatening the reliability or power quality of the distribution system.

79 Exhibit 22534-X0113, SkyFire responses to Commission questions, PDF page 19.

80 ATCO Electric, Distribution Facility Data, Retrieved from: http://www.atcoelectric.com/Services/GIS-Maps; and Transcript Volume 5, page 736, PDF page 199.

81 Transcripts Volume 1, PDF pages 71-74.

82 The Alberta Electric System Operator, Connecting to the Grid. Retrieved from: https://www.aeso.ca/grid/connecting-to-the-grid/.

process. A project developer must meet all of the requirements[83] within each stage before progressing to the next stage.

156. As of November 2017, there were 1,384 MW of wind projects that were approved by the AUC that are either on hold or in construction. Many of those projects already have an approved interconnection to the transmission system. Another 2,694 MW of wind projects have an active AUC power plant application (some of these also have active transmission connection applications) and a further 4,240 MW of wind projects are currently in the connection queue. Additionally, there are 267 MW of solar projects that are approved by the AUC, and that are either on hold or in construction. Another 55 MW of solar projects have an active AUC power plant application, and a further 2,831 MW of solar projects are currently in the connection queue. Most of these solar projects are expected to be connected to the distribution system, and may require some transmission related improvements.[84]

157. A few participants suggested that the AESO should revise its review and queuing process to enable smaller-scale or community-owned DCG projects to connect in priority to other large-scale DCG projects. Alberta Solar Co-op[85] stated the AESO's process favours large-scale projects with the result being that no available transmission and distribution capacity remains for community-owned projects. Alberta Renewable Energy Co-operative (also known as SPARK)[86] suggested community-owned projects be provided priority access to transmission capacity as a means of promoting province-wide participation. Otherwise, the capital requirements to secure this capacity under the AESO's current process would be a barrier to the growth of community-owned generation.

158. Renewable Energy Solutions™[87] stated large-scale projects should not have priority in the queue if a DCG project further down in the queue priority could fulfil the requirements at a lower connection cost. In high solar irradiation areas where a lack of interconnection capacity exists, proponents suggested that community and co-operatively owned solar projects have a higher priority access to interconnection capacity.

159. Not all large-scale generators shared this view.[88] These participants stated that all generation projects, regardless of size, should abide by the same established rules and processes to remain consistent with the government's stated policy of fair, efficient and open competition in the electricity market.[89]

160. One approach to address these issues is to consider how the telecommunication industry addressed its connection issues. The Canadian Radio-television and Telecommunications Commission (CRTC) dealt with issues similar to those noted by proponents in this study, (i.e.,

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83 The Alberta Electric System Operator, Connection Process Overview. Retrieved from: https://www.aeso.ca/downloads/ConnectionProcessOverview.pdf.
84 The Alberta Electric System Operator, Long-term adequacy metrics – November 2017. Retrieved from: https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/.
85 Exhibit 22534-X0162, Alberta Solar Co-op responses to Commission questions, PDF page 7.
86 Exhibit 22534-X0150, SPARK responses to Commission questions, PDF page 2.
87 Exhibit 22534-X0157, Renewable Energy Solutions™ responses to Commission questions, PDF page 3.
88 Exhibit 22534-X0118, Capital Power responses to Commission questions, PDF page 2.
89 See for example the Alberta Department of Energy's Policy Direction for Alberta's Capacity Market Framework. Retrieved from: http://www.energy.alberta.ca/Org/pdfs/PolicyDirection_AlbertaCapacityMarketFramework.pdf.

access to information, technical connection standards and responsibility for connection costs) through stakeholder consultations that resulted in standards that were then set out in the CRTC's Regulatory Policy documentation.[90]

161. The AUC adopts a similar process when it engages in consultation as part of its rule-making authority.[91] The AUC's settlement system code is an example.

5.2 The capability of distribution systems to absorb growth of DCG

162. The OIC states that "the Government of Alberta has set a firm target for 30 per cent of electric energy produced in Alberta to be generated from renewable sources" by 2030 and that "significant growth in distribution system-connected generation, including micro- and small-scale community generation, will contribute to the 30 per cent renewable electricity energy generation target." For the purposes of this report, the AUC has referred to this target as the 30-30 target.

163. The ability of the distribution system to absorb sufficient growth in DCG is a potential barrier to DCG playing a significant role in achieving this 30-30 target. In this section, the AUC reviews the level of growth distribution wire owners consider achievable to enable the government to reach its 30-30 target and explores possible models to facilitate that growth. The AUC then reviews the forecast system investments that would be required to enable that growth.

164. All participants anticipated that alternative and renewable DCG would contribute to meeting the 30-30 target and that there were no barriers to facilitating the current organic levels of growth. However, no distribution wire owner could predict at what point growth would cause operational issues on its system that would require significant distribution system investment, or where on their systems those issues might arise.

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90 The Canadian Radio-television and Telecommunications Commission (CRTC) created the CRTC Interconnection Steering Committee ("CISC") in Telecom Public Notice CRTC 96-28, Implementation of Regulatory Framework – Development of Carrier Interfaces and other Procedures. The CRTC had previously determined that increased competition in the local telephone market would be in the public interest (Telecom Decision CRTC 94-19, Review of Regulatory Framework). The CRTC required information from industry on the specific technical and administrative matters necessary to implement that policy determination, such as co-location, component unbundling, and number portability. In the course of these follow-up processes, which had relied on ad hoc working groups and requests for information, CISC was established as a more formal body to support advisory activities of this nature.

91 CISC does not make policy or binding determinations on regulatory matters. Instead, it provides recommendations on technical, administrative, or operational matters required for the implementation of decisions made by the CRTC. CISC assists the CRTC by developing information, procedures, and guidelines in support of regulatory policies. CISC is chaired by CRTC staff. Individual items are assigned to working groups, comprised of representatives from industry, the CRTC, and other stakeholders depending on the subject matter. Membership is open to all interested parties. Once a working group completes a task, it prepares a report for consideration by the larger committee. Working groups aim to achieve consensus in their tasks, however, in some cases, no consensus is possible. CISC then submits recommendations to the CRTC, either in the form of a consensus or non-consensus report. The CRTC makes decisions after considering CISC's recommendations, which are not binding unless approved by the CRTC. The CRTC may approve, reject, or amend any recommended measure as it sees fit.

5.2.1 Current and future growth

165. During the oral hearing, as part of the AUC's preliminary information gathering process, the AUC invited the distribution wire owners to comment on the 30-30 target. Specifically, the AUC wanted to understand the level of DCG that could realistically be integrated to contribute to meeting this target and the level of DCG penetration that would cause distribution wire owners to make investments in their systems to absorb and accommodate increasing levels of DCG.

166. None of the distribution wire owners was able to either quantify the amount of DCG that could be integrated now nor the level of DCG penetration that would result in the requirement for further investments. All said the current level of DCG does not pose an operational problem, and all said that continued growth would result in the need for additional resources, both human and equipment, to integrate large additions of DCG. The changes required were, to some extent, dependent on whether the distribution wire owner operated in a rural or urban setting and whether DCG growth was concentrated in pockets on their systems.

167. ATCO Electric, operating a primarily rural distribution system, estimated that its service area would need to accommodate 600 MW of DCG to meet the 30-30 target. Assuming the majority of DCG capacity was over 150 kW, this would significantly increase the volume of interval meter data. As such, there would be an increase in data storage and processing costs. In addition, since the billing process is not automated for DCG customers, additional billing staff would be required to manually calculate the demand and energy credits.

168. ENMAX, operating a primarily urban distribution system, submitted that the current level of DCG adoption has not created significant issues on its distribution system. Although currently its DCG connections have remained low and are dispersed throughout its system, a concentration of DCG in one part of ENMAX's system could compromise the safe and reliable operation of the system. Further, higher volumes of DCG interconnection requests will likely require distribution system reinforcement, as well as process and support systems modifications. ENMAX noted that the penetration of alternative and renewable DCG in Alberta is well below the projected target under the Residential and Small Commercial Solar Rebate program. However, if this program achieves its goal, ENMAX's distribution system may begin to experience localized operational issues. These issues include voltage regulation on secondary voltage circuits due to clustered development of small micro-generators on a residential block or multi-housing facilities, voltage regulation and excessive short circuit current on the feeder level due to multiple large exporting DCGs interconnected on the same feeder and capacity related issues such as overloaded transformers and conductors.

169. Other participants also provided submissions regarding the contribution that DCG could make. For example, Energy Efficiency Alberta did not expect small-scale renewable DCG to be a significant provider of the generation required to achieve the 30-30 target under the Climate Leadership Plan. According to Energy Efficiency Alberta, transmission-connected renewable generation will be part of the solution and both sources were necessary and valuable.[92] Currently, micro-generation constitutes only 0.12 per cent of installed capacity, and large DCG only 2.5 per cent of installed capacity. When evaluated on an energy production basis, these amounts are miniscule.

[92] Transcript, Volume 7, pages 1002-1003, PDF pages 22-23.

170. Even at current levels, there was conflicting information regarding when upgrades to respond to growth in DCG would be required. DCG proponents CanSIA and Canadian Wind Energy Association (CanWEA) stated the variability of load on a feeder is commonly up to 20 per cent. Consequently, they submitted that distribution system upgrades should not be needed for DCG penetration below 20 per cent since the variability would be within the normal range of existing load fluctuations. According to these proponents, DCG's operational effects become more noticeable above 20 per cent penetration, so that a connection impact assessment would need to be conducted to determine whether additional devices or equipment, such as battery storage or line upgrades, are required to accommodate any additional DCG.

171. EPCOR stated it limits the amount of DCG on each of its circuits to 15 per cent of the circuit's peak load. Above this threshold, it carries out a more detailed review of the specific circuit and the proposed DCG addition to ensure that the new DCG can be accommodated. EPCOR, as referenced previously in subsection 5.1.2.2, is conducting a detailed research study to determine the acceptable DCG penetration level for each of its 286 distribution circuits, advised that the results of its preliminary assessment indicates the acceptable penetration level is highly feeder dependent and can be influenced by the type of load on the feeder, the electrical and physical characteristics of the feeder, the size of the DCG, the location of the DCG along the feeder, the presence or not of voltage regulators, and the type of control algorithms used by the distribution-connected generator.

5.2.2 Planning to contribute to the 30-30 target

172. The AUC asked participants to consider plans that might enable DCG growth on the distribution systems. Options discussed included: (1) building out the distribution system in advance of requests for DCG interconnections, similar to the model employed on the transmission system where capacity is built in advance of requests for transmission connections, (2) integrated planning and (3) centralized planning. Each of these options is discussed below.

173. As explained by EPCOR,[93] "distribution utilities have an obligation to ensure that distribution access service is sufficient such that load customers and owners of DCG can exchange electric energy through the grid. This means load can be served without curtailment and, likewise, DCG owners can export and sell their energy to the grid without being curtailed." Although the design and construction of the distribution system is to meet peak demand requirements, the level of DCG penetration is not yet at the stage where changes are required to their planning considerations.

Build in advance model

174. With the introduction of the 30-30 target, the AUC asked participants to consider whether adopting a model similar to the transmission "build in advance of need" model mandated in legislation and regulation[94] would enable the development of alternative and renewable DCG. As explained in Section 4 of this report, with the development of the competitive generation market, the AESO became legislatively responsible for ensuring that transmission access was available for generators to deliver their electrical energy to the market. Large-scale DCG generators participate in that energy market; however, rather than connecting at the transmission level, they

[93] Exhibit 22534-X0144, EPCOR responses to Commission questions, PDF page 22.
[94] Specifically, the *Electric Utilities Act*, *Hydro and Electric Energy Act* and the *Transmission Regulation*.

connect at a distribution level, where no such requirement to build facilities in advance is mandated. No participants advocated the extension of this model to the distribution system.

175. The issue regarding build in advance is one of timing and costs. Building the new infrastructure too far in advance of the expected introduction of the DCG may result in overcapacity in the distribution system, so the investment may not be very cost-effective initially.

176. AFREA stated that prebuilding the system upgrades in anticipation of DCG would result in additional, and potentially stranded, costs if DCG does not develop as forecast. The cities of Lethbridge and Red Deer also stated that there would be some danger in requiring advance investment because system upgrades are specific to the DCG being connected and both the distribution and DCG technologies are evolving quickly. The cities of Lethbridge and Red Deer as well as EPCOR stated that at current levels of DCG development, the distribution system effects should be considered on a case-specific basis. Otherwise, it would be difficult to anticipate the needed system upgrades and their associated costs. Thus, upgrading the system in anticipation of DCG growth would increase the risk of making unnecessary investments for which distribution system customers would have to pay. EQUS, the UCA and CanWEA all stated that system upgrades should be made in response to the demand for service by DCG and not in advance of need.

Integrated planning

177. Other participants commented on the need to plan for growth in DCG in a more holistic manner. Teric Power Ltd. (Teric)[95] stated that it makes little sense to plan the development of distribution networks having regard to only alternative and renewable DCG and ignore other forms of DCG that could have an effect on the networks. AltaLink suggested the use of pilot or small-scale upgrades as a measured, staged response to increasing DCG penetration to assess the performance of new technologies and operational systems before proceeding to full-scale deployment. Findings from other jurisdictions could also be incorporated. This planned approach should also consider the effects on the transmission system. [96]

178. According to AltaLink, a holistic review of the distribution, transmission and generation systems is required to integrate DCG in the most efficient and cost-effective manner for all ratepayers. The planning review would focus on safety, reliability, power quality and the financial effect on ratepayers. Further, rather than focussing on DCG, AltaLink suggested that the initial priority should be on connecting renewable generation to the transmission system to take advantage of the available capacity that currently exists.[97] AltaLink asserted that this would be more cost effective and avoid the additional costs associated with potential upgrades to the distribution system.

Centralized planning

179. The AESO mentioned the need for a coordinated approach with distribution wire owners to manage situations where the actions required to maintain distribution system reliability would

[95] Exhibit 22534-X0098, Teric responses to Commission questions, PDF page 29.
[96] Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 3.
[97] Exhibit 22534-X0202, AltaLink responses to Commission supplemental questions, PDF pages 13-14.

conflict with the actions required to maintain transmission system reliability, particularly given the intermittent nature of alternative and renewable DCG.

180. The AESO explained that a high penetration level of DCG could result in voltage control issues for the distribution system that, in turn, could affect the operation of the Alberta Interconnected Electric System. It stated that it will require some real-time visibility and control of DCG, similar to the AESO's current visibility and control of transmission-connected generation, as the penetration level of DCG rises. Consequently, the AESO indicated it may need to develop new ISO technical rules, technical standards, guidelines, practices, or ISO operating rules to ensure the integration of DCG occurs in a safe and reliable manner. Presently, the AESO has received approval for a new ISO rule and two amendments to existing rules that address the technical and operating requirements for DCG resources.[98] These market-related ISO rules apply to any generating resource that is 5 MW or greater, including those connected to the distribution system and are in effect September 1, 2018.

181. The AESO also anticipates that it may require the ability to direct the distribution wire owners to control DCG on their feeders to mitigate real-time transmission reliability issues.

182. The AESO, in its role of system operator, monitors the electricity supply (generation) and demand (load) to ensure it is balanced at all times. The AESO may require distribution wire owners to reduce load to bring the system in balance during adverse system events. This is accomplished by disconnecting distribution lines from the transmission system, which would not only disconnect load customers, but also disconnect DCG customers (generation). At the current low penetration level of DCG, this is of no consequence. However, at a greater level of DCG penetration, the distribution wire owner may need to ensure only load is disconnected and not DCG. The distribution wire owners may therefore need to invest in new equipment and devices to distinguish load from generation.

183. Finally, the AESO expects that new distribution control centres may be required to operate the distribution system safely and reliably and to properly monitor and control DCG. According to the AESO, this will require investments in distribution management systems and communication systems by the distribution wire owners and the distribution-connected generator to enable communication among the distribution control centre, the AESO, the transmission facility owners, and the distribution-connected generator.

5.2.3 System investment to contribute to the 30-30 target

184. Distribution systems are in transition. Historically, distribution systems received electrical energy delivered by the transmission system, reduced the voltage, and then delivered the electrical energy to customers. The expectation was that distribution wire owners would provide reliable service at a reasonable cost. Today's distribution systems are also being relied upon to integrate an increasing amount of distributed generation and energy storage systems without any reduction in service standards. The introduction of a greater penetration of DCG, with its variability and intermittency, into a system that was not designed or built for this

[98] Section 502.8, *SCADA Technical and Operating Requirements*, Amendment to Section 304.3, *Wind and Solar Power Ramp Up Management* (Effective September 1, 2018), and new Section 304.9, *Wind and Solar Aggregated Generating Facility Forecasting* (Effective September 1, 2018).

purpose, will create challenges for the distribution wire owners to maintain their high levels of service quality and reliability for all Alberta customers.

185. The AUC asked participants about the investments required by the distribution wire owners, and the timing of those investments, to enable a greater penetration of DCG. Distribution wire owners told the AUC that as DCG penetration levels increase, they will need to invest in monitoring, control, communication and protection devices and systems to maintain system reliability, power quality and the safe operation of their distribution systems. Real-time knowledge of each systems' capacity could allow for the more efficient use of the existing infrastructure. Although these technological investments could enable the development of alternative and renewable DCG, the necessary investment costs could be a barrier.

186. Participants identified the following distribution system investments as being required to manage the expected increase in operational complexity and variability as the amount of DCG being integrated into the distribution system increases:

- Advanced metering infrastructure (AMI) and meter data management systems
- Improved communication networks
- Enhanced load settlement, data processing and billing systems
- Reinforced distribution system infrastructure and protection systems
- Distributed energy resource management systems (DERMS) and advanced distribution management systems (ADMS)
- Increased use of emerging technologies such as utility-scale energy storage or electric vehicle charging infrastructure to manage system load profiles

187. A discussion of the pace of some of these technological changes and their effect on DCG growth is provided in Section 7 of this report. These investments would enable distribution wire owners to acquire enhanced visibility to each distribution system's condition and performance.

188. ATCO Electric[99] added that distribution wire owners' investment in non-wire technologies such as energy storage and DCG could be a least-cost solution to accommodating DCG and maintaining reliability. The definition of "electric distribution system" in Section 1(m) of the *Electric Utilities Act* excludes a generating unit. It is unclear whether battery storage would fall within the definition of "generating unit" as set out in Section 1(u) of the *Electric Utilities Act*.[100]

189. Further, as explained in Section 5.1.2, as the penetration level of DCG increases, participants indicated that more detailed information such as hosting capacity maps would assist

[99] Exhibit 22534-X0249, ATCO Electric opening statement, PDF page 2.

[100] The Texas Public Utility Commission is considering whether regulated transmission and distribution companies can own and operate energy storage solutions, such as battery storage, as part of its regulated function. Texas PUC Docket No. 46368, Application of AEP Texas North Company for regulatory approvals related to the installation of utility-scale battery facilities.

proponents in identifying suitable areas to locate their projects. These costs would be in addition to the costs that the wire owners would incur to maintain safe and reliable service.

190. There are three ways that the solar proponents suggested that solar DCG could be used to maximize the use of the distribution systems' existing infrastructure without the need to invest in upgrades.

(1) CanSIA and SkyFire suggested that solar DCG could provide ancillary services such as frequency and voltage control but mostly on a short-term basis[101]; and

(2) Further, Aura Power stated that: "[e]ffective solar DCG development is dependent on maximizing the utilization of existing distribution infrastructure. Therefore, we encourage any technical or commercial effort by the distribution utilities and other agencies to maximize the availability of existing infrastructure for solar DCG development."[102]

(3) Pembina's witness asserted that solar power could be used to reduce the peak on a distribution system in the summer. However, Pembina did acknowledge that shaving the summer peak would not reduce the infrastructure required to meet the winter peak.[103]

191. The AUC observes that none of these parties explained how these approaches could be successful given the intermittent nature of solar.

192. When the integration of DCG causes the distribution wire owners to make investments in their systems, the challenge will be to identify who will be responsible for these costs. Participants proposed various alternatives including having DCG customers be solely responsible (through customer contribution payments or through rates), having all ratepayers bear the costs or having a government-sponsored program, such as the carbon levy, fund the upgrades of the systems. This matter is discussed in further detail in Section 5.3 below.

5.3 Rate design and tariff structure

193. Rate design, "the process of translating the revenue requirements of a utility into the prices paid by customers"[104] is a complex process. The design chosen can enable DCG growth or can act as a barrier. As noted above, system enhancements can enable DCG growth. However, the costs of these enhancements will need to be recovered to ensure the financial health of the distribution wire owners so that they can continue to provide safe and reliable service. These additional costs may act as a barrier to increased DCG growth.

194. In this subsection, the AUC first provides an overview of the components that make up a customer's bill and examines whether the presentation of these costs within the bill could serve to enable growth in DCG. The AUC then examines the various rate design options, including net

[101] Exhibit 22435-X0133, CanSIA responses to Commission questions, PDF pages 3-4; Exhibit 22534-X0113, SkyFire responses to Commission questions, PDF page 3.
[102] Exhibit 22534-X0116, Aura Power responses to Commission questions, PDF page 2.
[103] Transcript Volume 8, page 1427, PDF page 324.
[104] NARUC Manual on Distributed Energy Rates Design and Compensation, PDF pages 20-21. Retrieved from: https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0, on December 8, 2017.

metering and net billing, proposed by participants for the recovery of these costs. Finally, the AUC reviews the effect that growth of DCG may have on creating stranded assets.

195. Some participants indicated that changes to the information provided on a customer's bill could enable further DCG growth. Regarding the rate design proposals discussed, most participants rejected using rate design, including net metering or virtual net metering, solely to incent renewable and alternative DCG growth. Last, several participants commented on the increased risk of stranded assets that may result from growth in DCG and indicated that this risk could present a barrier to its development.

5.3.1 Electricity bill components

196. A foundational understanding of the basic components of the costs that make up a customer's bill is necessary before discussing the details of rate design modifications that participants proposed that might enable further DCG growth.

197. A customer's bill is produced based on usage information, which is obtained from the customer's meter. Meters record the amount of electrical energy used by a customer in a billing period (usually a month) and are collected by distribution wire owners. This usage information is passed on to retailers. This information is also provided to the AESO, which uses the information to invoice retailers for their customers' electrical energy usage. Retailers also receive invoices from distribution wire owners for the transmission and distribution costs related to delivering the electrical energy to the retailers' customers.

198. Retailers recover the electrical energy costs paid to the AESO and the costs of transmission and distribution paid to the distribution wire owners from their customers. Retailers also bill their customers for the services they provide, including producing the customer's bill and providing customer service.

199. The *Billing Regulation* sets out the requirements of presenting costs on a customer's bill. A customer's bill must display, as separate line items, the following charges:

- energy charge
- delivery charge (including transmission and distribution)
- administrative charge
- local access fee

200. A description of the purpose of each of these charges is discussed below for a typical customer.

Energy charge

201. The electrical energy charge recovers the retailer's cost of purchasing the electrical energy on behalf of customers. The energy charge is determined by multiplying the total amount of electrical energy used in a billing period (usage information obtained from the customer's meter) by the energy rate (expressed in kilowatt hours) charged to customers by the retailer.

