Alberta Utilities Commission

Distribution System Inquiry

Final Report

February 19, 2021

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Final Report
Proceeding 24116

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Executive summary

1. The electric power system is evolving to accommodate changes in the ways electricity is produced, delivered and used. This is the result of technological improvements, policy-driven incentives affecting both the supply of and demand for electricity, and changes in consumer tastes and preferences for different types of technology and service offerings. More than ever before, customers have greater choice and control over how, when, where and from whom they obtain their electricity. The range of choices available to them is impressive and growing: in Alberta, generating systems are moving from traditional fuel sources to a greater reliance on natural gas and renewables (such as solar, thermal and wind); various technologies and systems now offer the ability to reduce or shift consumption (such as energy efficiency and demand response technologies); and impressive strides are being made in expanding the capabilities of energy storage resources, among other emerging technologies. In this report, these *distributed energy resources* are referred to collectively as DERs.

2. In Alberta, it is not uncommon to hear electric utility customers complain about steadily rising prices for the utility services they consume each month. In fact, higher monthly utility bills are causing customers to begin questioning the value of grid-provided service and, in still small but growing numbers, to begin looking for alternative means of obtaining electricity.[1] Significantly, by enabling all customers, from small to large, to self-supply electricity, DERs are creating new avenues for customers to potentially bypass utility service and the associated tariff charges. This not only creates competitive pressures where none existed before, but also raises questions about the future viability of electric utilities and the role of regulation during a period of significant industry transformation.

3. This inquiry has focused on the distribution segment of the electric grid (in Alberta, referred to as the AIES or Alberta Interconnected Electric System). However, in their submissions various parties highlighted the importance of employing a wider lens to ensure a system-wide view of AIES planning and operations. Parties emphasized the importance of effectively coordinating across the distribution and transmission systems, as well as the wholesale and retail markets to ensure efficient outcomes for the system as a whole.

4. Although Alberta has not yet experienced DERs adoption rates at sufficiently high levels to significantly strain the distribution systems beyond manageable levels, it is widely expected that DERs adoption will continue to increase in Alberta due to declining technology costs, embedded price signals, government policies, and shifts in consumer preferences. Module One of the inquiry highlighted the considerable uncertainty over the scale and timing of DERs

[1] Higher rates are the result of a host of factors and are an important driver of the adoption of DERs. While this report deals with some of the reasons tariff rates may increase (e.g., grid bypass resulting in an erosion of billing determinants), other potential reasons for these increases (e.g., slower demand growth, escalating costs from underutilized investments, demands for higher service reliability, etc.) are outside the scope and focus of the report.

adoption generally, with the exception of energy storage. Nevertheless, many parties agreed that further progress is both necessary and possible in both the near and longer term to identify and resolve barriers in the regulatory framework preventing the full realization of benefits from distributed resources.

5. Several parties indicated that, ultimately, what customers care about is their *total* electricity bill, and not the individual components of their bill and that reducing the total cost of electricity consumption is the primary reason for installing DERs. At the same time, transmission and distribution tariffs have historically relied on rate designs, the primary objective of which has been to recover total revenue requirements, rather than to send accurate (cost-based) price signals to consumers. Moreover, traditional rate designs have relied on, and continue to be constrained by, simple metering arrangements that limit what can actually be billed and how frequently. Taken together, these factors have combined to create strong incentives to install DERs to avoid tariff charges perceived to be excessive. The problem of such tariff avoidance from the perspective of the public interest is that it leads to cost shifting among customers, and uneconomic bypass of the grid. That is, the avoided costs do not disappear but must be recovered from other customers. Left unchecked, cost transfers from one group of customers to another as a result of tariff avoidance will strengthen the incentive for the remaining customers, who are then left to pay even higher charges, to similarly bypass the system, exacerbating the harm and launching a vicious cycle of rising utility rates and more customers choosing to bypass the system by way of self-supply.

6. Other identified issues with respect to the deployment of DERs include level playing field considerations: (i) between transmission-connected generation (TCG) and distribution-connected generation (DCG); and (ii) arising from differences in the regulatory treatment accorded various DERs despite appearing to be functionally very similar in their impact on the grid. On the latter issue, several parties expressed a view that the current regulatory framework creates different incentives depending on the DER and connection configuration being considered, preventing a level playing field.

7. Parties emphasized that, as technology continues to evolve, the incentives market participants face should promote efficient investment choices. Failure to expeditiously address these issues is likely to not only encourage wasteful spending and unnecessarily increase customer costs in the short term, but may increasingly threaten the economic viability of the electricity system, necessitating a more disruptive set of changes in the future. Parties also pointed to the experience of other jurisdictions, highlighting that once large numbers of customers have made long-term (and potentially socially inefficient) investments in DERs, the situation becomes increasingly difficult to rectify.

8. However, parties also recognized that the effect of DERs on the distribution and transmission systems can be positive or negative, depending on how they are integrated into the grid and how energy flows are priced. With proper price signals and grid planning, DERs have the potential to offer value to the grid. The Commission heard from parties that in order to harness the value of DERs to the benefit of all Albertans, a combination of the following regulatory and industry-led initiatives and undertakings will need to be considered:

(i) Continuing emphasis on promoting the goals and objectives of the existing legislative framework governing the Alberta electricity industry including, especially, encouraging fair, efficient and openly competitive electricity markets (where "fair," as much as anything, means maintaining a level playing field between market participants).

(ii) Working with industry participants, as well as the Alberta Electric System Operator (AESO), to encourage a closer alignment of rates with costs for regulated distribution and transmission network service providers alike.

(iii) Deploying modern metering functionality in the form of advanced metering infrastructure (AMI) systems.

(iv) Facilitating broader access to information, while protecting personal privacy.

(v) Ensuring an efficient electricity system that provides the right incentives for market participants, including customers and utilities, to invest in DERs at a pace and scale that will deliver benefits across the value chain.

9. The vast majority of parties expressed the view that a suite of coordinated actions by all electricity industry stakeholders will be needed to develop solutions and an appropriate framework to address the challenges and opportunities presented by the industry transition already underway. Parties recommended leveraging existing regulatory processes, additional regulatory and/or stakeholder consultation processes led by the Commission, and actions led by other stakeholders (including the AESO, distribution utilities, and potentially the provincial government) and supported by the Commission.

10. For the time-constrained reader, a good grasp of the subject matter considered and key issues examined during the inquiry, including the implications thereof for the industry, can be acquired by focusing on the following sections:

1 Introduction
2 The need for an inquiry on distribution systems (including subsections 2.1 and 2.2)
3.4 The problem of uneconomic bypass
4.0 Summary of issues facing electricity industry uncovered through the inquiry
5.0 Summary of tools and considerations for addressing the issues
6 Parties' recommendations for next steps

11. Readers desiring an in-depth discussion and, where required, a more technical assessment of the principal challenges and opportunities associated with modernizing Alberta's electricity grid, as raised by parties during the course of the Distribution System Inquiry, are encouraged to read the report in its entirety.

1 Introduction

12. Technological change is playing an increasingly important role in the transformation of the electricity industry. For example, it is providing customers with greater choice in where they obtain their electricity, as well as when and how much they can consume, and at what cost to themselves and the system. Customers, in fact, are a central driving force in this transition, as they seek to connect to the electricity grid various new technologies that (i) increase the demand for electricity (such as electric vehicles (EVs) and heat pumps); (ii) introduce new sources of electricity supply (such as rooftop solar panels and combined heat and power systems); (iii) allow greater management of electricity consumption (such as energy storage resources, energy efficiency measures, and a growing number of smart technologies to automatically monitor and manage electricity use); and (iv) no less importantly, make it possible for customers, based on where they install or deploy these technologies relative to the location of utility meters, to avoid or bypass certain charges that must then be recovered from other customers. These technologies are often collectively referred to as distributed energy resources (DERs).

Distributed energy resources (DERs). It is clear from submissions in the inquiry that there is no settled definition of DERs. In this report, to be as inclusive and comprehensive as possible, DERs are defined to include any technology that is connected to the distribution grid and affects the supply of and/or demand for electricity. At present, DERs generally fit into the following categories:

- Supply-side – Technologies, such as solar panels and combined heat and power systems, that generate electricity and supply it to distribution customers, either for a customer's own use through behind-the-meter generation (self-supply), as DCG primarily for the purposes of export to the grid, or a combination of the two (self-supply with export).
- Demand-side – Technologies that allow for load shedding and/or load shifting, including energy efficiency, smart appliances, demand response and electric vehicles.
- Energy storage resources – Technologies that allow energy to be stored and used at a later time, such as batteries and pumped hydro. Energy storage resources have the ability to appear and behave similarly to supply-side and demand-side technologies from the perspective of a grid operator (e.g., self-supply, export, load shed and load shift).

This definition aligns with the National Association of Regulatory Utility Commissioners' (NARUC)[2] and the Electric Power Research Institute's (EPRI)[3] definitions of DERs. As these technologies continue to develop, they will increasingly provide multiple services and will become harder to categorize. For example, electric vehicles may eventually supply energy to the grid at times and operate like energy storage resources.

13. As these technologies are generally connected at the distribution system level, distribution utilities are at the forefront of responding to both the opportunities and challenges arising from these changes as they seek to operate and maintain the electric distribution system in a safe, reliable and economic manner. For example, distribution utilities increasingly find themselves being required to connect and provide service to larger loads and more sources of

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[2] Exhibit 24116-X0150, Fortis Module One submission, paragraph 24.
[3] Exhibit 24116-X0180, EPRI, "The Integrated Grid: A Benefit-Cost Framework," February 2015, PDF page 19.

generation, handle two-way flows of energy, and accommodate shifts in consumption patterns. This is making grid planning and operation more complex and, potentially, more costly, yet it is also offering new and innovative ways to deliver service.

14. At the same time, DERs are creating new avenues for customers to potentially bypass utility service and associated charges (either fully or partially) by way of self-supply. This not only creates competitive pressures where none existed before, but also raises serious questions about the future regulation of the industry. The transformation of the telecommunications industry several decades ago from a natural monopoly to a much more competitive industry structure is instructive in this regard. In particular, the earliest instances of competitive entry into the supply of network services in that industry were driven not so much by the proliferation of new and lower cost technologies, but by the fact that tariffs designed for monopoly supply were not (and typically are not) sustainable in the presence of competitive alternatives. That is, to the extent that the rates and tariffs for grid-supplied services are not cost-based, the continued ability of distribution utilities to discharge their obligations under the "regulatory compact" *and* still recover their revenue requirement well into the future is no longer reasonably assured. As will be discussed at greater length later in this report, this is particularly the case where competitive inroads are premised (in whole or in part) on "cream-skimming" and uneconomic bypass, neither of which is in the public interest. This, in turn, raises concerns that assets may become stranded and, potentially, calls into question the future viability of regulated utilities unless significant tariff reform and related measures better suited to a more competitive industry structure are undertaken on a timely basis.

15. In fact, it was with these considerations in mind that the AUC initiated the Distribution System Inquiry. The Commission's express purpose in doing so was to conduct a fact-finding process to identify the key factors likely to affect the future evolution of the distribution system and how industry regulation may need to adapt to these new circumstances. This report provides a summary of the information gathered and key issues identified as a result of the inquiry.

16. Parties have encouraged the Commission to take a proactive and comprehensive approach to addressing the systemic issues driving the evolution of the electric grid.[4]

17. To this end, parties have raised issues that will require regulatory (and some policy) direction as the grid is modernized, which can be generally summarized as: tariff and rate redesign, metering, access to data and information, and integration of DERs. Stakeholder comments and presentations provided valuable input about the experience of other jurisdictions in reforming their respective regulatory frameworks to prepare for, or adjust to, grid modernization. Many of these examples are relevant to the Alberta experience either as potential solutions or as missteps to be avoided.

18. The inquiry has raised the profile of many of the opportunities and challenges associated with grid modernization. To some extent, the inquiry has prompted stakeholders to take more proactive efforts in addressing the looming challenges, and positioning themselves to take

[4] Exhibit 24116-X0727, AltaLink concluding remarks, paragraph 1; Exhibit 24116-X0719, AddÉnergie and ChargePoint concluding remarks; Exhibit 24116-X0720, Lionstooth concluding remarks; Exhibit 24116-X0733, ENMAX concluding remarks, paragraph 4; Exhibit 24116-X0734, AltaGas concluding remarks, PDF page 2; Exhibit 24116-X0735, AESO concluding remarks, paragraph 6; Exhibit 24116-X0737, Pembina concluding remarks, PDF page 6; Exhibit 24116-X0738, Capital Power concluding remarks; Exhibit 24116-X0742, E3 concluding remarks; Exhibit 24116-X0730, CGWG concluding remarks, paragraph 25.

advantage of the opportunities. For instance, many, if not all, of Alberta's distribution utilities are taking steps to modernize their grid, either proactively or in response to issues raised over the course of this inquiry process. Several notable examples include:

- The AESO's DER and energy storage roadmaps.
- The AESO-led transmission and distribution coordinated planning framework.
- DER hosting capacity maps published by ATCO, ENMAX and Fortis.
- ATCO's AMI pilot project and pilot EV charging station rate class.
- ENMAX's EV charging pilot program.
- EPCOR's joint research with the University of Alberta on potential DERs impacts to urban utilities.
- Fortis's several internal and external initiatives, studies and pilots to cost-effectively integrate DERs.
- Alberta Innovates-led Smart Grid Consortium customer survey.
- EQUS's installation of Canada's first extra-urban and rural-adapted wireless AMI system.
- The City of Medicine Hat's deployment of electric, natural gas, and water utility meters conversion to AMI as part of an interconnected metering and billing system.

19. Although the initial focus of this inquiry was on the distribution segment of the electric grid (in Alberta, referred to as the AIES or Alberta Interconnected Electric System), it quickly became apparent that changes to how distribution systems are planned, operated and regulated have the potential to affect other aspects of the AIES. For this reason, the inquiry gradually embraced a more comprehensive approach to examining many of the issues detailed in this report, including transmission, retail, and wholesale market considerations.

20. The Commission heard that Alberta has not yet experienced DERs adoption rates at sufficiently high levels to significantly strain the distribution systems beyond manageable levels. Nevertheless, parties cautioned the Commission not to allow this fact to create a false sense of security and conclude that no effort is needed. Several parties mentioned California and Hawaii as notable examples of how inefficient pricing led to rapid adoption of DERs and significant increases in system costs during the course of a single decade. In contrast, other parties pointed to the experiences of New York state and Australia, both of which were able to leverage DERs to lower or defer system cost increases.

21. Therefore, most parties recommended that the Commission take a proactive and comprehensive approach to regulation, rather than addressing issues in a piecemeal fashion as, and when, they arise. Considering the experience of other jurisdictions, parties suggested that the present is an ideal time to give thoughtful consideration to the evolution of distribution systems and the governing regulatory framework, before DERs adoption rates stress the system and regulatory change becomes more difficult due to significant amounts of sunk investment and entrenched positions.

22. Many of the submissions did not consider that drastic or wholesale changes to the regulatory framework are required immediately in order to accommodate the emerging economic

and technological forces that were identified and considered in some detail in this inquiry. Certain aspects of the regulatory framework may need to be clarified or adjusted to improve investment certainty as a result of technologies and businesses that did not exist or were not contemplated when legislation was enacted, as is the case with energy storage.

2 The need for an inquiry on distribution systems

23. The Commission's mandate includes regulating electric utilities and electricity markets to protect the social, economic and environmental interests of Alberta where competitive market forces alone do not.[5] This role requires an awareness and understanding of the rapidly changing economic and competitive market forces that have begun transforming the electric grid. The Commission undertook this inquiry to examine three fundamental questions:[6]

- How will technology affect the grid and incumbent electric distribution utilities, and how quickly?
- Where alternative approaches to providing electrical service develop, how will the incumbent electric distribution utilities be expected to respond, and what factors should be considered in determining whether affected services and/or service providers should be subject to a greater or lesser degree of regulation as circumstances change?
- What factors should be considered in determining whether the rate structures of the distribution utilities should be modified to ensure that price signals encourage electric distribution utilities, consumers, producers, prosumers and alternative technology providers to use the grid and related resources in an efficient, cost-effective way?

24. Throughout the inquiry the Commission benefitted from input provided by approximately 90 different parties, representing a diverse and broad set of interested and informed stakeholders based in Alberta as well as abroad.[7] These included rural and urban distribution electric and natural gas utilities, electric transmission utilities, firms specializing in transmission- and distribution-connected generation, technology providers, DER proponents,[8] special interest advocacy groups, rural landowners, and internationally recognized expert consultants. This input was received in the form of responses to information requests, written submissions, expert reports and technical meetings. These submissions produced valuable information on: (i) potential emerging technologies; (ii) the current and anticipated impacts of these emerging technologies and trends on grid reliability, existing business models, rate structures, and the ability to provide appropriate price signals; and (iii) potential areas of innovation for the Alberta electricity industry in general and the AIES in particular.

25. At the outset of the inquiry, ATCO made a compelling case to include natural gas distribution systems in the scope of the inquiry.[9] The Commission invited submissions on this topic throughout the proceeding. While there are several emerging issues that overlap the natural gas and electric distribution systems, there are many issues that apply to only one or the other. Parties' submissions revealed that the potential transformative effect of the new technologies and

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5 http://www.auc.ab.ca/pages/mission-statement.aspx

6 See Bulletin 2018-17, Electric Distribution System Inquiry, December 6, 2018. These questions are slightly modified from the original text of the bulletin to reflect the greater understanding that has resulted from the inquiry.

7 For a full list of parties that participated, see Appendix 6.

8 For the purposes of this report, "DER proponents" are DER vendors, installers and for-profit businesses that focus on installing stand-alone DCG.

9 Exhibit 24116-X0079, ATCO's Module One submission on Scope and Process, June 18, 2019.

innovations on the natural gas systems is much weaker than on electric distribution systems.[10] Therefore, the focus in this report is on mapping out the key issues related to the future of the electric distribution system and any reference to "distribution systems" or "distribution utilities" in this report is given to mean electric distribution systems and electric distribution utilities, unless noted otherwise. Observations on natural gas distribution systems are provided in Appendix 3.

2.1 Current trends affecting the electricity industry

Key takeaways:
The deployment of DERs will continue to grow, although there is considerable uncertainty with respect to the pace and scale of DERs growth in general and in Alberta specifically. This is creating both opportunities and challenges for distribution utilities; some argue they will need to become more "customer centric" in order to adequately respond.

26. The electricity industry is entering a period of significant change. Newly affordable technologies are increasingly creating viable alternatives to the traditional means of producing and consuming electricity. Other exogenous forces such as shifts in consumer preferences and public policies encouraging renewable energy and greater efficiency in energy consumption are further accelerating the potential disruption of the status quo. While these changes are affecting all segments of Alberta's electricity industry, electric distribution systems are likely affected the most because they connect end-use customers adopting new technologies.

27. At a high level, the main exogenous forces (sometimes referred to as mega-trends) generally affecting the energy systems of today, and distribution systems in particular, include the following:[11]

> **Decentralization.** Increased adoption of DERs increases the complexity of grid planning and operation, particularly for distribution systems. This includes creating challenges to manage increased two-way flows of energy from a growing number of renewable energy resources, which can be intermittent and non-dispatchable. Alternatively, this may also include opportunities to leverage DERs to provide alternatives to wires solutions and, in the process, potentially lower the cost of the grid. Should higher adoption rates for DERs not be accompanied by a reduction in grid-related costs, pressures will mount to adjust rates to more closely align with costs in order to avoid cost shifting between customers and uneconomic bypass.[12]

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[10] Exhibit 24116-X0442, Federation of Alberta Gas Co-ops Module One response submission, paragraphs 17-38; Exhibit 24116-X0622.01, Federation of Alberta Gas Co-ops Combined Module response submission, paragraph 11.

[11] Exhibit 24116-X0716, Transcript, Volume 1, page 15; Exhibit 24116-X0184, Pembina Module One submission, page 10; Exhibit 24116-X0152, ATCO Module One submission, PDF pages 15, 17, 49, 52; Exhibit 24116-X0420, Fortis Module One presentation, PDF page 13; Exhibit 24116-X0650, CEER paper on Electricity Distribution Tariffs Supporting the Energy Transition.

[12] As will be described in more detail in Section 3.4, uneconomic bypass is the inefficient allocation of resources from society's perspective whenever individual customers make investments that lower their own costs of consuming electricity, but do not reduce or minimize the total cost of the grid, thereby shifting costs to other customers.

Digitalization. Digitalization allows for the creation and proliferation of large amounts of new and existing data from multiple sources, including system monitoring devices and revenue meters. Leveraging data potentially enables distribution utilities to operate the grid more efficiently through enhanced abilities to plan and operate their system. Digitalization also creates an ability to bill customers on various units (such as demand and time-varying charges), thus allowing rate design to more closely align with cost causation and deliver effective price signals to promote economic efficiency. Information and data made more broadly available may also enable more informed decisions by customers, retailers, and generators of all sizes, which supports fair, efficient and open competition.

Decarbonization. Policies set at all levels of government, together with changes in consumer preferences favouring lower carbon emissions, may increase the demand for electricity and lead to a higher penetration of renewable energy sources. The cost of investments in decarbonization may decline when technology improvements in digitalization and decentralization are leveraged.

28. These exogenous forces may require the distribution utilities' roles and functions to expand in some areas, and contract in others. For example, distribution utilities may be increasingly required to handle two-way flows of energy, connect and provide service to increased loads and generation sources, as well as accommodate shifts in consumption patterns. Conversely, distribution utilities may face less demand for their services, as DERs create new avenues to potentially bypass utility service, either partially or fully.

29. During Module One of the inquiry, parties focused most of their attention on the following technologies and innovations:

- distribution-connected generation (DCG)
- electric vehicles (EVs)
- energy storage
- technologies and conduct primarily affecting electricity demand (e.g., energy efficiency and load shifting)
- AMI
- advanced distribution management systems (ADMS) and/or distributed energy resource management systems (DERMS)
- information technology (IT) advancements (e.g., the internet of things and smart devices)

30. The inquiry greatly benefited from the Module One submissions and technical conference discussions, particularly in answering the first of the central questions of the inquiry ("How will technology affect the grid and incumbent electric distribution utilities, and how quickly?"). A comprehensive summary of the Module One submissions and a detailed description of each of the above technologies and innovations is beyond the scope of this report, partly because there

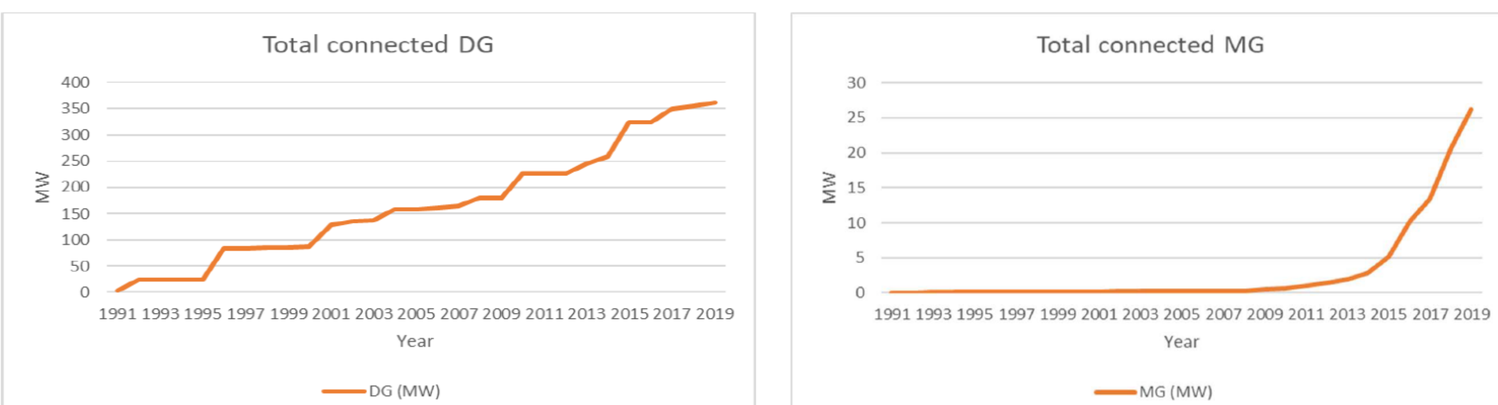
are numerous academic and industry publications discussing these issues and partly because it would quickly become out of date as these technologies continue to rapidly evolve.[13]

31. Although Alberta has not yet experienced DERs adoption rates at sufficiently high levels to significantly strain the distribution systems beyond manageable levels, it is widely expected that DERs adoption will continue to increase in Alberta due to declining technology costs, government policies, shifts in consumer preferences and, unless more closely aligned with costs in future, a favourable tariff structure for such entry. Module One revealed that there remains considerable uncertainty with respect to the scale and timing of DERs adoption. Nevertheless, parties urged the Commission not to be lulled into a false sense of security and default to the view that no action is required on its part in identifying, assessing and then addressing the potential impacts of the industry's continued evolution towards greater competition. Fortis put it succinctly:

> DERs are here to stay. With the evolution of new technologies, customer preferences to manage and control their energy consumption, environmental mandates to transition from carbon-based fuels and related governmental and regulatory policies, DERs will continue to grow.[14]

32. With its service area in west-central and southern Alberta, where the province's solar and wind resources are most abundant, Fortis is a distribution utility that may be most affected by the interconnection and integration of alternative and renewable generation-related DERs. In Module One, Fortis shared how supply-side DERs have grown in its service territory. As shown in Figure 1 below, the installed capacity of distribution-connected generation (DG in the figure; greater than 5 megawatts (MW) and not co-located with load) nearly doubled over the last decade, going from roughly 200 MW to over 350 MW. Micro-generation (MG in the figure; less than 5 MW and co-located with load), which is predominately distributed rooftop solar photovoltaic (PV) systems, went from nearly zero to over 25 MW installed capacity over the same period.

Figure 1. Growth of distribution-connected generation and microgeneration in Fortis's service area



13 Parties' Module One submissions are contained in exhibits 24116-X0134 to 24116-X0182.
14 Exhibit 24116-X0741, Fortis concluding remarks, paragraph 3.

33. ATCO Electric, a distribution and transmission utility with a service territory generally in the central and northern part of Alberta, also reported growth in recent years in the adoption of DERs by customers on its system:[15]

> Since the implementation of the Micro-Generation Regulation in 2008, the number of completed connections of DERs less than 150 kW [kilowatts] in nameplate capacity to ATCO Electric's system have been increasing steadily year over year until 2016 where the number of DERs and the total installed nameplate capacity has more than doubled in the last 2 years.
>
> Although none are currently deployed, there has been an increase in the number of requests for connections of solar DERs since 2016 with nameplate capacity of greater than 5 MW and less than 25 MW.
>
> The number of deployed DERs with non-renewable fuel sources has also increased over the last few years with an increased interest in generation less than 5 MW in size (up 70% from 2016). These are mostly gas-fired generators.

34. The two urban utilities, ENMAX and EPCOR, that provide distribution and transmission services in Calgary and Edmonton, respectively, also experienced an increase in DER penetration in their service areas.[16]

35. Parties submitted that the costs of DERs have been rapidly declining and are expected to continue to decline, providing a key driver for increased customer interest and adoption. For example, in the case of solar, while some of the increase in adoption of solar PV sized less than 5 MW can be attributed to previous provincial government programs,[17] part of the growth in solar DERs has been driven by rapidly declining costs, making them more cost competitive. Figure 2 shows declines in the levelized cost of energy (LCOE)[18] for utility-scale solar PV. It should be noted that the dollar amounts shown in Figure 2 are not based on the Alberta experience, and are presented to illustrate a notable, industry-wide, historical trend of rapidly declining costs.[19] While the cost of grid-scale solar is significantly lower on an LCOE basis, both grid-scale and distributed solar have experienced a similar trend in cost reduction, in terms of the slope and shape of the curve shown in Figure 2.

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15 Exhibit 24116-X0329, ATCO-AUC-2019AUG07-006 (Multiple), PDF page 30.

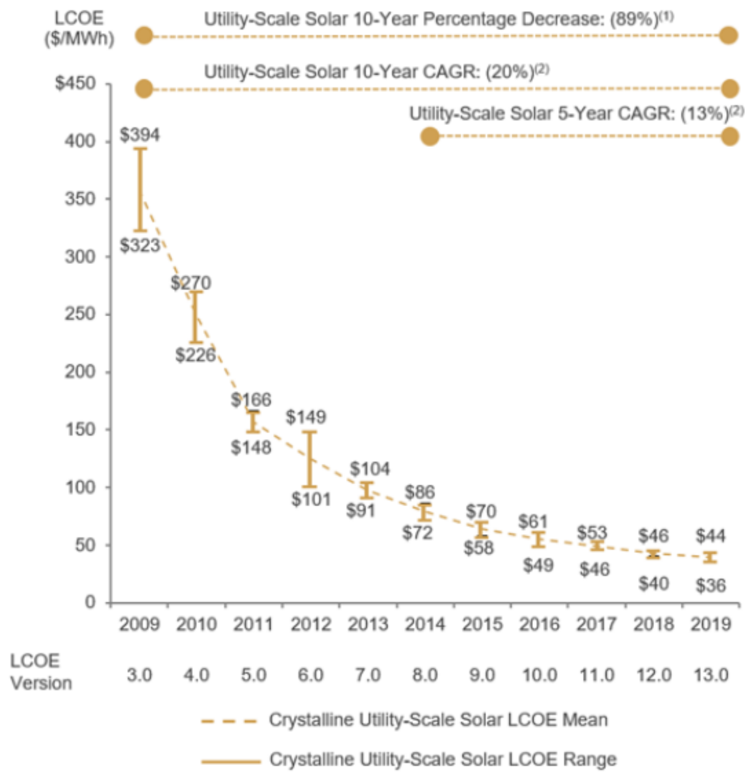
16 Exhibit 24116-X0154, ENMAX Module One submissions, PDF pages 7-8; Exhibit 24116-X0170, EPCOR Module One submission, Figure 2.4.1-2, paragraph 87.

17 See, for example, Government of Alberta press release on November 12, 2018: "Albertans take a shine to solar power," https://www.alberta.ca/release.cfm?xID=61994563367BA-0EC6-1D31-CC7CD5DA3E43BB51.

18 The LCOE is a measure of the average net present cost of electricity generation for a generating plant over its lifetime. The LCOE is calculated as the ratio between all the discounted costs over the lifetime of a electricity generating plant divided by a discounted sum of the actual energy amounts delivered. The LCOE is used to compare different methods of electricity generation on a consistent basis.

19 Nevertheless, the quantum of dollars shown may be in the range of what might be seen in Alberta, as judged by the Government of Alberta's 2019 announcement of procuring electricity from three grid-scale solar projects, with an average cost of $48.05 per MWh.

Figure 2. Historical cost of utility-scale solar PV[20]



36. Other technologies, such as energy storage, are similarly forecast to decline in cost in the coming years, as shown in Figure 3. This cost decrease will make technologies increasingly competitive in a growing number of applications, leading to higher DER adoption levels. Here again, the dollar amounts shown in Figure 3 are less important than the slope and shape of the trend.

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20 Lazard, Levelized Cost of Energy Analysis: version 13.0 (Lazard, November 7, 2019), https://www.lazard.com/perspective/lcoe2019. The 2018 estimates were provided on the record in Exhibit 24116-X0175, PDF pages 8-9; and Exhibit 24116-X0181, PDF pages 12-13.

Figure 3. Forecast of utility-scale energy storage costs[21]

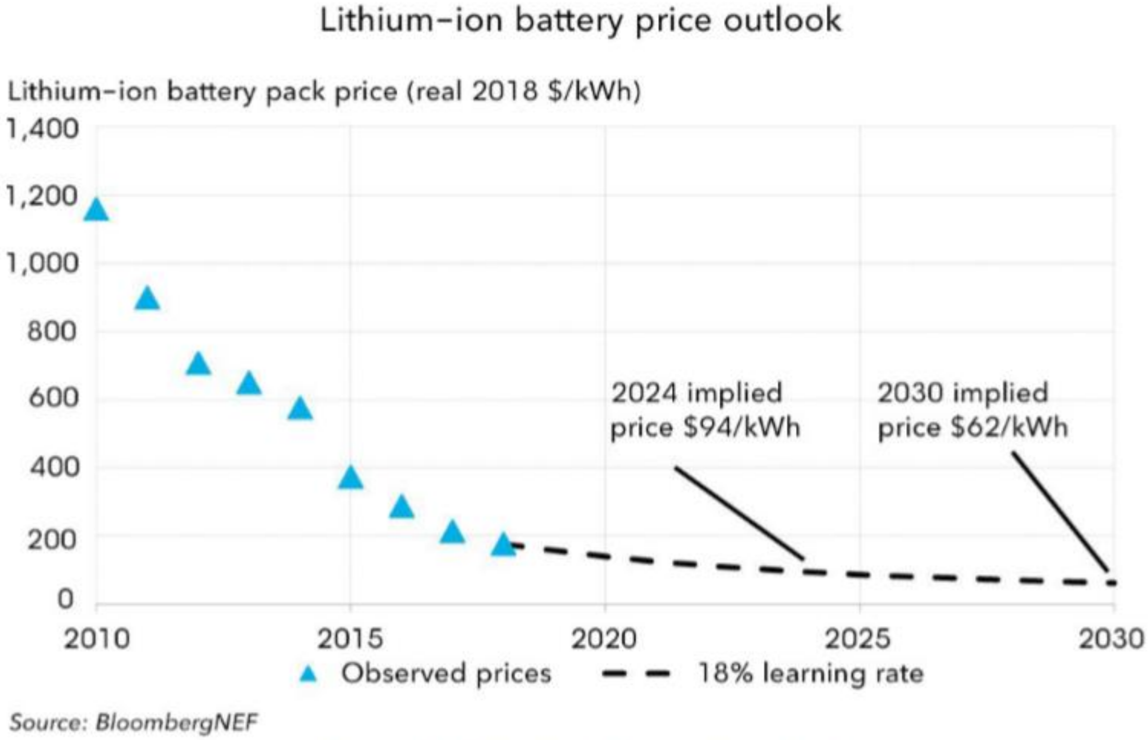

Figure 5: Lithium-ion battery price outlook

37. In the next section, the report examines what these trends may mean for distribution utilities.

2.2 Future of the electricity grid

> **Key takeaways:**
> As the industry transitions to an as yet undetermined state, distribution utilities are being confronted with significant challenges, including: (i) potential for increased loads, partly driven by the electrification of transportation and heating; (ii) dynamic energy flows on the distribution system; (iii) weakened provincial economic growth and a need to keep grid-supplied electricity as affordable as possible; (iv) increased customer choice and growing competitive pressure to more closely align rates with costs; (v) the need to become more responsive to the needs of customers; and (vi) new technologies to help respond to these issues in new and innovative ways. Taken together, these developments constitute a series of unprecedented challenges and opportunities for distribution utilities that will require new and innovative approaches to be dealt with effectively.

[21] Exhibit 24116-X0579, E3 Combined Module submission, Figure 2.

38. When planning and preparing for the regulatory framework of the future, a useful starting point is envisioning what the grid of the future may look like. Nearly every party to this proceeding expressed the view that market forces are likely to be an important, if not the primary, driver of industry transformation both through rapid technological change and significant changes in consumer tastes and behaviours that shape market offerings and industry structure. In the result, the electricity grid, and distribution systems in particular, are widely expected to become more "customer centric." This section summarizes parties' submissions about what the future of the electricity grid might look like and how the current grid is expected to evolve to that future state.

39. Parties agreed that the exogenous forces described in the previous section, namely, decentralization, digitalization and decarbonization, will continue to intensify in the years ahead. The trend to "electrify everything," particularly future modes of transportation and the heating needs of buildings, is expected to increase the demand on the system, the speed and magnitude of which will be a function of the future direction(s) in which government policy "pushes" and consumer demand "pulls" the industry.

40. At the same time, DERs are providing new means and new avenues of supplying that load growth. Major options include siting generation closer to load as well as self-supply. A potential, and quite likely, outcome is that electricity generated from DERs representing renewable sources of energy will steadily increase. Thus, grid planners and operators will need to address the challenges associated not only with potentially much greater demand for electricity, but also with how to manage such increases in a dynamic setting, including possible changes in electricity flows, given increased penetration of DERs and intermittent renewables.

41. Alberta's renewable energy resources are well documented. Fortis contrasted its service territory (shown in Figure 4 as dark blue; ATCO's service territory is shown in light blue) with Natural Resource Canada's renewable resource mapping. Thus, as Fortis pointed out, some distribution utilities will experience these exogenous forces to greater or lesser degrees, and at different rates of change.

Figure 4. Geography of Alberta’s renewable resources and distribution service territory[22]

42. As this report was being written, the province was still dealing with the many complex medical, social and economic challenges posed by the ongoing COVID-19 pandemic, as well the devastating financial impact on Alberta of the global collapse in oil and natural gas prices. These events have severely affected economic growth and led to large budget deficits. As a consequence, distribution systems looking to respond to the growing competitive challenges they face are apt to encounter financial constraints in doing so given the limited ability and appetite of customers to absorb higher rates.

43. In addition, the declining cost of DERs is creating new opportunities for customers to meet their energy needs in non-traditional ways by allowing them to potentially bypass utility service, either partially or fully. This, in turn, may lead to increased competition and possible changes in industry structure.

44. This is consistent, for example, with the submission of external expert witness, Dr. Faruqui, of the Brattle Group, who, in describing his expectations of the future of the grid, specifically noted that the distribution utilities will be forced to adapt to the changing needs and expectations of customers, or be left behind.

> I think everyone is on the same page that change is coming. And even though it might not be evident today in Alberta, it is extremely likely that in the next five to ten years the landscape will look very different, with a lot of DERs, a lot of new digital technologies. All of those mean that the utility regulated monopoly that we have today will not look at all like what it will look like in five to ten years’ time. Because if it doesn't move, if it doesn't change with the times, it will see more and more customers defecting as batteries and rooftop solar and other devices like micro-grid and CHP [combined heat and power] come into play. So the utility will have to redefine its relationship, in my view, with its customers. It will have to reinvent itself. And I believe the best way to do that would be

22 Exhibit 24116-X0420, Fortis Module One presentation, PDF page 9.

> for the utility to become customer centric, which basically means that the process of regulation will have to recognize that and give utilities that opportunity. So that might mean in many cases perhaps the utility doing new functions than what it has done in the past.
>
> …
>
> So there are big gaps in coverage today between what the utility does and what it could do. It will require a reinterpretation of the regulatory compact to redefine the utility's role as the market changes. Otherwise it will become increasingly less and less relevant to what's happening inside the customers' premises.[23]

45. Other parties, including industry experts appearing on behalf of specific parties, offered similar visions of the future. Several key themes emerged from their submissions, including the following:

(i) While the delivery of electricity remains a monopoly business, customers increasingly have alternatives to meet their electric energy needs.

(ii) Distribution utilities may need to become increasingly "customer centric" in meeting the evolving needs and expectations of their customers.

(iii) While distribution utilities and other electric service providers (including those that install DERs) may lose some traditional loads, they may also be required to provide service to changed and entirely new loads as electricity is increasingly used to meet more diverse energy needs.

(iv) There is a need to ensure that the distribution tariff aligns with the principles of cost causation and setting effective price signals to minimize cost shifts within and between customer groups (i.e., rate classes). If utility rates are not based on underlying costs to provide service, opportunities are created for customers to bypass system costs by means of self-supply (investing in DERs). If those customers provide significant contributions to the recovery of the common costs of the distribution system, this situation may be viewed as an equivalent to what is referred to in the regulatory economics literature as "cream-skimming."[24]

46. Just as many new technologies and other innovations are creating new avenues for competitive supply, they simultaneously offer distribution utilities the potential to develop and operate their systems in a more orderly, efficient and safe manner, particularly as they address growing electricity demands and shifting consumption patterns.[25]

47. Viewed collectively, these evolving and increasingly accelerating trends – including: (i) growing loads; (ii) dynamic energy flows on the distribution system; (iii) weakened provincial economic growth and a need to keep grid-supplied electricity as affordable as possible; (iv) increased customer choice and growing competitive pressure to more closely align rates with

23 Exhibit 24116-X0716, Transcript, Volume 1, pages 224-225.

24 In general, "cream-skimming" happens when competitors capture customers that make significant contributions to the incumbent company's profit, leaving that company to serve less profitable customers. This often leads to the need to increase prices to the remaining customers, initiating the next round of "cream-skimming" and a vicious cycle of defecting customers and increasing costs.

25 See Appendix 4 – Case study: Brooklyn Queens Demand Management Project (BQDM project) as an example.

costs; (v) the need to become more responsive to the needs of customers; and (vi) new technologies to help respond to these issues in new and innovative ways – impose unprecedented challenges upon distribution utilities but also present tremendous opportunities for evolution and development of their business models. The distribution utilities will need to respond in new and innovative ways in order to deal effectively with these challenges and opportunities.

48. In this regard, the UCA's consultant, InterGroup Consultants Ltd., indicated it may be helpful to measure utility performance against customer needs:

> We'll know that the distribution system is working optimally when we can measure the performance against the customer need. And the customer need is changing so we have to develop metrics for performance that optimally reflect the customer need, and then measure that performance on a continuous basis. And that will be done through the regulatory process, as it is today, and it will be done by customer response to what regulated utilities provide.[26]

[26] Exhibit 24116-X0716, Transcript, Volume 1, pages 229-230.

3 Essential background to understand the issues facing the industry

49. In considering how current trends in the adoption of new technologies and ongoing changes in consumer preferences are likely to affect industry structure and performance, not to mention the composition and configuration of the physical grid itself, it is necessary to understand Alberta's existing statutory and regulatory framework. This includes such key elements as deregulated generation and retail segments; a substantially congestion-free transmission system; a policy of load customers generally paying for transmission system costs and generators paying for transmission line losses; existing statutory and regulatory provisions for DERs to connect to the distribution system; key elements of a customer's electricity bill; and price signals embedded in the current structure of rates and tariffs.

50. This section provides information that is essential to understanding the concepts discussed in this report. Section 3.1 presents a high-level overview of the structure of the deregulated electricity industry in Alberta. In Section 3.2, the report introduces the most commonly observed generation and load configurations, and associated regulatory pathways permitting them, that together result in the flows of electricity entering and leaving the electric system. In Section 3.3, the report presents a simple, illustrative example of the energy flows and prices faced by a customer engaged in all three flows of energy, that is, a self-supply and export customer. Finally, Section 3.4 discusses the conditions under which DERs-enabled uneconomic bypass can occur, an issue that was raised repeatedly during the inquiry.