Delivery charge

202. The delivery charge includes transmission and distribution charges. Transmission charges reflect the cost of moving electrical energy from generating facilities through high-voltage transmission lines to the distribution wire owners' lower voltage distribution lines connected to the transmission substation transformers. Transmission charges also include the cost of building new transmission facilities, and the costs of operating and maintaining the transmission system. The transmission charge on a customer's bill is based on the amount of electrical energy used by the customer. Distribution charges recover the cost of moving the electrical energy from the substation transformers through distribution lines to the customers' site of usage. Distribution charges also cover the cost of operating and maintaining the distribution system, including connecting new customers (load and DCG), meter reading, maintaining a billing system and restoring service after an outage. The distribution wire owners are responsible for calculating the delivery charge for each customer in its service area and passing this information on to the retailer serving the customer.

203. For RRO customers, the *Regulated Rate Option Regulation* requires the RRO provider to display the delivery charge for distribution access service and system access service (transmission) separately as either (1) a distribution charge and a transmission charge or (2) a fixed delivery charge and variable delivery charge.

204. Transmission delivery charges are composed of energy or variable delivery charges, while distribution charges are composed of both variable and fixed charges. Fixed charges on residential services are called service charges; on large industrial, farm and commercial services, they are referred to as demand or capacity charges. A demand charge relates to the maximum amount of electrical energy needed (demanded) by the customer at any given time. The transmission and distribution systems are designed and built to meet the maximum demand (peak) that all customers require at any given time. Distribution wire owners design their rates to recover the cost of investing in the facilities required to be available to meet that demand. Having separate charges for electrical energy consumption and demand is generally accepted in the utility industry as a fair method of billing the costs of providing service to customers.

Administrative charge

205. Under the *Electric Utilities Act*, retailers are responsible for maintaining customer records and accounts, preparing and issuing bills, collecting payments, and responding to customer inquiries and complaints. The costs of these activities are recovered through the administrative charge. This charge is displayed as a dollar amount for each billing period.

Local access fee

206. The local access fee is a charge established and imposed on the distribution wire owner by a municipal government for allowing the distribution wire owner to access land to construct, maintain and operate the distribution system that provides the service to the municipality's residents.

Rate riders

207. Rate riders are used to flow through or reconcile costs that are incurred by a distribution wire owner that were not included in its base distribution tariff rates at the time those rates were

approved by the AUC. Rate riders collect or refund the differences in these amounts as calculated at the point in time the rate rider is approved by the AUC. The two most common riders are the Balancing Pool allocation rider[105] and the Transmission Tariff True-up rider.[106]

5.3.2 Bill presentation

208. The AUC asked participants if standardizing or changing the information presented on a customer's bill could be used as a tool to promote further DCG. Responses from the participants were varied.

209. Several DCG proponents recommended that all retailers be required to display generation and consumption on their bill. Presently, there is no requirement to display generation information on the DCG customer's bill; it is at the retailer's discretion. Some retailers show their DCG customers the consumption and generation amounts (measured in kilowatt hours) on separate line items on the bill so the DCG customer can see the amount of electrical energy it produces and the amounts of electrical energy it consumes. Other retailers display only the amount of net kilowatt hours on the bill. Consequently, these DCG customers would not know the gross amount of their generation during the billing period.[107] These proponents argued that requiring this information from all retailers would enable DCG growth, and other than a comment from Pembina that this information could provide a verification of a DCG's system performance and revenue generation, [108] did not elaborate further.

210. Pembina, in particular, recommended more information be presented on a customer's bill to incent customers to install DCG. Some of the information recommended was environmental in nature, such as carbon emissions, and some of the information was comparative, such as consumption relative to neighbouring sites.[109]

211. During the oral portion of the inquiry, the AUC recognized that one of the marketing tools available to retailers, who compete for customers, is the way in which they communicate with their customers. ATCO Electric agreed, stating that because retailers prepare the bill for their customers, it thought that the individual retailer would want to determine the information presented on the bill.[110] As well, the AUC understands, from the evidence, that adding additional information to the customer's bill will require system changes and will increase billing costs. It inquired of participants if it would be as effective to receive this information through other

105 The Balancing Pool was established in 1999 by the Government of Alberta to help manage certain assets, revenues and expenses arising from the transition to competition in Alberta's electric industry. Under provisions of the *Electric Utilities Act*, each year the Balancing Pool is required to forecast its revenues and expenses to determine any excess or shortfall of funds. These fees or credits are passed on to all Alberta energy consumers.

106 Each quarter, the AESO recovers or refunds accumulated deferral account balances which are comprised of differences between revenues and costs incurred in providing system access service to the distribution wire owners. The distribution wire owners, in turn, add an adjustment rider, which could be a charge or refund, to their delivery charges at the beginning of each quarter (January 1, April 1, July 1 and October 1). This adjustment reconciles current costs to date and estimates transmission costs into the next quarter.

107 The eligibility requirements under the *Micro-generation Regulation* state that the intent of the micro-generation generating unit is to meet all or a portion of the customer's total annual energy consumption at the customer's site and the total nameplate capacity does not exceed the rating of the customer's service. Therefore, it will be the usual case that the DCG customer's bill will display a net consumption amount.

108 Exhibit 22534-X0146, Pembina responses to Commission questions, PDF page 4.

109 For a complete list see Exhibit 22534 -X0146, Pembina responses to Commission questions, PDF page 4.

110 Transcript, Volume 5, page 691, PDF 154.

means, such as emails or other notices, rather than on a standardized bill format, as some competitive retailers already do. Participants, including Pembina, agreed that other mediums could be equally effective.[111]

212. Although some proponents' preference was to have more detailed information displayed on the bill, including community generation activity,[112] there was no consensus regarding who should be responsible for paying the associated costs of providing this additional information. For example, the cities of Lethbridge and Red Deer suggested that DCG customers should pay for the costs of having distribution wire owners collect the information displayed on bills if this information is not currently required for tariff billing purposes.

5.3.3 Distribution rate design

213. As explained in subsection 5.3.1 above, the costs incurred by distribution wire owners to provide electricity services to Alberta consumers are currently recovered through a distribution tariff, which includes both distribution and transmission delivery charges. Generators, including distribution-connected generators, do not currently pay any delivery charges for the electrical energy they deliver to the system.

214. The distribution wire owners, AFREA, the CCA and the UCA all supported the rate design principle of cost causation. This principle requires those who cause the costs incurred by utilities to provide electricity services to be responsible for paying for those costs.[113] For example, EPCOR noted that the current rate treatment of large-scale DCG accurately reflects the cost to serve, and in its view, these costs represent a small financial burden to the distribution-connected generator. Regarding large and small micro-generation DCG, EPCOR noted that even though connection costs are borne by all ratepayers, and not solely by those who cause the costs, this allocation of costs enables micro-generation DCG.[114]

215. The AUC explored with participants whether different rate designs could enhance DCG growth and if so, whether they considered it advisable to adopt such changes. The rate designs discussed included: (1) net billing versus net metering; (2) virtual net metering; (3) recovering delivery services through fixed charges; and (4) creating a separate DCG rate class.

216. Participants generally rejected net metering and virtual net metering. Support for the creation of a new customer class was mixed as was support for the recovery of delivery services through fixed charges.

111 Transcript, Volume 8, pages 1415-1416, PDF pages 312-313.

112 See for example, Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 7.

113 Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 76; Exhibit 22534-X0182, EPCOR reply evidence, PDF page 9; Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 36; Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 84; Exhibit 22534-X0143, the City of Lethbridge and the City of Red Deer responses to Commission questions, PDF page 25; Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 6; Exhibit 22534-X0200, CCA responses to Commission supplemental questions, PDF page 3; Exhibit 22534-X0199, UCA responses to Commission supplemental questions, PDF page 8.

114 Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 34; Exhibit 22534-X0144, EPCOR responses to Commission questions, PDF pages 38-39; Exhibit 22534-X0119, EQUS responses to Commission questions, PDF page 16.

217. In general, wire owners and DCG proponents disagreed on how transmission and distribution tariffs should be designed to enable DCG. Wire owners stated that a tariff designed more heavily weighted towards fixed charges would act as an enabler providing the correct price signal to the distribution-connected generators, while DCG proponents favoured variable charges and credits to encourage DCG by providing savings on their electricity bills. Wire owners and DCG proponents do not share the same views regarding the value that DCG brings to the transmission and distribution systems, especially with respect to the availability of solar DCG and its effect on peak demand. There appears to be a gap in DCG proponents' understanding regarding the drivers of transmission and distribution system investments and how costs are allocated to enable distribution wire owners to recover these costs. Distribution wire owners and interveners are concerned with providing subsidies to DCG through distribution tariffs to the detriment of load customers, and there was a general agreement that building subsidies in a tariff design could have unintended consequences. Many participants expressed a need for the AUC to engage stakeholders in a process to address the complexity of tariff design and its effect on Alberta consumers and DCG before any changes are made.

218. For the purposes of the following discussion on rate design, it is assumed the DCG customer is both a distribution-connected generator and a consumer of electrical energy from a distribution system.

5.3.3.1 Net billing versus net metering

219. As part of its information gathering process, the AUC asked parties to consider the differences between net billing and net metering and to comment on the effect that these different methodologies might have to enable increased levels of DCG. Under the provisions of the *Micro-generation Regulation*, the billing affects only the energy charge portion of the bill. The other components of the bill remain unaffected by the operation of the DCG unit, because the net billing method, as prescribed by the regulation, rather than net metering, is used to calculate the energy credits and delivery charges. DCG proponents preferred the net metering method because this method would enable DCG customers to realize additional savings on their bills. Distribution wire owners favoured net billing as this method provides a more equitable allocation of costs to their customers.

220. Net billing is the method prescribed by legislation in Alberta for compensating DCG customers for the excess electrical energy delivered to the distribution system and for charging the DCG customer for the consumption of electrical energy from the system.

221. The *Micro-generation Regulation* enables a DCG customer to receive a credit on its electricity bill for the electrical energy it delivers to the distribution system (generation) during their billing period (usually one month). The credit is equal to the amount of electrical energy delivered to the distribution system minus the amount of electrical energy used by the DCG customer over a billing period, multiplied by the DCG customer's energy rate. This rate may vary from one DCG customer to the next depending on whether the customer is on the RRO rate or a contracted rate provided by its retailer. To facilitate the calculation, a bi-directional meter having two separate registers is required; the first register measures the total amount of electrical energy delivered to the DCG customer from the distribution system, the second measures the total amount of electrical energy delivered to the distribution system from the DCG customer's site during the billing period. The delivery charges are calculated using the total amount of energy measured in the first register.

222. After the retailer provides the credit to the DCG customer, the *Micro-generation Regulation* obligates the AESO to compensate the retailers for the credits provided to the retailers' DCG customers. In turn, the AESO collects the amount paid out in compensation to retailers through its transmission tariff. Thus, all ratepayers provide the funding for the net billing credits.

223. In contrast to net billing, net metering would allow a DCG customer to reduce the meter's measurement of the DCG customer's consumption by the amount of generation supplied to the distribution system. Whenever the DCG customer is generating more than it is consuming at any time during the billing period, the excess generation is delivered to the distribution system and the DCG customer's meter "runs backwards." This results in the DCG customer being billed for a lower consumption amount. Net metering therefore would recognize a greater saving for the excess generation than net billing because the DCG customer could avoid both energy and delivery charges.[115] The collection of net metering data could be achieved by one meter with a single register within it to track net consumption or net generation, two separate meters each measuring the flow in one direction, or one meter which has two registers within it.

[115] This occurs because distribution wire owners bill a portion of the delivery charges based on energy usage.

224. The table below illustrates how a customer's bill would change depending on whether a DCG customer is billed on the net billing method or the net metering method. For purposes of this example, the following assumptions were made:

- The energy rate is five cents per kWh.
- The delivery rate is assumed to be a fully variable charge of six cents per kWh.

Table 5. Net billing versus. net metering

	Net billing	Net metering
Total monthly energy consumed by the DCG customer	1,100 kWh	1,100 kWh
DCG monthly energy production	800 kWh	800 kWh
Monthly energy delivered to the distribution system by the DCG	200 kWh	200 kWh
Energy supplied by the DCG to the DCG customer[1]	600 kWh	600 kWh
Energy supplied to the DCG customer by the distribution system	500 kWh	500 kWh
Register 1 (measures the total amount of electrical energy delivered to the DCG customer from the distribution system)	500 kWh	300 kWh[2]
Register 2 (measures the total amount of electrical energy delivered to the distribution system from the DCG customer)	200 kWh	n/a
Energy charge[3]	$25.00	$15.00
Delivery charge[4]	$30.00	$18.00
Energy credit[5]	$(10.00)	
Total charges	$45.00	$33.00
Costs to be recovered from non-DCG ratepayers	$10.00	$22.00

1 Energy supplied by DCG is not equal to DCG monthly energy production because the energy is produced at times when it is not needed by the customer. The excess energy (200 kWh) is delivered to the distribution system.

2 Net metering = 1,100 kWh consumed minus 800 kWh generated = 300

3 Energy charge = Register 1 kWh multiplied by energy rate

4 Delivery charge = Register 1 kWh multiplied by delivery charge rate

5 Energy credit = Register 2 kWh multiplied by energy rate

225. Using the net billing method, the first register would record 500 kWh of electrical energy used and the retailer would calculate that customer's energy and delivery charges using 500 kWh. The DCG customer has saved on delivery charges by supplying 600 kWh of its own electrical energy requirements to itself. The second register would record 200 kWh, and this value would be used to calculate the credit. Therefore, effectively, the DCG customer will have paid an energy charge based on 300 kWh of consumption.

226. If one were to use the net metering method, the meter would record the net 300 kWh of electrical energy supplied from the distribution system during the billing period. The retailer would calculate the DCG customer's energy and delivery charges using 300 kWh.

227. The distribution wire owners support the net billing approach because effectively a customer that requires 500 kWh from the system, whether they are generating or not, will be billed based on 500 kWh. Many DCG proponents support using the net metering approach because the DCG customer will receive a lower bill.

228. Distribution wire owners asserted that net metering would result in DCG customers not paying for all of their share of the distribution costs that they are using. These DCG customers

rely on the distribution system for the delivery of electrical energy when their DCG unit is unable to generate (for example, at night and when it is cloudy for solar DCG or when the wind is not blowing for wind DCG) and in doing so, experience the same levels of reliability enjoyed by all customers connected to the distribution system. If these DCG customers are only billed on the basis of net generation, non-DCG customers, who are often less affluent Albertans who cannot afford or have the opportunity to install DCG on their homes, are paying costs caused by the DCG customers. ATCO Electric, the cities of Lethbridge and Red Deer, as well as the UCA, all noted that vulnerable ratepayers might be affected because DCG is typically more prevalent in affluent neighbourhoods.[116]

229. AltaLink also stated that DCG customers might not pay their fair portion of transmission charges under a net metering scheme. [117] This situation can arise because the AESO's transmission tariff, which is largely fixed costs, is billed by the distribution wire owners to customers on a variable (i.e., consumption) basis. Consequently, DCG customers would avoid paying certain fixed transmission costs and the non-DCG customers would bear the responsibility for paying the costs avoided by the DCG customer.

230. Some DCG proponents[118] suggested that the use of a net metering mechanism would help to realize the objectives of the Climate Leadership Plan. Pembina believed at a low DCG penetration level, the amount of costs shifted from DCG customers to non-DCG customers would result in an insignificant change in the delivery charges, therefore these non-DCG customers would not notice the increase in delivery charges on their electricity bill. [119] Pembina asserted that the increase in delivery charges could be justified on the basis that non-DCG customers were not paying for the true value of renewable energy being generated by DCG customers in terms of health and environmental impacts. However, Pembina did concede that a change to the cost-recovery methodology would be required once DCG penetration reached a level where the increase in delivery charges to non-DCG customers became noticeable but did not indicate at what price or level that occasion might arise.

231. Other proponents did not share Pembina's view and rejected net metering as a premise for promoting DCG. SkyFire[120] mentioned that in Nevada, the introduction of net metering has led to lawsuits and court actions that have stifled the growth of DCG in that state. Howell Mayhew [121] stated net billing was a more equitable and practical billing mechanism than net metering for both DCG customers, non-DCG customers and distribution wire owners. Howell Mayhew explained that DCG customers should continue to pay the delivery charges since these customers receive a necessary service from the distribution system in the form of voltage and frequency support (needed for the proper operation of the DCG unit) and access to the system to deliver their excess generation. Howell Mayhew further added that the introduction of the *Micro-*

116 Exhibit 22534-X0106, UCA responses to Commission questions, PDF page 7; Exhibit 22534-X0205, ATCO Electric responses to Commission supplemental questions, PDF page 13; Exhibit 22534-X0143, the City of Lethbridge and the City of Red Deer responses to Commission questions, PDF page 25.

117 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 19.

118 See Exhibit 22534-X0150, Spark review submission (promoting community generation); Exhibit 22534-X0146, Pembina responses to Commission questions (establishing market value for solar generation).

119 Transcripts, Volume 8, page 1390, PDF page 287.

120 Transcripts, Volume 2, page 233, PDF page 99.

121 Transcripts, Volume 8, page 1221, PDF page 118.

generation Regulation, and its net billing mechanism, has been successful in promoting the growth of solar DCG.

5.3.3.2 Virtual net metering and virtual net billing

232. Virtual net metering was another rate design mechanism proposed by some proponents to encourage DCG development.

233. FortisAlberta described virtual net metering as a process whereby the records (i.e., consumption, generation, or both) from multiple interval meters are combined to produce single records as if there were one “virtual” meter. Under virtual net metering, a group of customers would be allocated the generation output from a DCG unit and this allocation would be used to reduce the measured consumption at each of these customers’ sites before the calculation of the delivery and energy charges. The customers and the DCG unit need not be in proximity to each other.

234. EPCOR provided a simplistic example of 10 customers owning equal shares in a community solar project. [122] If, in a single billing period, the total generation amounted to 5,000 kWh, each customer would receive a notional credit of 500 kWh that would be netted against its consumption at its site, and the net result (in kWh) would be used in the calculation of delivery and energy charges.

235. Pembina stated that virtual net metering would allow more Albertans to participate in renewable generation because it believed that the *Micro-generation Regulation* does not allow for off-site community solar energy projects and excludes Albertans living in rented premises or condominiums from participating. [123]

236. Howell Mayhew asserted that virtual net metering would not be an attractive business proposition for existing retailers due to the complexities of managing the accounts of the customers involved in the virtual net metering arrangement. Howell Mayhew considered that the members in the virtual net metering arrangement should be responsible for maintaining their own records and accounts.

237. The distribution wire owners did not support the introduction of virtual net metering. FortisAlberta mentioned that any manipulation of metering data (i.e., adding or subtracting values recorded by two or more meters) under a virtual net metering arrangement must comply with Measurement Canada Policy E-27.[124] [125] This policy allows some measurement values to be manipulated and prohibits the manipulation of other measurement values. Depending on the size of the generation and the type of meters used to record the values, net metering (virtual or otherwise) may not be permitted under Measurement Canada’s policy. ENMAX[126] and EPCOR[127] explained that their load settlement and billing systems would need changes that would be

[122] Exhibit 22534-X0203, EPCOR responses to Commission supplemental questions, PDF page 13.
[123] Exhibit 22534-X0146, Pembina responses to Commission questions, PDF page 5.
[124] Policy E-27 deals with situations where a metering value is determined (totalized) for a measurement point that is not directly measured by a meter. This totalized value must be calculated using accepted measurement methodologies and be within the legislated tolerances set out in the policy.
[125] Exhibit 22534-X0194, FortisAlberta responses to Commission supplemental questions, PDF page 13.
[126] Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 27.
[127] Exhibit 22534-X0144, EPCOR responses to Commission questions, PDF page 28.

significant in scope and costs to accommodate virtual net metering because their existing systems are configured to meter, settle and bill each site individually.

238. One party, SkyFire, recommended a change to AUC Rule 021 to enable shared solar virtual net metered systems to encourage community solar projects. However, EPCOR responded that "[i]f we had net metering on the distribution side but 100 per cent fixed rates, we wouldn't have a problem recovering costs on the distribution side, but it would totally mess up the SAS [system access service] charges because we still would need to know how much energy is being delivered to a site in order to properly design and recover the costs of the DTS [demand transmission service]."[128] EPCOR further explained that the implementation of virtual net metering at a community level would magnify the degree of cross subsidization between customers as compared to net metering at one site.[129]

239. EPCOR proposed an alternative way of billing community energy projects. They referred to it as "virtual net billing." Currently, the distribution wire owners can collect metering data from multiple sites for consumption and from the DCG site for generation and pass this data on to the retailer[130]. EPCOR stated that at the account level, retailers already have the functionality in their billing systems to aggregate billing and metering information for one customer with multiple sites. The retailer could then allocate the generation credits and calculate the bills according to the arrangement in place with the customers.

240. Regardless of whether virtual net metering or virtual net billing is considered, there would be additional costs associated with implementing either of these arrangements.

5.3.3.3 Adjustment to the fixed charges component

241. The wire owners asserted that their concern with the rate design proposal to net metering is not that customers are generating their own supply of electrical energy; the issue is the billing structure attempting to recover fixed costs through a variable rate. Because the electric system is primarily a fixed-cost infrastructure, providing capacity and operational support such as voltage control, these fixed costs should be recovered through fixed rate structures. This approach would be consistent with the principle of cost causation, because the accurate cost driver for the delivery rates would be the size of the facilities required to provide delivery service and not the volume of electrical energy delivered. Otherwise, recovering fixed costs through volume-based (i.e., energy dependent) rates could lead to incorrect price signals and questionable cost allocation issues.

242. AltaLink summarized the value that fixed infrastructure brings to DCG as follows:

> And fundamentally from a wire's perspective, when you're connected to the wire you're getting the value every minute that you're connected to it. And so that value comes in voltage. It comes in frequency. It comes in instantaneous access to capacity to essentially pull on the grid when you need it. It comes in energy transactions that you can push to the grid when you want to when you're not matching your load. So that's all created by fixed infrastructure. And there's not a large variable cost to that fixed infrastructure. And so if

128 Transcript, Volume 1, PDF page 125.
129 Exhibit 22534-X0203, EPCOR responses to Commission supplemental questions, PDF page13.
130 The customer could also become a self-retailer, thus receiving metering and billing information directly from the distribution wire owner.