3.1 Structure of the industry

Key takeaways:
The generation and retail segments of Alberta's electric system are deregulated. Alberta's wholesale electricity market is operated as an energy-only market. Alberta relies on a substantially congestion-free transmission system to provide market participants a reasonable opportunity to exchange electricity. Alberta has multiple transmission and distribution utilities and each of these utilities has an exclusive service territory. The largest transmission and distribution utilities are regulated by the Commission. The cost of the transmission system is largely recovered from load customers.

51. This section highlights several key aspects of how Alberta's electricity industry is currently organized, given existing (and emerging) technologies, prevailing rates and tariffs, and the broader legislative framework focusing, in particular, on existing "regulatory pathways" (i.e., specific, and not always consistent, rules and regulations) that permit different assets and technologies to connect to the grid to provide different services under different conditions for different purposes. This can then be contrasted with expectations of market participants for the grid of tomorrow.

52. The Government of Alberta deregulated the generation and retail segments of Alberta's electric system in the late 1990s and early 2000s. The central feature of this initiative was the creation of an offer-based wholesale electricity market. Alberta's wholesale electricity market is one of just two energy-only markets in North America. It operates in real time, and all electrical

energy entering the AIES, with a few exceptions, is transacted at a single, province-wide clearing price.

53. Under this framework, decisions regarding the investment in, and operation of, generation facilities are guided by market forces. There is no explicit mechanism to procure generation capacity; generators seek to recover all of their costs through the sale of energy and ancillary services. As a result, when the Commission approves new generation facilities, it does not consider the facilities' need or economic viability[27] but, rather, focuses on the social, economic and other impacts of the projects, including their effect on the environment.

54. The retail function is also mostly deregulated. Albertans are able to receive their electrical energy from either a competitive retailer or a regulated retailer (known as the regulated rate option (RRO) provider). Generally, the Commission has limited involvement with the interactions between competitive retailers and their customers.[28] For the RRO providers,[29] each distribution utility must make available to eligible customers[30] in its service area the option of purchasing electricity services in accordance with a regulated rate tariff, as an alternative to purchasing electricity services from a competitive retailer. For each of the RRO providers under the Commission's jurisdiction, the Commission approves the energy price-setting plan that describes how its regulated rate is calculated each month. The Commission also verifies that the monthly RRO rates were calculated in accordance with the approved methodology.

55. The transmission and distribution segments of Alberta's electric industry, by comparison, continue to be regulated. Alberta has several transmission and distribution utilities, and each of these utilities has an exclusive service territory. The largest transmission and distribution utilities are regulated by the Commission.[31]

56. The AESO is an independent, not-for-profit corporation established under the *Electric Utilities Act*. The AESO is responsible for the safe, reliable and economic operation of the AIES and for promoting a fair, efficient and openly competitive market for electricity.[32] It does so, in part, by planning and operating the transmission system, providing those that wish to participate in the electricity markets a reasonable opportunity to do so, as well as dispatching electric energy on the basis of economic merit.

57. Alberta's deregulated energy market relies on a substantially congestion-free transmission system to provide market participants a reasonable opportunity to exchange electric energy and ancillary services, thereby facilitating a province-wide level playing field and robust pricing signals in the wholesale electricity market.[33] Another cornerstone of Alberta's transmission policy is that load customers pay for most of the costs of the transmission system.

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27 *Hydro and Electric Energy Act*, Section 3(1).

28 Customer complaints about billing may be filed with and addressed through the Market Oversight and Enforcement division of the Commission.

29 *Regulated Rate Option Regulation*, Section 2.

30 Customers who consume less than 250,000 kW hours of electrical energy per year are eligible to receive electricity service under the RRO rate pursuant to the *Regulated Rate Option Regulation*.

31 These include AltaLink Management Ltd., ATCO Electric, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc. and FortisAlberta Inc.

32 *Electric Utilities Act*, Section 16(1).

33 *Transmission Regulation*, Section 15, *Electric Utilities Act*, sections 17(b) and 29.

This is colloquially referred to as "load pays for wires." On the other hand, the current regulatory framework requires owners of generators to pay for the cost of transmission system losses.[34]

58. Each of the distribution utilities is responsible for making decisions about building, upgrading and improving its electric distribution system in order to provide safe, reliable and economic delivery of electric energy, to operate and maintain the electric distribution system in a safe and reliable manner, and to provide service that is not unduly discriminatory.[35] The four electric distribution utilities regulated by the Commission are subject to a performance-based regulation (PBR) framework. Under PBR, rates are calculated by adjusting prior-year rates using a formula that incorporates inflation (I) and productivity growth (X), the so-called I-X mechanism. The PBR formula also includes items outside of the utilities' control, such as flow-through costs, exogenous events, and an additional provision for capital projects.

59. For additional background on the current structure and organization of Alberta's electricity industry, see the AUC's Final Report for the Alberta Electric Distribution System-Connected Generation Inquiry (Proceeding 22534).

3.2 Generation and load configurations and their regulatory pathways

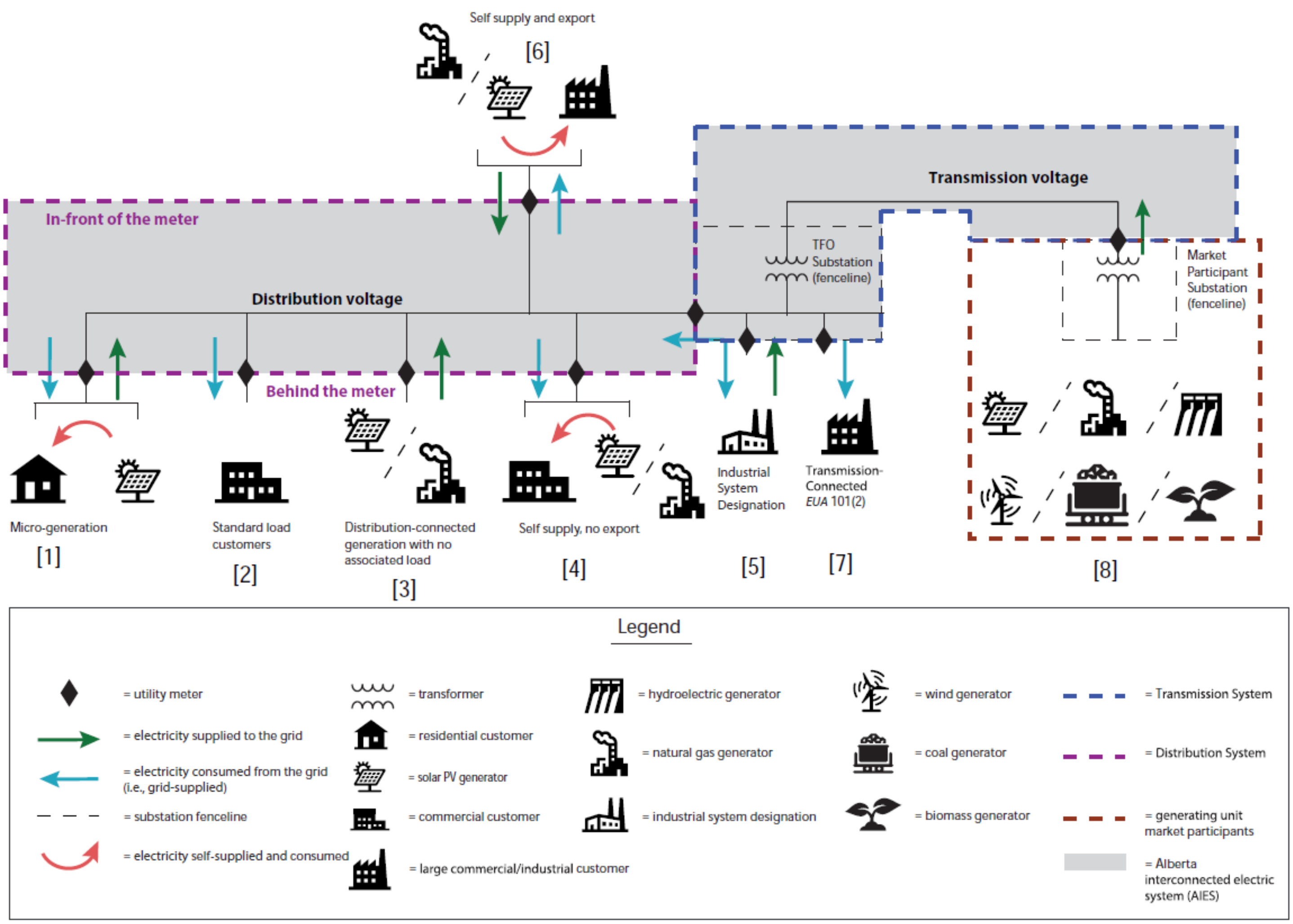
Key takeaways:
A multitude of statutory and regulatory provisions exist for DERs to connect to the distribution system. In some cases, regulatory pathways overlap for certain DERs and connection configurations. In other cases, certain DERs and connection configurations have no defined regulatory pathway that would allow for grid connection. Each regulatory pathway is designed for a particular subset of DERs and connection types, creating its own unique set of incentives particular to that regulatory pathway. However, despite the apparent complexity, in almost every case where an issue was raised by parties in this inquiry, it can be viewed in terms of the implied value associated with some or all of the three flows of electricity: (i) payments made for electricity drawn from the grid; (ii) payments received for electricity supplied to the grid; and (iii) savings (avoided costs) resulting from self-supply, less the cost to install and operate the DER.

60. As described in Section 2, it is widely expected that, in the future, distribution systems will need to be able to accommodate the increased variability in the flows of energy entering and leaving the AIES.[36] This section introduces, at a very high level, the most commonly observed present-day generation and load configurations, and associated regulatory pathways, that result in the flows of electricity entering and leaving the electric system. The purpose of providing this analysis is to be able to more readily identify gaps between the status quo and the expected grid of tomorrow. The report will then rely on the same schematic illustrations to identify and explain the various issues that parties raised during the inquiry.

34 *Transmission Regulation* Section 31; ISO Rule 501.10.
35 *Electric Utilities Act*, Section 105(1).
36 Exhibit 24116-X0176, AESO Module One submission, PDF page 18; Exhibit 24116-X0578, Fortis Combined Module submission, paragraph 12.

61. For this examination, the report relies on an illustration of select generation and load configurations on the AIES, presented to parties in the Commission's preliminary IRs to the Combined Module. Figure 5 below is a modified reproduction of that image.

Figure 5. Illustration of generation and load configurations on the AIES



62. Traditionally, the grid was designed to connect load customers with generation assets typically in a one-way flow of electricity. With reference to the figure above, this would mean electricity flowed from transmission-connected generation [8], to load customers (i.e., customers that do not have generation) connected to the distribution system [2]. Several large customers are connected directly to the transmission system [7].[37] When compared to transmission-system connected generation [8], distribution-connected generation [3] is a small component of total

[37] The term "transmission-connected load" is often used in the following contexts:

1. A customer of the distribution utility (Direct-connect, Rule 021: *Settlement System Code Rules*). In this case, the distribution utility owns the customer's meter and provides the meter data management functions, but otherwise the AESO's Rate DTS (demand transmission service) is flowed through to the customer. Generally these customers are still placed in distribution facility owner (DFO) rate classes and could be considered to be represented by [2] in Figure 5.
2. A customer of the AESO. Here, a customer who has been relinquished from the DFO service territory as per Section 101(2) of the *Electric Utilities Act* and is responsible for their own meter data management and load settlement. This is shown as [7] in Figure 5.

electricity production in Alberta; however, it is not a recent or unknown development in the province.[38] As mentioned in the previous section, all electricity provided by generators (green arrows) and consumed by load (blue arrows) through the AIES is exchanged through the wholesale electricity market, with a few exceptions.

63. Self-supply customers [4] experience two flows of electricity. They consume electricity generated on-site (red arrow), and cover the rest of their electricity needs by drawing energy from the grid (blue arrow). They never supply electricity to the grid. The statutory scheme in Alberta expressly allows persons[39] to generate, transmit or distribute electric energy on their own property for their own use. Under Section 2(1)(b) of the *Electric Utilities Act*, a person may produce electricity on a property that they own or are the tenant of, if the electricity is consumed solely by that person and solely on that property without being subject to regulation under the *Electric Utilities Act*.

64. Regulatory pathways for customers with three flows of energy (that is, electricity (i) consumed from the grid; (ii) self-supplied; and (iii) supplied to the grid), which customers are also referred to as "self-supply with export customers," are less well defined. The Commission concluded in a series of recent decisions, and a related discussion paper, that in the absence of a statutory exemption, the owner of a generating unit that serves on-site load is prohibited from exporting excess electricity produced on-site for sale in the wholesale electricity market. Referring to Figure 5, one possible arrangement in which self-supply with export is possible applies under the *Micro-generation Regulation* to customers with generation less than 5 MW, subject to certain other requirements [1].[40] Other instances of allowed self-supply with export include generating units co-located with load that have received an industrial system designation (ISD) [5], generating units connected under the municipal own-use exemption, and generating units under the *Flare Gas Generation Regulation*. Each of these regulatory pathways is designed for a particular subset of generation and connection types, creating its own unique set of incentives particular to that pathway. All other configurations involving self-supply with export that are not otherwise authorized by an enactment have no defined regulatory pathway and are currently functioning as legacy facilities [6].[41]

65. Many of the load and generation configurations presented in Figure 5, and their respective regulatory pathways, or lack thereof, were subject of an in-depth discussion and debate in the inquiry, contributing to parties' and the Commission's understanding of these

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38 Proceeding 22534, Alberta Electric Distribution System-Connected Generation Inquiry, Final Report, December 29, 2017, paragraph 114.

39 As defined by the *Electric Utilities Act* at Section 1(1)(kk), a person includes an individual, unincorporated entity, partnership, association, corporation, trustee, executor, administrator or legal representative.

40 The *Micro-generation Regulation* sets out separate regulatory treatment for two DER connection configurations:

- "small micro-generation" generally refers to a system with nameplate capacity less than 150 kW, that exclusively uses sources of renewable or alternative energy, and is intended to provide all or a portion of the customer's total annual energy consumption at the customer's site.
- "large micro-generation" generally refers to a system with nameplate capacity of at least 150 kW, but not exceeding 5 MW that uses sources of renewable or alternative energy only, and is intended to provide all or a portion of the customer's total annual energy consumption at the customer's site. A large micro-generation customer also could be a customer that has less than a 150 kW system installed, but also has a bi-directional *interval* meter installed (not a bi-directional *cumulative* meter).

41 Self-supply and export – Alberta Utilities Commission discussion paper, June 5, 2020; https://engage.auc.ab.ca/11140/widgets/62166/documents/37607.

matters. The report will further address issues related to several (above-described) configurations in Section 4 of this report. However, a detailed description of each of the configurations and associated regulatory pathways is not necessary here given the Commission's previous publications on this subject. Specifically, the Commission's final report on the DCG Inquiry presents a detailed and comprehensive description of all matters related to DCG in Alberta.[42] The Commission's recent discussion paper on self-supply with export, referenced earlier in this section, provides an in-depth analysis of permissible self-supply with export connection configurations under the existing statutory scheme.[43]

66. Despite the apparent complexity, all possible load and generation configurations depicted above can be thought of in terms of the energy flows they create. Although the increase in two-way flows of electricity on the distribution system (that is, electricity drawn from, and electricity supplied to, the system) was the focus of a great deal of the discussion, an understanding of the third flow of electricity depicted above – namely, that of self-supply – is necessary to understand the incentives for installing DERs. The report further notes that in almost every case where an issue was raised by parties in this inquiry, it can be viewed in terms of the implied value associated with some or all of the three flows of electricity:

(i) The payments made for electricity drawn from the grid (blue arrow).

(ii) The payments received for electricity supplied to the grid (green arrow).

(iii) Savings (avoided costs) resulting from self-supply, less the cost to install and operate the DER (red arrow).

67. To aid in the understanding of the price signals that customers currently face, Section 3.3 provides a simple but illustrative example of the prices faced by a customer engaged in all three flows of energy.

[42] Proceeding 22534, Alberta Electric Distribution System-Connected Generation Inquiry, Final Report, December 29, 2017.

[43] Self-supply and export – Alberta Utilities Commission discussion paper, June 5, 2020; https://engage.auc.ab.ca/11140/widgets/62166/documents/37607.

3.3 An illustrative example of a customer with three flows of energy (i.e., self-supply with export)

Key takeaways:
The following three flows of energy provide a useful construct to understanding a customer's interaction with the electric grid: (i) drawing electricity from the grid; (ii) self-supplying; and (iii) supplying electricity to the grid. Metering configuration, specifically the location of the meter, and the metering practice being followed (such as net metering, net billing or gross metering) to measure on-site load and generation, are key determinants of the "energy flow" of self-supply. The metering configuration determines whether and how each of the energy flows will be measured, and what billing units can be applied to them. The metering configuration influences the implied value of the energy flows, specifically for self-supply. Together, metering configuration and metering practice are key determinants of the incentive to self-supply.

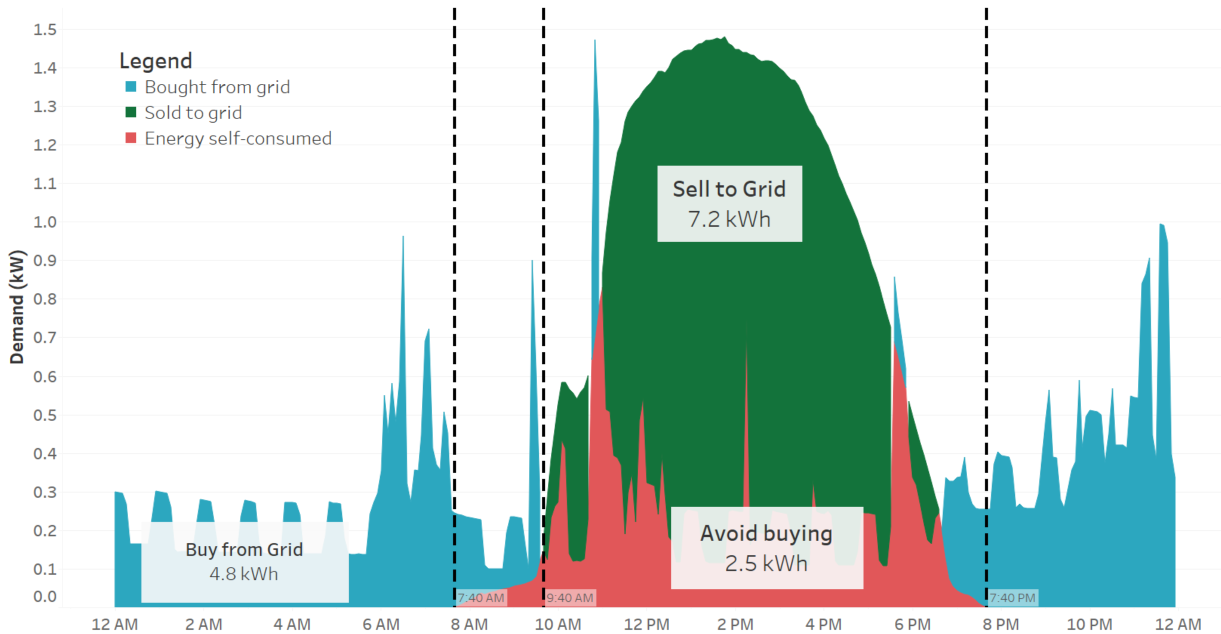
68. An understanding of the three flows of energy, what they represent and their underlying price signals and incentives, as presented in Figure 5, is critical to understanding all the other concepts presented in this report. Towards this end, this section provides an illustrative example of the energy flows and prices faced by a customer engaged in all three flows of energy, that is, a self-supply with export customer. This example is based on the case of a small microgeneration customer with solar PV, as presented in the Commission's preliminary IRs.[44] However, this example can easily be generalized to explain the basic concepts applicable to any self-supply with export customer.

3.3.1 Flows of energy involved

69. Figure 6 below shows flows of energy over the course of 24 hours for a small microgeneration customer with an on-site supply-side DER. The colours represent the same energy flows as those shown in Figure 5 above but, in this case, they show the demand (height of the curve) and the total volume (coloured area under the curve).

[44] Exhibit 24116-X0470, AUC Preliminary IRs to All Parties, November 29, 2019.

Figure 6. Flows of energy for a small micro-generation self-supply with export customer: from the customer's point of view

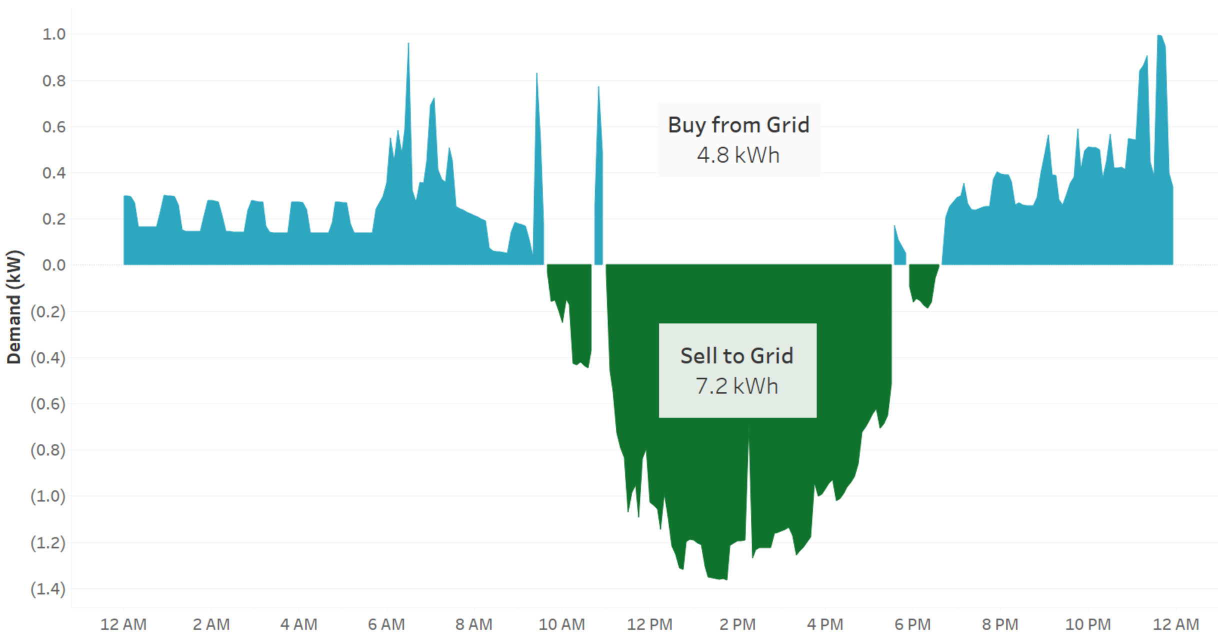


70. As can be seen from this illustration of a 24-hour period (commencing at midnight), when the customer's on-site generation DER is not producing any energy (the exclusively blue area in Figure 6), from 12 a.m. to 8 a.m. and again between 8 p.m. and midnight, that customer only consumes energy from the grid. In other words, the customer is engaged in only one energy flow – drawing energy from the grid. During these hours, that customer appears just like any other load customer from the utility's point of view.

71. Starting at 8 a.m. (shown by where the red area starts in Figure 6), the customer's DER ramps up its generation of electricity, resulting in the customer drawing less electricity from the grid and meeting an increasing amount of its own energy needs by on-site generation. The customer is now engaged in two flows of energy – namely, consuming from the grid as well as consuming self-supplied electricity produced on-site (overlapping blue and red areas in Figure 6). A utility would see the customer's load decreasing between roughly 8 a.m. and 10 a.m.

72. By 10 a.m., the customer's on-site generation has increased to the point where it meets all of the customer's energy needs. The customer stops drawing electricity from the grid and starts supplying excess electricity being produced to the grid. The customer is now engaged in a different set of two flows of electricity – consuming produced electricity and supplying electricity to the grid (overlapping red and green areas in Figure 6). At that point, the utility would see the customer not as load, but as a generating unit, supplying electricity to the grid. The customer's generation would reach its peak just before 2 p.m., at which point the process reverses. What is visible to the utility, as recorded by the meter is depicted in the image below.

Figure 7. Flows of energy for a small micro-generation self-supply with export customer: from the utility's point of view[45]



73. The customer's on-site generation starts declining and, at some point after 6 p.m., the customer stops supplying electricity to the grid and reverts to being a load customer again. As on-site generation continues to decline, the customer's draw of electricity from the system increases. At around 8 p.m., the on-site DER stops producing electricity and the customer resumes securing all of its electricity needs from the grid.

74. There are a few brief periods of time during the day (at around 10 a.m. and at 6 p.m.) when the customer's on-site generation perfectly matches its electricity needs, thus neither drawing electricity from, nor supplying electricity to, the grid at all. In Figure 7, these points in time are shown at 0.0 kW demand (neither blue nor green). During these times of the day, the customer is engaged in solely one flow of energy, that of self-consumption (red area in Figure 6). These points in time are very brief (almost instantaneous) because of the technology and fuel source used in the illustrative example (solar PV). However, other DERs (such as a gas turbine or a battery) are able to match on-site generation with load more precisely for sustained periods of time.

3.3.2 Importance of metering configuration

75. Metering configuration, specifically the location of the meter(s),[46] and metering practices measuring on-site load and generation, are key determinants of the incentives facing each of the

45 As is explained further in Section 3.2, this image represents the point of view of a single meter with separate registers for (i) drawing electricity from the grid; and (ii) supplying electricity to the grid. Both net metering and net billing metering practices are possible.

46 In Exhibit 24116-X0708, AESO-AUC-2020JUN03-009, the AESO pointed out that two aspects of measurement are important when discussing the location of metering: (i) revenue metering for the purposes of determining energy payments or charges and allocating wires costs; and (ii) supervisory control and data acquisition (SCADA) for the purposes of energy market dispatch compliance (if applicable). This section deals with the first aspect. The second aspect, SCADA for the purposes of energy market dispatch compliance, is discussed in Section 4.4.1.

generation and load configurations presented in Figure 5. The metering configuration determines whether and how each of the energy flows described in the previous sections (drawing electricity from the grid, self-supplying, and supplying electricity to the grid) will be measured, and what pricing structure (i.e., billing units) can be applied to them. This (price times the volume) determines the economic value of each of the energy flows which, in turn, determines just how strong or weak the incentive is to install DERs.

76. Three metering practices for measuring on-site load and generation were mentioned by parties in the inquiry: net metering, net billing, and gross metering (buy all/sell all). Definitions of these metering practices are provided in the text box below. As set out in the textbox, there is no consistent definition of "net metering" with different jurisdictions employing different variations of this metering practice. As such, the term "net metering" can be quite ambiguous and of limited assistance unless the specifics of the metering configuration are known.

77. Often, a particular metering practice is determined by the type of meter that is available as well as the physical location of the meter. For example, if a mechanical meter with no ability to separately record inflows and outflows of electricity is installed, then net metering is the only choice. If a meter that separately records the inflows and outflows of electricity is available, then net billing is possible (net metering can also be implemented in this situation by applying the same prices to inflows and outflows of energy).

Metering practices[47]

Net metering: A practice in which the energy supplied to the grid is netted against, or subtracted from, the energy drawn from the grid. There are many ways in which this netting may be done and, as a result, many jurisdictions have their own unique ways of defining "net metering" based on policy and the type of meters installed. For the purposes of this report, net metering is considered as a practice of billing (crediting) the customer for the sum of all net (i.e., offsetting) energy flows for a billing period with the prices applied to drawing electricity from the grid ("buy" rate) being equal to the prices applied to supplying electricity to the grid ("sell" rate). Therefore, the customer is indifferent between self-supplying electricity and selling it to the grid, as it has the same value applied to it in both cases.
This type of net metering can be done using a single meter without separate registers running forwards (backwards),[48] should a customer be a net consumer (producer) at any given time for the billing period. It can also be done with separate registers on the same meter or multiple meters at different locations, by offsetting energy flows (possibly across different time periods) at the same price.

Net billing: A metering practice in which a customer has separate readings for (i) drawing electricity from the grid; and (ii) supplying electricity to the grid, either as a result of having separate registers on the same meter or multiple meters at different locations. The customer's bill is calculated as the net of the energy flows at an instantaneous point in time. Once the energy flows are subtracted from each other at a given point in time, the net flow is measured and has a price applied to it. Thus, during periods when the customer

47 Based on Exhibit 24116-X0571, CRA Combined Module submission for the CCA, pages 32-33.
48 Where allowable.

is not a net supplier but is self-supplying some portion of its demand, it is able to consume from on-site generation and reduce its billing volumes, and possibly reduce any peak charges. Because the two energy flows for grid consumption and export are measured in separate registers (or meters), distinct prices can be applied to electricity drawn from the grid ("buy" rate) and electricity supplied to the grid ("sell" rate). Generally the "buy" rate is greater than the "sell" rate, due to the inclusion of wires charges in the "buy" rate, so the customer is better off matching load with on-site generation and self-supplying. This metering practice corresponds to the metering practice depicted in the illustrative example in the previous Section 3.1 (flows of energy).

Gross metering (buy all/sell all): A metering practice where there is no netting of energy flows (i.e., no red self-supply area). All consumption is metered with no adjustment for on-site generation, and that quantity is used to calculate a customer's bill. Any and all generation is metered separately on a separate meter, is sold to the grid, and the "sell" rate applies (which may or may not be the same as the "buy" rate). In other words, on-site generation cannot be used to offset consumption.

As noted earlier in this textbox, there is no consistent definition of "net metering." Some jurisdictions refer to what is defined here as "net billing" as a form of "net metering." Therefore, when considering and comparing metering practices, particularly across jurisdictions, the following aspects need to be taken into account: how the flows of energy are measured (i.e., on separate registers/meters, or on one); over what time period the flows of energy are netted (i.e., over a sub-hourly interval, or across monthly or annual billing cycle); what price is applied to the flows of energy (i.e., whether the price is different or not, and whether this changes over time); and when the price is applied (i.e., before or after any netting of energy flows).

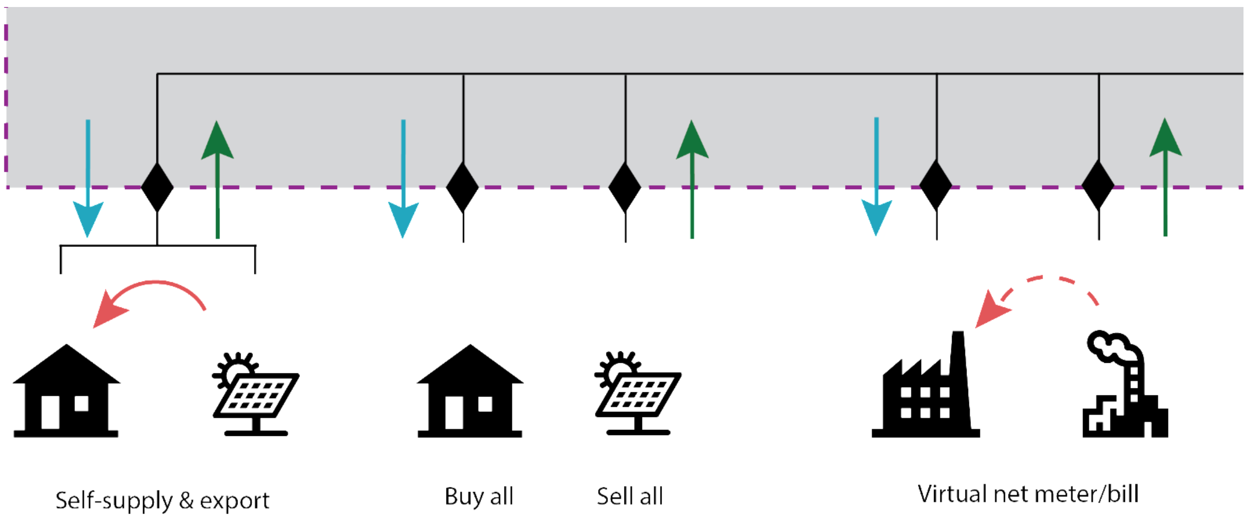
78. The physical location of the meter is also important because it determines whether a particular energy flow can be measured and, in part, determines the metering practice that will be used. On the left side of Figure 8 below, the meter is placed in such a way that the customer's generation and load are netted before the meter. This could correspond to the metering practices of net metering or net billing, depending on the regulatory framework and assuming the single meter has two registers. Due to the meter placement, only the net flows (i.e., net load or net supply) present themselves to the distribution system. This allows the customer to consume self-supplied electricity (red arrow) before consuming from the grid.

79. In contrast, in the middle of Figure 8, two meters are placed to measure customer generation and load separately. This metering configuration can be used to enable gross metering (buy-all/sell-all) and eliminates the ability to self-consume energy (i.e., no red arrow).

80. In a third scenario, shown on the right side of Figure 8, the readings of the two meters can be netted or "totalized" resulting in de-facto (or "virtual") net metering or net billing. The Commission is aware that there are large customers in the province (such as industrial system designations, or ISDs) with several meters at the points of connection to the distribution or

transmission systems where the hourly readings on these meters are totalized to arrive at a net result and respective "buy" or "sell" prices apply consistent with the net billing practice.[49]

Figure 8. Location of the meter can determine the ability to self-supply



81. Figure 9 below shows energy flows that are read by the meter under the metering practices shown above. On the left side of Figure 9, the meter registers only the net flows (i.e., net load or net supply). On the right side of Figure 9, all of the customer's generation is assumed to be supplied to the grid and all of the customer's consumption is assumed to be drawn from the grid. Both flows are visible to the utility (i.e., there is no masked load). In other words, the energy volumes drawn from the grid under buy-all are higher than in the left of Figure 9 as no energy is being self-supplied. Similarly, under sell-all, all volumes are supplied to the grid, instead of selling only excess energy to the grid.

49 The Commission notes that the metering practice described here for ISDs is also sometimes referred to as "net metering." However, in this case, the terminology is used in a more general sense to describe the netting of flows of energy. An important distinguishing factor in metering practices is the price(s) applied to the flows of energy that are netted against each other. Thus, a distinguishing feature of net metering described in the textbox is that the same prices are applied to drawing electricity from the grid ("buy" rate) and supplying electricity to the grid ("sell" rate), which is not the case for ISDs. Similarly, the Commission notes that the term "totalization" is also sometimes used to describe how energy flows are netted, but this term is ambiguous because it is unclear whether the totalization occurs behind the meter or in front of the meter.

Figure 9. Illustrative comparison of the different metering configurations (net billing and gross metering)

Self-supply with export customer with a single bi-directional meter used to record energy flows

Sell-all

Buy-all

82. Location of the meter and metering practice are important and related concepts. The location of the meter determines whether a particular energy flow *can* be measured, whereas the metering practice dictates whether it *should* be measured and what prices should be applied to the flows.

3.3.3 Impacts to customer bill

83. Dr. Faruqui, an independent consultant retained by ATCO, pointed out that, ultimately, what customers care about most is their total electricity bill, as opposed to the individual components of their bill.[50] He and Dr. Orans, an independent consultant retained by Fortis, further noted that if the total bill is unacceptably high, customers now have options to install technologies that could reduce their bills. Moreover, the incentive to install such new technologies will continue to grow as their price declines relative to customer electricity bills.

84. Referring again to Figure 6, for a customer that installs a DER and engages in three flows of energy, the total cost of electricity is a function of the implied value associated with all three energy flows: (i) the payments made for electricity consumed from the grid (blue area); (ii) payments received for electricity supplied to the grid (green area); and (iii) savings (avoided costs) on account of self-supplied electricity, less the cost to install and operate the DER (red area).

85. In Alberta, the amount a customer pays for grid-supplied electricity is the sum of the following billing components:

50 Exhibit 24116-X0716, Transcript, Volume 1, page 26.

- Commodity charge for the customer's consumption of electric energy. The commodity charge recovers the retailer's cost of purchasing the electrical energy on behalf of customers. It is billed as a volumetric charge ($/kWh).
- Administrative charge to recover the cost of retail services.[51] It is typically billed as a fixed monthly fee.
- Delivery charges to recover the cost of the transmission and distribution systems. These are typically billed as a combination of a fixed monthly fee, a volumetric charge, and/or a demand charge ($/kW or $/kVA).
- Local access fee imposed by a municipality.[52] Depending on the municipality, it is billed either as a volumetric charge or as a percentage of wires charges, or a combination of the two.

86. Generally, the Commission only regulates the delivery charges (transmission and distribution, as well as the adjoining rate riders[53]), and does not regulate the energy charge for the commodity, the administration charge levied by competitive retailers, or the local access fee.

87. Regarding payments received for electricity supplied to the grid, DERs that generate electricity typically receive the pool price from the Alberta wholesale market, but may have other financial agreements for energy supplied (for example, through forward contracts or bilateral agreements).[54]

88. Savings (avoided costs) attributable to self-supplied electricity are a function of the billing components that can be avoided by installing DERs as well as the metering arrangements. As shown in Table 1, a customer engaging in self-supply is able to avoid the (horizontal) sum (shown in column (F)) of the volumetric charges otherwise applicable to the consumption of energy that are typically levied in each of the following product and service categories: commodity, distribution, transmission and miscellaneous. Depending on the exact type of demand charge,[55] the customer may also be able to avoid or reduce certain demand charges by modifying its consumption of energy.

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51 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.

52 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.

53 Rate riders are used to flow through or reconcile costs that are incurred by a distribution wire owner, which 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.

54 As will be discussed in Section 4.4.2, small micro-generators are an exception and are compensated for the electricity they supply to the grid under a separate mechanism.

55 Demand charges vary widely between distribution utilities, by both the design of the rates and how they are determined, but are typically based on "billing capacity," which is determined to be the greatest of:
(i) The highest metered demand during the billing period (approximately 30 days).
(ii) 90 per cent of the highest demand in the last 12 months (or 24, in the case of transmission-connected customers). This arrangement is also referred to as a demand ratchet.
(iii) The contract demand.

Table 1. Billing components for energy drawn from the grid

	Charges for energy drawn from the grid					Effective value of energy consumed on-site
	Commodity	Retail administration	**Distribution (regulated by the AUC)**	**Transmission (regulated by the AUC)**	Miscellaneous (e.g., local access fee)	
	(A)	(B)	**(C)**	**(D)**	(E)	(F)
Volumetric (energy) charge	$/kWh		$/kWh	$/kWh	$/kWh	Avoidable through self-supply
Demand charge			$/kW/day for billing capacity	$/kW /day for billing capacity		May be avoidable through self-supply (depending on the type of a charge)
Customer charge		$/month	$/month			Non-avoidable

89. Returning to the illustrative example of a small micro-generation customer presented at the start of this section (Section 3.3), Table 2 below applies illustrative prices to the energy flows depicted in figures 6 through 9.[56] Column (F) shows the effective value of self-supplied and consumed electricity. Note also that a column (G) has been added to Table 2. The illustrative prices selected for this table show that the customer receives greater value from self-supply of electricity than from exporting it to the grid. This incentive exists in all self-supply, and self-supply with export, configurations (for example, those shown in Figure 5) where the sum of the volumetric charges (and demand, if applicable) for electricity consumed from the grid is greater than the price received for electricity exported to the grid. In Table 2, the illustrative prices for energy consumed on-site are $0.14/kWh compared to $0.05/kWh for energy exported to the grid. This means, from a total bill perspective, that the customer is incented to match generation output from DERs with its load, as this creates a higher value stream for the customer by avoiding portions of the distribution tariff.[57] Although not shown in Table 2, the same mechanisms exist for customers exposed to demand charges – they are incented to self-supply and consume energy produced on-site in different ways and at different times to lower their demand charges.

56 Figure 6 shows that on this day, the customer uses 7.3 kWh, of which 4.8 kWh is bought from the grid and 2.5 kWh is consumed from self-produced energy. 9.7 kWh is produced from the DER, of which 2.5 kWh is consumed on-site and 7.2 kWh is sold to the grid. The calculations below assume this daily usage was repeated over a 30-day month. See Appendix 4 for a more detailed account of the calculations.

57 Supply-side DERs generally are advantaged to capture this difference by aligning on-site generation with load (to arrive at the lowest cost of electricity consumed) rather than maximizing energy export and achieving only the wholesale rate for energy.

Table 2. Billing components for consumption for a small micro-generation customer under a hypothetical residential rate class[58]

	Charges for energy **drawn from** the grid (i.e., blue area in Figure 6)					Effective value of energy consumed on-site* (i.e., red area in Figure 6)	Energy sold to the grid (i.e., green area in Figure 6)
	Commodity	Retail administration	Distribution	Transmission	Miscellaneous		
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Energy charge	$0.07/kWh		$0.01/kWh	$0.04/kWh	$0.02/kWh	$0.14/kWh	$0.05/kWh[59]
Customer charge		$6/month	$20/month				

* Note: The effective value of energy consumed on-site is the sum of all charges avoided by self-consuming the DER-generated electricity.

90. From the customers' point of view, their electricity bill is the highest under the gross (buy-all/sell-all) metering practice because it removes the ability to self-supply. All produced electricity is assumed to be sold to the grid and then bought back, with attendant wires charges. This reduces the benefit of installed DERs. But from the utility's point of view, this metering practice is preferable because there is no bypass (either economic or uneconomic).

91. The metering practice most advantageous from the customer's perspective is net metering. As described in the textbox in Section 3.3.2, this practice equates the prices applied to drawing electricity from the grid ("buy" rate) to the prices applied for supplying electricity to the grid ("sell" rate). Further, energy flows across different time periods may be netted against each other. Therefore, this creates the highest price signal to avoid (bypass) the wires charges.

92. The metering practice most often used in Alberta where self-supply with export is permitted is a form of net billing. This metering practice provides a middle ground of sorts, in that it allows for netting energy flows that occur instantaneously (i.e., self-supply). Numerical examples demonstrating the above are provided in Appendix 4.

58 These hypothetical rates were obtained by averaging the discrete elements of ATCO Electric's D31, ENMAX's D300, EPCOR's medium commercial rate, and Fortis's Rate 61. While such an averaging does not constitute a representative rate for a typical residential customer in Alberta, it provides a useful illustration of the concepts discussed in this report.