> the value is there and it's driven by fixed infrastructure, then the recovery of that should be through fixed rates.[131]

243. FortisAlberta noted that its current tariff evolved based on a centralized grid model characterized by ratepayers receiving all of their electrical energy needs from the transmission and distribution networks. It considered that growth in DCG will change the current grid model to one where customers may be providing their own electrical energy, while still requiring an interconnection to the distribution system. Since currently most of its costs are recovered from load customers, this new model will require changes to transmission and distribution cost allocation and rate design.[132] To accommodate this evolving model, FortisAlberta recommended a transition from rates based on end-use to rates based on capacity, so that charges to ratepayers reflect the costs required to serve them.[133] It noted that the costs to serve DCG and non-DCG customers are the same, therefore the fact that a DCG customer can deliver electrical energy to the distribution system should not factor into rate design.[134]

244. In contrast, some DCG proponents favoured a rate that was weighted towards variable charges. SkyFire stated that rates based on variable charges would encourage more electrical energy consumption from on-site DCG.[135] During the oral portion of the inquiry, SkyFire clarified its position, noting that there should be some recognition of fixed charges associated with being connected to the distribution system:

> If they're, in my opinion, as a generator that relies on the grid to operate and that consumes energy at night and winter and what have you, that there is a cost associated again with having those wires to your site, that transformer, or the maintenance, et cetera, and ultimately I feel like that is something that you should be paying for. That shouldn't be offloaded onto another consumer who maybe can't afford solar. So I think that's fair.[136]

245. Pembina argued that U.S. utility commissions have determined that higher fixed costs proposed for DCG by U.S. utilities overestimate the cost to serve DCG and undervalue the benefits they bring.[137] Like Pembina, CanSIA considered that fixed charges would result in DCG cross subsidizing non-DCG ratepayers:

> I would take a contrary position that 100 percent fixed charges also distort price signals and cause cross-subsidization. It would be our position that rate design not only needs to enable utilities to recover their costs but also needs to incentivize or send a price signal to customers to behave in ways which are beneficial to the grid and to the rate base as a whole.
>
> So, for instance, if you've got two neighbours next door to each other. One installs LED lighting; they're efficient when they use their different appliances; maybe they've got solar; maybe they've got storage. In that instance where they're – where they're drawing less from the grid and behaving, you know, in a way that's beneficial to the system or the grid as a whole, to ask that they pay the same costs for wires I think is cross-subsidizing

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131 Transcript, Volume 5, pages 661- 662, PDF pages 124-125.

132 Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF pages 39-40.

133 Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 84.

134 Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 85.

135 Exhibit 22534-X0111, Lion’s Tooth Solutions responses to Commission questions, PDF page 29; Exhibit 22534-X0113, SkyFire responses to Commission questions, PDF page 13.

136 Transcript, Volume 2, page 298,PDF page 164.

137 Exhibit 22534-X0146, Pembina responses to Commission questions, PDF page 5.

> the inefficient customers or the customers who aren't behaving in a way that's beneficial to the grid or to the system as a whole. So we would favour a rate design structure where there is a price signal for customers to behave efficiently as opposed to inefficiently.[138]

246. EPCOR provided an illustrative example of the consequence of using a tariff based on a variable charge:

> A simple example is if we think about two houses, one with rooftop solar and one without, if, for example, you were recovering the cost of the connection to each of the homes by just the amount of energy they used in a year, it's possible that the house with rooftop solar could have a net energy use of zero. They could use electricity at night when it's dark and they could deliver electricity to the grid during the day when it's sunny, and their net delivery over the course of a year might be zero.
> So if you were assessing your rate for that connection that they're clearly using, based on energy, they pay nothing. Meanwhile, the guy next door with exactly the same house and the same usage, would be paying for exactly the amount of electricity that was delivered through exactly the same facilities. So that's not fair.[139]

247. ENMAX noted that as DCG increases, the revenue recovered by distribution wire owners through variable charges will decrease, and a mechanism to ensure distribution wire owners have the opportunity to earn a reasonable return may be required. It proposed an annual deferral account with amounts based on DCG reported generation, to recover this lost variable revenue recovered from: 1) all distribution ratepayers, 2) all non-DCG ratepayers, 3) all DCG ratepayers or 4) all ratepayers in the respective distribution wire owner service areas.[140]

248. Some DCG proponents proposed that rates should recognize the value that they considered an alternative or renewable generator provides to society. They suggested that rates be reflective of an alternative or renewable distribution-connected generator's reduction or elimination of the need for investment in transmission and/or distribution infrastructure or its beneficial environmental effects.[141] For example, AMP Solar Group Inc. (AMP Solar Group) suggested that "[g]iven the intermittency of solar generation and the volatility of the Alberta pool price there is a required operational and settlement flexibility to incentivize DCG with a standard fixed price tariff that encapsulates the net energy, the social and environmental attributes and the capital deferral benefits for the Distribution System."[142] Renewable Energy Solutions™ stated that:

> [..] rates should be set to distinguish and give higher value for:
> 1. ability to generate at peak time of day (solar matches high summer cooling loads);
> 2. ability to produce low carbon / low emission electricity (most renewables);
> 3. ability to generate at or close to load (to minimize transmission and connection infrastructure);
> 4. ability to deliver power reliably (large-scale energy storage will mitigate intermittency of wind and solar). [143]

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138 Transcript, Volume 3, page 406, PDF page 51.
139 Transcript, Volume 1, page 58,PDF page 58.
140 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF pages 4 and 64.
141 Exhibit 22534-X0093, Bullfrog Power responses to Commission questions, PDF page 3; Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 3; Exhibit 22534-X0146, Pembina responses to Commission questions, PDF page 3; Exhibit 22534-X0157, Renewable Energy Solutions™ responses to Commission questions, PDF page 2.
142 Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 8.
143 Exhibit 22534-X0157, Renewable Energy Solutions™ responses to Commission questions, PDF page 2.

249. Northern Lights Clean Energy Corp was of the view that tariffs should be region dependant to balance solar DCG investment opportunities across the province.[144]

250. Contrary to the positions advanced above, EPCOR explained that DCG at current penetration levels does not result in distribution system cost savings because the system must be designed to operate independent of DCG because of its intermittency. EPCOR further asserted that because load customers pay for the full cost of the distribution system, they, not generators, should benefit from any reduction or elimination of investments in distribution infrastructure.[145]

251. In Teric's view, rate design and structure changes are not required to support the development of DCG.[146] Teric stated that a charge to DCG would be required to cover costs for the provision of electricity when the DCG is not operating so that non-DCG ratepayers are not allocated a disproportional share of costs. However, Teric noted that determining the correct allocation to DCG is difficult because not all DCG would require backup at the same time and assuming so would overestimate the associated costs.[147]

252. Distribution wire owners and customer representatives[148] were of the view that if it is determined to be necessary to provide financial subsidies to stimulate further growth of DCG, that these financial subsidies should be provided outside of the tariff and not through distortions to the tariff design.[149]

253. The AUC observes that a cautious approach was taken by Ontario when it considered rate design changes. Ontario is moving to 100 per cent fixed charges for residential ratepayers after concluding that this approach balanced the needs of distribution-connected generators and distribution wire owners. The Ontario Energy Board undertook an exhaustive consultative process before making its decision to implement the policy, and is implementing it over a four-year period. The three main objectives of the approach as stated in the *OEB EB-2012-0410 Board Policy: A New Distribution Rate Design for Residential Electricity Customers* are:

- It will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services.
- It is a fairer way to recover the costs of providing distribution service.
- It will provide greater revenue stability for distributors, which will position them for technological change in the sector, remove any disincentive to promote conservation, and help with their investment planning.

144 Exhibit 22534-X0165, Northern Lights Clean Energy Corp responses to Commission questions, PDF page 2.
145 Exhibit 22534-X0182, EPCOR reply evidence, PDF page 9.
146 Exhibit 22534-X0098, Teric Power Ltd.'s responses to Commission questions, PDF page 21.
147 Exhibit 22534-X0188, Teric Power Ltd.'s responses to Commission supplemental questions, PDF page 3.
148 Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 6; Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 18; Exhibit 22534-X0194, FortisAlberta responses to Commission supplemental questions, PDF page 14; Exhibit 22534-X0200, CCA responses to Commission supplemental questions, PDF page 3; Exhibit 22534-X0205, ATCO Electric responses to Commission supplemental questions, PDF page 14; Exhibit 22534-X0207, the City of Lethbridge and the City of Red Deer responses to Commission supplemental questions, PDF page 12; Exhibit 22534-X0182, EPCOR reply evidence, PDF page 11.
149 For example, EPCOR stated that "the carbon tax itself creates an efficient, if indirect, incentive to DCG development that does not distort the competitive market for electricity." Exhibit 22534-X0182 EPCOR reply evidence, PDF page 11.

5.3.3.4 Requirement for a new distribution tariff customer class

254. The AUC questioned participants regarding whether a new class of customer for DCG should be considered. The responses were varied and comments from the participants indicated that a new customer class would be neither an enabler nor a barrier to DCG.

255. FortisAlberta stated that a separate customer class for DCG is not required, because as DCG penetration increases, a tariff designed to accommodate both load and generation will be required. However, it stated that a separate billing determinant[150] for DCG may be required.[151]

256. AFREA, AltaLink, ATCO Electric, and ENMAX all considered that a new customer class may be advantageous to clearly show the capital and the operating and maintenance costs that are driven by DCG and to facilitate their recovery. However, this support was qualified. AFREA noted that the administrative burden that would be required to implement a separate rate class may outweigh the benefits, unless there was a significant increase in DCG penetration levels. Although EPCOR also considered that there may be some benefits, it did not recommend a change to its current tariff.[152]

257. The CCA did not comment specifically about creating a separate rate class for DCG. Rather, it stated that both transmission and distribution rates would require restructuring and suggested a separate tariff for delivering electrical energy and a separate tariff for consuming electrical energy. It noted that this type of structure would also facilitate the integration of storage into the system.[153]

258. The response from DCG proponents was varied. Lion's Tooth Solutions did not support the creation of a new customer class explaining that it would be expensive to implement and that these costs would then be passed on to ratepayers.[154] Renewable Energy Solutions™ stated that a separate rate class was not required, however carbon offsets should be incorporated into rate design to reward low carbon electricity DCG.[155] SkyFire was supportive of a separate DCG rate class if that rate class was designed to compensate the distribution-connected generator for the value it asserted alternative and renewable DCG brings to the distribution system.[156] AMP Solar Group and Bullfrog Power were not prepared to commit to a stance on this matter and stated that any rate design changes should be undertaken with stakeholder consultation and engagement.[157]

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150 A billing determinant is the measure (for example by amount of kW, or kWh) used to calculate a customer's bill.

151 Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 46.

152 Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 41; Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 41; Exhibit 22534-X0144, EPCOR responses to Commission questions, PDF pages 47 and 49; Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 20; Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 26.

153 Exhibit 22534-X0160, CCA evidence, PDF page 5.

154 Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF page 19.

155 Exhibit 22534-X0157, Renewable Energy Solutions™ responses to Commission questions, PDF page 2.

156 Exhibit 22534-X0113, SkyFire responses to Commission questions, PDF page 14.

157 Exhibit 22534-X0093, Bullfrog Power responses to Commission questions, PDF page 3; Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 14.

259. The AUC observes that while theoretically beneficial, there is presently no need to adjust the rate design to create a separate DCG rate class in order to enable DCG growth. Rather, the determination of what percentage of the delivery charges should be fixed is the bigger issue for enabling growth of DCG while ensuring adherence to cost causation principles.

5.3.4 Transmission tariff structures

260. In addition to changes to the distribution tariff, the AUC also received submissions from participants concerned about the effect that increased levels of DCG might have on the transmission system and the charges currently captured in the AESO tariff. Three matters in particular were raised: (1) the Generating Unit Owner's Contribution (GUOC), (2) transmission tariff-based credits, and (3) transmission injection tariffs.

5.3.4.1 Generating Unit Owner's Contribution

261. One or several distribution-connected generator(s) can cause electrical energy to enter the transmission system from a substation point of delivery (POD) when more electrical energy is delivered to the distribution system than is used by customers connected to the same POD. When a distribution-connected generator of 1 MW or greater causes electrical energy to enter the transmission system, the AESO collects a one-time contribution called the Generating Unit Owner's Contribution (GUOC)[158] from the distribution wire owner. The amount of the GUOC varies based on where the generation facility is located. The contribution may then be refunded over a ten-year period based on performance criteria calculated by the AESO as set out in the ISO rules.[159] When this happens, the AESO also applies its Supply Transmission Service (STS) rate (refund or charge) to the distribution wire owner's invoice.

262. A GUOC exemption for DCGs was proposed by wire owners to remove a potential barrier to DCG and to reduce the administrative complexities of calculating the individual DCG charges and refunds.

263. FortisAlberta stated that the STS and GUOC charges or refunds should flow-through to the distribution-connected generators. However, flowing through the charges might create a barrier to increasing levels of DCG. FortisAlberta also suggested that the AESO review the requirement to apply its GUOC and STS charges to the distribution PODs. FortisAlberta noted that it may become administratively unworkable to calculate these costs for each DCG as the growth in DCG increases.[160]

264. ATCO Electric also supported the exemption of DCG from GUOC. Alternatively, it proposed an annual rider to true-up the total GUOC payments and refunds and that the total rider amount be allocated across all PODs (all rate payers). It acknowledged that its rider proposal may weaken the locational signals incented by these charges and refunds.[161]

265. AltaLink suggested that the distribution wire owners and the AESO should work together to develop a method to allocate AESO costs to DCG taking into consideration cost causation

[158] The Alberta Electric System Operator, ISO Tariff, Section 10 Generating Unit Owner's Contribution.
[159] The Alberta Electric System Operator, ISO rules, Section 505.2 Performance Criteria for Refund of Generating Unit Owner's Contribution.
[160] Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 49.
[161] Exhibit 22534-X0205, ATCO Electric responses to Commission supplemental questions, PDF page 10.

principles.[162] EPCOR proposed that stakeholder consultation could be initiated by the AUC, but stated that each distribution wire owner should be responsible for implementing the allocation of these costs to the DCG.[163]

266. AFREA did not support the exemption of DCG from GUOC and noted that the allocation of these costs to DCGs was not a concern. AFREA stated that the GUOC was designed to incent generators to locate in certain areas with the intention of reducing transmission investment. AFREA was of the view that a generator connected to the distribution system is no different from a generator connected to the transmission system in terms of the need for transmission investment, and therefore an exemption would remove the location-based incentive.[164]

267. The AESO stated that it intends to propose revisions to the GUOC provisions in its next tariff application, including provisions whereby associated payments and refunds would be made by and to the distribution-connected generator directly to and from the AESO. Regarding the STS losses charge component, in the AESO's view, no changes were required, because the losses charge recovers transmission system losses up to the point of supply. Further, the AESO stated that the distribution wire owners are in a better position to calculate these costs for each distribution-connected generator.[165] In its rebuttal submission, ATCO Electric noted that the AESO's proposal to decouple the distribution-connected generator's maximum capability and rate STS contract capacity may result in distribution-connected generators who are not currently required to pay a contribution to pay one, and this could create a barrier to DCG development.[166]

268. The Alberta Irrigation Projects Association was of the view that distribution-connected generators should not pay transmission system charges because it believed that distribution-connected generators produce and consume electrical energy locally.[167] Additionally, Aura Power stated that the GUOC should be reduced or eliminated because it believed that the GUOC contribution will be equal to the GUOC refund for renewable distribution-connected generators with no fuel costs as they are likely to meet the performance criteria calculated by the AESO.[168]

5.3.4.2 Transmission tariff-based credits

269. The demand transmission service (DTS) system access service rate in the AESO tariff includes both fixed and variable charges that are based on billing capacity[169] and metered energy that is supplied from the transmission system to the distribution system. Because DCG supplies electrical energy at a local level, less electrical energy is required to be supplied from the transmission system. Therefore, DCG has the potential to reduce the amount paid by the distribution wire owners to the AESO for DTS. At the current levels of DCG penetration, wire owners consider transmission tariff-based credits to be another subsidy to distribution-connected

162 Exhibit 22534-X0202, AltaLink responses to Commission supplemental questions, PDF page 4.
163 Exhibit 22534-X0203, EPCOR responses to Commission supplemental questions, PDF page 10.
164 Exhibit 22534-X0184, AFREA responses to Commission supplemental questions, PDF pages 5-6.
165 Exhibit 22534-X0196, AESO responses to Commission supplemental questions, PDF page 70.
166 Exhibit 22534-X0295, ATCO Electric rebuttal submission, PDF page 6.
167 Exhibit 22534-X0163, Alberta Irrigation Projects Association responses to Commission questions, PDF page 7.
168 Exhibit 22534-X0204, Aura Power responses to Commission supplemental questions, PDF page 3.
169 Billing capacity is defined as the highest of: (i) the highest metered demand, which is the highest amount of electricity delivered by the transmission system, measured in any 15-minute period in the calendar month; (ii) 90 per cent of the highest metered demand in the previous 24-month period; or (iii) 90 per cent of the contract capacity as set out in the agreement between the AESO and the distribution wire owner.

generators paid by customers without DCG. The assertions made by DCG proponents and wire owners were completely at odds, and the discussion around transmission tariff-based credits highlighted a large gap in DCG proponents' understanding regarding the drivers of transmission and distribution system investments and how costs are allocated to enable distribution wire owners to recover these costs.

270. DCG proponents viewed transmission-based credits as an enabler to DCG and expressed concerns that DCG investments would not be made without the availability of these credits. However, the distribution wire owners proposed that the dissolution of transmission tariff-based credits would reflect a more equitable allocation of costs.

271. ATCO Electric, ENMAX and FortisAlberta tariffs all include a provision that provides a transmission tariff-based credit to large-scale DCG providers. Micro-generators are not eligible to receive transmission tariff-based credits. FortisAlberta explained that this is consistent with the provisions of the *Micro-generation Regulation*, which is intended to apply to generators that are sized to meet the on-site load, and not to deliver electrical energy to the distribution system.[170]

272. FortisAlberta's credit is referred to as Option M, ATCO Electric's credit is referred to as rate D32 and ENMAX's credit is known as rate D600. Neither EPCOR nor the REAs currently offer these credits.

273. FortisAlberta explained that its Option M was originally intended to incent gas flare generation as a means of offsetting the environmental impact of flaring activity. These Option M credits have evolved and now serve as a subsidy paid by load customers to incent DCG customers to deliver electrical energy to the distribution system as a means of reducing transmission charges.

274. The credits are calculated based on the electrical energy delivered by the distribution-connected generator to the distribution system, and are the difference between the AESO system access service charges to the distribution wire owner (with the generator in operation) and the charges that would have been incurred if the generator had not been in operation. The amounts are calculated manually for each DCG using actual hourly metering data.[171]

275. EPCOR explained why it does not offer this credit:

> But I should point out that the credit -- the so-called credit, it doesn't reflect an actual reduction in the cost of anything because the DTS tariff reflects the cost of the transmission system, which similar to how I described the distribution system, is based on the facilities that have been installed that are out there. So simply connecting a DCG customer to a transmission system in no way affects the cost of the transmission system. What it may do, though, it just may change how that cost is allocated to different customers.
> So if a DCG connects to a particular distribution system and that reduces the amount of electricity that's delivered from the transmission system to that particular distribution

[170] Exhibit 22534-X0179, FortisAlberta response evidence, PDF page 3.
[171] Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 42; Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 39; Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 39.

system, then that distribution system owner will pay less DTS costs to the AESO. But the AESO will still have the same costs on their side of the equation. So they'll simply do a true-up either through a rate adjustment or through their deferral account system to collect that missing revenue. So it just gets moved around, and there is no reduction in costs. So we don't see why there should -- a credit should be given to a customer that comes onto our system.[172]

276. In its rebuttal submission, EPCOR[173] also provided an illustrative example of how the full cost of DTS service is recovered from load customers:

Table 6. Impact of DTS Credit to Load Customers (illustrative example, $)

		A **No DTS Credit**	B **No DTS Credit**	C **With DTS Credit**	D **Notes**
1	DTS Cost	100	100	100	Cost Incurred by AESO
2	DTS Revenue	90	80	80	Collected from Load and paid to AESO
3	DTS revenue short fall due to actual to forecast variance	10	10	10	Reduction in DTS revenue due to variance between actual to forecast energy and demand
4	DTS revenue reduction due to DCG production	0	10	10	Reduction in DTS revenue due to DCG production
5	DTS Credit	0	0	10	Paid to DCG and collected from Load
6	DTS Cost true-up	10	20	20	Row 1 – row 2
7	**Total Cost to Load**	**100**	**100**	**110**	**Row 2 + row 5 + row 6**

277. The AUC observes that because the AESO does not provide a credit to the distribution wire owners for reduced transmission system costs due to DCG, the distribution wire owners that provide this credit today must recover the cost of this credit from all of its distribution customers. This amounts to a cross-subsidy from non-DCG customers to DCG customers.

278. Although EPCOR did not consider a credit to recognize savings to the transmission system was justified simply because a DCG unit was connected, it did acknowledge that the DCG unit may provide some benefit toward reducing transmission line losses when DCG reaches a certain level of penetration and that that benefit could be passed on to the distribution-connected generators. EPCOR explained this fully in its reply evidence.[174] The AUC recognizes that doing so could be extremely complex and costly to implement, especially when there are multiple DCG units connected to a particular POD on the transmission system.

279. EPCOR acknowledged that real DTS savings could be realized in the long term with a significant increase in DCG penetration, if it resulted in the elimination of a need for additional transmission investments. However, the increase in DCG could trigger an increased need for additional distribution facilities. In addition, EPCOR stated that because load customers currently pay for all transmission system investments, they should benefit from any savings.[175]

172 Transcript, Volume 1, pages 60-61, PDF pages 60-61.
173 Exhibit 22534-X0296, EPCOR rebuttal submission, PDF page 5.
As described by EPCOR, “As shown in row 7, the full cost of DTS service is recovered from load customers. As there is no reduction in overall DTS costs, the payment of DTS credits results in load customers paying more than the cost of the AIES system and subsidizing DCG. As a result, load customers pay twice as load is responsible for the full amount of DTS costs, by way of DTS tariff and true-up of any shortfall, and for the amount of the DTS credit paid to DCG customers. As no real costs are avoided and load customers pay twice, DTS credits do not send correct price signals to either load customers or to DCG customers and should not form part of the DFO’s tariff.”
174 Exhibit 22534-X0182, EPCOR reply evidence, PDF page 8.
175 Exhibit 22534-X0182, EPCOR reply evidence, PDF page 8.

The cities of Lethbridge and Red Deer agreed.[176] Other distribution wire owners echoed EPCOR's view that transmission tariff-based credits will not represent a true savings until DCG penetration increases to a level that would reduce or eliminate transmission system investments.[177]

280. DCG proponents disagreed with the wire owners. They asserted that DCG does provide a benefit at the current level of penetration and consequently reduces the transmission charges paid by the distribution wire owner to the AESO. They further asserted that they should receive the value of this benefit and some DCG proponents claimed that those distribution wire owners who do not provide a transmission tariff-based credit were unfairly retaining the value of these benefits. Moreover, they argued that many distribution-connected generators rely on these credits (Option M, rate D32, rate D600) to make their DCG projects viable and viewed these credits as an enabler for the development of DCG. [178]

281. The UCA favoured a consistent approach.[179]

282. Some DCG proponents stated that transmission tariff-based credits should also apply to micro-generators and non-renewable generators. [180] Some DCG proponents were of the view that the credits should also apply to electrical energy that is produced and consumed on-site.[181] In response to further questioning from the AUC, CanWEA stated that since avoided transmission costs provide value to all ratepayers, "any costs should be supported through funds collected through the Carbon Levy."[182]

283. FortisAlberta and AltaLink recommended that transmission tariff-based credits should be considered as part of the AESO's next tariff application before the AUC. This would allow the AUC to consider all of the complexities associated with these credits, including a review of the original purpose of these credits as a locational based signal for siting generation. Further, FortisAlberta stated that this approach would allow the entity that plans the transmission system

176 Exhibit 22534-X0207, the City of Lethbridge and the City of Red Deer responses to Commission supplemental questions, PDF page 17.

177 Exhibit 22534-X0179, FortisAlberta response evidence, PDF page 10; Transcript, Volume 6, page 934, PDF page 152; Transcript, Volume 5, page 712, PDF page 175.