59 For simplicity, it is assumed that the customer gets credited at the wholesale market rate in all scenarios. As explained in Section 4.4.2, small micro-generation customers would get credited at their retail rate under the net billing arrangement.

3.4 The problem of uneconomic bypass

Key takeaways:

Uneconomic bypass describes a situation where a customer's bypass decision (i.e., supplying its needs through other means) shifts the recovery of fixed system costs, in whole or in part, to other customers due to tariff design. It is important to emphasize that from an individual customer's perspective, all bypass is economic since that customer would presumably only choose to bypass the electricity grid if it is in their own economic interest. Uneconomic bypass is thus meaningful only when considered from the perspective of society as a whole.

93. As will be further discussed in Section 5.2 on tariffs, utility rates are not merely blunt instruments for recovering costs. Whether intended or not, they send price signals to customers (users of the electric system) driving different behaviours and affecting their consumption of grid services. If those price signals are effective, each customer connected to the distribution system will be prompted to use the amount of distribution services (namely, electricity and the physical capacity for its delivery when needed) that reflects what they are willing to pay for. This results in what is called "economic efficiency":

> From the standpoint of economic theory, efficiency implies that every resource is optimally allocated to serve each individual or entity in the best way, while minimising total system costs. This means that goods or services are consumed by whoever benefits most from them and that they are produced at the lowest cost.[60]

94. In contrast, when distribution price signals are not efficient, the opposite occurs:

> … network users could act in inefficient ways, where they will consume either too much or too little network capacity or energy, compared to the optimal consumption level. If they consume too much, when they could instead have regulated their demand, it will lead to a situation where the network is overly expensive, as it would need to be expanded to accommodate this demand, compared to a situation with cost-reflective tariffs, which signal whether network users should regulate their demand. If too little is consumed, the opposite situation will occur, leading to overpriced distribution services and an underutilised network, which deviates from the optimal level of social welfare.[61]

95. In the short term, customers may respond to inefficient pricing by consuming either too much or too little of the distribution system services "at the wrong time" as described in the quote above. For example, they may consume too much electricity when the system is constrained or they may consume too little electricity when the system has available capacity. This behaviour, while resulting in a temporary congestion (in the former case) or idling (in the latter case) of the system, is rectified relatively easily by correcting prices because customers have not yet made any irreversible decisions.

96. In the long term, however, customers may respond to inefficient pricing by making long-term investments to reduce their utility bill and that decision is not easily reversible. This gives rise to a problem referred to as uneconomic bypass. In this case, "bypass" refers to a customer

[60] Exhibit 24116-X0650, Council of European Energy Regulators (CEER) paper, PDF page 9.
[61] Exhibit 24116-X0650, CEER paper, PDF page 9.

bypassing the service of the utility (i.e., supplying its needs through other means), typically because of the ability to self-generate (supply-side DERs), but can also occur as a result of demand-side measures (demand-side DERs). An extreme case of bypass is grid defection, when a customer completely disconnects from the grid and entirely self-supplies its electricity needs.

97. In simple terms, **uneconomic bypass** describes a situation where a customer's bypass decision (i.e., supplying its needs through other means) shifts fixed cost recovery, whether in whole or in part, to other customers. This occurs when a customer's decision to self-supply electricity does not change (or even increases) system costs, but results in that customer paying a smaller share of the fixed costs. This unrecovered fixed cost must then be collected from other customers. Furthermore, because the customer made an investment and potentially incurred ongoing costs to self-supply, more money is being paid overall to deliver the same amount of service to all customers (including the one making the self-supply decision), making it a negative result for society.

98. In contrast, **economic bypass** occurs when a customer supplying its needs through other means results in reduced costs for other customers.[62] This happens when a customer's decision to self-supply electricity lowers system costs; so it is not only the self-supplying customer who is paying less for the system costs, but the costs for other customers are also reduced.

99. It is important to emphasize that from an *individual customer's perspective*, all bypass is economic since that customer would presumably only choose to bypass the electricity grid if it is in their own economic interest.[63] However, though profitable for an individual customer, "Uneconomic bypass wastes society's resources by creating new capacity that idles efficient, existing capacity"[64] thus increasing total social costs of providing a given level of service. Uneconomic bypass is thus meaningful only when considered from the *perspective of society* as a whole.

100. The vast majority of parties shared the view that rate design inadequacies are the principal drivers of uneconomic bypass, and that rectifying these shortcomings in rate design is the most effective means of discouraging what, from a societal perspective, constitutes wasteful economic behaviour. Dr. Orans (external expert retained by Fortis) observed that current distribution tariff structures in Alberta generally recover a significant portion of fixed system costs through either volumetric (on a $/kWh basis) or peak demand ($/kW) charges that can be avoided through the installation of DERs. This gives rise to several inter-related issues.

101. First, these prices tend to exceed the marginal costs of distribution service thus creating an artificially high perception of the marginal value of energy (i.e., the value of the next unit of

[62] On a more theoretical level, **uneconomic bypass** occurs when a customer's total incremental cost of self-supply (the cost of building the generating unit plus the operating costs) is (i) less than the total rate it pays the utility, making it a privately profitable decision for the customer; but (ii) greater than the utility's marginal costs (i.e., the cost of producing and delivering one more unit of energy), making it a negative result for society. **Economic bypass** occurs when a customer's total incremental cost of self-supply is less than the utility's marginal costs (as reflected in its rate to the customer). See *When Technology Gives Customers Choices, What Happens to Traditional Monopolies?* by S. Hempling, in Trends (American Bar Association, Section of Environment, Energy and Resources, July/August 2014), page 2. This paper is not on the record of the inquiry but is provided for additional information on uneconomic bypass.

[63] Exhibit 24116-X0716, Transcript, Volume 1, pages 26 and 100 (Dr. Faruqui) and page 35 (Mr. Friesen).

[64] *When Technology Gives Customers Choices, What Happens to Traditional Monopolies?* by S. Hempling, page 2.

energy available for consumption). This over-incents the installation of DERs. For example, as shown in the hypothetical example in Section 3.3.4, in Alberta the value of self-consumed generation for residential customers is in the order of $0.14/kWh, representing the avoided volumetric cost of wires (distribution and transmission), and energy charges averaged across the province. Of this amount, energy charges were assumed to be $0.07/kWh.

102. Second, as more DERs are installed, more and more customers are able to underpay for the fixed costs of the network, shifting costs to other customers and further exacerbating uneconomic bypass. Further, accommodating the increasing number of DERs will likely require grid upgrades, the costs of which will be disproportionately borne by the non-DERs customers under the variable rate frameworks. This type of cost shifting onto customers who do not adopt DERs will have a negative impact on rate and bill stability for these customers. With sufficient penetration of DERs, and with no changes to the existing rate structure, there is a risk that a distribution utility would experience billing determinants erosion, resulting in ever increasing per-unit charges. This, in turn, would incent more and more customers to install DERs to bypass those charges, and, if unmitigated, could, in the extreme scenario, lead to a utility "death spiral" when it can no longer collect its revenue requirement from a dwindling customer base. Parties acknowledged that this may be an issue in the future, but indicated that it is not an immediate concern given current and expected levels of DERs penetration in Alberta.[65]

103. Dr. Orans indicated that uneconomic bypass is a common result of DER adoption under traditional rate structures throughout North America. He provided examples of California and Hawaii, where a combination of factors resulted in the rapid growth of distributed solar. However, because of the volumetric rates and net metering practice, this led to cost shifting and higher charges to customers without rooftop solar. This, in turn, led to more adoption of these DERs, initiating a vicious cycle of utility revenue erosion and rising charges. In order to prevent uneconomic bypass, Dr. Orans urged that proper price signals and rate structures be put in place prior to large numbers of customers making significant investments in DERs because once that occurs, these situations have proven difficult to rectify.[66] Many parties agreed with this recommendation and offered their views on how to improve the distribution (and transmission) tariffs in Alberta. This report addresses the tariffs issue in Section 5.2.

104. The textbox below provides an example of uneconomic bypass that can stem from residential rooftop solar DERs under the net metering practice and a rate structure heavily skewed towards volumetric rates.

Example of uneconomic bypass:[67]

Net metering (and to a lesser degree, net billing) of residential rooftop solar is a classic example of uneconomic bypass. A customer with solar PV is able to considerably reduce overall consumption of electricity (and in the case of net metering, even reduce it to zero

65 Exhibit 24116-X0554, IPCAA Module One submission, PDF pages 2-3;
Exhibit 24116-X0579, E3 Combined Module submission for Fortis, PDF pages 11-12;
Exhibit 24116-X0578, Fortis Combined Module submission, PDF pages 54-55;
Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 18;
Exhibit 24116-X0577, EDTI Combined Module submission PDF page 7;
Exhibit 24116-X0569, ATCO Combined Module PDF page 9;
Exhibit 24116-X0570, Brattle Combined Module Submission, PDF pages 8-9.

66 Exhibit 24116-X0579, E3 Combined Module submission for Fortis, PDF pages 37-39.

67 This example is based on Exhibit 24116-X0579, E3 page 48, Q/A52, and Exhibit 24116-X0571, CRA, page 37.

on a monthly basis) and thus avoid the majority of volumetric charges. It is likely that solar customers are underpaying for the fixed costs of the grid, as they continue to use the grid extensively to balance their solar generation and load. Also, it is likely that their peak demand will remain unchanged (as it occurs in late evening), so by cost causation logic, the customer contribution to DFO revenue should likewise be largely unchanged. However, the traditional rate design for residential customers, with its heavy emphasis on volumetric charges, will allow for "rate bypass" wherein consumers are able to reduce a significant portion of their wires bill while still imposing nearly the same costs on the system.

In the aggregate, since rates must recover total embedded system costs, a dollar that is not collected through one customer or billing component must be recovered from another customer or billing component. Accordingly, given the assumptions underlying this example, as more customers install rooftop solar, there will be an increasing cost shift of the system's fixed costs from solar customers to non-solar customers.

105. This does not in any way suggest that customers should not be using DERs (such as solar PV) to satisfy their energy needs. The point is to ensure that the adoption of DERs by customers does not result in cost shifting to other customers. This means ensuring that customers adopting DERs pay tariffs that are based on cost causation and that send price signals that encourage efficient resource usage.

106. Returning to the hypothetical example in Section 3.3.3, from the distribution and transmission utilities' perspective, they "lose" (that is, "do not deliver") the 75 kWh[68] of energy that are self-supplied by the customer under the net metering and net billing approaches. Applying the illustrative distribution and transmission rates in Table 2 above, the distribution utility is missing 75 kWh of energy at $0.01/kWh or $0.75 in energy deliveries for the month. The transmission utility (in Alberta's case, the AESO) would be missing 75 kWh at $0.04 or $3 in energy deliveries for the month. As discussed further in this report, in Section 5.2, because of the predominantly fixed nature of distribution and transmission system costs, these amounts not recovered from the DER customer would have to be recovered from other customers.

68 2.5 kWh/day * 30 days.

4 Issues facing electricity industry uncovered through the inquiry

4.0 Summary of Section 4

108. This section (Section 4) of the report relies on Figure 5 (introduced in Section 3.2) and the idea of the three energy flows (presented in Section 3.3) as aids in examining the central issues presently facing the electricity industry according to parties to this inquiry. This report addresses these issues in the context of the principal connection configurations – load; generation; self-supply (no export), including demand-side management; self-supply with export; and several novel technology applications poised to affect the grid, such as microgrids, EVs and energy storage. As part of this analysis, consideration is given to the energy flows associated with these connection configurations, focusing, in particular, on how the type of meter and its placement (i.e., physical location) affects (i) the measurement of these energy flows; (ii) their pricing (or implied value); and (iii) the incentives these prices create to alter supply and/or demand behaviour.

109. Parties highlighted that, currently, tariff avoidance is a key motivation for installing DERs. This incentive is present in all DER-related installations and configurations used for self-supply, including supply-side DERs, demand-side DERs, self-supply with export and microgrids. Transmission and distribution tariffs, in conjunction with rate designs that have historically focused primarily on recovering total revenue requirements, rather than sending accurate price signals, and which have relied on, and are constrained by, simple metering arrangements, have created strong incentives to avoid tariffs. As explained in Section 3.4, tariff avoidance leads to cost shifting among customers, and uneconomic bypass of the grid, contrary to the public interest. Left unchecked, cost transfers resulting from tariff avoidance will strengthen the incentive for other customers to similarly bypass the system, exacerbating the harm and launching a vicious cycle of rising utility rates and more customers choosing to bypass the system by way of self-supply.

110. Parties also commented on tariff inconsistencies between transmission-connected generation (TCG) and distribution-connected generation (DCG). A more consistent, predictable, cost-reflective tariff design between the transmission and distribution elements of the system is a long-term objective. There are currently several matters related to differences in how TCG and DCG are treated that are being dealt with as part of ongoing proceedings related to the AESO tariff. More generally, several parties expressed a view that the current regulatory framework for connecting DERs often creates different incentives depending on the DER and connection configuration being considered.

111. As the rate of uptake of new technologies increases, it is important that the incentives market participants face promote efficient investment choices rather than socially uneconomic bypass or the exploitation of unfair or undue regulatory advantages. Parties cautioned that if these issues are not addressed, inefficient investment and higher wires costs may result in the short term, and may increasingly threaten the economic viability of the electricity system necessitating a more disruptive set of changes in the future. This point is underscored by the experience of certain jurisdictions – once large numbers of customers have made long-term (and potentially socially inefficient) investments in DERs, the situation becomes increasingly difficult to rectify.

112. To date, efforts to prevent uneconomic bypass have focused on either technical measures (such as the AESO's adjusted metering practice on the transmission system to limit the amount of local load offset by DCG) or administrative measures (such as limiting permissible generation and load configurations in recognition of their potential to bypass system costs[69]). However, given the advent of new technologies, with rapidly declining costs, available to virtually every customer from small to large, these measures are unlikely to result in a sustainable long-term solution. As noted in Section 3.4, and further discussed in Section 5.2, the most effective means of discouraging uneconomic bypass is to design rates based on costs to deliver the network service.

113. New technologies, such as EVs and energy storage, are starting to be adopted in Alberta. Parties pointed out that if not managed well (through (i) tariffs based on cost-causation, as well as (ii) grid planning and operation that takes DERs into account), these technologies could result in an increase in costs to serve these new loads. If managed well, however, these technologies can be leveraged to not only optimize the use of the current system (in the case of EVs) but to actually lower system costs through the provision of system services (in the case of energy storage). As numerous parties to this proceeding have stated, it is better to address these issues now, while the level of DERs penetration is still quite low, than to refrain from remedial action until the problem becomes larger, more acute and more difficult to solve.

114. All customers, whether or not interested in adopting DERs, will likely be affected by grid modernization prompted by the deployment of DERs. This is explored further in Section 5 of this report.

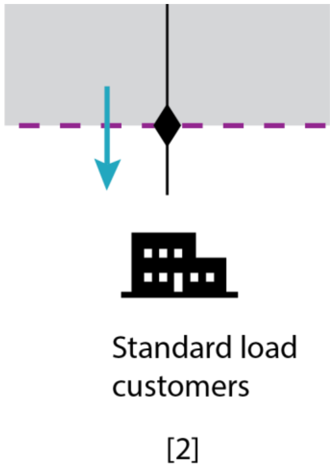
4.1 Electricity consumed from the grid (i.e., grid-supplied electricity)

Key takeaways:
All customers, whether or not interested in adopting DERs, will likely be affected by grid modernization undertaken in response to DERs because of the possibility of cost shifting if DERs are not integrated properly. It is in the best interests of all customers that this integration be successful.

115. The discussion and analysis of energy flows starts with the simplest and most familiar one – that of electricity consumed from the grid. In industry parlance, this is referred to as load, as shown in Figure 10. A representative example includes all residential homes and apartments, and most commercial businesses.

[69] As noted at page 29 of the AUC's recent discussion paper on self-supply and export, "both the legislation and associated policy documents emphasized that ISDs should not facilitate (a) the development of independent electric systems intended to avoid costs associated with the interconnected system; and (b) uneconomical bypass of the interconnected system. Presumably, the limited nature of the ISD exemption based on the strict criteria, coupled with the caution against uneconomic bypass, reflected the legislature's desire to preserve, where they are the most efficient solution, the monopolies of the transmission and distribution utilities." Similarly, the *Micro-generation Regulation,* Section 1(1)(h)(ii), limits the size of such units so as to just meet all or a portion of the customer's total annual energy consumption.

Figure 10. Load customer



116. Among the concerns most frequently raised by parties during the inquiry was how prices are set for electricity consumed from the grid. In particular, the issue of modernizing distribution (and transmission) tariffs for all customers to meet the exigencies of a modern grid and avoid the potential, unintended harmful effects arising from the proliferation of DERs was a matter of considerable focus and discussion. Given the complexity of and interrelationships between the many issues associated with this particular energy flow (including, for example, pricing of grid supplied electricity, uneconomic bypass, integration of DERs, grid planning and operation), these issues will be discussed in greater detail in Section 5.

117. At first blush, it might appear that load customers who do not adopt DERs would not have a stake in grid modernization, since their use of the grid would not appear to be affected. However, virtually every party to this inquiry expressly noted that the grid is paid for by all customers, and that the possibility of cost increases and/or cost shifting can arise if DERs are not effectively integrated into the grid. Thus, all customers, whether or not interested in adopting DERs, will likely be affected by grid modernization undertaken in response to DERs. Moreover, it is in their best interests that these efforts be successful.

4.2 Electricity supplied to the grid by DCG

Key takeaways:
Grid modernization will require significant thought and effort to ensure a level playing field for all sources of generation.

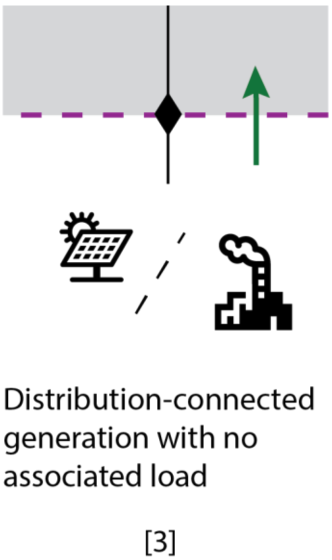
118. This section examines the configuration of pure-play DCG, that is, generation with no associated load[70] that supplies energy to the AIES at distribution voltages (i.e., nominal voltage of 25 kV or less). DCG is a subset of what is referred to in this report as DERs and, more

70 As noted by Lionstooth, "all power plants, whether they are connected to the distribution system or the transmission system, have on site electrical demands that must be served during all hours of operation, regardless of whether the plant is producing electricity or not. These electric loads can range from a few kWs for plant site lighting or site office loads, all the way to 10's of MWs for pump and fan drives in larger power generation facilities (larger than most DCGs)." (Exhibit 24116-X0528, PDF page 14.)

specifically, supply-side DERs. DCG may use various fuel sources including, but not limited to, solar PV, run-of-river hydro turbines, wind turbines and combustion turbines (including CHP units).

119. With reference to Figure 5, part of which is reproduced below, DCG produces a one-way flow of electricity, namely, supply to the grid.

Figure 11. Distribution-connected generation with no load



120. As noted in the Commission's final report for the DCG inquiry,[71] when compared to transmission-connected generation (TCG), DCG represents a small component of electricity production in Alberta (approximately one per cent of installed generation capacity in the province).[72] However, DCG is not a recent or unknown development in the Alberta electricity system, with many generating units having connected to distribution systems since industry deregulation in the mid-1990s.

121. Throughout this inquiry, parties called for a "level playing field" between TCG and DCG in order to incent economically efficient outcomes.[73] As the AESO stated, "from a wholesale energy-only market perspective, long-term investment in generation capacity and short-term dispatch to meet demand will be most efficient if all resources, both on the distribution systems and transmission system, respond to the same price signals."[74] AltaLink said that an "un-level playing field may result in tariff shopping between the transmission system and distribution system and incent investment on the distribution network even when such investments may result in an overall system cost increase."[75]

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71 Proceeding 22534, Alberta Electric Distribution System-Connected Generation Inquiry, Final Report, December 29, 2017, paragraph 114.

72 http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet as of September 2020: 16,245 MW. https://www.aeso.ca/market/market-and-system-reporting/micro-and-small-distributed-generation-reporting/ as of September 2020, 221 MW of DCG and micro-generation.

73 Exhibit 24116-X0562, Capital Power Combined Module submission, PDF page 2.

74 Exhibit 24116-X0594, AESO Combined Module submission, PDF page 7.

75 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 89.

122. Parties identified potential concerns with: (i) the allocation of transmission system costs, (ii) DCG credits, and (iii) differences in how the costs of transmission system line losses are attributed to TCG and DCG as contributing to inconsistencies between transmission and distribution tariff design.

123. With respect to the first issue, parties pointed out that in accordance with provincial legislation, the costs of the transmission system are generally recovered from load customers, with owners of generating units being charged their local interconnection costs[76] as well as a refundable financial contribution towards transmission system upgrades (generating unit owner's contribution). DCG proponents[77] raised concerns in this inquiry that some of the cost-sharing provisions in the AESO tariff (the so-called "substation fraction" mechanism) may have the effect of allocating costs of the transmission system to DCG.[78] Parties indicated that if, as a result of these provisions, DCG is levied a portion of the transmission system costs, this creates a non-level playing field in favour of TCG. This issue was recently decided in Decision 25848-D01-2020,[79] and, as such, will not be addressed further in this report.