178 Exhibit 22534-X0098, Teric Power Ltd.'s responses to Commission questions, PDF page 10; Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF page 4; Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 4; Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF pages 18-19; Exhibit 22534-X0116, Aura Power responses to Commission questions, PDF page 3; Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 6; Exhibit 22534-X0140, CanSIA responses to Commission questions, PDF page 5; Exhibit 22534-X0145, BluEarth Renewables responses to Commission questions, PDF page 2; Exhibit 22534-X0146, Pembina responses to Commission questions, PDF page 3; Exhibit 22534-X0158, URICA responses to Commission questions, PDF page 5; Exhibit 22534-X0162, Alberta Solar Co-op responses to Commission questions, PDF page 3; Exhibit 22534-X0163, Alberta Irrigation Projects Association responses to Commission questions, PDF page 7.

179 Exhibit 22534-X0106, UCA responses to Commission questions, PDF page 9.

180 Exhibit 22534-X0113, SkyFire responses to Commission questions, PDF page 13.

181 Exhibit 22534-X0121, Alberta Direct Connect Consumer Association responses to Commission questions, PDF page 2; Exhibit 22534-X0140, CanSIA responses to Commission questions, PDF page 6.

182 Exhibit 22534-X0186, CanWEA responses to Commission supplemental questions, PDF page 3.

(the AESO) to assess whether there is a benefit and to facilitate consistent treatment across all distribution wire owner service areas.[183]

5.3.4.3 Injection and withdrawal tariffs

284. The CCA submitted that "In effect the tariff design, both at the AESO level and at the distribution level would require restructuring so that there is a separate tariff for injecting power into the system and a separate tariff for withdrawal of power. The use of separate injection and withdrawal tariffs would also facilitate the integration of storage into the system."[184] The CCA recommended that the AESO review its tariff structure to consider changes, such as injection tariffs, that would allocate costs to generators and load ratepayers based on cost causation principles.[185] It stated that reform of transmission tariffs is required to provide price signals for efficient resource allocation into the future and injection tariffs would serve the public interest.[186]

285. The AESO did not support such changes and explained that allocating new costs to existing generators would likely lead to inter-generational inequity between existing and new loads and generation, which, in turn, could affect the viability of the generator. The AESO also opposed making these changes because doing so could lead to unpredictable injection tariffs year-by-year due to transmission system and generator additions being lumpy. Further, it considered that a new injection tariff would require amendments to the *Electric Utilities Act* and the *Transmission Regulation.*[187]

5.3.5 RRO Tariff

286. Under the *Micro-generation Regulation*, small micro-generators receive credits for the electrical energy they produce but do not consume. They are credited for the electrical energy delivered to the distribution system on a monthly basis at their retail energy rate. Consequently, small micro-generators who are provided service under the RRO rate will be provided a credit using the RRO rate.

287. The AUC asked participants if the availability of the RRO rate service offering would depress demand for the adoption of alternative and renewable DCG. Respondents said it would not.[188] [189]

288. Some participants considered the RRO rate to be a suitable one to encourage the development of DCG in Alberta. This is because the RRO rate fluctuates with market conditions so it provides the proper market price signal. EQUS[190] stated that the RRO rate could become a major stimulant to DCG; however, EQUS did not consider it a necessary requirement. EPCOR[191] stated that the RRO rate provides predictability to allow distribution-connected generators to

183 Exhibit 22534-X0179, FortisAlberta response evidence, PDF page 11; Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 20.
184 Exhibit 22534-X0160 CCA Evidence, PDF page 5.
185 Exhibit 22534-X0287, CCA further submission, PDF page 4.
186 Exhibit 22534-X0297, CCA reply submission, PDF pages 2-5.
187 Exhibit 22534-X0286, AESO further submission, PDF page 5.
188 Exhibit 22534- X0113, SkyFire responses to Commission questions, PDF page 14.
189 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 43.
190 Exhibit 22534-X0119, EQUS responses to Commission question, PDF page 18.
191 Exhibit 22534-X0144, EPCOR responses to Commission questions, PDF page 50.

manage their generation knowing the value of the electrical energy being both withdrawn from, and delivered into, the system. According to EPCOR, this predictable pricing information may promote a greater penetration of DCG. AltaLink stated that the RRO rate serves as a good benchmark for other retail offerings as its pricing mechanism, rates, and terms and conditions are transparent and consistently overseen by the AUC. [192] Another advantage of the RRO rate is that it is known in advance.

289. ENMAX[193] stated that regardless of the compensation scheme, low energy prices reduce the incentive to invest in DCG because it will take longer to recover the investment. Direct Energy Marketing Limited [194] also stated that current low prices would discourage the development of DCG. Decentralised Energy Canada (DEC)[195] stated that in addition to the low prices of electricity, the high relative costs of transmission, distribution and riders are hindering consumers from realising the benefits of Alberta's cheap energy.

5.4 Stranded assets

290. In the OIC, the AUC was asked to consider "the potential for stranded infrastructure" as part of its exploration of methods of assessing costs and benefits to enable and facilitate broader deployment of alternative and renewable DCG.

291. Participants acknowledged that a substantial increase in DCG could result in both the requirement to install new assets and technology and the premature retirement of existing assets that may no longer be needed to provide electricity service. Participants generally proposed that there be legislative clarity to address the risk of stranded assets. Further, some participants suggested that the distribution wire owners should bear some of the risk of stranded assets as they have the ability to structure their tariffs to minimize the costs of stranded assets.

292. As noted by the Alberta Court of Appeal, the regulated utilities are not immune to change:

> [1] In Alberta, the regulatory compact, which involves a balancing of the interests of utility companies and their customers, has its limits. And this case demonstrates one of them. The roots of the regulatory compact, as it has been dubbed, can be found in the 19th century and the emergence of public utility regulation in North America. That regulation was designed to prevent the abuse of monopolistic powers by utility companies. The shape and content of the regulatory compact were initially developed through the common law. Later, as in Alberta, legislators in individual jurisdictions statutorily defined the specific terms governing its scope.
>
> [2] The general concept is that in return for the undertaking to serve all customers in a defined service area, the utility is granted an *opportunity* both to earn a reasonable return on its prudent investment and to recover its prudently incurred expenses. However, the regulatory compact was never an arrangement under which utility companies were entitled to find pockets deeper than their own – their ratepayers – in order to recover every expense incurred in pursuit of their corporate and shareholders' interests. Put

192 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 20.
193 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 43.
194 Exhibit 22534-X0155, Direct Energy Marketing Limited responses to Commission questions, PDF page 6.
195 Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF page 11.

> simply, the regulatory compact did not confer on utilities an absolute guarantee that they would be entitled to recover all incurred costs and expenses, reasonable or otherwise.
>
> [3] Moreover, the terms of the regulatory compact have always been subject to evolution and the re-balancing of competing interests of consumers and utility companies when times and circumstances change. This is as it should be, especially in this era of deregulation of the gas and electrical sectors in Alberta. There is no industry today that is immune to change. Or that enjoys a right to be protected from the consequences of change, whether those arise from legislative choices, deregulation or court decisions.[196]

293. For the AUC-regulated distribution wire owners, the potential for their existing assets to become pre-maturely obsolete and stranded, as a result of having to accommodate the increase in DCG, represents a significant business risk, especially in the current regulatory framework established by the AUC in Decision 2013-417[197] (the UAD decision), where the AUC determined that:

> the principles related to assets used or required to be used to provide utility service established in the Alberta Court of Appeal cases dealing with gas utility assets apply equally to electric utility assets and, accordingly, the costs of all utility assets of both gas and electric utilities that are no longer used or required to be used for utility service must be removed from customer rates. All revenues generated by, and all costs associated with, such assets that are no longer used or required to be used for utility service are for the account of the utility shareholder.[198]

294. This risk exists because most distribution system assets, such as poles, conductors and cables, have relatively long lives. For example, ATCO Electric noted that over 90 per cent of its distribution assets have expected average lives of 40 years or more.[199] If these assets are no longer required because of the increased deployment of DCG and the assets are removed prematurely from service before the end of their useful lives, the distribution wire owners will have to bear the financial consequences.

295. ENMAX considered this matter to be a barrier to the future development of DCG as distribution wire owners may be reluctant to invest in the assets and technology that may be necessary to help achieve the government's renewable energy goals if doing so results in stranded assets and financial loss.[200]

296. FortisAlberta suggested that legislative revisions or other government policy clarity would be required to confirm the reasonable opportunity for distribution wire owners to recover the costs of prudently incurred investments, past and future, to support the implementation of DCG initiatives.[201] It requested that the government address the contradiction in requiring distribution wire owners to make substantial investments to further the objectives of the

[196] ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission), 2014 ABCA 397 (CanLII).
[197] Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-01, November 26, 2013.
[198] Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-01, November 26, 2013, paragraph 283.
[199] Exhibit 22534-X0115, ATCO Electric response to Commission questions, PDF page 74.
[200] Exhibit 22534-X0123, ENMAX responses to Commission supplemental questions, PDF page 4.
[201] Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 17.

Climate Leadership Plan, while exposing such investments to potential non-recovery in accordance with the UAD Decision principles.[202]

297. ATCO Electric stated the same concerns regarding the potential disruption to the regulatory compact. Distribution wire owners and their investors should have certainty regarding the right to recover prudent investments made to advance the government's goals under the Climate Leadership Plan. Consequently, legislative changes would be required to remove any fear that investments to promote DCG may result in existing assets or costs becoming stranded.[203] It claimed this is required to ensure the regulatory compact remains balanced.

298. The UCA also made mention of the possible issue of stranded assets and costs due to changes in technology that are necessary to accommodate any new processes. The UCA provided some examples.[204]

299. The CCA stated that the distribution wire owners (and transmission facilities owners) should bear some of the risk of stranded assets and costs if the distribution wire owners were not prudent in their planning for the transition to a more DCG-intensive operation. It was also concerned that growth in DCG for the purpose of self-supply, both at the micro-generation and industrial-scale level, where those customers were no longer connected to the electrical system, would result in fewer load customers remaining to pay the increased infrastructure costs. This is often referred to as the utility death spiral. The CCA proposed restructuring of the transmission and distribution tariffs to minimize the potential for these stranded costs.[205] The CCA stated a reasonable method of restructuring the tariffs would be through the introduction of injection and withdrawal tariffs.[206] Subsection 5.3.4.3 of this report provides a further discussion of injection and withdrawal tariffs. The CCA explained that its injection/withdrawal tariff would ensure that DCG customers pay their portion of the costs to be connected to the transmission and distribution systems (the injection portion of their proposed tariff scheme) rather than having to rely on the traditional load customers to cover all the costs.

300. The cities of Lethbridge and Red Deer stated that as the penetration of DCG grows on the distribution systems, so does the risk of stranded assets. This risk would arise as more customers become self-suppliers of electrical energy or if the amount of electrical energy exported to the distribution system exceeded the capacity of the system resulting in increased system investment. A likely solution to the issue of stranded assets would be for the distribution wire owners to decouple revenue from volumes, i.e., establish tariffs that do not rely upon usage (as measured in kilowatt hours) to recover their investments.[207]

301. Teric also stated that arrangements to self-supply, with no reliance on the distribution system for back-up support, would result in reduced revenues for the distribution wire owners

[202] Exhibit 22534-X0284, FortisAlberta response evidence submission, PDF page 4.
[203] Exhibit 22534-X0115, ATCO Electric response to Commission questions, PDF page 74.
[204] Exhibit 22534-X0169, UCA Report. PDF page 19.
[205] Exhibit 22534-X0046, CCA Appendix 1, PDF page 10.
[206] Transcript, Volume 4, pages 502-507, PDF pages 43-48.
[207] Exhibit 22534-X0143, the City of Lethbridge and the City of Red Deer responses to Commission questions, PDF page 2.

and may lead to stranded costs or making the remaining load customers responsible for the costs.[208]

302. AFREA stated the potential for stranded costs would be a significant issue for REAs, given the existing legislation, which limits the ability of REAs to recover additional or stranded costs from anyone other than its existing members.[209] According to AFREA, the potential for stranded costs could arise in a number of circumstances such as duplicate distribution lines being constructed by both the REAs and the investor-owned distribution wire owners[210] along the service area boundaries to connect DCG or building the distribution system in advance of the interconnection of DCG and the DCG development not occurring as anticipated. AFREA's recommendation for avoiding stranded costs was to make the DCG proponents responsible for the costs to connect to the distribution system. It stated distribution wire owners should not make investments in advance of a DCG proponent’s request to connect.

303. Likewise, EPCOR stated a wide-ranging infrastructure improvement is not recommended because of uncertainties regarding the timing of DCG connections and uptake levels.[211] Rather, EPCOR's approach to investments in distribution system improvements was to consider them on an “as-needed” basis so as to not strand assets.

5.5 Subsidies

304. Throughout the inquiry, the issue of subsidies, who should receive them, who should pay for them, where current subsidies exist and whether further subsidies should be implemented to encourage growth of DCG, both large-scale and micro, was a matter of concern to participants.

305. In this subsection, the AUC explores the reasons offered to deploy subsidies and the subsidies that are currently in place that are designed to enable DCG. The AUC then considers future subsidies proposed and the effect that these might have on the level of DCG growth.

306. Participants generally considered that there was a need for subsidies in order to promote DCG especially in light of the persistently low power pool prices. Where parties differed was in how those subsidies should be implemented. The majority of participants indicated that it would be preferable to provide subsidies outside of the tariff rate structure.

5.5.1 Policy considerations

307. As set out in Section 5.3.3 in the report, many participants rejected using tariff design as a means to encourage growth of DCG. Consequently, the AUC explored with parties their views on the effectiveness of providing direct subsidies to enable growth in alternative and renewable DCG.

308. Parties were generally receptive to applying such a direct approach. As stated by EPCOR, “the best way to facilitate or to increase the rate of adoption of DCG is through direct subsidies to those DCG proponents…we don't see the rationale for distorting the tariff structures that we

[208] Exhibit 22534-X0188, Teric responses to supplemental questions, PDF page 4.
[209] Exhibit 22534-X0095 AFREA responses to Commission questions, PDF page 20.
[210] ATCO Electric and FortisAlberta are the two investor-owned distribution wire owners that have overlapping service areas with the REAs.
[211] Exhibit 22534-X0203, EPCOR responses to Commission supplemental questions, PDF page 20.

have today to achieve the goal of increasing DCG, because what it does is it actually distorts things; causes a bust in, say, the principles of cost causation; it causes cross-subsidization by one customer class to another or one customer to another. It's far more effective to simply reduce the economic costs in the first place of the DCG [proponent]."[212]

309. Customer representatives, such as the CCA, also considered direct subsidies to be a preferred approach to stimulate DCG growth stating:

> If the Government is of the view that the pace of deployment of alternative and DG may not proceed at a rate that would achieve the 30% renewable portfolio standard by 2030, there may be justification for providing subsidies directed to reducing the capital costs of developers of renewable projects to reflect any social and environmental costs, not reflected in the pricing of competing fossil fuel generation; this should be subject to the proviso that the capital cost subsidies to developers, if provided, would be progressively reduced as the price of carbon is factored into the price of fossil fuel energy through the mechanism of the carbon tax.[213]

310. The REAs also expressed support for using direct subsidies rather than through rate design. AFREA stated:

> If the Alberta Government seeks opportunities to subsidize DCG, it should do so explicitly in separate mechanisms (such as tax incentives) and not use load customers who have no DCG to provide the subsidy.[214]

311. Participants indicated that the current electricity policies effectively subsidized certain generators over others or created the need for a subsidy to make DCG viable. Of note, parties identified two principal concerns: (1) policies to support transmission-connected wind generation and (2) policies affecting the pool price. This latter factor was considered a barrier to the development of DCG.

5.5.1.1 Transmission-connected wind generation

312. AFREA was particularly concerned about the effect that policies to support transmission-connected wind generation have had on Albertans. It explained:

> To date, the AESO has spent over $5.1 Billion on transmission in order to enable access for approximately 2,500 MW of potential future wind development. With the inclusion of carrying costs on the yet to be used assets, this has, to date, cost ratepayers approximately $2.4M per MW of transfer capacity.
>
> By building transmission into the best production areas for wind instead of connecting into existing transmission lines with surplus capacity, the wind developers gain a production benefit in the order of 20% which is a capital investment saving of $600,000/MW for the wind developer. But even if the currently unused or largely unused transmission lines were to reach full utilization over the next five years, the cost to ratepayers of this hidden subsidy will have exceeded $3.0M

212 Transcript, Volume 1, page 11, PDF page 11.
213 Exhibit 22534-X0160, CCA evidence, PDF page 12.
214 Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 7.

per MW of wind capacity. This means that, because of this hidden subsidization, Albertans will now pay 50% more for wind than was actually necessary. [215]

313. AFREA indicated "the fundamental flaw with the current transmission policy is a lack of any cost causation based rates for the large industrial-scale wind developers and conventional generators. A level playing field approach would be to at least charge close to the benefit of the higher value wind locations and include an escalating charge by location in order to minimize the economic loss Albertans must take for these sub-optimally planned developments from the perspective of overall delivered cost." [216]

5.5.1.2 Pool price

314. As noted previously in this report, the government has begun implementation of its Climate Leadership Plan which includes the establishment of the 30-30 target. The announced mechanisms for achieving this target included the Renewable Electricity Program, micro-generation, and Energy Efficiency Alberta. Other aspects are the introduction of a carbon levy and the transition from an energy-only wholesale market to a framework that includes an energy market and a capacity market.

315. As explained in Section 4.2 of this report, compensation for large-scale distribution-connected generators and large micro-generators is at the pool price. Since 2014, the pool price has averaged $33.68 per MWh per year.[217] Many DCG proponents stated it is economically challenging to invest in DCG at these current and persistently low pool prices. These proponents claim the transition from an energy-only market to one designed with elements of a capacity market and an energy market will likely continue to sustain low pool prices, which will adversely affect the economics of developing additional DCG.

316. The AUC also heard that the framework of the initial competition under the AESOs Renewable Electricity Program would have a negative effect on DCG development. The requirements of the engagement process, such as the documentation and qualification fee, were considered barriers for the smaller-sized proponents. As well, individual DCG units were too small to qualify for the program. The requested support payments of the successful proponents were expected to be lower than the intrinsic value of the renewable generation. Compensation from the pool price alone will not provide the incentive to develop DCG projects under a capacity market design and under the Renewable Electricity Program.

317. Many DCG proponents stated, that without access to predictable sources of revenue streams such as capacity payments, projects would not be feasible to connect to the distribution system. Where capacity payments would not be possible, some of the alternative revenue streams mentioned included the establishment of a compensation premium for solar/renewable energy generation, based on monetizing the environmental attributes of the renewable energy source. In this way, the total compensation received for renewable energy generation would be higher than the pool price.

[215] Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 31.
[216] Exhibit 22534-0095, AFREA responses to Commission questions, PDF page 31.
[217] The Alberta Electric System Operator, "AESO 2016 Annual Market Statistics." Retrieved from: https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/.

318. A number of participants mentioned the use of funding from the carbon levy as a means of promoting renewable energy generation.[218] AltaLink suggested that carbon levy funding be used to promote renewable energy generation, specifically projects that demonstrate the greatest reduction in greenhouse gas emissions (GHGs) for the least cost. According to AltaLink, these projects would tend to be transmission-connected or DCG-sized projects greater than solar rooftop micro-generation.[219] Other DCG proponents suggested using the carbon levy to fund the creation of the premium that would supplement the revenue received through the pool price.[220] The belief was that a premium compensation rate would be a better long-term solution to achieving the government's objectives than the reliance on government-sponsored funding. This is because DCG developers could then assess the financial viability of their project based on the price signal provided by the premium compensation rate.[221]

319. According to AMP Solar Group, the volatility of the pool price is the greatest barrier to developing alternative and renewable generation. Alternatively, AMP Solar Group proposed that distribution-connected generators be provided a fixed price tariff indexed to a base price for renewable generation and could be set through a procurement process.[222]

320. Some participants did not believe incentives or financial assistance programs were required to promote the growth of DCG.[223] These participants stated all entities participating in the electricity market should be guided by the same principles and rules with respect to realizing the government's policies under the Climate Leadership Plan. Those principles included accurate price signals, minimizing cost impacts to customers, maintaining the reliability of the electrical grid, no cross-subsidization between customer classes and cost-effective use of government-sponsored funding.[224]

5.5.2 Alternative proposals to rate design or direct subsidies

321. Some proponents suggested alternative proposals to either rate design or direct subsidies to enable DCG growth.

322. In their view, access to financing was a barrier to the development of renewable generation, especially micro-generation projects at the residential, farm and small commercial customer class levels. For example, EQUS[225] stated access to funding from financial institutions would enable the growth of renewable generation at the micro-generation level, specifically in rural Alberta for members of REAs. EQUS noted that a similar loan guarantee program established in the 1930s for cattlemen was instrumental in the growth of the livestock industry in Alberta. EQUS suggested ATB Financial could be the financial institution to provide financial

218 See for example Exhibit 22534-X0150, Spark submission, PDF page 2; Exhibit 22534-X0256, UCA opening statement, PDF page 2; Exhibit 22534-X0140, CanSIA responses to Commission questions, PDF page 7; Exhibit 22534-X0263, Howell Mayhew opening statement, PDF page 4.

219 Exhibit 22534-X0109, AltaLink evidence, PDF page 2.

220 Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 3.

221 Transcript, Volume 2, pages 266-267, PDF pages 132-133; Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 8.

222 22534-X0103, AMP Solar Group response to Commission questions, PDF page 3.

223 Exhibit 22534-X0118, Capital Power submission, PDF page 2; Exhibit 22534-X0112, ATCO Power responses to Commission questions, PDF page 24.

224 See for example Exhibit 22534-X0109, AltaLink evidence, PDF page 2, Exhibit 22534-X0118 Capital Power submission, PDF page 1.

225 Transcript Volume 8 page 1137, PDF page 34.

assistance, supported by a loan guarantee from the government. Others also mentioned the potential involvement of ATB Financial.[226]

323. AFREA also proposed an alternative funding mechanism to enable DCG to be connected to REA distribution systems. It suggested that any distribution system costs incurred by the REAs to connect alternative and renewable DCG to their systems be passed on to the AESO for recovery from all Alberta ratepayers. In its view, this approach would remove a competitive barrier that exists for REAs to connect alternative and renewable DCG in their service areas. Further, the REAs could then accommodate standard technologies and processes approved for use by the AUC to connect alternative and renewable DCG in the same form as the other distribution wire owners and the incremental cost to connect alternative and renewable DCG would be transparent.

324. Howell Mayhew[227] suggested a viable funding mechanism, especially in the urban areas, could be through property taxes. Under its suggestion, if permitted by law,[228] the municipality could finance the costs of the micro-generation project then recover its costs through property taxes with no upfront cost. Howell Mayhew noted municipalities currently finance community upgrades such as sidewalk and streetlights through local improvement charges added to property taxes, so the payment mechanism is already established. Such a plan, if incorporated into legislation, would help address an important barrier to the longer payback periods currently being experienced for certain technologies, for example, the 18-year payback for solar PV rooftop projects.

[226] Exhibit 22534-X0150, SPARK responses to Commission questions, PDF page 2; Exhibit 22534-X0157, Renewable Energy Solutions ™ responses to Commission questions, PDF page 1.