124. Parties also pointed to the credits paid to DCG by some distribution utilities as contributing to a non-level playing field because no similar mechanism exists for TCG. A brief explanation of the DCG credit mechanism and related issues about which parties raised concerns is provided in Section 5.5.3. Capital Power stated, "As there is no comparable credit for transmission-connected generation, this out-of-market incentive leads to an unlevel playing field where transmission and distribution-system connected generation are not treated equally. This treatment undermines the FEOC [fair, efficient and open competition] operation of the electricity market and is a direct violation of the purpose of the EUA [*Electric Utilities Act*]."[80] AltaLink stated that DCG credits create a distorted energy market in which DCGs that receive the credits obtain an advantage over TCG or DCG without credits. Because these credits add an additional revenue stream to the DCGs that receive them, if such DCGs were to bid-in their energy into the market, it would be at a subsidized price in comparison to TCG that lacked access to such additional source of revenue.[81] The CCA[82] and the AESO[83] made similar observations.

125. While Kalina Power also called for a level playing field between DCG and TCG,[84] it still supported DCG receiving credits because, in its view, connecting DERs to the distribution system resulted in lower DTS costs, which allowed for cost savings. Kalina submitted that it was reasonable for an entity to earn a credit if it allowed a distribution utility to save on its DTS

76 *Transmission Regulation*, Section 28.
77 Exhibit 24116-X0599, Kalina Power Combined Module submission, paragraph 9; Exhibit 24116-X0581, ACREI Combined Module submission, paragraphs 99-104; Exhibit 24116-X0561.01, CGWG Combined Module submission, paragraph 5.
78 Specifically, the ISO tariff requires that where transmission facilities are shared, any participant-related costs associated with those facilities incurred within the past 20 years are also shared. If the transmission facility was originally built to serve loads, as is typically the case for DCGs connecting to DFO substations, then this provision has the effect of allocating a portion of the costs of those facilities, to them.
79 Decision 25848-D01-2020: Alberta Electric System Operator, Stage 2 Review and Variance of Decision 22942-D02-2019, Adjusted Metering Practice and Substation Fraction Methodology, Proceeding 25848, December 23, 2020.
80 Exhibit 24116-X0562, Capital Power Combined Module written submission, PDF page 3.
81 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF page 18, paragraphs 89-90.
82 Exhibit 24116-X0571, CCA Combined Module written submission, PDF page 55.
83 Exhibit 24116-X0594, the AESO Combined Module written submission, PDF page 8.
84 Exhibit 24116-X0599.01, Kalina Combined Module written submission, PDF pages 9-11; Exhibit 24116-X0644, Kalina response submission, PDF page 14.

charges.[85] Contrary to the views expressed by Capital Power and AltaLink, Kalina claimed that DCG was discriminated against and faced barriers to interconnection.[86] This was similar to the position taken by the Allied Community of Renewable Energy Interests (ACREI).[87]

126. The last issue contributing to tariff inconsistency between distribution and transmission system users is the recovery of transmission system losses from generating units.[88] These costs are currently allocated to (i) owners of TCG based on incremental line losses incurred in delivering energy and (ii) to distribution utilities if they have net generation flowing onto the transmission system as a result of DCG connected to their system. DCG is not directly charged transmission line losses by the AESO, but these costs may be flowed through by the distribution utility where generation produced by a DCG unit flows onto the transmission system. Like TCG, DCG is not responsible for distribution system losses, as those are paid by retailers.

127. Each of the three issues addressed above is affected by the physical location of the relevant meter, as discussed in Section 3.3.2. The AESO sought approval to meter energy flows entering or leaving the transmission system on individual distribution feeders. This request (referred to as the adjusted metering practice) was approved by the Commission recently in Decision 25848-D01-2020. It is anticipated that when this adjusted metering practice is implemented, it will begin to lessen the impacts of the second and third issues identified above. That is, the magnitude of DCG credits will decline and net exports from individual feeders onto the transmission system will attract transmission loss charges.

4.3 Electricity self-supplied and consumed (no export)

Key takeaways:
Grid modernization will require that significant thought and effort be applied to metering, tariffs and rate design to avoid cost shifting within or between customer rate classes, and to discourage uneconomic bypass. This applies equally for on-site generation, and demand-side management technologies.

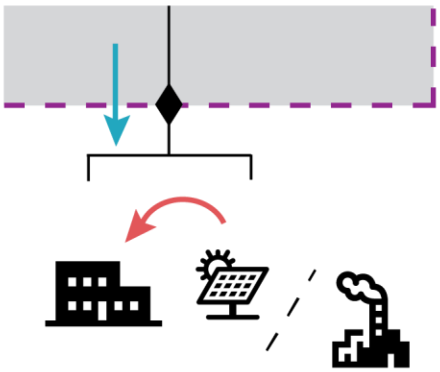
128. As described in Section 3.2, there are two types of self-supply customers that are connected to the grid: those that self-supply to meet some portion of their own needs, and those that self-supply with export to the grid. This section examines the former, that is, customers who have generation on their property (on-site or "behind-the-fence" generation) to satisfy some or all of their load needs but who do not supply electricity to the grid.[89] Customers who are able to

85 Exhibit 24116-X0599.01, Kalina Combined Module written submission, PDF page 30.
86 Exhibit 24116-X0644, Kalina response submission, PDF pages 14-15.
87 ACREI is composed of the following individual parties: Action Surface Rights Association, Alberta Surface Rights Federation, St. Mary's Irrigation District, the County of Taber, 3B Energy Ltd., Determination Drilling, the Southern Alberta Investment Co-Op for Renewable Energy, Iron and Earth, the Orphan Well Association, and SkyFire Energy.
Exhibit 24116-X0725, ACREI concluding remarks, PDF page 21.
88 *Transmission Regulation*, Section 31; ISO Rule 501.10.
89 An important clarification is that the self-supply (no export) customers are still connected to the grid with behind-the-fence generation supplementing (or at least being available to supplement) the energy drawn from the grid. This is different from a case where a customer is disconnected from the grid completely (with no ability to connect) and relies exclusively on on-site generation to meet their energy needs.

self-supply electricity (with or without export) are also sometimes referred to as "prosumers," as they are able to both produce and consume electricity.

129. In other words, the self-supply (no export) customers considered in this report engage in two energy flows: (i) drawing electricity from the grid; and (ii) self-supplying, as shown in the image below reproduced from Figure 5. In such a configuration, at times when energy is being self-supplied, the flows of energy recorded are the net inflows from the grid after having served some of their needs from their on-site generation.

Figure 12. Self-supply (no export) configuration



Self-supply, no export

130. As noted in the Commission's recent paper, the statutory scheme in Alberta has expressly recognized and authorized the operation of "behind the fence" generation and transmission for more than 50 years. The self-supply exemption continued under deregulation and is currently embedded in the *Electric Utilities Act*.[90] These legislative provisions enable customers to choose between consuming self-produced electricity and electricity supplied by the grid (as long as no self-produced electricity is exported to the grid).

131. Customers engaging in self-supply may be in any of the distribution utility's rate classes (commercial, industrial, residential, etc.). With its strong industrial sector, Alberta has abundant examples of self-supply configurations.[91] An industrial complex with an on-site combustion turbine powered by natural gas would be an example of such an arrangement, subject to the following important condition. That is, although such a customer is connected to the grid, their self-generated energy never leaves the customer's site (i.e., flows past the customer's meter into the AIES). Perhaps a simpler, and even more common, example is a residential customer or farm owner that uses a gasoline or diesel generator to run equipment or machinery (for reasons of cost or convenience), rather than plugging in and consuming electricity from the grid.[92]

90 Self-supply and export – Alberta Utilities Commission discussion paper, June 5, 2020, page 7.
91 Self-supply and export – Alberta Utilities Commission discussion paper, see charts on page 5, and information on page 7.
92 A further example was provided by the Alberta Irrigation Districts Association (Exhibit 24116-X0116.01, paragraph 43), explaining that irrigation pumps could be powered by a diesel generator or electricity drawn from the grid.

132. As a result of the metering configuration (described in Section 3.3.2), from the distribution utility's point of view, self-supply (no export) customers appear only as a load.[93] When the self-supply generating unit is operating, it offsets all, or a portion, of the customer's load creating what is generally referred to as "masked load."[94] This can make it challenging for grid planning and operations, particularly if the DER relies on intermittent fuel sources for generation.

133. Historically, self-supply was principally installed for operational reasons such as increased reliability (i.e., backup power), or as part of an industrial process (CHP). Parties pointed out in the inquiry that instances of self-supply may be increasing because of two contributing factors: the declining cost of DERs, and increasing distribution and transmission charges.

134. The declining cost of DERs was described in Section 2.1. Several parties commented on the steady increase in distribution and transmission charges. TransAlta described the rising wires costs as follows:

> Transmission wires costs per MWh delivered have increased over 400% from 2005 to 2018 and distribution costs per MWh delivered have increased over 200% during the same period. In contrast, wholesale electricity prices per MWh have declined by over 20% during the same period.[95]

135. There are several factors contributing to higher rates, many of which are beyond the scope of this report. However, IPCAA pointed out that one partial explanation for these increases in wires costs may be the result of the onset of uneconomic bypass, particularly with respect to the setting and collection of the AESO tariff.

- First, customers seeking to shelter from further increases in distribution [and transmission] rates will install behind-the-fence generation to reduce their dependence on the system and lower their cost of electricity. As an outcome of this new behind-the-fence generation, those consumers who choose not to install behind-the-fence generation will face even higher distribution rates.

- Second, increased DERs results in a reduction in the quantities of energy transferred from the transmission system to the distributions systems. This incentive for DERs has the potential to lead to a spiral of rising rates and increasing amounts of DERs.

- Third, DERs and specifically behind-the-fence generation, have significant potential to improve the efficiency and lower the costs of distribution and transmission systems. However, without a framework that identifies the benefits of DERs and incentivizes cooperation between developers and DFOs to maximize these benefits, DERs may unfairly be restricted to merely minimize the rate effects described in the

93 As described in Section 3.3.2, the generating unit may not be visible to the utility because of where the meter is located and the self-supplied electricity (red arrow) never passing through the meter. Alternatively, the generating unit may be visible to the utility, but could be totalized with the reading from another meter.

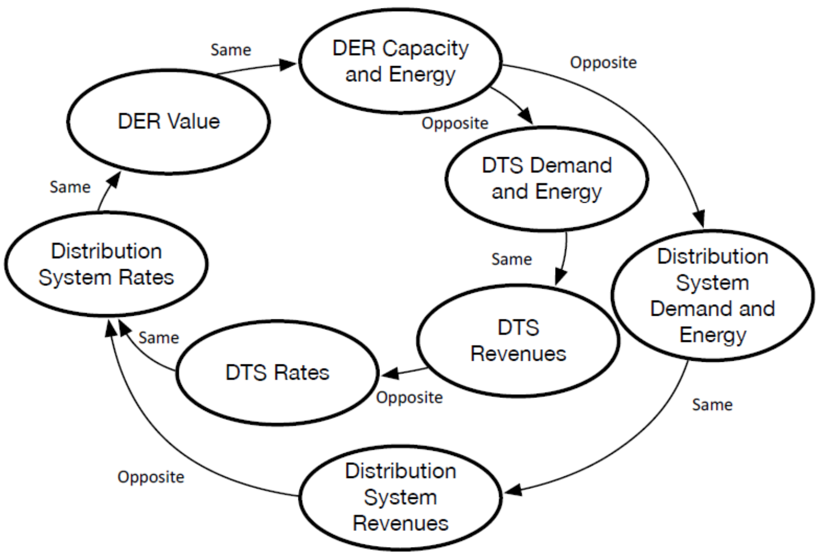
94 Exhibit 24116_X0578, FortisAlberta Combined Module Submission, paragraph 50: "Load masking arises when the full load consumption behind the meter is not visible to the system due to the effects of offsetting generation downstream of a meter."

95 Exhibit 24116-X0550, TransAlta Combined Module submission, paragraph 13.

previously identified concerns; i.e. the absence of a clear framework will be an impediment to the proper application of DERs.[96]

136. IPCAA provided Figure 13 to further explain how the deployment of DERs may lead to uneconomic bypass if they are not properly integrated into the system and if transmission and distribution price signals are not properly set.

Figure 13. Illustration of the effect of DERs on transmission and distribution rates



Note to the image, as provided by IPCAA:[97]

The labels "opposite" and "same" indicate the relationship between the variables in each bubble. "Opposite" means the variables connected by the arrow next to the label move in opposite directions in response to a change.

"Same" means the variables connected by the arrow next to the label move in the same direction when there is a change. If peak demand and load on a distribution system decrease, then the distribution system revenues should decrease; and if the same outside loop is followed, then it is expected, as a result of the decrease in revenues, distribution rates will increase.

137. IPCAA explained that the causal loop diagram helps to show the short-term effect of a small-scale combined heat and power facility DCG located at an industrial facility connected to a distribution system. For example, the outer loop shows that if the amount of DER capacity increases, the amount of electricity required by the distribution system will decrease and the peak demand of the distribution system will decline. The inner loop shows a similar logic for DTS (i.e., the charges a distribution utility pays on behalf of all its distribution-connected customers). If the amount of DER capacity increases in a distribution system, less energy will be required from the transmission system; and at the same time, coincident peak demand will decrease. In the short-term, the net effect of an increased amount of DERs on a distribution system is a reduction in the amount of energy flowing from the transmission system to the distribution system. Following along the inner loop, a decrease in DTS and energy and demand should result in an increase in DTS rates, which in turn will contribute to an increase in distribution system

[96] Exhibit 24116-X0164, IPCAA Module One submission, PDF pages 2-3.
[97] Exhibit 24116-X0164, IPCAA Module One submission, PDF page 3.

rates. As distribution rates increase so does the value of DERs, which leads to an increase in DER capacity.[98]

138. The AESO corroborated this general analysis and described it as a "vicious cycle."[99]

139. In this regard, Dr. Orans in his submission on behalf of Fortis highlighted that the current distribution system pricing structure (and AESO tariff) can over-incent the installation of DERs, and the associated increase in self-supply will result in cost shifting to other customers, leading to uneconomic bypass. AltaLink agreed that the same problem exists for the transmission system. The issue of uneconomic bypass garnered much attention in the inquiry and was examined in some detail in Section 3.4.

4.3.1 Demand-side DERs (demand-side management)

140. Enel X,[100] Energy Efficiency Alberta,[101] Pembina[102] and the Energy Efficiency Alliance[103] raised the possible benefits of installing demand-side DERs and the price signals that promote such installation.[104] These parties explained that while these technologies can provide benefits to the grid in terms of reduced load and lower system peaks, the price signal to install these technologies can be distorted or muted from the customer's point of view.

141. Even though the self-supply (no export) configuration is predominantly associated with on-site generation as a means to self-supply, demand-side DERs can operate with similar effect. Namely, energy efficiency and demand response measures reduce a customer's load in much the same way as on-site generation *appears* to reduce load from the perspective of the meter and the utility. That is, from the distribution utility's perspective, using on-site generation or demand-side DERs may lead to a similar outcome (i.e., decreased load). Therefore, the concern parties raised about on-site generation for self-supply (no export) that allows customers to bypass wires delivery charges and shift wires costs to other customers, in many cases, applies equally to demand-side DERs.

142. As explained in Section 3.4, uneconomic bypass occurs when a customer bypasses the utility system, in whole or in part, by investing in DERs with the subsequent effect of sales losses for the utility and higher prices for the remaining utility customers. It does not matter whether the investments made by individual customers are in supply-side or demand-side DERs. If these investments do not change the total cost of the grid from what would have existed had these investments never been made, but still allow the customers in question to bypass wires charges, then society is worse off from the standpoint of economic efficiency.

98 Exhibit 24116-X0164, IPCAA Module One submission, PDF pages 3-4.
99 Exhibit 24116-X0518, AESO-AUC-2019NOV29-009, PDF page 34. The Commission notes that at this reference, the AESO was specifically commenting on the motivation to install DCG, but as will be explained in sections 5.2.2 and 5.5.3 of this report, the price signals to install DCG are similar to those for installing on-site generation.
100 Exhibit 24116-X0161, Enel X Module One submission, PDF pages 4-5.
101 Exhibit 24116-X0568, Energy Efficiency Alberta Combined Module submission, paragraph 24.
102 Exhibit 24116-X0175, Pembina Institute Module One submission, PDF pages 23-25;
Exhibit 24116-X0443, Pembina Institute Module One supplemental submission, PDF page 3.
103 Exhibit 24116-X0549, Alberta Energy Efficiency Alliance Combined Module submission, PDF page 7.
104 Defined in Section 2.1 as technologies that allow for load shedding and/or load shifting, including energy efficiency, smart appliances, demand response and EVs.

143. In this regard, the ability to measure and bill a customer based on their hourly consumption can not only reduce the incentives to engage in uneconomic (i.e., socially inefficient) bypass, but also increase the incentives for economic (i.e., socially efficient) bypass, since the price signal would more accurately reflect the value of installing the DER. An example of a customer with a very low-cost hourly load shape (i.e., most of their consumption occurs during hours of low wholesale priced electricity) is illustrative here. If this customer is billed based on a standardized and assumed load profile,[105] the customer may find it profitable to make an investment that reduces its demand during low priced hours, even though the wholesale energy cost savings from this investment are significantly less than the cost of this investment. But, by measuring and billing this customer on its hourly consumption instead, the customer would have no financial incentive to make this investment in demand-side management. This example can be considered in reverse as well – a customer with a very high-cost hourly load shape would not be incented to install demand-side management measures unless the customer was exposed to its actual hourly cost of consumption.

144. These issues associated with demand-side DERs relate more broadly to access to information and use as non-wires alternatives (NWAs),[106] and will be discussed in sections 5.3 (access to information) and 5.5 (integration of DERs), respectively.

4.4 Self-supply with export

Key takeaways:
The issues relating to self-supply with export are, at their core, not that different from those applicable to self-supply (no export), namely, metering and the pricing of energy flows. However, for self-supply with export, there is the additional consideration of the market implications of electricity supplied to the grid.

145. This section deals with customers that engage in all three flows of energy: they draw electricity from the grid, consume self-generated electricity, and supply electricity to the grid. Such customers are referred to as "self-supply with export customers."

146. As described previously in this report, the current statutory scheme in Alberta expressly recognizes and authorizes unlimited self-supply (no export), discussed in Section 4.3; however, the ability to self-supply and export excess electricity onto the grid requires a statutory exemption. The Commission recently held stakeholder consultations exploring the benefits and

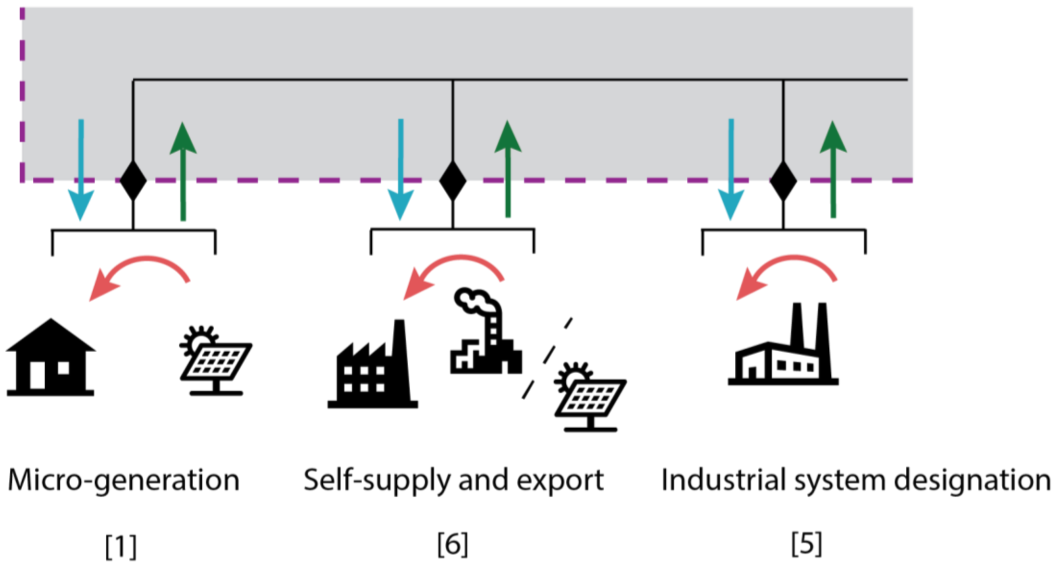
[105] Load profiles are used for assigning cumulative energy consumption to specific hours to customers with cumulative meters for the purposes of billing and load settlement because actual hourly consumption data does not exist for these customers. This concept is further addressed in Section 5.4.1.

[106] Non-wires alternatives or NWAs are defined as grid investments or projects that use non-traditional transmission and distribution solutions, including but not limited to: DCG, energy storage, energy efficiency and demand response. The purpose of NWAs is to defer or replace the need for specific infrastructure upgrades (e.g., upgrading a transformer). The use of DERs as NWAs is further discussed in Section 5.5.

drawbacks of expanding the circumstances under which customers could engage in self-supply with export and, if so, how to address issues that might arise.[107]

147. Figure 5 contains three examples of self-supply with export customers connected to the AIES: micro-generation customers [1], ISD customers [5] and self-supply with export customers not otherwise enabled by an enactment that are functioning as legacy facilities [6]. These are reproduced below, including a distribution-connected ISD.

Figure 14. Self-supply with export configurations



148. Real-life examples of self-supply with export depend on the category. For micro-generation, a typical customer is a residential customer with solar panels. For the other two categories, a typical example might consist of an industrial complex with on-site generation that supplies excess electricity to the grid.

149. Because self-supply is a part of this configuration, all of the same characteristics and issues discussed in Section 4.3 above for self-supply (no export) customers are also relevant for self-supply with export customers. For example, self-supply with export customers also have masked load, making grid planning and operation more challenging. As well, the ability to self-supply creates the opportunity to avoid wires charges, leading to cost shifting between customers and potentially uneconomic bypass.

150. On this point, it is worth noting that while many parties that made submissions on self-supply with export configurations focused on preventing uneconomic bypass, this concern is not limited to self-supply with export customers. AltaLink stated that preventing uneconomic bypass is the central reason to maintain the statutory restrictions on the conditions under which customers may be allowed to self-supply with export.[108] However, as explained in Section 4.3, this same issue also arises for self-supply (no export) customers, who face no prohibitions under

107 The interested reader is referred to the following for more detail: https://engage.auc.ab.ca/Self-SupplyAndExport, and the summary report: Self-supply and export – Alberta Utilities Commission discussion paper, June 5, 2020.

108 See Bulletin 2020-01, Exploring market concerns and tariff issues related to self-supply and export reform, January 1, 2020, PDF pages 2-3.

the current regulatory framework (i.e., unlimited self-supply is permitted from supply-side and demand-side DERs). The inquiry revealed that the decision to self-supply, within the current environment, is largely based on the desire to avoid wires charges;[109] the ability to export excess electricity to the grid simply improves project economics.

151. Nevertheless, the introduction of the third flow of energy, that of export to the grid, introduces an additional consideration – namely, how to accommodate the electricity supplied to the grid from DERs into the wholesale market while maintaining fair, efficient and openly competitive electricity markets. Section 4.4.1 examines this issue. Section 4.4.2 addresses concerns regarding small micro-generation customers receiving non-market rates for electricity supplied to the grid. Section 4.4.3 addresses the issue of microgrids in the general context of "self-supply with export."

4.4.1 Market implications of DERs export and dispatch

152. Alberta's electricity markets are predicated on fair, efficient, and open competition. The wholesale electricity market affords all participants who exchange electricity a reasonable opportunity do so on non-discriminatory terms.[110] The AESO is tasked with operating the wholesale and ancillary services electricity markets in a fair, efficient and open manner and in establishing a province-wide clearing price for each settlement interval[111] (currently, hourly).

153. Parties raised two major concerns during the inquiry about DERs selling electricity directly into the wholesale market. First, to the degree that DERs self-dispatch, are intermittent in nature or are not adequately visible, their presence may impede the formation of robust prices. And second, to the degree that DERs investment is motivated by tariff avoidance and securing non-level playing field advantages over other generators, then by improving their economics, exports to the grid may enhance these advantages and exacerbate their impacts on the wholesale electricity market. These issues are discussed in turn.

Potential impacts of DERs electricity sales on the formation of robust prices

154. Parties to the inquiry observed that there were two general models governing permissible self-supply with export: "net-to-grid" and "gross-to-grid." These can be thought of as offer and dispatch compliance pathways and are distinct from the metering practices described in Section 3.3.2. Both models can affect the formation of robust prices in the wholesale electricity market.

155. Heartland Generation Ltd. explained that when self-supply with export customers operate net-to-grid, the customer offers the net generation from their site (after load has been offset) into the wholesale electricity market.[112] Because load is not required to make "offers" in the market, when the customer's site is a net load, its on-site generation can be self-dispatched up to the point of net-injection into the grid (see Figure 7 in Section 3.3.1, where demand is $\geq$ 0 kW). Thus, the customer can participate as it wishes and its net load seen by the grid can fluctuate as a result of generation self-dispatch. When the customer has net export energy flows (i.e., demand is < 0 kW in Figure 7), the customer's net output to the AIES is subject to dispatch by the AESO, and the site as a whole is subject to dispatch tolerance requirements. The net energy flows and

109 See, for example: Exhibit 24116-X0716, Transcript, Volume 1, page 88; Exhibit 24116-X0164, IPCAA Module One submission, PDF pages 2-3.
110 See, for example: *Electric Utilities Act*, sections 5(b) and (c), 18.
111 See, for example: *Electric Utilities Act*, sections 17 and 18.
112 Exhibit 24116-X0523, HGL-AUC-2019NOV29-006(e), paragraphs 24-25.

tariffs of a customer operating net-to-grid are based on its net participation as load and supply on the AIES in various hours.

156. Heartland Generation further explained that the incentives and results are the same for the gross-to-grid model:

> Under gross-dispatch, an ISD is incented to offer such that it ensures dispatch up to its site load to avoid site load going unserved or having to import from the grid. Under net-dispatch, an ISD would presumably offer similarly to a standalone generator, since it is only dispatched on its generation in excess of its onsite load. In other words, a net-dispatch ISD is not required to offer generation which is consumed by the onsite load into the Power Pool.[113]

157. Alberta Direct Connect stated that the decision to offer on a net or gross basis is based on the specific generation type, relationship to the on-site load, and ability to meet the AESO dispatch tolerance rule. Alberta Direct Connect also submitted that energy volumes that are transacted through the wholesale market attract trading charges,[114] which self-supply avoids. Self-supply also reduces the two-month financial security required of load participants that directly participate in the wholesale market.[115]

158. The AESO noted that it is currently unable to collect data from certain DERs that do not directly participate in the wholesale market. However, it appeared (relatively) unconcerned about the potential impact of these DERs on the formation of robust prices given current penetration levels of DERs, but noted that this requires monitoring as DERs become more widely deployed.

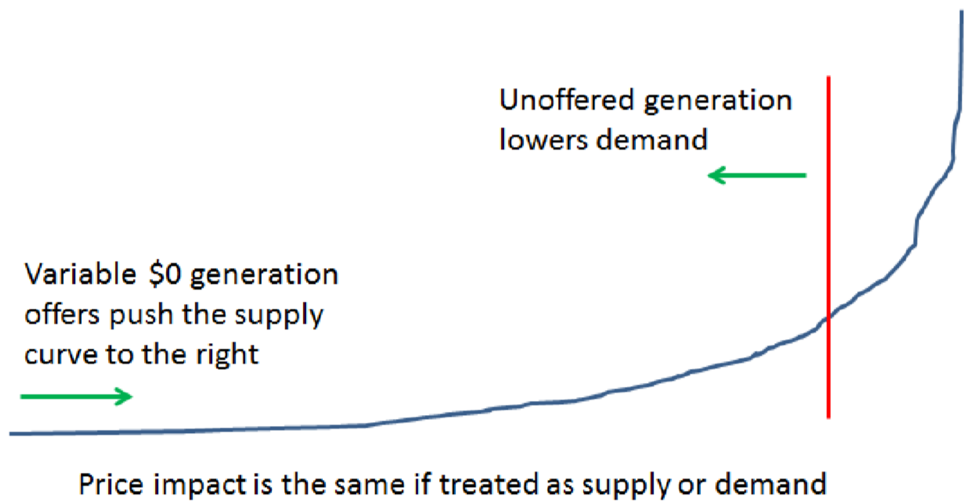
> [M]arket-related ISO rules apply to generating resources that are 5 MW or greater. Assets smaller than 5 MW are not required to adhere to most market-related ISO rules. In practice, this allows for these smaller units to have greater flexibility as they are not subject to offer and dispatch requirements in the energy market. While such resources currently make a relatively small contribution to the overall capacity of the AIES, their contribution is expanding and will require increased awareness and oversight.
>
> …
>
> As smaller DERs that are less than 5 MW proliferate, the AESO's inability to monitor and dispatch these resources will increasingly affect its ability to balance supply and demand, dispatch supply efficiently, understand and manage constraints on the AIES, and respond to emergency situations.[116]

159. To illustrate the effect DERs smaller than 5 MW have on wholesale market price formation, the AESO provided Figure 15. This shows how such smaller DERs account for "unoffered generation" that masks load and thus shifts the demand curve (i.e., the red line in Figure 15) to the left. The AESO contrasted this situation to generation that is offered at $0/MWh (labelled in Figure 15 as "variable $0 generation"), which is how DERs less than 5 MW would offer in to the wholesale market if they were required to do so. Increasing the amount of generation offered at $0/MWh would shift the supply curve (i.e., blue curve) to the

[113] Exhibit 24116-X0523, HGL-AUC-2019NOV29-006(e), paragraphs 24-25.
[114] The power pool trading charge for 2020 is $0.46/MWh. https://www.aeso.ca/market/energy-market-trading-charge/
[115] Exhibit 24116-X0526, ADC-AUC-2019NOV29-007(a).
[116] Exhibit 24116-X0176, AESO Module One submission, PDF pages 20 and 22.

right. Thus, from the perspective of the equilibrium wholesale market price, the outcome is the same whether DERs net their generation with coincident and co-located load, or are required to offer into the market at $0/MWh.

Figure 15. Price impact of unoffered generation[117]



160. Capital Power took the opposite position, submitting that allowing DERs to net their generation with load reduces available information on total demand and total supply (i.e., prior to any netting) and, thus, affects market participants' offer strategies, and negatively affects price formation.[118]

161. The AESO is responsible for the operation of the wholesale electricity market and has a public interest mandate to do so according to the principle of fair, efficient and open competition. The AESO has stated that current levels of generation from unoffered DERs (i.e., less than 5 MW) are sufficiently low that no changes are required, but that this situation requires monitoring as DER penetration grows. The AESO may propose changes to wholesale market rules including real-time monitoring, if necessary. Accordingly, this report will not address any further concerns relating to the potential impact of DER participation in the wholesale electricity market on monitoring and price discovery.

162. Nevertheless, the AESO has voiced its support for relaxing restrictions on who should be permitted to engage in self-supply with export, and under what circumstances, provided that price signals reflect costs. The AESO has also observed that this would increase the amount of unoffered generation, as there would be greater opportunities to install DERs to self-supply on-site load.

> [T]he AESO is a proponent of legislative change to enable unlimited self-supply and export, provided that tariff pricing signals effectively reflect both the cost of transmission and the value obtained through a connection to the AIES. In the AESO's view, unlimited self-supply and export is most likely to result in outcomes that are consistent with fair,

117 Exhibit 24116-X0518, AESO response to the Commission's preliminary IRs, PDF page 8.

118 Alberta Utilities Commission, Self-supply and Export Discussion Paper, June 5, 2020, PDF pages 21-22; https://engage.auc.ab.ca/11140/widgets/62166/documents/37607.

efficient and openly competitive markets as it will enable consumers to optimize their electricity consumption based on competitive forces, regardless of how they choose to self-supply and/or export to the AIES. Transparent tariff price signals that do not include inefficient distortions or cross subsidies will, however, be required.[119]

Uneconomic bypass and non-level playing field considerations

163. Uneconomic bypass resulting from tariffs that do not reflect costs and that raise concerns about non-level playing fields are discussed elsewhere in this report. As previously noted, the incentive to install DERs is very sensitive to tariff design. This observation applies equally for DERs of every kind, including those installed for the purposes of self-supply, which would mask load, as well as DERs that are connected in order to supply electricity to the grid (i.e., DCG or self-supply with export). The refinement of transmission and distribution tariffs to better align with costs and, thus, generate price signals more likely to promote the efficient adoption of DERs, was a central issue explored in this inquiry. Observations and broad-based conclusions emerging from the submissions received during the inquiry on this issue are presented in Section 5.2.

4.4.2 Non-market rates for small micro-generation

Key takeaways:
Payments to small micro-generators for electricity supplied to the grid using the retail rate for electricity consumed from the grid as a proxy in effect shifts costs from small micro-generators to all other AESO tariff customers. They do so by creating perverse incentives to behave inefficiently (by encouraging small micro-generators to sign up for high-priced retail contracts during months when solar output is greatest). While the total quantum of these payments is presently low, they are a growing problem that may become more difficult to rectify the larger these payments become. It was noted more than once by parties during the inquiry that one way to address this problem would be to require the installation of bi-directional interval metering for small micro-generation customers. A further perceived benefit of such an approach is that it aligns with broader expectations of the need for AMI as part of the grid modernization process, as described in more detail in Section 5.3 of this report.

164. In preliminary IRs, the Commission outlined the regulatory framework for both small and large micro-generating units.[120] Among other provisions, the *Micro-generation Regulation* specifies that a micro-generator's retailer[121] must act as the electricity market participant and deal with the AESO in respect of the electric energy generated by the micro-generator.[122] The retailer also provides a credit to the micro-generator for the electricity it supplies to the grid.

[119] Exhibit 24116-X0518, AESO-AUC-2019NOV29-013, PDF page 44.
[120] Exhibit 24116-X0470, [Responder]-AUC-2019NOV29-001, [Responder]-AUC-2019NOV29-002, and [Responder]-AUC-2019NOV29-003.
[121] The *Micro-generation Regulation* uses the term "service provider" that includes retailers or regulated rate providers. For simplicity and to avoid confusion with terminology that refers to distribution utilities as wires service providers, the Commission uses the narrower, but more descriptive term "retailer" (i.e., the electricity market participant that provides retail function) in this section.
[122] The *Micro-generation Regulation,* Section 7(3).

165. In the case of small micro-generation, this credit is calculated using the rate the retailer charges the micro-generator's site for electricity consumed from the grid. For example, if a customer is paying an RRO rate for the electricity it draws from the grid, that customer will also receive the same RRO rate for the electricity it supplies to the grid. Or, if a customer is paying a contract price (for example, a fixed three-year rate of $0.06/kWh), that customer will receive the same retail price for the energy supplied to the grid.[123]

166. As per the *Micro-generation Regulation*, the AESO must compensate small micro-generation customers, through their retailers, based on the aggregate amount of electricity supplied by the customer to the grid for the billing period, multiplied by the retail rate agreed upon between the retailer and the small micro-generation customer for that same period. The AESO has no influence on the retail rate agreed to by the retailer and the small micro-generation customer, even though it must compensate the small micro-generation customers at this rate through its tariff. These payments to small micro-generation customers from the AESO, via their retailers, are not settled within or recovered from the power pool (i.e., wholesale electricity market).

167. In the case of large micro-generation, all electricity supplied to the grid from large micro-generation sites is settled at the power pool price.[124] This means that the AESO must compensate the large micro-generator's retailer at the pool price for each settlement interval in the billing period (i.e., the wholesale price). The retailer then provides this amount as a bill credit to the large micro-generator, unless a different rate is agreed upon between the retailer and the large micro-generator (i.e., a contract price). As such, any difference between the pool price and the rate that large micro-generation customers receive for their energy exports is borne by their retailer.

168. The difference in treatment between small and large micro-generation is likely driven by metering limitations. For small micro-generation, only a bi-directional *cumulative* meter is required. These meters are only capable of measuring the electricity drawn from and supplied to the grid for the cumulative period between reads. This means that the electricity supplied to the grid during hourly intervals by small micro-generation is not known and thus cannot be settled at the hourly power pool price.[125] Without an ability to settle electricity supplied to the grid by small micro-generation at the power pool price, the AESO uses the retail rate (on which the retailer and the customer agreed) to compensate small micro-generators through its tariff. For large micro-generation customers, a bi-directional *interval* meter is required by the regulation, and thus electricity supplied to the grid from these sites can be settled at the hourly power pool price.

169. Because the retailers bear no risk in compensating small micro-generation customers at retail rates different from the pool price (since they are not the party ultimately responsible for paying these amounts), this arrangement is prone to gaming.[126] Some retailers offer retail rates to small micro-generation customers that are approximately triple that of the average retail contract

[123] As was described in Section 3.3.2, in Alberta, small micro-generators are billed for the electricity drawn from the grid, and credited for the electricity supplied to the grid, under what is referred to as **net billing**.

[124] *Micro-generation Regulation*, Section 7(7).

[125] The same issue is also present for the energy drawn from the AIES. The method of load profiles is used to assign hourly values to each of the values measured from the cumulative meter read and then applying the pool price to each of the assigned hourly values to settle the load amounts through the power pool. There is currently no similar "generation profile" to assign the energy produced by small micro-generation units to specific hours.

[126] Exhibit 24116-X0527, UCA-AUC-2019NOV29-003, PDF page 22.

during months when solar output is greatest, and then allow these customers to switch to a lower rate during months with much lower solar output. In 2020, these retail rates were approximately $0.22/kWh.[127] Micro-generation customers that are net energy exporters during the higher output solar months benefit from these higher retail contracts, even though they are paying a higher amount for electricity consumed from the grid during non-daylight hours. Retailers benefit because they are able to sell electricity to these customers at these high retail rates when the customer is consuming electricity from the grid. Overall, this creates a wealth transfer from other AESO tariff customers to the small micro-generators participating in these high retail rates.[128]

170. To be clear, there is no issue with retailers setting their own prices and offering high retail rates, so long as it is those retailers that bear the burden of their business decision and the ensuing transactions do not materially impact other AESO tariff customers. It is important to note as well that not all small micro-generators participate in the high retail rates offered by certain retailers. Nevertheless, whether or not all small micro-generation customers participate in these high retail rates, wealth transfers will occur whenever the agreed-upon retail price for any small micro-generation customer differs from the pool price, with the ultimate impact depending on the quantum of this transfer.

171. The AESO provided a historical account of the energy volumes and total compensation to small micro-generators provided through its tariff.

Table 3. Payments issued and energy volumes for small micro-generation sites[129]

Year	MWh	Payments issued
2012	669	$59,275
2013	1,282	$119,835
2014	2,081	$161,862
2015	3,233	$214,137
2016	4,477	$236,709
2017	7,103	$351,651
2018	11,946	$819,354
2019	20,277	$1,616,311

172. As can be seen from the table, recent payments issued to small micro-generators are still relatively small, but growing. Since 2017, payments to small micro-generators have approximately doubled each year. This rapid increase in payment amounts is very likely to continue in the future as DERs adoption accelerates.

173. Given the relatively small dollar totals observed to date for these wealth transfers, the need to adjust the credit mechanism for small micro-generators may not yet be so pressing or urgent as to warrant immediate corrective action. However, it is a good example of an issue that

127 https://ucahelps.alberta.ca/cost-comparison-tool.aspx

128 A question that naturally arises is whether ratepayers benefit from the energy sent to the grid by small micro-generators. The electricity sent to the AIES reduces distribution line losses. To the extent that a distribution utility has a large amount of small micro-generation in its service territory, it reduces unaccounted-for energy (UFE) for all retailers in that distribution utility's service territory. Only that distribution utility's customers benefit from the reduced UFE, while costs go to all AESO tariff customers.

129 Exhibit 24116-X0518, AESO-AUC-2019NOV29-003(c).

while not quite constituting an immediate policy concern, could well become economically untenable if not addressed in a timely manner as the adoption of DERs accelerates.

174. A possible long-term solution that has been suggested by some parties would be to make the retailers bear the risks and rewards of any difference between the wholesale market price and the contract price, not just for electricity consumed from the grid by the customer (as is currently done), but also for electricity supplied to the grid.[130] This mechanism is in place for large micro-generators and appears to be effective in discouraging cost shifting between customers. The interval metering in place allows for settlement at the hourly power pool price, yet still creates the flexibility for retailers to offer to micro-generators rates different from the pool price, as long as retailers are willing to take on that risk.[131] An additional benefit of using interval metering is that it promotes more robust competitive market outcomes, rather than relying on approximations or non-market mechanisms for pricing certain products. This further underscores the need for the eventual deployment of AMI, which would enable bi-directional interval metering for small micro-generators.[132] In fact, some distribution utilities install AMI meters at small micro-generation sites that could be used as interval meters, but only use them as cumulative meters. It must be noted that taking steps to deal with this issue, and in what manner, is ultimately a policy decision to be addressed through the *Micro-generation Regulation*.

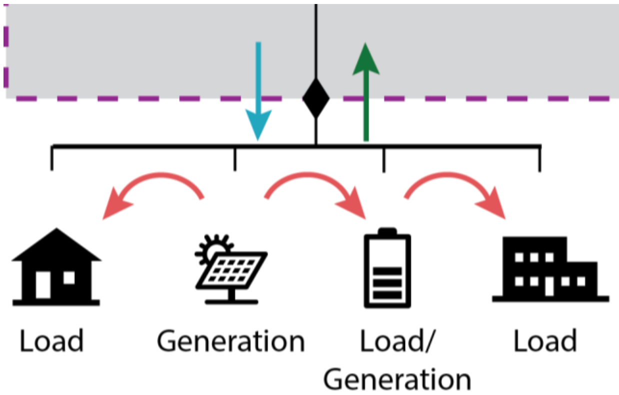
4.4.3 Microgrids

Key takeaways:
Based on the information gathered in the inquiry, it appears that, with the exception of specialized cases (such as industrial complexes, military bases, or other activities for which uninterruptible supply of energy is critical), there are limited benefits from a public interest perspective of microgrids nested within a distribution system. This is because microgrids essentially create another form of self-supply with export, raising the possibility of cost shifting and uneconomic bypass. The case for microgrids appears to be more compelling for remote customers either off-grid, or on the fringes of the grid, where the provision of grid service is too expensive.