[227] Transcript, Volume 8, pages 1230-1231, PDF pages 127-128.

[228] See for example Section 264 of the *Municipal Government Act*.

6 Effect of parallel government green initiatives

Key Observations:

Parties are concerned that initiatives like the REP program, the capacity market and the cap on the RRO rate may cause reductions in energy market prices that would make further expansion of DCG uneconomic. If the government believes that DCG needs to be a significant contributor to the 30-30 target, further subsidies for DCG will be required.

Subsidies are in place for certain types of generation, such as programs to reduce the upfront capital cost of solar PV and the REP program. A review of current and proposed future subsidies would help to understand the effect of these subsidies on electricity prices and if certain technologies are favoured.

325. Included within the preamble to the terms of reference of the OIC, at item G, it states:

> The development of alternative and renewable distribution system-connected generation in Alberta, including micro- and small-scale community generation, should be in line with the Government of Alberta's objectives of providing clean, affordable and reliable energy to Albertans.

326. In this section, the AUC reviews existing government policies under the Climate Leadership Plan that were raised and discussed by participants during the inquiry. In its review, the AUC considered the Renewable Electricity Program (REP), the creation of a capacity market, the establishment of the Climate Change Office, including the Energy Efficiency Alberta agency, and the cap on the RRO rate.

327. The Climate Leadership Plan contains a number of elements that might affect wholesale and retail electric energy market prices, and hence revenues. As many distribution-connected generation (DCG) proponents commented, the viability of their DCG projects is dependent on expectations of sufficient revenues. Should these not be met, DCG proponents indicated that they would require subsidies in order for their projects to move forward.

6.1 Renewable Electricity Program

328. The Government of Alberta announced its Renewable Electricity Program on March 24, 2017, and designated the AESO to implement and administer the program. The program is intended to contribute to connecting 5,000 megawatts (MW) of renewable electrical energy generation to the Alberta Interconnected Electric System at either the transmission or the distribution system by 2030.

329. The AESO is using a series of auctions to identify the successful proponents. The first auction commenced on March 31, 2017, for up to 400 MW of renewable electrical energy generation. The auction was open to all renewable technologies, with lowest cost qualified

projects to receive financial support in the form of an indexed renewable energy credit payment for a 20-year contract term.[229]

330. Eligible projects were required to be a new or expanded project, be operational in 2019, be equal to or greater than 5 MW, meet the definition of renewable energy, and utilize the existing transmission or distribution systems. Bidders were also required to submit a non-refundable submission fee calculated to be $1,000 per MW of nameplate capacity.

331. A number of participants stated that the REP would not encourage DCG. The 5 MW minimum generating capacity requirement, demonstration of financial viability and the submission fee were barriers to participation for small-scale proponents. As well, since the winning bids were to be determined based on the lowest cost to provide service, this would have a dampening effect on the market price for electrical energy, making the economics of DCG less attractive.

332. ATCO Power Canada Ltd. (ATCO Power)[230] stated that the design, operation and outcome of the REP would have a significant effect on the deployment of DCG. According to ATCO Power, enhancing the opportunity for DCG to participate in future REP rounds would assist in reducing the investment barriers for DCG projects. ATCO Electric[231] stated that future REP auctions targeted to DCG might still be required to fulfill the government's 30-30 target. However, under the current compensation design, successful bidders would be price takers, depressing energy market prices, which represent a significant component of a distribution-connected generator's revenue stream.

333. CanWEA[232] stated the effect of the REP on DCG would depend on the share that each renewable generation type receives in the 5,000 MW REP program. CanWEA stated that power pool prices might be lower if wind generation represents the entire 5,000 MW allotment, which would consequently reduce the revenue stream for larger-scale DCG.

334. URICA Energy Real Time Ltd. (URICA)[233] stated:

> "For larger scale alternative and renewable DCG, the REP may cause many developers to delay development of any stand-alone merchant facilities in the hope that they are successful in the REP auction. For many renewable developers, because of the financial uncertainty caused by the new capacity market and energy market, development of new facilities will only go ahead if they are successful in the REP auctions." [234]

335. CanSIA noted that the structure of the first round of the REP auction was to award contracts to projects having the lowest bid price. Consequently, solar projects did not expect to be chosen in the initial auction. CanSIA identified three factors that would determine the ability of distribution system-connected solar projects to be successful proponents in future REP

229 For details on the REP program, The Alberta Electric System Operator, Renewable Electricity Program, Background and resources. Retrieved from: https://www.aeso.ca/market/renewable-electricity-program/background-and-resources/.

230 Exhibit 22534-X0112, ATCO Power responses to Commission questions, PDF pages 20-21.

231 Exhibit 22534- X0115, ATCO Electric responses to Commission questions, PDF page 69.

232 Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 12.

233 URICA is a service provider to DCG entities by providing facility dispatch and asset optimization services.

234 Exhibit 22534-X0158, URICA responses to Commission questions, PDF page 12.

auctions. Those factors were i) procurement design (i.e., fuel-neutrality or approaches to valuing differences in generation profiles); ii) the competitiveness of distribution-connected projects relative to transmission-connected projects and other large-scale renewable generation options; and iii) whether the policy and regulatory framework or market-based opportunities send alternate build signals for solar DCG greater than 5 MW that are deemed more preferable by developers than the REP. [235]

336. Alberta Solar Co-op,[236] DEC[237] and Lion's Tooth Solutions[238] all stated the REP process, as currently designed, is focused on large commercial development of renewable generation and would not incent the development of DCG. Alberta Solar Co-op and DEC stated this design will not provide nearly the same policy outcomes, in terms of economic, environmental, and social benefits to the province and communities than what widely dispersed, community-owned distribution-connected generation could offer. Lion's Tooth Solutions stated the need for similar programs to support other forms of DCG, particularly natural gas-fired generation and cogeneration. Alberta Solar Co-op recommended that the REP allow the opportunity for community-owned generation to participate in the procurement process.

337. The Alberta Renewable Energy Co-operative (SPARK) recommended a substantial portion of the REP be designated to community-owned generation projects. SPARK believed that over 1,000 MW of capacity could be built by the community/co-operative sector over the next 10-20 years.[239]

338. SkyFire stated that the REP will result in additional downward pressure on future market prices, and the existing owners of DCG will suffer from the reduced revenue. SkyFire indicated government programs attempting to increase renewable generation should not penalize these early adopters, which started the growth of the solar energy industry in Alberta without government incentives. Consequently, changes would be required in the compensation scheme for micro-generation to avoid having the REP, or other government subsidies, have harmful, unintended consequence to existing generators.[240]

339. On December 13, 2017, the government announced the results of the opening round of the Renewable Electricity Program. Three companies were chosen to provide 600 MW of renewable, wind-powered electrical energy. The amount was 200 MW greater than was originally planned for procurement in the first round. The weighted average price of the successful bids was 3.7 cents per kWh. According to the government's news release, "the successful bids have set a record for the lowest renewable electricity pricing in Canada."

6.2 Capacity Market

340. In October 2016, the AESO released a report recommending the introduction of a capacity market into Alberta's wholesale electricity market structure. Some of the AESO's reasons for recommending a capacity market included providing generators with revenue sufficiency and stability, ensuring reliability, compensating generators who could readily supply

235 Exhibit 22534-X0132, CanSIA responses to Commission questions, PDF page 9.
236 Exhibit 22534-X0162, Alberta Solar Co-op responses to Commission questions, PDF page 7.
237 Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF page 13.
238 Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF page 27.
239 Exhibit 22534-X0150, SPARK response to Commission questions, PDF page 1.
240 Exhibit 22534-X0113, SkyFire response to Commission questions, PDF page 20.

electrical energy when needed, maintaining market incentives and implementing key areas of the government's Climate Leadership Plan. On November 23, 2016, the Government of Alberta announced its endorsement of the AESO's recommendation to transition from an energy-only market to a capacity market that retains elements of the energy-only market. The AESO will be responsible for designing and implementing the capacity market, which is expected to take three years to develop. The capacity market is expected to be in place by 2021.

341. The current compensation for large-scale DCG and large micro-generating units is the pool price. Between 2014 and 2016, the pool price averaged $33.68 per MWh per year.[241] Many DCG proponents stated it is economically challenging to invest in DCG at the current and persistently low pool prices. These proponents claim the transition from an energy-only market to one designed with elements of a capacity market and an energy market will likely continue to sustain low pool prices, which will adversely affect the economics of developing additional DCG.

342. ATCO Power[242] stated that because the AESO is in the initial design phase of the capacity market, it may be too soon to anticipate the affect that the capacity market design may have on DCG. According to ATCO Power, detailed matters such as cost allocation, participation eligibility and obligations, performance penalties, and the future design of the energy and ancillary service markets will need to be considered and determined before being able to assess the effect of the capacity market on the development of DCG.

343. Other proponents stated that the proposed capacity market design will not benefit DCG. The Alberta Solar Co-op stated that the proposed capacity market design might hamper DCG development by allowing traditional and centralized energy providers the opportunity to lower their bid prices into the power pool because of the revenue stream provided from capacity payments. SkyFire expressed the same concern and stated that the current low wholesale prices were inhibiting the development of micro-generation.[243] The Alberta Solar Co-op also had concerns with the current energy-only market in that the bidding by coal-fired generation at marginal cost is keeping wholesale prices artificially low.[244]

344. CanWEA[245] and DEC[246] stated that the project revenues under a capacity market design were expected to be lower than an energy-only framework. Consequently, the capacity market would have a negative effect on the development of DCG and other financial assistance would be required. CanSIA stated that should the compensation mechanism of the capacity market fail to recognize the environmental and operational attributes of alternative and renewable DCG, this would reduce the pace and scale of DCG development.

345. Capital Power stated renewable DCG should not be eligible to participate in the capacity market if it receives financial assistance either through a REP contract or government program. According to Capital Power, this approach would be consistent with the AESO's announcement of not allowing successful proponents in the initial REP auction to participate in the capacity

[241] The Alberta Electric System Operator, "AESO 2016 Annual Market Statistics", online: https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/.
[242] Exhibit 22534-X0112, ATCO Power response to Commission questions, PDF pages 19-20.
[243] Exhibit 22534-X0113, SkyFire response to Commission questions, PDF page 20.
[244] Exhibit 22534-X0162, Alberta Solar Co-op response to Commission questions, PDF page 3.
[245] Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF pages 11-12.
[246] Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF page 13.

market. Conversely, a renewable DCG project could compete in the capacity market if the project did not receive government funding and it accepts the same eligibility and performance requirements (i.e., market rules, tariffs, connection costs, and obligations) as transmission-connected renewable generation.[247]

346. Capital Power also stated large-scale generation would continue to contribute to the future of Alberta's electric industry because this generation is needed to provide reliability support to the large volumes of intermittent renewable generation added through the REP and to fulfil the supply adequacy goals of the capacity market currently under design. Thus, any government program that promotes the increase in DCG should not create unintended consequences and risks for large-scale generation investors and should not significantly dampen the price signal for new investment.

6.3 Climate Change Office

347. In February 2016, the government announced the creation of the Climate Change Office to help implement the strategies outlined in its Climate Leadership Plan. The Climate Change Office established Energy Efficiency Alberta. This entity is mandated to promote and deliver programs focused on renewable energy and energy efficiency.

348. Under the Climate Leadership Plan, the government also introduced the following programs to help Albertans install solar PV systems and to be more energy efficient:

- The On-Farm Solar PV Program that provides funding towards solar PV on Alberta farms.
- The Alberta Indigenous Solar Program, a pilot program that provides grants to Alberta Indigenous communities or organizations to install solar PV systems on facilities owned by the community or organization.
- The Alberta Indigenous Community Energy Program, a pilot program that provides tools and funding to help Indigenous communities understand how energy is used in their buildings and identify opportunities to save energy and financial resources.
- The Alberta Municipal Solar Program, a $5-million fund that provides financial rebates to Alberta municipalities who install solar PV systems on municipal facilities or on municipal land.
- The Residential and Commercial Solar Program, a five-year, $36-million rebate program for solar installation on residential and commercial buildings.

349. These programs were not specifically discussed by the parties during the inquiry. However, these programs do provide some funding for solar and energy efficient projects.

350. Energy Efficiency Alberta is a new crown corporation providing programs and services to Albertans to reduce energy usage and save money.[248] Energy Efficiency Alberta[249] stated its programs focused on enabling more energy efficient buildings, reducing electrical and natural gas energy usage, and supporting programs around water efficiency and transportation. It includes residential housing, (single- and multi-family), commercial and institutional non-profit

[247] Exhibit 22534-X0118, Capital Power response to process letter, PDF page 2.
[248] Transcript, Volume 7, page 984, PDF page 4.
[249] Transcript, Volume 7, page 987, PDF page 6.

facilities, and small-scale industrial facilities. This entity is also educating Albertans on the Alberta Residential and Commercial Solar Program.

351. The CEO of Energy Efficiency Alberta attended the oral portion of the inquiry to provide the AUC with more information about its mandate and the programs that it offers. In her discussion with the AUC, she stated:

> We recognize that utilities are preparing for a future where there will be more distributed generation…and where there will be different load requirements than there have been historically. And so are very interested in being part of the conversation about how our programs can support that transition for utilities.
>
> […]
>
> So I would say we don't see Energy Efficiency Alberta as owning the question of what is the best option for how utilities might adapt or structures in the market might change to enable them to change their business model, for example.
>
> We do recognize, though, that we are incenting a reduction in energy use and a shift to more renewable energy, and that that does impact their costs. And so [we] are very interested in working with them and working with others in the marketplace to understand where the pace -- how we might contribute to that. Both how we might contribute to the pace and whether that's moving some things faster or slower.[250]

6.4 Cap on the RRO rate

352. As previously set out in subsection 3.3.4.1 of this report, Alberta customers have the option of purchasing electricity services in accordance with a regulated rate tariff instead of purchasing electricity services at a competitive retail energy rate. This is known as the regulated rate option (RRO).

353. In late 2016, the Alberta Government announced plans to place a price cap on the RRO rate. This cap, in which consumers pay no more than 6.8 cents per kWh, came into effect on June 1, 2017, and will be in place until May 31, 2021.[251] At that time, the average RRO rate was 3.19 cents per kWh and as of the release of this report, in December 2017 the RRO rate is 3.93 cents per kWh. However, TransAlta Corporation's recent decision to mothball a number of coal-fired generating units, in addition to the retirement of its Sundance 1 unit in 2018, could raise the wholesale market price sufficiently to trigger the RRO rate cap.

354. CanSIA[252] stated this cap on the RRO rate might have negative effects on the government's Climate Leadership Plan objectives. One negative effect identified by CanSIA would be the elimination of the price signals that would incent consumers to change their behaviour to use electricity more efficiently when these prices rose above the RRO rate cap. Alberta Solar Co-op[253] stated another negative effect might be to suppress the future earning potential of the distribution-connected generator when the actual RRO rate exceeds the cap.

250 Transcript, Volume 7, pages 1023-1025, PDF pages 43-45.
251 *An Act to Cap Regulated Electricity Rates*, RSA 2017, c C-2.3.
252 Exhibit 22534-X0139, CanSIA responses to Commission question, PDF page 3.
253 Exhibit 22534- X0162, Alberta Solar Co-op responses to Commission questions, PDF page 6.

Overall, these two participants stated the cap on the RRO rate could limit the adoption of solar-based DCG.

355. The CCA[254] stated placing a cap on the RRO rate will distort the price signal and could lead to unnecessary cross-subsidies between classes of customers and the blunting of the proper responses (e.g., reducing consumption when the price rises or investing in energy efficient devices). The CCA's suggestion was that caps be subsidized by the government (i.e., taxpayers) and be kept outside of the pricing mechanisms of the electricity market.

356. The AUC observes that artificially low prices that could result from the RRO rate cap being triggered, reduce customer's incentives to adopt DCG and other efficiency measures.

[254] Transcripts Volume 4, page 482, PDF page 23.

7 Technological change

Key observations:

Participants noted technological advances that are ongoing in the industry, such as energy storage, and considered these to be a significant contributor towards enabling future growth of DCG.

357. The AUC asked participants in the inquiry to provide their assessment of the pace and nature of technological changes as new technologies can enable distribution-connected generation (DCG) growth through lowering of costs while also presenting barriers to growth as additional DCG can require further infrastructure to support the DCG and to continue to provide safe and reliable service.

358. Technological advances identified by participants included: (1) advances in measurement, (2) enhanced control and monitoring, (3) enhancements to cyber security, (4) energy storage and demand response measures and (5) blockchain technology.

7.1 Measurement

359. Some participants commented that smart meter technology could incent growth in DCG because consumers could then have readily available access to information regarding their consumption and generation of electrical energy. Participants acknowledged that investments in smart metering technologies would be required to support an increasing amount of DCG and maintain the safety and reliability of the distribution system. Generally, with the exception of AFREA, participants did not address who would be responsible for the costs or whether the costs were justifiable.

360. AFREA considered the installation of smart meters to impose a financial barrier, especially for rural Albertans. AFREA was of the opinion that a universal, province-wide, mandatory requirement for smart meter installation with bi-directional communication had the potential to burden REA members and taxpayers with costs that far exceed the benefits in rural locations.[255] AFREA was not opposed to the use of smart meters, but the level of sophistication deployed should be supported by a sound and locally-focused cost-benefit analysis and that the costs of deployment be recovered from the parties who are causing the costs.

7.2 Control and monitoring

361. The management of distribution systems with high levels of DCG, such as rooftop solar, will become an imminent issue for distribution wire owners. This is because the present distribution system design is not suited to the intermittency that is characteristic of renewable DCG, like solar or wind. Distribution wire owners will require an increased awareness of the real-time situation of their systems in order to manage the technical, operational, and economic effects of having a high penetration of DCG. As stated in Section 5.2 of this report, distribution wire owners are currently unable to advise when that penetration level would be problematic.

[255] Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 8.

362. Throughout the inquiry, distribution wire owners and the AESO expressed concern regarding their continued ability to provide safe and reliable service when they have no visibility or control over DCG. Distribution wire owners stated the deployment of technologies could address their concerns.

363. As mentioned in subsection 5.2.3 of this report, the two software-based programs that could assist distribution wire owners with integrating an increasing amount of DCG while maintaining the safety and reliability of the distribution system are distributed energy resource management systems (DERMS) and advanced distribution management systems (ADMS).

364. DERMS is a management tool that assists distribution wire owners in the planning, monitoring, and control of their distribution systems. A key feature of the DERMS tool is its capability to integrate more renewable DCG into distribution systems, to mitigate the effect of renewable DCG on grid reliability and to use the renewable DCG to improve the operation of the system (e.g., smart inverters). ADMS is a management tool that provides distribution wire owners with the capability to manage the effects of renewable DCG on the distribution system while optimizing the performance of the distribution system.

365. According to industry publications[256], both of these management tools are emerging technologies being deployed as pilot projects. They require a high level of customization to develop and are expensive to implement.

7.3 Cyber security

366. The North American Electric Reliability Corporation (NERC) has developed cyber security regulations at the bulk electric system level.[257] The AESO established Critical Infrastructure Protection Reliability Standards for Alberta (Alberta Reliability Standards),[258] based on NERC's Critical Infrastructure Protection requirements. The AUC approved the Alberta Reliability Standards through the process set out in Section 19 of the *Transmission Regulation.*

367. These approved Alberta Reliability Standards govern the interfaces between the bulk electric system's cyber systems and any other systems, including DCG systems. These Alberta Reliability Standards protect the bulk electric system's cyber systems from exposure to threats that could lead to the instability or an unintended operation of the bulk electric system.

368. While none of the distribution wire owners reported that a cyber security attack had occurred on its systems, the larger distribution wire owners were unanimous on the need for cyber security standards at the distribution system level. EPCOR[259] and FortisAlberta[260] stated

[256] See for example, Greentech Media: *The Distributed Energy Resource Management System Comes of Age*. Retrieved from:https://www.greentechmedia.com/articles/read/north-american-distributed-energy-resource-software-market-to-reach-110m-in#gs.FQPqnrc (Accessed December 18, 2017).

[257] The NERC defines the bulk electric system as "all transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy."
See NERC, Bulk Electric System Definition Reference Document, April 2014. Retrieved from: http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf.

[258] See The Alberta Electric System Operator for the Critical Infrastructure Protection Reliability Standards in effect. Retrieved from: https://www.aeso.ca/rules-standards-and-tariff/alberta-reliability-standards/.

[259] Exhibit 22534-X0144, EPCOR response submission, PDF pages 36-37.

that automated communication and control systems would be required as more DCG integrates into the distribution systems. ENMAX[261] stated that an increase in DCG technologies connected to the distribution systems would increase cyber security threats and potentially lead to asset damage, and power quality, reliability and safety concerns on the distribution and the bulk electric systems.

369. There are no AESO mandated cyber security standards for the distribution systems; however, their absence was not regarded as a barrier to the development of DCG.

370. Some participants thought that cyber security standards at the distribution level were required and some did not.

371. The cities of Lethbridge and Red Deer stated that they have adopted the AESO's Alberta Reliability Standards regarding cyber security for transmission on their distribution systems.[262]

372. ATCO Electric suggested that, "in collaboration with industry partners and regulators, new controls for ensuring cyber security be explored and considered as part of the overall strategy for DCG implementation across Alberta."[263] The AESO agreed that any discussion about the development of cyber security must include the distribution-connected generators "because a lot of the technical issues that we speak about here, and the impacts on system reliability, and all of those kinds of things, they're going to be influenced by DCG no matter how they're fuelled. And I think if we're going to come up with an industry-wide solution to these problems that's fair and equitable to everybody and solves the whole problem, then those non-renewable DCG facilities need to be included in the discussion."[264] As well, although EPCOR characterized the risk involved as being relatively low, it stated that "in order to protect the distribution and DCG systems, encryption and cyber security standards may need to be put in place to prevent malicious entities from taking control of DCG. Malicious entities could leverage such control of DCG assets to gain access to the communication network and subsequently aid a cyber intrusion of BES [Bulk Electric System] cyber systems."[265]

373. These distribution wire owners also indicated that without a set of cyber security standards, each distribution wire owner is determining its own communication and protection requirements. These requirements may vary between systems requiring distribution-connected generators to meet these different standards. This may be a barrier to DCG growth.

374. Many participants were concerned about the costs of implementing cyber security standards at the distribution level, noting this would be a financial barrier for distribution-connected generators as well as an additional distribution cost for all ratepayers.

375. ATCO Power[266] stated "there should be a requirement to develop cyber security standards for the distribution system, especially in light of the desire for increased penetration of DCG

260 Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF pages 38-39.
261 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 35.
262 Exhibit 22534-X0143, the City of Lethbridge and the City of Red Deer responses to Commission questions, PDF page 19.
263 Exhibit 22534-X0205, ATCO Electric responses to Commission supplemental questions, PDF page 7.
264 Transcript Volume 5, pages 597-598, PDF page 60-61.
265 Exhibit 22534-X0203, EPCOR responses to Commission supplemental questions, PDF page 8.
266 Exhibit 22534-X0112, ATCO Power responses to Commission questions, PDF page 11.

throughout the province." AFREA[267] stated cyber security concerns were dependent upon the size of the DCG and the level of technology deployed, but it considered this to be less of a concern for the distribution system than for the bulk electric system. DEC[268] stated having DCG would lessen the effects of a cyber attack on the bulk electric system and increase the resiliency of the Alberta Interconnected Electric System.

376. Other participants[269] stated the establishment of cyber security standards would be a barrier to the development of DCG but did not explain why they considered this to be the case. One possible reason, identified by many participants, is that the costs of implementing cyber security standards at the distribution level would be a financial burden to distribution-connected generators as well as to ratepayers.

377. The AESO stated it would monitor the NERC and other sources and develop cyber security standards applicable to the distribution system as needed. It also provided publications from other jurisdictions that examined the need for cyber security standards. A list of these publications is included in Appendix 7 to this report.[270]

7.4 Energy storage

378. Energy storage is the capture of energy produced at one time, for use at a later time. It is neither a pure generator nor a pure load. Energy storage technologies can be used to store electrical energy produced by renewable generation sources that might be otherwise unused or curtailed. Energy storage can take many forms: compressed air energy storage, battery energy storage, flywheel storage, pumped hydroelectric energy storage, and superconducting magnetic energy storage.

379. Energy storage can play two roles. It can serve as a back-up resource for renewable DCG sources such as wind and solar which are intermittent in nature. As well, it can play a commercial role by arbitraging energy prices by purchasing and storing energy when wholesale prices are low and selling that energy when wholesale prices are high. Commercial storage can also provide additional services such as load balancing, voltage support and operating reserves. This is consistent with the definition of ancillary services found in Section 1(1)(b) in the *Electric Utilities Act.*

380. Energy Storage Canada (ESC),[271] which describes itself as the industry association representing the broad range of companies engaged in the energy storage business across Canada, provided information regarding energy storage's role in promoting the development, growth, and integration of DCG. ESC's view was that energy storage could be a significant enabler of DCG for the distribution-connected generator and distribution wire owner because of its operational capabilities.

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[267] Exhibit 22534-X0095, AFREA responses to Commission questions, PDF page 24.
[268] Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF pages 9-10.
[269] Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 10, Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, page 17. and Exhibit 22534-X0158, URICA responses to Commission questions, PDF page 6.
[270] Exhibit 22534-X0196, AESO responses to Commission supplemental questions, PDF page 4.
[271] Exhibit 22534-X0122 Energy Storage Canada responses to Commission questions, PDF page 2.

381. ESC stated energy storage uses the distribution systems in ways that are operationally different from a conventional generator and a normal end-use customer. Specifically, it is flexible. It is able to be a rapidly dispatchable load when having to absorb excess electrical energy generated by renewable DCG, and it is able to be a dispatchable source when having to deliver this energy back to the system, such as when the wind stops blowing or when the sun stops shining.

382. ESC stated energy storage’s unique capabilities are not being recognized from an operational and financial perspective.[272] Operationally, ESC stated there is a lack of understanding in Alberta regarding how to integrate energy storage into the electrical system to make the generation output from renewable sources more predictable and dispatchable while enhancing system reliability. As an example, ESC stated that energy storage’s ability to absorb the overproduction of electrical energy from roof-mounted solar DCG could prevent this overproduction from being delivered to the transmission system and could assist distribution wire owners in managing the bi-directional flow of electrical energy on the distribution system.

383. ESC claimed that under a commercial storage arrangement, renewable electrical energy purchased and withdrawn from energy storage is subject to distribution rates twice as compared to the electrical energy that flows directly from a generator to the end-use customer. It stated that “[d]istribution tariffs are charged to energy storage projects when they are taking power off the system AND when they put that power (minus losses) back on to the system, as if they were a firm end use customer. Essentially there is a double distribution rate charged for energy that is generated by DG, stored, put back onto the system and delivered to the end use customer.”[273] Further details were provided by ESC in its submission.

384. The AUC observes that the above scenario of distribution rates being charged twice does not occur in all situations. For example, it does not apply if the energy storage is fully used by the distribution-connected generator on its own property (i.e., generated, stored and consumed by the DCG customer).

385. ESC further stated that traditionally, distribution systems were built and the tariffs structured to accommodate the peak demand of end-use customers. Energy storage can absorb electrical energy during off-peak hours and supply this energy during peak demand times, which has the effect of reducing the peak demand requirements of the distribution system. Because of this beneficial attribute, ESC believes energy storage should be subject to a different type and level of rates than those charged to end-use customers.

386. Lion's Tooth Solutions argued that distribution wire owners should not be allowed to own or develop energy storage. It stated “[i]t is our belief that Energy Storage is a form of generation, in that it has the capability to sell electricity into an energy market. For example, storage could be used to capture wind energy in low priced hours overnight, and sold into the market in higher priced [h]ours. “Investment” in energy storage or load shedding technology (i.e. by selling stored energy behind the fence during peak hours) by a regulated utility would have the potential to

[272] Exhibit 22534-X0253, Energy Storage Canada opening statement, PDF page 3.
[273] Exhibit 22534-X0253, Energy Storage Canada opening statement, PDF page 2.

affect power prices, and would be a violation of FEOC. Therefore we would oppose development of energy storage by regulated utilities."[274]

387. As noted in paragraph 188 of this report, the issue of whether a regulated distribution wire owner can or should own battery storage, it is also the subject of debate in some jurisdictions in North America.

388. Other energy storage proponents noted that distribution wire owners were reluctant to integrate energy storage systems without owning the technology themselves. Because the distribution wire owners prefer to own the technology, the proponents found it challenging to demonstrate the usefulness of storage to distribution wire owners, even on a trial basis.

Transmission grid benefits

389. According to ESC, distributed energy storage assets could also provide a number of benefits to the AIES. Energy storage has the potential to be aggregated to provide ancillary services such as operating reserves that are typically provided by large transmission-connected assets.[275] This aggregation could also mitigate the operational effects caused by a surplus of electrical energy supply from intermittent renewable generation at the transmission level.

390. As well, ESC stated energy storage could take advantage of off-peak demand periods to absorb electrical energy from the grid and then deliver this electrical energy to offset load requirements during peak periods, thus extending the asset life of the transmission line.

391. Another example of transmission and infrastructure deferment, according to ENMAX,[276] would be to use energy storage as an alternative to a transmission or distribution substation upgrade that may be necessary because the substation was operating near maximum capacity. According to ENMAX, an energy storage system that is strategically located near the substation could absorb electrical energy during off-peak hours and deliver that stored electrical energy during peak load periods, which would reduce the net demand requirements at the substation. This would have the effect of keeping the substation operating below the peak levels, thereby deferring the need for the substation upgrade. The addition of energy storage may be a lower cost alternative for meeting peak demands compared to a complete substation upgrade.

Assessments of the benefits and costs of energy storage in other jurisdictions

392. ESC stated the use and deployment of energy storage in other jurisdictions in North America demonstrates that energy storage is not an emerging or unproven technology. ESC noted that in the United States, the states of California, Massachusetts, Nevada and New York mandated the deployment of energy storage. The regional transmission organizations in Texas (ERCOT) and the northeastern area of the United States (PJM Interconnection LLC) have hundreds of megawatts (MW) of energy storage connected to their grids. The Federal Energy Regulatory Commission has determined that energy storage is not the same as a load customer and that system operators should develop tariffs that recognize the benefits of energy storage

[274] Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF page 22.
[275] Exhibit 22534-X0253, Energy Storage Canada opening statement, PDF page 4.
[276] Exhibit 22534-X0201, ENMAX responses to Commission supplemental questions, PDF page 18.

being realized. In Ontario, the independent electric system has relied on energy storage to provide ancillary services for the Ontario grid.

393. ESC also referred to a number of studies from the United States that describe the methodologies to assess the benefits and costs of energy storage. ESC stated that the results from these studies and the actions taken in the major electricity markets in North America, would suggest there is no need to assess the benefits of energy storage in Alberta. Rather, the focus should be on developing a procurement process for energy storage similar to the one established under the Renewable Electricity Program.

394. To date, there are no formal energy storage technologies operating at the distribution system level in Alberta.

7.5 Demand response

395. In the OIC at (1)(d)(iv), the AUC was asked to identify how demand response would enable and facilitate broader deployment of alternative and renewable DCG. The AUC received a limited number of submissions regarding what role demand response should play in the government's renewable energy policy.

396. Demand response can take many forms, and when used effectively as a resource, it can lower the cost of electricity in wholesale markets by avoiding the dispatch of more costly generation resources.

397. Where formal demand response programs have been developed, larger load customers, such as commercial and industrial customers or retailers can shed load at the direction of the independent system operator to respond to events that adversely affect the distribution or transmission system such as high power prices, peak load conditions, extreme weather events and unplanned generator outages. Program participants that can reduce their electricity consumption are paid for reducing their load for discrete periods of time. Further, in some jurisdictions demand response is economically scheduled simultaneously with merit-order generator resources. By reducing consumption, program participants provide benefits to the whole electrical system and are compensated for it.

398. In jurisdictions where residential customers on time-of-use pricing can materially affect electricity demand at peak load periods, end-use customers can directly benefit through lower energy bills. Where enabled through technology, the use of direct load control programs allows for the cycling of customer air conditioners or electric water heaters on and off during periods of peak demand in exchange for a financial incentive. Alberta does not have time-of-use pricing.[277]

399. Demand response can also refer to an independent system operator's efforts to curtail load at times when intermittent renewable generators are not able to generate (i.e., when the wind is not blowing or the sun is not shining). Curtailing load at these times could enable the system to facilitate growth of intermittent generation (or renewable DCG) without requiring as much fossil fuel generation back-up.

[277] Time-of-use pricing means that there are several different rates, depending on the time of day you use energy.

400. The CCA[278] stated that utilizing the potential of existing and future consumer-level demand response programs would facilitate the better utilization of resources. The CCA's proposed methodology to realize this potential for demand response would be to introduce a binding, day-ahead wholesale market. A market participant could then be responsible for aggregating the demand response resources, bidding the resources into the market and dispatching the resources if the bidding was successful. According to the CCA, offering demand response services into a binding, day-ahead market would result in stable and predictable pricing and reflect the true economic value of demand response.

401. The AESO provided two documents that addressed demand response in other jurisdictions. One entitled "Distributed Energy Resources Integration"[279] included a section on the unique challenges faced by independent system operators in their efforts to integrate demand response into the operation of the transmission grid. The other was entitled "Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets"[280] which outlined the manner in which the New York Independent System Operator was dealing with demand response programs.

402. The AESO and Alberta's wire owner companies currently do not have any demand response programs in place nor do they have any under development.

7.6 Blockchain technology

403. A blockchain is a web-based bookkeeping system maintained by a network of computers. These computers verify transactions between individual users. Each user can access the bookkeeping ledger in a transparent manner, as there is no central authority to act as an intermediary for the transactions. Blockgeeks.com explains blockchain as follows: "Information held on a blockchain exists as a shared — and continually reconciled — database. This is a way of using the network that has obvious benefits. The blockchain database isn't stored in any single location, meaning the records it keeps are truly public and easily verifiable. No centralized version of this information exists for a hacker to corrupt. Hosted by millions of computers simultaneously, its data is accessible to anyone on the internet."[281]

404. The AUC's independent research on activities in the community generation sector in other jurisdictions uncovered a microgrid pilot project in Brooklyn, New York, U.S. that uses blockchain technology to document energy transactions between members of the community. In this project, a member producing excess renewable electrical energy could sell the excess to another member at a mutually agreed upon price and without the involvement of the local distribution wire owner, retailer or wholesale market system operator in the transaction.

405. According to its supporters,[282] blockchain technology can provide members with greater control and flexibility over how the community generation's output is bought and sold. Sellers

[278] Exhibit 22534-X0160, CCA evidence, PDF page 6.
[279] Exhibit 22534-X0129, AESO Attachment 1,Distributed Energy Resources Integration report, by Olivine Inc. June 24, 2014.
[280] Exhibit 22534-X0126, AESO Attachment 2, Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets, by NY ISO, January 2017.
[281] Blockgeek.com, What is Blockchain Technology? A Step-by-Step Guide For Beginners. Retrieved from: https://blockgeeks.com/guides/what-is-blockchain-technology/.
[282] See for example LO3 Energy (https://lo3energy.com/) and the Rocky Mountain Institute (https://www.rmi.org/).

have the potential to achieve a higher value for their generation by transacting peer-to-peer with other members rather than having to sell to the distribution system at a prescribed or administered price. Buyers can determine the price they are willing to pay, or accept the real-time price signals, and then seek a willing seller.

406. In the Alberta context, blockchain technology has the potential to provide virtual net billing services for community generation members without the need for retailer involvement. Recognizing that further analysis and stakeholder engagement would be necessary first, blockchain technology could result in cost and process efficiencies with little or no disruption to the business practices of the current market participants.

8 Moving forward

Key observations:

The AUC's review of certain programs implemented in other jurisdictions suggests that while feed-in tariff programs may be successful in stimulating the growth of DCG projects, ultimately this growth results in higher costs for customers and may result in grid management challenges.

The AUC also observed that other jurisdictions are facing challenges relating to net metering compensation mechanisms and are either adjusting these compensation mechanisms, or moving away from net metering altogether.

Participants generally agreed that prior to implementing any policies to accelerate DCG, extensive studies should be conducted to determine where there is existing capacity on the distribution wire owners' feeders.

Many participants identified the need for a coordinated and inclusive approach to planning as a key success factor for the integration of additional DCG to the electric system.

Overall, the AUC observes that the existing legislation and rules do not restrict the development of community generation. Indeed, it enables it in practically unlimited ways. Participants provided varied examples of how individuals and organizations have successfully established what they described as community generation programs under the existing legislative framework.

The AUC observed that participants were concerned that the introduction of further legislation or rules to define community generation may place artificial boundaries and limits on the possible opportunities to establish communities that meet their needs.

The AUC further observed that although the existing legislation and market rules enable Albertans, either individually or collectively, to become involved with DCG, many participants stated that the absence of education programs to create a greater awareness of DCG options, financial programs and processes act as a barrier to the growth and development of DCG.

407. It is important to consider how to resolve the issues identified by participants in this inquiry if distribution-connected generation (DCG) is expected to contribute significantly more to the meeting of the 30-30 target than it does today.

408. In this section, the AUC first presents experiences from other jurisdictions that have taken steps and enacted policies to accelerate DCG. The AUC then presents the two principal themes that emerged from this inquiry regarding future DCG growth: education and planning. Finally, the AUC discusses advances and development in community generation and other green energy programs.

8.1 Lessons learned from other jurisdictions

409. Although Alberta has had DCG for many decades, growth of DCG has been gradual and reflective of economies of scale and scope. Absent the same type of financial programs that have been present in other jurisdictions to accelerate DCG growth, few Albertans have been financially incented to absorb the cost required to become a distribution-connected generator. Consequently, it is helpful to look to other jurisdictions that have used various subsidies and programs to stimulate growth in DCG.

410. A particular theme that emerged during the inquiry concerned the need to carefully plan and consider the many factors that can either enable further development of DCG or create barriers. Practices which many participants cautioned against deploying in Alberta in order to stimulate further DCG penetration included: (1) changing tariff design in a way that ignored cost causation principles and (2) stimulating growth through various subsidy programs without first understanding the capacity limitations of the wire system or the resultant costs to execute those programs. Either of these practices could affect the affordability of electricity to Albertans.

411. The AUC examined programs in other jurisdictions to understand the extent to which the factors identified by participants in this inquiry had been experienced in those jurisdictions. In particular, it examined jurisdictions that had implemented feed-in tariff programs[283] to stimulate growth, and jurisdictions in which tariff rate structures were adjusted to encourage particular types of generation.

8.1.1 Ontario

412. Ontario's Feed-in Tariff (FIT) program was launched in 2009 to encourage the development of renewable energy technology, attract investment and create new clean energy jobs in Ontario. Feed-in tariffs refer to the specific prices paid to renewable energy suppliers for the electrical energy produced by the generating facility.[284] The FIT program consists of two streams depending on the nameplate capacity of the project (the FIT and the microFIT programs). The Independent Electricity System Operator (IESO) administers the program. The IESO is required to review the prices offered to generators under the FIT and microFIT programs on an annual basis. The IESO recently concluded its fifth and final round of FIT procurement. The Ontario government directed the IESO to cease accepting applications under the FIT program as of December 31, 2016.

413. Under the FIT program, the price offered to developers is dependent on project size and technology type. Solar rooftop projects consistently receive the highest prices. The original FIT prices for small solar rooftop (less than or equal to10 kW) were as high as 82 cents per kWh.

[283] A "feed-in tariff" (FIT) is a rate per kWh that small-scale energy producers are guaranteed for a fixed period of time. The guaranteed rates are intended to provide small-scale energy producers with enough economic certainty to invest in renewable energy projects. "Feed-in" means that energy produced by these projects will be delivered into the electricity grid. More than forty-five jurisdictions around the world, including Spain, Germany, and Ontario, have established FITs that support small-scale and community ownership. These programs let newcomers participate in the renewable electricity industry, and encourage the development of projects over widely-dispersed rural areas.

[284] Exhibit 22534-X0169 – UCA report, PDF page 25.

FIT prices are currently at 31.1 cents per kWh for projects with a size smaller than 6 kW and 28.8 cents per kWh for projects with a size between 6 kW and 10 kW.[285]

414. Funding for the FIT program is collected in part from Ontario customers through the Global Adjustment charge on their bills. The Global Adjustment is set monthly and reflects the difference between the wholesale market price of electricity and the guaranteed rates paid to generators as well as the costs for conservation and demand management programs, which includes the FIT program.[286]

415. According to the IESO's latest report,[287] the contracted capacity under the FIT program grew from 13 megawatts (MW) in March 2010 to 4,728 MW as of June 2017. The number of contracts associated with this capacity was 3,772. In July 2012, the Ontario government announced the FIT program to be a success regarding the jobs created, investments made in renewable energy, improving air quality and engaging individual Ontarians in the process of developing renewable energy. However, according to a media story of February 24, 2017, the Ontario Energy Minister indicated in a speech that the FIT program resulted in over-manipulation of the province's energy sector and in the removal of competitive incentives for energy producers.[288]

416. Additionally, Ontario's Auditor General examined the government's renewable energy initiatives and provided its findings in its 2015 annual report. The Auditor General found that a lack of system and renewable procurement planning resulted in higher costs to consumers. According to the Auditor General's calculations, Ontario electricity consumers will pay $9.2 billion more for renewable generation over the 20-year FIT contract terms than they would have paid under the previous procurement program for renewable energy.[289]

8.1.2 Nova Scotia

417. The Nova Scotia government implemented the COMFIT program under its 2010 Renewable Electricity Plan, which set a target to achieve 40 per cent renewable energy sources by 2020. COMFIT encouraged community-based renewable energy projects by guaranteeing a rate per kWh for the electrical energy that is delivered into the province's distribution system. The program's design was to broaden ownership of renewable electricity in Nova Scotia and to facilitate community investment in electricity projects. Consequently, the program targeted municipalities, Indigenous groups, co-operatives and non-profit groups. The funding for the COMFIT program was paid for by all ratepayers through their tariffed rates collected by the distribution wire owner.

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285 The Independent Electricity System Operator (IESO) Feed-In Tariff Program. Retrieved from: http://www.ieso.ca/en/sector-participants/feed-in-tariff-program/overview accessed November 2017.

286 The Independent Electricity System Operator (IESO) Global Adjustment Costs. Retrieved from: http://www.ieso.ca/en/learn/electricity-pricing/global-adjustment-costs accessed November 2017.

287 Ontario Independent Electric System Operator A Progress Report on Contracted Electricity Supply, Second Quarter 2017. Retrieved from: http://www.ieso.ca/en/power-data/supply-overview/transmission-connected-generation.

288 See Global News story *Ontario energy minister admits mistake with green energy program,* Retrieved from: https://globalnews.ca/news/3272095/ontario-energy-minister-admits-mistake-with-green-energy-program/ accessed December 10, 2017.

289 See: the Office of the Auditor General of Ontario 2015 Annual Report, Chapter 3.05: Electricity Power System Planning. Retrieved from: http://www.auditor.on.ca/en/content/annualreports/arreports/en15/3.05en15.pdf.

418. The program established a target of 100 MW. There were strict technical requirements at the application stage. For example, only projects connected and serving loads at the distribution level of the electrical system and within the capacity of the existing system were eligible for COMFIT rates. Various technologies such as wind, solar, hydro, tidal and combined heat and power qualified for the program.

419. The COMFIT rates varied depending on the technology and size. Wind-powered generators over 50 kW received the lowest rate of 13.1 cents per kWh while small-scale in-stream tidal projects received the highest rate of 65.2 cents per kWh.

420. By 2015, the province exceeded its target in terms of penetration with 125 MW of renewable generation. Consequently, the government announced a suspension in the processing of applications in order to review the further need for the program.[290] The review found that the COMFIT program had exceeded expectations in economic development in communities and in renewable energy generation. The government subsequently ended the COMFIT program. Nova Scotia's energy minister stated: "This is the right time to bring COMFIT to a close, it has achieved its objectives. We are now at a point where the program could begin to have a negative impact on power rates. Nova Scotians have told us they want stability and affordability when it comes to power rates, and industry wants clarity on the future of the COMFIT program. We are listening."[291] The AUC understands that extending the COMFIT program would have required that the distribution system be expanded to accommodate further renewable energy supply.

421. During the inquiry, the AUC explored with participants the applicability of implementing one aspect of the program for Alberta. Specifically, parties indicated that a critical success factor of the COMFIT program was that Nova Scotia Power Inc. knew the capacity of all the feeder lines and substations in the entire province. A renewable energy supply project could not be deployed in a geographic area unless there was capacity on the feeder to accommodate the project. Participants in this inquiry proposed that the AUC work with the AESO to conduct studies to determine where there is existing capacity on the distribution systems to accommodate DCG projects without having to increase the capacity of the distribution wire owners' feeders.[292] As discussed earlier in Section 5.1.2.2 of the report, these studies would be labour and resource intensive and the recovery of the costs to conduct the studies would have to be collected from Alberta ratepayers.

8.1.3 Germany

422. Germany's *Renewable Energy Sources Act*, or the EEG, promotes energy efficiency, renewable energy sources, and micro-generation. The provisions of the EEG allow renewable energy sources priority interconnection to the grid. Compensation is through a feed-in tariff that provides a fixed tariff to the renewable energy source owner for a 20-year period based on the technology, the year of installation and the size. The majority of the installed capacity is at the distribution system level.

[290] Nova Scotia Department of Energy COMFIT Review January to July 2015. Retrieved from: https://energy.novascotia.ca/sites/default/files/COMFIT%20Review.pdf.

[291] Nova Scotia Department of Energy, – News Release, Minister Announces COMFIT Review Results, August 6, 2015. Retrieved from: https://novascotia.ca/news/release/?id=20150806001.

[292] Exhibit 22534-X0124, CanWEA response to Commission questions, PDF page 5.

423. One quarter of the installed generation capacity in Germany consists of solar PV systems (40 gigawatts as of 2016). This high penetration of intermittent generation has posed grid management challenges and led to negative prices at times because the renewable energy supply cannot be curtailed.[293] Therefore, recently announced reforms to the EEC will eliminate the government-set subsidy for renewable energy, establish an auction process to have competitive forces set the feed-in tariff and require newly installed renewable generation to be equipped with devices that could curtail the delivery of renewable energy onto the electric system.

424. Electricity ratepayers fund the feed-in tariff through a surcharge collected by the transmission system operators. Because not all customers pay this surcharge (heavy electricity users in trade-sensitive areas are partially exempt), the burden is falling on residential ratepayers.[294] According to one news source, the average household spending on electricity is up 50 per cent from 2007 levels.[295]

8.1.4 United States

425. In the United States, many states have experienced exponential growth in distributed solar PV as a result of preferential tariff structures and subsidies. Net metering compensation mechanisms, together with high feed-in tariffs, bundled retail rates, and other preferential terms for DCG have resulted in lucrative revenue streams for distributed solar PV generators that have left other ratepayers who rely on the utility for 100 per cent of their energy needs paying more. Bundled retail rates generally refer to rates charged (or paid to distributed solar PV customers) for electricity that includes both the cost of the electricity itself and the cost of delivering the electricity. In Alberta, retail energy rates are unbundled, whether a customer has an RRO service or a competitive service. In addition to inequitable cost allocation, concerns with the technological feasibility and grid reliability have resulted in efforts across the United States to slow the growth of net metering. Appendix 9, provides a summary of these efforts. Additionally, a brief summary of California's, Nevada's and Hawaii's experience with renewable generation is described below.

California

426. California is one of the states with the largest number of small-scale distribution-connected solar PV producers. Since 2007, the California Public Utilities Commission (CPUC) has sought to integrate demand side energy solutions and technologies through utility program offerings. The CPUC has developed and is continuing to refine a wide range of policies for the development and implementation of distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. The CPUC has also developed a Distributed Energy Resources Action Plan[296] in order to provide a

293 National Renewable Energy Laboratory (NREL), Evolving Distributed Generation Support Mechanisms; Case Studies from United States, Germany, United Kingdom, and Australia; Travis Lowder, Ella Zhou, and Tian Tian, March 2017, PDF page 22. Retrieved from: https://www.nrel.gov/docs/fy17osti/67613.pdf.

294 National Renewable Energy Laboratory (NREL), Evolving Distributed Generation Support Mechanisms; Case Studies from United States, Germany, United Kingdom, and Australia; Travis Lowder, Ella Zhou, and Tian Tian; March 2017, PDF page 22. Retrieved from: https://www.nrel.gov/docs/fy17osti/67613.pdf.

295 Fortune magazine, Germany's High-Priced Energy Revolution, Jeffrey Ball, March 14, 2017. Retrieved from: http://fortune.com/2017/03/14/germany-renewable-clean-energy-solar/.

296 California Public Utilities Commission, California's Distributed Energy Resources Action Plan: Aligning Vision and Action, Discussion Draft: September 29, 2016. Retrieved from:

roadmap for the implementation of those policies and has divided the relevant proceedings or initiatives into three groups: rates and tariffs; distribution grid infrastructure, planning, interconnection and procurement; and wholesale distributed energy resources market integration and interconnection.

427. Increased solar capacity, however, contributes to changes in daily patterns of energy consumption that result in challenges as well as benefits to the power grid. CPUC in its report on the effects of the distribution-connected generation on the distribution system noted that "at sufficiently high penetrations, solar power produces a classic 'duck curve' pattern in daily net load, in which energy consumption dips during peak solar output in the middle of the day and then rises sharply in the early evening. In the winter and spring, this can result in over-supply of power in the middle of the day and require large amounts of fast-acting resources (such as gas plants, batteries, or demand response) to ramp up quickly as the sun sets and solar power production drops."[297] One way that the California Independent System Operator (CAISO) is currently working towards integrating and managing such large amounts of solar generation is through the Western Energy Imbalance program[298] with neighboring Independent System Operators from five active western states and six other prospective states to enter the program by 2020, including southern British Colombia.

428. Also, CAISO is working with the CPUC and the utilities in the state to address one of the challenges of the increased distribution-connected generation in order for the CAISO to have more visibility between transmission and distribution grids.

429. Regarding the cost of distribution-connected solar PV, the UCA report[299] noted that "in August of 2015, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) filed proposals with the CPUC to reduce the economic value of customer solar systems under current net-metering compensation rules. In December of 2015, the CPUC issued a proposed decision to preserve the net metering remuneration program and recommended adjustments including a one-time interconnection fee, adding new non by-passable charges, and implementing time-of-use rates to net-metering customers."

Nevada

430. The state of Nevada is an example of where its public utilities commission is taking steps to overhaul its net metering policies in response to disproportionate contributions by various ratepayers to the recovery of distribution system costs. In December 2015, the Nevada Public Utilities Commission (NPUC) ordered that the amount of compensation offered to homeowners and businesses using rooftop solar (NEM or net metered customers) be reduced and imposed heavy charges on them for their use of the electricity grid.

http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/2016-09-26%20DER%20Action%20Plan%20FINAL3.pdf.

297 California Public Utilities Commission, Impacts of Distributed Energy Generation on the State's Distribution and Transmission Grid, In Compliance with Public Utilities Code 913.10, January 1, 2016, Retrieved from: file:///D:/Legislative%20Report%20on%20Impacts%20of%20Distributed%20Energy%20Generation%20Submitted....pdf.

298 Western Energy Imbalance Market, Initiatives. Retrieved from: https://www.westerneim.com/Pages/Initiatives/default.aspx.

299 Exhibit 22534- X0169, UCA Report, PDF page 29.

431. In 2015, a marginal cost of service study considered by the NPUC found that solar users (NEM) were being subsidized by non-NEM customers by between $471 and $623 per customer, per year. In response, Nevada essentially moved from a net metering to a net billing scheme whereby NEM customers would begin paying an increased basic service charge for fixed costs of meeting solar customers' needs, higher than what other retail, non-NEM customers pay. Also, under a new volumetric rate for energy, the NEM customer is no longer paid the fully bundled energy rate (e.g. including delivery costs) but is now paid only the current energy market rate (i.e., the same way that Alberta currently does).

432. These changes substantially reduced compensation (and thus the subsidization) to Nevada's NEM customers to the tune of 80 per cent. For instance, prior to 2016, NEM customers in NV Energy's northern service territory would have paid a $12.75 per month basic service charge and just over 11 cents per kWh for electricity. They would also receive 11 cents for every kWh of electricity they sent back to the grid. By the time the NPUC's order takes full effect in 2028, however, the same customer will pay a $38.51 per month basic service charge and roughly ten cents per kWh for electricity. When that customer sends power back to the grid, they will receive only two cents per kWh in compensation. In the interim to when the new pricing policy would take full effect (it is being phased in over several years) the NPUC ordered the wire owner to include a line item on every customer's bill for the amount of the "NET ENERGY METERING SUBSIDY" they pay each month to draw attention to NEM customers.

433. In the United States, 41 states plus the District of Columbia currently use some version of net metering. However, the shape of these laws is beginning to change as 10 of these states now require that the distribution-connected generator be paid for the electricity it puts in the system at a level lower than the full bundled energy rate. These numbers do not include Nevada, which has moved away entirely from traditional NEM in order to rectify inefficient and unfair subsidies in the form of net metering tariff structures.[300]

Hawaii

434. Like Nevada, Hawaii also recently ceased its traditional net metering tariff design in 2016, replacing NEM with a different rate structure. Exponential growth in distribution-connected solar PV installations exceeded distribution wire owners' ability to manage interconnections and costs as demand increased and created a boom cycle for installers. However, interconnection approvals slowed due to safety, reliability, and operational concerns on the distribution system.[301]

435. The increased growth in residential solar PV raised concerns about grid stability for distribution wire owners because of the high level of DCG being fed into the system during peak sunlight hours. Although it was recognized that the problem of grid stability could be resolved technically, the distribution systems required significant updates to their existing technology. Consequently, in 2014, the Hawaii Public Utility Commission ordered the distribution wire

[300] Science Direct, Lincoln L. Davies and Sanya Carley, Emerging shadows in national solar policy? Nevada's net metering transition in context, 2017. Retrieved from: http://www.sciencedirect.com/science/article/pii/S1040619016301762#.

[301] Hawaii Public Utilities Commission, Advancing Renewables: Lessons Learned in Hawaii presentation for the US Energy Information Administration 2016, Retrieved from : https://www.eia.gov/conference/2016/pdf/presentations/gorak.pdf.

owners to provide DCG interconnection plans in order to support further developments of renewable distribution-connected PV solar.[302]

436. The Hawaiian Electric Companies (HECO) released a plan to mitigate a range of technical issues (e.g., improvements to inverters, circuits, and meters) and to allow for the further growth of distribution-connected solar PV. However, the utilities' plan also included a fixed standby charge and a decrease in the payment to customers for net excess generation, that is, generation above the level consumed by the building. In 2015, HECO released its "DG 2.0" implementation plan that would pay net excess generation at the wholesale rate but would also allow HECO to connect more distribution-connected solar PV.[303]

437. In Hawaii, residential solar PV customers can now choose from one of two options: 1) a self-supply option in which customers earn retail rate credits for aligning their electricity consumption with actual solar generation but receive no compensation for any energy that is sent to the grid, or 2) a grid-supply option that is a net billing scheme crediting solar PV customers at the utility's avoided cost of 15 to 28 cents per kWh. Previously NEM customers would have been paid at the average retail rate of 38 cents per kWh which included the recovery of fixed costs of the delivery system. Under either option, residential solar PV customers who stay connected to the grid will now pay a minimum bill each month of $25.[304] Under the old system, because the solar PV customers did not incur those costs, they should not have been paid as though they had incurred those delivery costs. In addition, because the wire owner had been paying these higher rates to the solar PV operators, non-NEM customers were effectively paying for those costs through higher rates.

8.2 Education

438. Many participants stated the need for a program to educate consumers, landowners, and others (e.g., DCG service providers, ancillary service providers, municipality staff) on the obligations, technical requirements, performance expectations and the costs associated with DCG.

439. At the residential customer level, participants believed the education should be about understanding the billing process (i.e., what charges can be avoided by installing DCG), billing information (what is on the bill and why) and the application and interconnection processes for installing DCG.

440. Howell Mayhew was one such participant stating the need for greater education programs to remove information barriers and to engage Albertans about DCG. Howell Mayhew summarized the education aspect as consisting of four components: awareness of solar PV, education about how to get engaged in adopting solar PV, capacity development training to

[302] Science Direct, David J. Hess, The politics of niche-regime conflicts: Distributed solar energy in the United States, 2016. Retrieved from: https://www.sciencedirect.com/science/article/pii/S2210422415300174#.
[303] Science Direct, David J. Hess, The politics of niche-regime conflicts: Distributed solar energy in the United States, 2016. Retrieved from: https://www.sciencedirect.com/science/article/pii/S2210422415300174#.
[304] Science Direct, Lincoln L. Davies and Sanya Carley, Emerging shadows in national solar policy? Nevada's net metering transition in context, 2017. Retrieved from: http://www.sciencedirect.com/science/article/pii/S1040619016301762#.

ensure there are enough properly trained installers and sales people and demonstration projects so that people can see how solar PV might work. This is more fully described in the transcript.[305]

441. Howell Mayhew mentioned that he maintains 12 Facebook groups to help DCG customers with their understanding of their electricity bills and the purpose for each line item on the bill, especially the fixed costs. Howell Mayhew stated that once DCG customers understood the services being provided by distribution wire owners (i.e., instantaneous and uninterrupted delivery of electrical energy, interconnection to the distribution system's voltage to enable the operation of the consumer's DCG unit), DCG customers became accepting of the charges.

442. SkyFire also stated the importance of educating consumers about DCG. According to SkyFire, when informed consumers understand the billing components of their electricity bill and the purpose for these billing components, it makes it easier for these consumers to recognize the benefits of their own DCG projects.

443. As noted in subsection 5.3.2 of this report, Pembina recommended that energy efficiency-related and carbon intensity-related information be included on a consumer's bill, and that the presentation of this information be standardized. During the oral portion of the inquiry, Pembina agreed there were other means (e.g., online) to provide their recommended information to consumers. However, the intent of having access to this information was to increase the "energy literacy" of consumers, so that more informed choices and actions could be taken by these consumers regarding energy usage. SkyFire also suggested that a consumer's bill provide DCG-related information (i.e., gross and net generation) for transparency and clarity purposes.

444. Energy Efficiency Alberta is one entity with an educational mandate to raise awareness among consumers of energy use and to promote, design, and deliver programs and carry out other related activities to support energy efficiency, energy conservation, and the development of micro-generation as well as community generation in Alberta. For example, Energy Efficiency Alberta stated that it is working with distribution wire owners to coordinate its grant application process with the distribution wire owners' connection processes. The purpose is to make it easier for consumers to access the funds to subsidize their projects.[306]

445. The AESO stated that in some instances distribution-connected generators are unaware of their obligation to register as a pool participant when their DCG projects have an operational effect on the transmission system or when the generation output of these projects will be delivered to the power pool. This obligation can arise regardless of the size of the DCG project. The AESO stated that a timelier notification from a prospective distribution-connected generator, in advance of a connection application, could ensure that the necessary capacity and cost review is conducted within the expected timelines of the distribution-connected generator. AFREA also considered it important that participants involved in the interconnection process be fully aware of the costs to connect DCG.

446. Some DEC members suggested "more specific training on life-cycle environmental footprints (GHGs, CACs, toxics, water) and energy efficiency for industrial and commercial systems including CHP and fuel cells. Education and awareness of energy reliability, diversity,

305 Transcripts, Volume 8, page 1271, PDF page 168.
306 Transcripts, Volume 7, pages 1007-1008, PDF pages 27-28.

resilience and lower transmission and distribution losses are key in understanding and appreciating its benefits and how the help create a business case for DCG."[307]

447. The UCA stated that the development of any new DCG policy and programs must consider educational awareness for vulnerable Albertans to enable this group to know the various options available for participating in the DCG program.

8.3 Planning

448. In this inquiry, the AUC heard about the need to plan for the integration of more DCG using the existing capacity of the distribution system and for adding more capacity when it may be required. The discussion regarding the planning with existing capacity is found in Section 5.2.2 of this report. This section discusses the planning that will be required when more capacity is needed. Many participants identified the need for a coordinated and inclusive approach to planning as a key success factor for the integration of additional DCG to the electric system. Participants used adjectives such as "practical", "effective", "proactive", "thoughtful", "clear", "measured", "staged", "comprehensive", and "transparent" to describe the approach that should be taken to the deployment of further DCG in Alberta.

449. AltaLink stated that a policy and plan should be developed using a comprehensive, transparent and well-understood cost-benefit framework that considers both the transmission and distribution systems and makes use of the existing infrastructure. AltaLink supported a regulatory approach that establishes common practices and requirements for distribution wire owners in planning their distribution system development and involves the AESO with defining the requirements for the planning framework to ensure that the distribution system plan can be optimized from an integrated perspective. Otherwise, according to AltaLink, limiting the planning to the distribution system only, would result in less efficient and more costly solutions for Albertans. As an example, AltaLink stated that the most cost-effective investment in community generation is currently at the transmission system level, "as it can achieve GHG reductions at approximately 50% of the cost of small scale renewables."[308]

450. AltaLink further stated that the plan should have a time horizon of five to ten years and contemplate integrating DCG through a staged approach because of the uncertainties regarding the performance of renewable DCG at higher penetration levels. As the distribution wire owners gain experience with operating their systems at higher penetration levels, the pace and scale of DCG development could be adjusted to minimize the cost to customers.

451. Finally, AltaLink suggested that the distribution wire owners, transmission facility owners and the AESO conduct a coordinated study to identify the technical and operational challenges and solutions associated with greater penetration of DCG, including the cost implications to customers.

452. Distribution wire owners stated a planned approach would be required to integrate DCG and to continue to serve customers in a safe, reliable and cost-effective manner. ATCO Electric[309] stated that investments in the technologies mentioned in Section 7 of this report would

307 Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF page 7.
308 Exhibit 22534-X0109, AltaLink responses to Commission questions, PDF page 3.
309 Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 21.

be needed eventually to accommodate the increase in DCG. Advanced planning using DCG penetration forecasts will be required to determine the timing of each investment throughout the distribution system.

453. ENMAX[310] stated that stakeholders should have the opportunity to participate in the development of the processes that will be required to accommodate a significant increase in the volume of DCG while ensuring that distribution wire owners continue to provide the safe, reliable and economic distribution service that Albertans require.

454. ENMAX also stated that an investment in advanced metering infrastructure (AMI) technology prior to the introduction of an increasing amount of DCG would provide enhanced visibility and control of DCG, provide a better understanding of the operation of DCG and enable the optimized planning and operation of the distribution system.

455. EPCOR[311] agreed with DCG proponents who suggested that a lack of visibility into existing distribution system capacity is a major barrier to DCG growth. EPCOR stated that more detailed information about existing and planned system capacity could help distribution-connected generators identify suitable locations for projects that avoid large interconnection costs. To this end, EPCOR is undertaking a detailed capacity study of a segment of its distribution system to provide more visibility.

456. FortisAlberta[312] likewise stated that capacity information will be necessary to effectively integrate DCG because it would help distribution-connected generators identify locations where the costs to interconnect their projects are likely to be lower. Investments in DCG-specific technologies such as ADMS and DERMS would also prepare FortisAlberta in accommodating DCG in an efficient manner.

457. Other participants also stated the need for advanced planning and analysis to optimize the timing of system improvements and the introduction of protection and control schemes.

458. AFREA[313] stated that the establishment of guiding principles and a practical planning process could enable the achievement of the 30-30 target.

459. CanSIA[314] stated that an annual planning process, similar to the approach undertaken by distribution wire owners to assess load growth and future investments, provides the opportunity for the distribution wire owners and distribution-connected generators to identify the segments of the system where DCG could be integrated at the least cost for the generators and ratepayers. The planning process should incorporate a cost-benefit analysis and a multiple-year planning horizon to determine the optimal investment required. A multiple-year horizon would also ensure that the pace and scale of the distribution system investments are aligned with the growth in DCG, i.e., made through a considerate analysis and not in a reactionary manner.

[310] Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 2.
[311] Exhibit 22534-X0182, EPCOR responses to Commission questions, PDF page 4.
[312] Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 3.
[313] Exhibit 22534-X0283, AFREA responses to Commission questions, PDF page 3.
[314] Exhibit 22534-X0133, CanSIA responses to Commission questions, pages 3-4 (Word document).

460. CanWEA[315] stated that any planning done by the distribution wire owners to accommodate DCG should engage distribution-connected generators in the process. According to CanWEA, stakeholder involvement is critical to ensure that the distribution system investments are considering the activities of distribution-connected generators and are aligning with the geographical locations of DCG development. This planning and engagement process is especially required for distribution wire owners serving in the rural areas of Alberta.

461. The UCA[316] stated any investments in the distribution systems to accommodate DCG should be in response to the demand by distribution-connected generators for service and not necessarily in anticipation of that demand. In addition, the distribution wire owners should be aware of the AESO's planning activities and the government's policy initiatives regarding alternative and renewable energy development. Consequently, the distribution wire owners should develop a clear plan indicating how they intend to integrate DCG and the investments required to accommodate the DCG growth. The UCA suggested this plan be a reporting requirement of the AUC and be subject to scrutiny.

462. The CCA[317] stated that an approach to minimize any unnecessary or imprudent upgrades would be to have the system plan of the distribution wire owners come under the review of the AUC or in coordination with an entity tasked with the distribution system control similar to the AESO at the transmission level. This system plan should include the results of capacity studies conducted to determine the investments required to accommodate DCG growth, and the expected pace of the investments.

463. Teric[318] stated that the planning and development of the distribution system should consider all forms of DCG, not only alternative and renewable DCG.

8.4 Community generation and other green energy service models

464. As part of the OIC, the government expressed an interest "in the current and potential opportunities to enable and facilitate the development of … micro- and small-scale community generation, throughout Alberta." For the purposes of this report, the AUC will simply refer to micro- and small-scale community generation as "community generation."

465. The AUC invited submissions from participants to provide their vision of community generation, including how or whether it should be defined and how community generation can continue to develop. Additionally, the AUC also considered the availability of "green energy products" as part of its community review.

8.4.1 Community Generation

466. Three questions arose from the AUC's examination of community generation: (1) Should "community" be defined? (2) How can the most flexibility be provided so that the form of potential communities is not restricted?, and (3) Are micro-grids necessary for the continued growth in community generation?

315 Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 2.
316 Exhibit 22534-X0106, UCA responses to Commission questions, PDF page 8.
317 Exhibit 22534-X0200, CCA responses to Commission questions, PDF page 5.
318 Exhibit 22534-X0098, Teric Power Ltd.'s responses to Commission questions, PDF page 29.

8.4.1.1 Should "community" be defined?

467. There is no commonly accepted definition of "community" as applied to community generation. Because there is no definition, there are no provisions that limit who or what can be considered a "community," or that restrict the amount of electrical energy a "community" can generate.

468. However, the absence of a definition does not preclude a community entity from taking an ownership and/or operational interest in community-owned generation for serving the energy supply needs of its residents. As stated by ATCO Electric:

> It is important to note that the ability for residential and commercial customers to invest in a larger renewable energy development already exists under the current regulatory framework and has existed since the implementation of customer choice under the EUA in 2001. A variety of commercial and retail mechanisms are available to consumers to participate in renewable energy and some of these are already well established in areas such as green energy contracts for consumers.[319]

469. Notwithstanding, the AUC asked participants to provide their definition of "community generation" in order to ascertain whether a commonly-held view existed. Unsurprisingly, no common definition was unearthed. Further, participants could not agree whether a definition was necessary.

470. Some participants encouraged the development of a clear definition of community generation so that guidelines for its integration into the grid could be established. This, it was suggested, would provide clarity regarding responsibilities and obligations and would ensure safe, reliable and efficient service from the distribution system.

471. Examples of some of the definitions that were suggested were as follows:

- "Small-scale community generation projects to include up to 5 MW of distribution connected systems with a significant portion of the ownership being from local individuals, businesses, REAs or co-operative members."[320]
- "Distributed generation for the sole use and benefit of a local community."[321]
- "Small-scale community generation is local renewable, alternative and lower emitting energy projects that are developed by public sector organizations. These projects are connected to the grid at the distribution level, and serve to offset the energy requirements of the community."[322]
- "Small-scale community generation operations would entail community entities having an ownership or operational interest in generation, either onsite and/or offsite, for the main purposes of managing energy supply for its community sites, which could include utilizing renewable energy solutions, selling surplus

[319] Exhibit 22534-X0115, at ATCO Electric responses to Commission questions, PDF page 8079. FortisAlberta agreed. See Exhibit 22534-X0105, PDF page 86.
[320] Exhibit 22534-X0113, Skyfire responses to Commission questions, PDF page 22.
[321] Exhibit 22534-X0143, Lethbridge responses to Commission questions, PDF page 43.
[322] Exhibit 22534-X0115, ATCO Electric responses to Commission questions, PDF page 79.

generation to the electrical grid and/or optimizing energy costs for its community's retail customers as a whole."[323]

- "Small-scale community generation could be anything from individual rooftop solar generation to natural-gas-fired combined heat and power systems sized for an entire town or community (5-10 MW), to combined solar/diesel generation for remote communities."[324]

472. Other participants were opposed to defining community generation.[325] It was argued that community generation operations may look different in different municipalities, as their design would be inextricably linked to municipal development. Standardization of the definition would only result in limiting its potential.[326] Lion's Tooth Solutions suggested that a rigid definition, other than potentially restricting size, or limiting to the offset of residential loads, would potentially limit the development of future technologies that have yet to be considered.[327] The cities of Lethbridge and Red Deer asserted that incentives to invest and innovate would be limited if the definition of community generation is artificially constrained.[328]

473. Rather than attempting to define community generation, many participants provided considerations or principles that they believed should apply to the concept of community generation. As with attempting to provide a definition, there was also no consensus regarding what these considerations or principles should be. While not exhaustive, some of the principles included:

- Albertans from all regions and economic means should be able to participate in some ownership aspect of Alberta's renewable energy opportunity to hedge price increases in power and benefit in the transition to a lower carbon economy.[329]
- The number of respective individual or business owners of DCG in a community should be limited to encourage diverse and mixed ownership and investment opportunities.[330] Limitations suggested included "a requirement that at least 50% of the subscriber (community member) accounts are residential" or "the community has at least 3 subscribers and that no one subscriber has a proportionate share of energy credit that exceeds 40%" or that "commercial and/or residential entities jointly invest in a portion of a shared solar [project] through a special purpose entity and receive a credit on their electric bills proportional to their contribution (percentage of kWh)."[331]
- Allowing for the participation of individuals or communities through direct ownership interest; community generation participation could occur through a

323 Exhibit 22534-X0105, FortisAlberta responses to Commission questions, PDF page 86.
324 Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF page 30.
325 Exhibit 22534-X0153, Alberta Municipal Power Systems responses to Commission questions, PDF page 10; Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF page 30; Exhibit 22534-X0143, the cities of Lethbridge and Red Deer responses to Commission questions, PDF page 43.
326 Exhibit 22534-X0153, Alberta Municipal Power Systems responses to Commission questions, PDF page 10
327 Exhibit 22534-X0111, Lion's Tooth Solutions responses to Commission questions, PDF page 30.
328 Exhibit 22534-X0143, the cities of Lethbridge and Red Deer responses to Commission questions, PDF page 43.
329 Exhibit 22534-X0100, Decentralised Energy Canada responses to Commission questions, PDF page 13.
330 Exhibit 22534-X0113, SkyFire responses to Commission questions, PDF page 22. Exhibit 22534- X0103, AMP Solar Group responses to Commission questions, PDF page 15.
331 Exhibit 22534-X0103, AMP Solar Group responses to Commission questions, PDF page 15.

financial arrangement such as the purchase of the output of the community generator.[332]

- Allowing communities to determine the size of their equity or level of involvement, if they have any involvement at all. The community should have the flexibility to determine its own ownership stake.[333]
- Irrigation districts, as defined under the *Irrigation Districts Act*, should be included in any policies or programs that are developed in support of community generation.[334]
- The threshold should be above the micro-generation threshold.[335]
- Using it to (i) enable energy in a remote location without interconnection to the AIES; (ii) a residential subdivision located within an existing distribution service territory as an alternative to traditional utility service; or (iii) a third-party aggregator[336] who produces and sells energy directly to consumers or distribution utilities as grid support.[337]
- Limiting it only by the access to distribution connections where the project is located.[338] [339]
- Not running it as a peer-to-peer mini system (i.e., operate as a micro-grid) and using the incumbent distribution wire owner's network to transfer energy and pay their fair share of costs.[340]
- Not cross subsidizing through mechanisms such as net metering as such a mechanism would result in sub-optimal development and inequity among customers.[341]

Overall, it was suggested that community generation operations could come in various forms, and that a definition might limit the possible arrangements. For example, community members may enter into financial arrangements to purchase renewable or alternative generation. Alternatively, it could involve the physical connection of multiple sites to a DCG source. Participants mentioned the Bull Creek Wind Project,[342] the Drake Landing project in Okotoks[343] and the provision for conditional aggregated sites[344] in the revised *Micro-generation Regulation* as examples of community generation arrangements currently in place. AltaLink also provided

332 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF pages 32-33.
333 Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 13.
334 Exhibit 22534-X0163, Alberta Irrigation Projects Association responses to Commission questions, PDF page 12.
335 Exhibit 22534-X0155, Direct Energy Regulated Services responses to Commission questions, PDF page 10.
336 An aggregator is an entity that organizes retail customers into a group so that an individual customer can take advantage of economies of scale, or be provided with better services than acting independently.
337 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF page 65.
338 Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 13.
339 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 33.
340 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 33.
341 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 33.
342 Exhibit 22534-X0145, BluEarth evidence, PDF page 2.
343 Exhibit 22534-X0106, UCA responses to Commission questions, PDF page 22.
344 See Section 1(1)(a.1) of the *Micro-generation Regulation.*

an example of 20 MW solar farms in the United States that could be community generators, allowing all levels of participation across the socio-economic spectrum.[345]

474. As stated by Howell Mayhew:

> Defining something puts it in a box, which may limit it. And I've always said that about [solar] PV and regulations. Don't put [solar] PV in a box or be very, very careful about putting [solar] PV in a box because I bet I can -- I and my colleagues in the industry can come along and show you perfectly fantastic examples, valid examples of [solar] PV that would blow the doors off your box that you didn't know about because you don't know the industry.
>
> So I would suggest that's similar with community energy generation in however it's going to be set up.[346]

8.4.1.2 How can the most flexibility be provided so that the form of potential communities is not restricted?

475. Even participants who encouraged the development of a definition for community generation emphasized that any definition should not inhibit, or act as a barrier to, the development of small-scale community generation.[347] CanWEA stated flexibility leads to more choice with less risk, less liability and lower costs for participating communities. Overall, fewer prescriptive requirements result in broader participation and lower costs. As well, flexibility puts the onus on the proponent to ensure optimal performance and to assume all development risk. Flexibility is also expected to result in the creation of new financing options for proponents, which will drive down overall costs for communities and consumers.[348]

476. While the ability to partake in community generation exists, it was suggested that if a formal community generation program is adopted in Alberta, it would lead to increased investment in the short term in DCG. However, without the ability for these community investors to partner with experienced power generation developers and utilities, long-term success may not be possible. Support from experienced developers would also potentially lead to more diverse implementation and investment in more innovative technologies.[349] Bullfrog Power[350] cited examples of solar projects moving beyond ground-mount systems in rural areas to encompass brownfield lands, carports, regional train stations and other areas where distributed and renewable resources have not traditionally been applied.

477. It was almost universally stated that there should not be a requirement for the site of the generation and the sites of the participants in a community generation operation to be “adjacent” as that term is used in the *Micro-generation Regulation*. Some participants noted that if community generation were structured as a financial arrangement (i.e., an accounting allocation of generation output and credits) and not as a physical arrangement (i.e., generation output connected to participants through a micro-grid), then location would not matter.

345 Exhibit 22534-X0107, AltaLink responses to Commission questions, PDF page 32.
346 Transcripts, Volume. 8, page 1259, at PDF page 156.
347 Exhibit 22534-X0119, EQUS responses to Commission questions, PDF page 30.
348 Exhibit 22534-X0124, CanWEA responses to Commission questions, PDF page 13.
349 Exhibit 22534-X0112, ATCO Power responses to Commission questions, PDF page 24.
350 Exhibit 22534-X0093, Bullfrog Power responses to Commission questions, PDF page 5.

478. Participants noted that an "adjacent" requirement would inhibit the evolution of small-scale community generation. For example, Alberta Irrigation Projects Association[351] stated that for irrigation purposes, the ideal locations for generation would be on less productive land while the ideal locations for pumps would be on highly productive land and these two locations are usually some distance apart. Access to the distribution system would be needed to deliver the electrical energy produced by the community generation project to the respective loads. Therefore, flexibility is needed in the definition of the word "adjacent" to promote the development of community generation.

479. It was also suggested that a community or homeowner's association could conceivably own distributed generation that is physically located on a separate property, or small-scale community generation could operate like a co-operative, where citizens may opt to hold shares in the co-operative. The generator need not be directly adjacent to the shareholders. It was stated that this model has been implemented successfully in other jurisdictions.

480. Should a small-scale community generation program be contemplated in the future, a number of suggestions were made regarding its development. These suggestions were: that a boundary be set, such as a maximum distance; that generators and loads be served by the same point of delivery (POD); that generators and loads be within the same service territories; and that a maximum generation output should be set.

481. The AESO added that regardless of whether the property of participants in a small-scale community generation operation is adjacent, participants would need to meet all applicable technical requirements, including Measurement Canada's metering requirements.[352]

8.4.1.3 Are Micro-grids necessary for continued growth in DCG?

482. A micro-grid is a local energy network in which the electrical energy generated by multiple distributed energy resources is delivered using a non-utility owned electrical distribution system to a multiple load centre site located within the energy network. Examples of multiple load centre sites are university campuses, industrial parks and hospitals. In addition to renewable energy sources, the micro-grid's distributed energy resources could include combined heat and power plants and energy storage devices. Micro-grids differ from DCG and community generation, in that they can be operated off-grid and are meant to be operated as a single, controllable entity.

483. Micro-grids provide energy in real-time to nearby small groups of customers, and allow supply to match demand. Although this technology can be expensive, it can increase capacity without the need for large transmission investments, and its flexibility can compensate for the economies of scale benefits provided by traditional systems.[353] For example, FortisAlberta stated that micro-grids may be cost-effective when used to supply electricity to remote communities with no transmission and distribution systems nearby. Micro-grids also have the following applications: to supplement a distribution system in areas with frequent outages; to allow an

[351] Exhibit 22534-X0163, Alberta Irrigation Projects Association responses to Commission questions, PDF pages 12-13.

[352] Exhibit 22534-X0130, AESO responses to Commission questions, PDF page 244.

[353] *Program on Technology Innovation: Microgrid Implementations: Literature Review.* EPRI, Palo. Alto, CA: 2016. 3002007384.

entity, for example a campus, to manage resources and lower costs through distributed generation, while still connected to the grid; and to displace high fuel (diesel) costs in remote communities.[354]

484. Alberta legislation already allows for the operation of micro-grids in specific circumstances. An example is the designation of an electric system as an industrial system (ISD) in Alberta. The ISD involves the production of electrical energy to supply the associated components and facilities of an integrated industrial process. The AUC approves requests for ISDs under the provisions in the *Hydro and Electric Energy Act*.

485. While the distribution wire owners supported the concept of community generation, they did not support the unrestricted use of micro-grids within the service area of a distribution wire owner. According to EPCOR, allowing small and potentially unregulated owners of micro-grids to operate within the service area of an existing distribution wire owner "would be a drastic, unprincipled step that would be contrary to the public interest" and is likely to create significant diseconomies of scale and introduce reliability and safety risks.[355]

486. EPCOR suggested that rather than a micro-grid, the community could function as a type of aggregator, which some communities already do, to manage the load and generation of its members. Functioning as an aggregator would enable the community to continue to take advantage of the reliability of the distribution system while preserving the right of choice for its members, and would avoid the many problems associated with operating and integrating an independent small-scale distribution utility.

487. ENMAX stated that depending on how community generation is structured, changes to legislation, including Section 45 of *Municipal Government Act*, sections 101 and 119 of the *Electric Utilities Act*, and Section 25 of the *Hydro and Electric Energy Act*, might be needed.[356]

488. The configuration of a micro-grid could also be complicated by a mix of customers that use the micro-grid and customers that use the incumbent utility service. The UCA took the position that all customers should have the option to receive their electricity services from the incumbent rather than the community-scale generator.[357] It stated it was important that 100 per cent participation by community members in community generation should not be required as this may hamper the viability and economic feasibility of the projects. The CCA submitted that the concept of a micro-grid with "back up supply from the utility should not be entertained at this time given the significant investment in T&D [transmission and distribution] facilities in Alberta and the risk of stranded investments arising from customer defections primarily to avoid T&D charges."[358]

354 Program on Technology Innovation: Microgrid Implementations: Literature Review. EPRI, Palo Alto, CA: 2016. 3002007384.

355 Exhibit 22534-X0144, EPCOR, responses to Commission questions, PDF page 79.

356 Exhibit 22534-X0123, ENMAX responses to Commission questions, PDF pages 68-71.

357 Exhibit 22534-X0106, UCA, responses to Commission questions, PDF page 23.

358 Exhibit 22534-X0161, CCA responses to Commission questions, PDF page 16.

8.4.2 Green energy products

489. As discussed in subsection 3.3.4.28.4.1, customers have the ability to participate in renewable energy generation programs through services offered by retailers offering green energy products. These retailers in Alberta include Alberta Co-operative Energy, Bullfrog Power Inc., ENMAX Energy Corporation, Just Energy Alberta L.P. or any of the retailers operated by Utility Network & Partners Inc. When customers enroll in one of these programs, electrical energy will be procured from a certified green energy source or carbon credits will be purchased. The intent of the program is to displace the amount of electrical energy that otherwise would be produced from a fossil fuel-based generating plant. In the case of all retailers except Bullfrog Power, the program complements their existing competitive retail services. Bullfrog Power's program is available to customers on the RRO rate as well as on a competitive rate, as they separately invoice customers who subscribe to their program. Moreover, an Albertan's choice to purchase one of these green energy products is a way to participate in initiatives that help reduce greenhouse gas emissions and move Alberta towards its 30-30 target.

9 Cost-benefit analysis

490. In the OIC, the government raised the issue of a cost-benefit analysis:

> 1. The AUC shall inquire into the following matters for the purpose of gathering information:
>
> (d) methods for assessing costs and benefits of infrastructure investments that may enable and facilitate broader deployment of alternative and renewable distribution connected generation and efficient energy use; including but not be limited to:
>
> **(i)** billing and settlement systems,
>
> **(ii)** smart meters,
>
> **(iii)** energy storage,
>
> **(iv)** demand response,
>
> **(v)** rate impacts to consumers, and
>
> **(vi)** the potential for stranded infrastructure;
>
> […]
>
> 4. The AUC's report:
>
> **(a)** must not make recommendations but shall, through its analysis of the evidence on the record of the inquiry and review, provide findings and costs and benefits on various issues as it deems appropriate,
> […]

491. The AUC asked registered participants to describe the methodology that should be used to analyze the costs and benefits of infrastructure investments to support distribution-connected generation (DCG) in the context contained in the terms of reference.

492. The AUC did not receive specific suggestions from participants, although some believed the methodology for assessing the costs and benefits as described in the AUC's January 2011 Smart Grid report could be used for DCG infrastructure investment. Others provided the AUC with DCG-related studies from other jurisdictions that dealt with the technical requirements for DCG deployment and other potential technical requirements.

493. The OIC asks for the methods of assessing the costs and benefits of infrastructure investments. In the simplest of terms, the costs would be the costs that would not otherwise have to be incurred except for the deployment of DCG. Changes in the costs listed in the OIC that are attributed to DCG infrastructure investment should be included in a cost benefit analysis. However, there are two types of costs that are not specifically included in the OIC that should be included and that could be significant. These are the potential costs for upgrades to make the distribution system capable of accommodating two-way electricity flows and the changes necessary to ensure that the system can adapt to the intermittency of the energy produced by solar, wind, and potentially other forms of renewable energy.

494. There are two principal benefits to the roll-out of DCG. The first is the deferral of capacity upgrades on the system, in particular on the transmission system. The second is the benefit of a reduction in carbon emissions.

495. The AUC heard that in Alberta there will be few if any benefits associated with the curtailment of transmission expansion. The backbone transmission system in Alberta has already been built to accommodate growth for many years to come. The roll-out of DCG does not eliminate the costs already incurred and therefore does not reduce rates paid by customers for the transmission system. While there might be some local, lower voltage transmission costs that might be deferred, few participants drew the AUC's attention to those types of costs and certainly no one had any cost estimates of the deferred costs that might be realized. Parties recognized that the value of deferred capacity costs on the transmission system in Alberta would be minimal.

496. Regarding the other potential benefit from DCG, the reduction in carbon emissions, in order to incorporate this benefit into a cost benefit analysis, it would be necessary to have a value for the reduction in carbon emissions made possible by DCG. This would require estimating how much carbon emissions would be offset by DCG as well as the value of that reduction. In the absence of a market price for carbon, it would be necessary for the government to determine a value to use in a cost benefit analysis.

497. As the AUC has noted, there is no immediate need to expand the capacity of the distribution systems in order to accommodate DCG. However, as more DCG is deployed and distribution systems approach the time that capacity and other costs might need to be incurred to accommodate that growth, a number of issues arise. The AUC has already addressed the different views of parties on the cost responsibility for distribution system upgrades. Here, the AUC discusses the geographic scope of a cost benefit analysis.

498. While some participants seemed to contemplate a province-wide cost benefit study, participants did acknowledge that such a study would be difficult to perform and that the data necessary for such a study are not available. Furthermore, other participants pointed out that a province-wide cost benefit study would not usefully measure the costs and benefits of DCG infrastructure investment because some parts of the distribution system can accommodate increased DCG while other parts of the distribution system may be less able to do so. Participants were generally in agreement that cost benefit studies should be carried out by the distribution wire owners for their own distribution systems, recognizing that there will be parts of the current distribution systems that may need no capacity upgrades while others might.

499. AltaLink raised concerns about focusing cost benefit analyses on the distribution systems only. According to AltaLink, limiting the planning to the distribution systems only would result in less efficient and more costly solutions for Albertans. As an example, AltaLink stated that the most cost-effective investment in community generation is at the transmission system level, "as it can achieve GHG [greenhouse gas emission] reductions at approximately 50% of the cost of small scale renewables."[359]

500. The AUC recognizes that the approach recommended by AltaLink could benefit electricity customers in the province.

[359] Exhibit 22534-X0109, AltaLink evidence, PDF page 3.

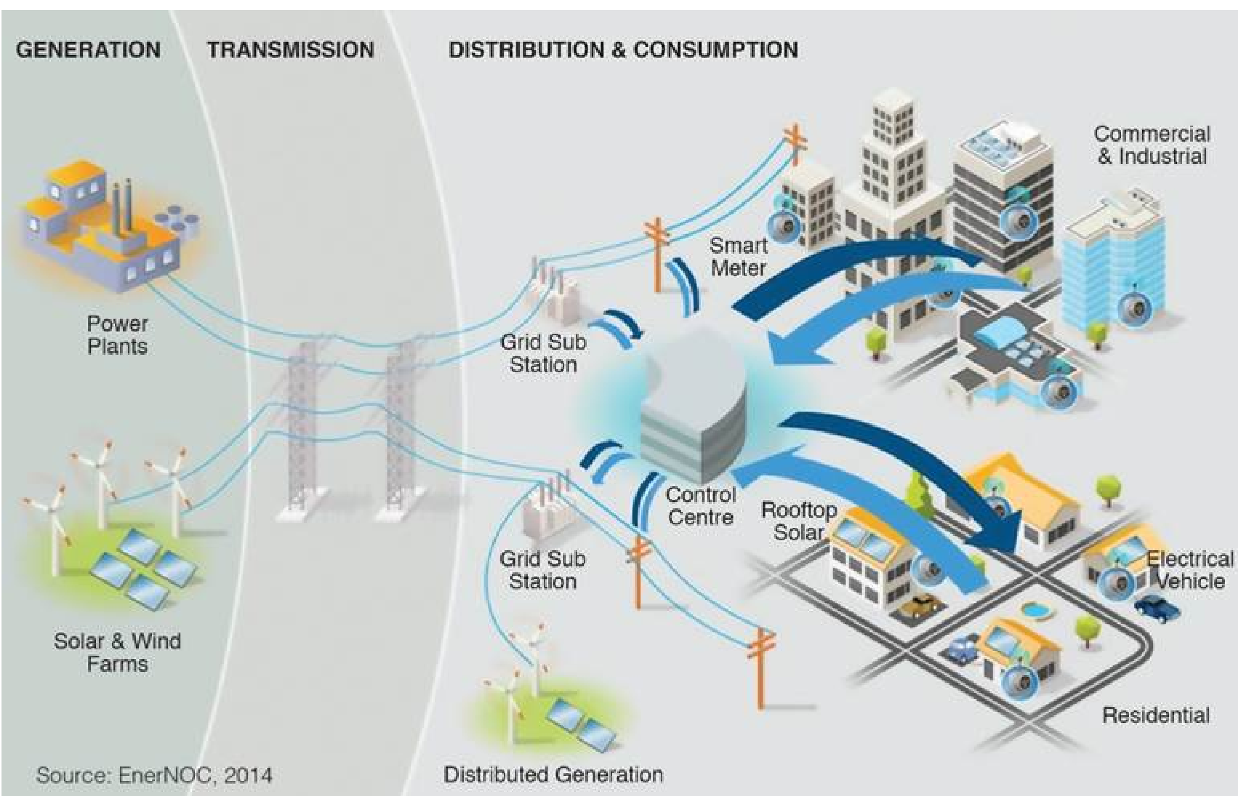
10 Conclusion

In this inquiry the AUC has learned that there is already distribution-connected generation in Alberta and has been for some time. The rate of growth of distribution-connected generation is increasing due to changes to the *Micro-generation Regulation*, which was updated in 2016. Overall, the existing legislative framework for the electricity system in Alberta and the rules adopted to give effect to it do not restrict the development of distribution-connected generation including community generation. Indeed, it enables it in practically unlimited ways.

In addition, the distribution wire owners confirmed that the distribution systems are capable of accommodating DCG at the current time, and into the foreseeable future at the current growth rates and at relatively little cost. The distribution wire owners will also be required to enhance their systems to accommodate the intermittency of solar, wind and other renewables to maintain the reliability of their distribution service.

However, as the capacity to accommodate more distribution-connected generation decreases, distribution wire owners will have to make investments at various places on their systems to accommodate further growth of distribution-connected generation. These future investments are likely to increase costs and will require careful planning by the distribution wire owners in order to take into account their unique local circumstances. By way of example, the electricity system of the future adapted for each individual distribution wire owner's system will likely resemble the diagram below.

Figure 3 - Electric Utility Model of the Future



The AUC also learned that cost allocation and pricing issues are controversial. Some parties advocated for rate structures, such as net-metering and feed-in tariffs, that would include implicit subsidies. The vast majority of participants argued that rates should continue to be based on the cost of service and any required subsidies should be transparent and administered outside of rate design and tariff structure. In the future as new capacity needs to be built, further issues of who should pay for those costs and who should take the risks of potential stranded infrastructure, will need to be addressed.

An important observation the AUC has made is that there is a critical role for government in the growth and development of distribution-connected generation. That critical role is to provide educational opportunities for Albertans who wish to participate in distribution-connected generation so that there is greater awareness of distribution-connected generation options, financial programs and processes.

Dated on December 29, 2017.

Alberta Utilities Commission

Willie Grieve, QC Chair	Tracee Collins Commission Member	Joanne Phillips Commission Member

List of appendices

The following list of appendices are part of the report but for ease of reference they are provided separately.

- Appendix 1 – Order in Council 2017-120
- Appendix 2 – List of DCG-related reports and other resources
- Appendix 3 – Notice of review
- Appendix 4 – List of active participants
- Appendix 5 – Commission questions to parties
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- Appendix 7 – List of DCG-related reports from participants
- Appendix 8 – Summary of Alberta Legislation
- Appendix 9 – Summary of strategies to reduce the growth of net metering
- Appendix 10 – Glossary and abbreviations
- Appendix 11 – Concordance table to the Order in Council 2017-120
- Appendix 12 – Alberta Utilities Commission panel, consultants and staff