175. Microgrids were explored in the inquiry in several contexts. Conceptually, microgrids can be defined as a group of interconnected loads and DERs that collectively can act as a single controllable entity with respect to the larger grid. A microgrid can connect and disconnect from the grid to enable it to operate in either a grid-connected or "island mode" and is able to seamlessly transition between these two states.[133] In theory, microgrids can be owned and operated by either a distribution utility or a third party. Figure 16 depicts a representative microgrid. This image is simply illustrative of the flows of energy, as microgrids can have many configurations.

[130] Exhibit 24116-X0527, UCA-AUC-2019NOV29-003, PDF page 23.
[131] Exhibit 24116-X0577, EPCOR Combined Module submission, note 4, PDF page 33.
[132] A less optimal solution to address this issue could be to develop generation load profiles, but this is not without its difficulties. Measuring actual interval electricity flows avoids complications of modelling different fuel-sources and specific outputs of technologies (for example, in the case of solar PV: shading, cloud cover, aspect, angle, etc.).
[133] Exhibit 24116-X0152, ATCO Module One submission, PDF page 81.

Figure 16. Illustrative depiction of a representative microgrid



176. Due to these properties, microgrids exhibit the three flows of energy (consuming, self-supplying, and exporting electricity) both *within* the microgrid, as it serves the electricity needs of its members, and *outside* of the microgrid as it interacts with the electric distribution system. Thus, microgrids can be thought of as a self-supply with export configuration with additional attributes due to energy flows between generation and load *within* the microgrid.

177. There are at least two fundamental reasons why parties may wish to install microgrids: (i) increased reliability; and (ii) the ability to totalize generation and load to avoid wires charges.

178. ATCO described the following five types of microgrids:[134]

(i) Campus, institutional, commercial and industrial microgrids are an aggregation of existing on-site generation with multiple loads located on contiguous land and managed by the same owner.

(ii) Commercial and industrial microgrids are usually driven by reliability and are created to reduce process downtime or eliminate outages.

(iii) Community microgrids contain as many as a few thousand customers and support the use of local energy and may integrate centralized or distributed battery energy storage.

(iv) Remote off-grid microgrids are not connected to the grid due to their remote location and always operate in island mode.

(v) Military base microgrids designed to ensure the security of a military base.

179. ATCO noted that microgrids under the first arrangement are currently permitted pursuant to the provisions of the *Micro-generation Regulation.* Commercial and industrial microgrids, meanwhile, are allowed under an ISD granted by the Commission. ATCO observed, however, that the third type of microgrids, community microgrids, are prohibited under Alberta's current legislative scheme.[135] As for the latter two types of microgrids, ATCO noted that the remote communities of Old Crow, Yukon and Fort Chipewyan are slated to receive DERs, batteries and microgrid controllers that would allow for these types of microgrid operations.[136]

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[134] Exhibit 24116-X0152, ATCO Module One submission, PDF pages 78-79.
[135] Exhibit 24116-X0152, ATCO Module One submission, PDF page 79.
[136] Exhibit 24116-X0152, ATCO Module One submission, PDF page 80. Several of these projects have now been completed since ATCO made this submission.

180. When asked about the incentives for communities to install a microgrid, Fortis pointed to a community's enhanced ability to manage and control its own level of service, reliability and economics associated with the provision of electricity services.[137] EPCOR added that microgrids enable a community to participate directly in energy projects and to generate revenue by selling electricity to the bulk system.[138]

181. In its Module One submission, the CCA stated that microgrids offer greater reliability against system failures and a higher level of resilience against events that could damage the electric system.[139] ATCO, on the other hand, submitted that distribution utilities would need to enhance the reliability of their own systems if microgrids begin to proliferate in tandem with DERs. In particular, were microgrids to be widely adopted, distribution utilities would need to ensure their seamless integration with the operation and safety and reliability features of the local distribution system. This would include synchronization, adjustment of power flowing at the interface point by dispatching DERs or curtailing load, and regulating the voltage in island mode.[140] EPCOR offered the countervailing proposition that the deployment of other smart grid technologies would assist microgrid systems in interconnecting and interoperating efficiently with the electric system.[141]

182. A second incentive for a community to install a microgrid is to avoid transmission and distribution charges by bypassing the distribution tariff. Such bypass could be either total, as would be the case were a microgrid to fully disconnect itself from the rest of the electric system, or partial.[142] Consistent with the discussion in Section 3.4, if not managed, such uneconomic bypass could result in loss of billing determinants, reducing the utility's ability to recover its approved revenue requirement and shifting costs to customers not part of the microgrid.[143] This upward pressure on rates would make it uneconomic for existing customers to remain grid-connected, initiating the vicious cycle of grid bypass.

183. ATCO noted that microgrid penetration is low in part because of the potential adverse impact on distribution systems.[144] The legal framework applicable to microgrids remains ill-defined and a transactional market has not been developed to allow microgrids to disconnect and balance the supply and demand of electricity.[145]

184. Fortis noted that if a community microgrid were implemented, the distribution utility would no longer be able to perform load settlement for each individual customer site within that community. This, in turn, would eliminate the ability of individual customers in a microgrid to obtain service from any competitive retailer of electricity.[146]

185. During the virtual technical meeting, Dr. Orans stated that microgrids could be considered an alternative to wires solutions when looking to address system needs.[147] However, it

137 Exhibit 24116-X0341, FortisAlberta's responses to the Commission's Module One IRs, PDF page 30.
138 Exhibit 24116-X0353, EPCOR's responses to the Commission's Module One IRs, PDF page 40.
139 Exhibit 24116-X0167, CCA Evidence of Dr. Richard Tabors, PDF page 11.
140 Exhibit 24116-X0152, ATCO Module One submission, PDF pages 79-81.
141 Exhibit 24116-X0170, EPCOR Module One submission, PDF page 45.
142 Exhibit 24116-X0342, ATCO's responses to the UCA's Module One IRs, PDF page 14.
143 Exhibit 24116-X0342, ATCO's responses to the UCA's Module One IRs, PDF pages 14-15.
144 Exhibit 24116-X0152, ATCO Module One submission, PDF page 80.
145 Exhibit 24116-X0152, ATCO Module One submission, PDF page 81.
146 Exhibit 24116-X0341, FortisAlberta's responses to the Commission's Module One IRs, PDF page 30.
147 Exhibit 24116-X0716, Transcript, Volume 1, pages 56-57.

is not clear whether his proposal was limited to using microgrids for remote customers or as a wires substitute in any part of the distribution system.

186. Mr. Larry Gibson, a private citizen, filed a submission raising the issue of "bulk-metered multi-family dwelling rates." He noted that such rates are offered in natural gas distribution tariffs, by way of a single natural gas boiler serving a multi-family complex; however, no such comparable rate exists in electric distribution tariffs. He suggested that the creation of such a rate would encourage innovation and environmentally friendly outcomes through the deployment of district energy systems.[148] In some ways, a single rate for bulk-metered multi-family dwellings and a district energy system would appear much like a microgrid or community (although multi-family dwellings and district energy systems would likely not be able to function in "island mode").

187. Based on the submissions of parties to the inquiry, the case for microgrids (other than for the specialized cases previously noted) appears to be more compelling for remote customers either off-grid, or on the fringes of the grid, where the provision of grid service is too expensive. The microgrid initiatives in Australia and Hawaii brought forward by Charles River Associates appear to focus on such remote customers, although energy resiliency of individual communities also features prominently.[149] As ATCO mentioned, there are several communities in Alberta not connected to the grid that use local generation (mostly diesel generators) to supply their needs. Traditionally, functioning in such an autonomous state was viewed as an expensive suboptimal solution, to be solved by connecting that community to the grid, whenever the opportunity presented itself. However, with the advent of DERs such as solar and energy storage, microgrids can become economic, sustainable long-term solutions for such remote communities, and can potentially obviate the need to connect these communities to the grid altogether, resulting in lower system costs overall. The question remains, however, whether parties other than utilities can own such microgrids.

4.5 Electric vehicles

Key takeaway: Electric vehicles

Electric vehicles are a growing source of load that may require distribution utilities to reinforce their systems, thus increasing costs. It may be possible to manage EV loads in ways other than traditional wires solutions, for example, by leveraging smart charging technologies (which are a form of DERs), incented by effective price signals.

The question arose during the inquiry whether any regulatory oversight was required of EV charging stations that provide public access to charging services. Most parties were of the view that no additional regulatory oversight is required at this time.

188. The adoption of EVs is a relatively recent phenomenon and represents the potential for substantially greater loads to be placed on distribution systems. If not managed well, this could drive distribution utilities to make significant investments in new infrastructure resulting in a

[148] Exhibit 24116-X0140, Rates and regulation suggestions, page 3.
[149] Exhibit 24116-X0571, Charles River Associates Combined Module submission, PDF pages 24-27.

significant increase in costs to serve these new loads. At the same time, new EV-related technologies are emerging that are indistinguishable from DERs (e.g., smart charging devices) that would shift EV charging to manage these loads in a manner comparable to many other demand-side management technologies. In the future, certain configurations may also allow EVs to supply and store energy, helping minimize the amount of new generation and grid investment that will be needed, potentially resulting in lower system costs. However, this outcome is not guaranteed, and in fact the opposite may occur. This section explains how EVs can increase distribution system costs and what can be done to potentially mitigate this.

189. Most, if not all, major vehicle manufacturers have begun placing greater emphasis on EV design, manufacturing, marketing and sales. The Bloomberg New Energy Finance *Electric Vehicle Outlook* projected that over half of all passenger vehicle sales will be electric in 2040.[150] This increase in EVs is expected to occur as the result of two powerful and mutually reinforcing trends: (i) government policies promoting and consumer preferences increasingly favouring decarbonization of the economy; and (ii) a continuation of the significant and sustained reductions being observed in the cost of high-capacity batteries.[151]

190. While global sales of EVs have risen steadily for the past few years, they have barely started in Alberta. Electric Mobility Canada reported that zero-emission vehicle sales rose from 344 in the third quarter of 2018 to 428 sales in the third quarter of 2019.[152] EPCOR provided a table on Alberta motorized vehicle registrations, showing that the number of registrations of hybrid vehicles (i.e., vehicles using hybrid electric and gasoline engines) was 0.5 per cent of total vehicle registrations in 2018.[153]

191. ENMAX modelled EV adoption rates under various scenarios. It concluded that adoption rates were highly sensitive to several factors, including government incentives and fuel prices. The scenarios were developed based on assumptions regarding vehicle purchase incentives, the availability of public DC fast charging or Level-2 charging, and access to home charging. A summary is provided below in Table 4.

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150 Exhibit 24116-X0165, AddÉnergie and ChargePoint Module One submission, PDF page 6.

151 Barriers to EV adoption still exist in Alberta, including a relatively low number of public charging stations (both Level-2 and DC fast charging) and range anxiety, which is the fear, in itself partly triggered by the relative scarcity of public charging stations, that an EV has insufficient range to reach its destination.

152 Electric Mobility Canada Sales Report for Q3 2019: https://emc-mec.ca/new/electric-vehicle-sales-in-canada-q3-2019/. Zero-emission vehicles encompass battery-electric, plug-in hybrid and hydrogen fuel cell vehicles, but not conventional hybrids.

153 Exhibit 24116-X0170, EPCOR Module One submission, PDF page 8.

Table 4. ENMAX modelling of EV adoption rates in Alberta[154]

		Low	Moderate	High
Vehicle Purchase Incentive		**No Incentives**	**$2,500** incentive for PHEVs **$5,000** incentive for BEVs (ramp down over time, final year of incentives in 2025)	**$5,000** incentive for PHEVs **$10,000** incentive for BEvs (ramp down over time, final year of incentives in 2030)
DC Fast Charging Installations	**Calgary**	**15 stations, 20 ports** by 2035	**25 stations, 150 ports** by 2035	**50 stations, 300 ports** by 2035
	Alberta*	**45 stations, 60 ports** by 2035	**75 stations, 450 ports** by 2035	**150 stations, 900 ports** by 2035
Level 2 Charging Installations	**Calgary**	**92 stations, 220 ports** by 2035	**275 stations, 1,650 ports** by 2035	**550 stations, 3,300 ports** by 2035
	Alberta*	**276 stations, 660 ports** by 2035	**825 stations, 4,950 ports** by 2035	**1,650 stations, 9,900 ports** by 2035
Home Charging Access		**0.5% of multifamily homes** with charging by 2035	**10% of multifamily homes** with charging by 2035	**50% of multifamily homes** with charging by 2035

**Alberta public infrastructure deployment assumed to be three times Calgary deployment, in line with historic trends.*

192. ENMAX anticipated that EV adoption rates in Alberta would fall somewhere between moderate and high, because the only currently available incentives promoting EV adoption in the province are federal government vehicle purchase incentives and funding for charging infrastructure. Alberta currently does not offer any provincial EV incentives or rebates.[155]

193. As EV sales continue to increase, more charging stations will be required in both residential and commercial settings, which will increase energy consumption, and possibly demand, on the distribution system. Currently there are three types of chargers in general use. They are described in Table 5.

[154] Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 31.
[155] Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 31.

Table 5. Types of EV chargers

Type	Description	Analog
Level-1 charger	Uses a standard outlet and charges at 120 volts and up to 1.4 kW. This type of charging would be typically installed at residential and small commercial customer sites for their private use.	In terms of energy consumption and demand, a Level-1 charger is comparable to any high-wattage residential appliance (such as kettles, toasters and portable heaters) that operate at 120 volts.
Level-2 charger	Charges at 240 volts and provides a power range from 3 kW to 20 kW. This type of charging may be installed at residential customer sites for their private use. It can also be installed by commercial customers for either private use (i.e., fleet vehicles or as employee incentives) or public use (for a fee).	Most residential electric clothes dryers, electric ovens and water boilers operate at 240 volts (hence the larger plug). However, home devices consume no more than 2.5 kW-3kW average at peak loading times, [156] and never approach the 20 kW demand that a Tesla Level-2 charger can impose on the system.
Direct current (DC) fast charging (also known as Level-3 charger)	Has a voltage range from 208 to 480 volts DC and a power range of 20 to 500 kW. This type of charging would only be installed by businesses that would make the facility available to the public for a fee, or at the site of large commercial customers to charge fleet vehicles.	DC fast chargers fit under the same power requirements as the existing commercial rate classes in Alberta. For example, ENMAX indicated DC fast chargers would fall into its existing small commercial rate class.[157]

194. AddÉnergie and ChargePoint referred to a number of recent studies (including several that were conducted in British Columbia) indicating that between 75 and 90 per cent of all charging takes place, and is expected to continue to take place, at home or at work settings using Level-1 or Level-2 chargers.[158]

195. As part of their duty to provide service, distribution utilities must ensure that they are capable of handling these EV charging loads. Parties explained that the increased electricity demand from EV charging could cause grid issues, such as overloaded transformers and voltage dips in the distribution system.

196. EPCOR conducted a study in 2015 on the potential impacts of DERs on its distribution system, which included loading from Level-2 EV chargers. According to EPCOR, at 15 per cent penetration of sites with charging stations (i.e., approximately one or two Level-2 chargers per residential block[159]), there would be a substantial risk to local infrastructure such as residential transformers becoming overloaded and voltage levels collapsing below minimum acceptable voltage.[160] Given these large loads, EPCOR suggested that EV charging may skew or prevent consistent and predictable consumption patterns on certain feeders and that, with the increasing adoption of EVs, infrastructure upgrades would be required to maintain safety and reliability of the system.[161]

197. EPCOR provided a high-level estimate that it would cost approximately $20 million to upgrade one underground residential feeder and the associated infrastructure to accommodate three Level-2 chargers capable of indiscriminate charging (i.e., at maximum charging capability

156 See Exhibit 24116-X0170, EPCOR Module One submission, PDF page 11 for further details.
157 Exhibit 24116-X0502, ENMAX's responses to the Commission's preliminary IRs, PDF page 55.
158 Exhibit 24116-X0165, AddÉnergie and ChargePoint Module One submission, PDF page 4.
159 Exhibit 24116-X0170, EPCOR Module One submission, PDF page 10.
160 Exhibit 24116-X0170, EPCOR Module One submission, PDF pages 9-10.
161 Exhibit 24116-X0577, EPCOR Combined Module submission, PDF page 10.

at any time of day) per residential transformer serving 12 households.[162] By way of comparison, the cost to install a residential Level-2 charger ranges from $1,000 to $2,500 (including hardware, municipal permitting and electrician fees).[163]

198. Parties identified three general approaches that could be taken to address loading issues associated with EV charging, each with its own advantages and disadvantages, including cost to implement and efficacy:[164]

(i) Infrastructure upgrades (e.g., transformers, feeders, etc.).

(ii) Time-of-use rates or rebates to incent charging during off-peak hours.

(iii) A smart charging algorithm to directly control EV charging loads and EV starting times (typically controlled by the utility).

199. Inquiry participants were asked whether the current legal and regulatory framework applies, or should apply, to EVs and, in particular: (i) should EVs have any kind of unique or special tariff treatment; and (ii) do EV charging stations require additional regulatory oversight? Each question will be addressed in turn.

4.5.1 Should EVs have unique or special tariff treatment?

200. A distribution utility's tariff comprises both the rates (i.e., prices) and terms and conditions of service. The price paid for electric distribution service includes connection costs (grid entry), ongoing rates (grid connected), and termination costs (grid exit). The question of whether EVs should have unique or special tariff treatment applies to both grid entry and remaining grid connected.

201. In general, from a planning and tariff perspective, distribution utilities currently treat EV charging stations like any other load. That is, they do not make any special adjustments in their standard system planning processes for different kinds of incremental loads, and customers pay for service upgrade and connection costs for grid entry beyond a set amount.[165]

202. With respect to system planning for the adoption of new EV chargers (particularly the grid entry of Level-2 and Level-3 chargers), ENMAX stated distribution utilities need a suite of tools to be able to adequately respond to future demand arising from EV charging. ENMAX suggested that one of these tools should be what it described as "make-ready" infrastructure. In this context, "make-ready" means that all necessary electrical infrastructure is installed to

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162 Exhibit 24116-X0170, EPCOR Module One submission, PDF pages 13-14.

163 Exhibit 24116-X0160, MSA Module One submission, PDF page 14. Additionally, Alberta Infrastructure released a report mentioning a cost of $1,750 to install a Level-2 charger in a residential setting. For more information, please see the following hyperlink: http://www.infrastructure.alberta.ca/Content/docType486/Production/DTSeries09ElecVeh2018.pdf.

164 In its Module One IRs, the Commission asked parties to provide their comments on solutions provided in IEEE paper "Electric Vehicle Charging on Residential Distribution Systems: Impacts and Mitigations" for mitigating EV load impacts. The reader is referred to the following submissions for parties' views on the advantages and disadvantages of each approach: Exhibit 24116-X0329, ATCO-AUC-2019AUG07-018; Exhibit 24116-X0272, MEDHAT-AUC-2019AUG07-018; Exhibit 24116-X0341, FAI-AUC-2019AUG07-018; Exhibit 24116-X0353, EDTI-AUC-2019AUG07-018; Exhibit 24116-X0381, Greenlots-AUC-2019AUG07-018; Exhibit 24116-X0360, AFREA-AUC-2019AUG07-018; Exhibit 24116-X0346, AddÉnergie-AUC-2019AUG07-018.

165 This amount is set out in their respective terms and conditions, which form part of their tariff, and is referred to as the maximum investment levels or MILs.

operate charging stations (i.e., all conduit and wire is pulled to the station location(s) and all concrete work is completed to mount the stations).[166] According to ENMAX, such make-ready infrastructure could help reduce the cost of charging stations for both the customer and the distribution utility and it would be treated consistently with any other capital expenditures. These types of investments could also provide distribution utilities with the location and demand information required for effective distribution system planning.[167]

203. AddÉnergie and ChargePoint recommended that utilities be allowed to include in rate base make-ready infrastructure programs for EV charging, specifically the interconnection point between the station owner's panel and the EV charging stations.[168] This approach may require changes to the traditional regulatory arrangements for utility investments.

204. As noted above, installation and use of Level-2 chargers at residential or small commercial customer sites may strain the distribution system, creating additional system costs. In some circumstances these costs may be charged back to the customer, as part of the grid entry fees (i.e., customer contributions). In the case where shared infrastructure is upgraded, these costs would be added to rate base and covered by multiple customers (whether or not they installed an EV charger).

205. A number of parties noted that there were multiple ways for customers installing Level-2 chargers to avoid service upgrades by using load management devices that ensured total customer demand did not exceed the service transformer capacity. In this sense, EV chargers would be considered as DERs (on account of their demand-side management capabilities), and generally everything stated in Section 5 about how to address the issues surrounding DERs is also applicable to EV chargers, particularly with respect to access to information, AMI and integration of DERs. On the issue of ongoing rates for being grid connected, the discussion in Section 5.2 is generally applicable but there are some nuances specific to EVs that are worth discussing here.

206. Some parties suggested that it might be necessary to modify current rate structures by introducing time-of-use rates for EV charging.[169] The reason for doing so would be to create an incentive for customers to charge EVs during off-peak periods. EPCOR pointed out that any rate design methodology still had to ensure rates continued to recover the actual distribution system costs. Since the cost of the distribution system is fixed, time-of-use rates may allow customers that are able to shift demand to off-peak periods to incur lower distribution system charges, while customers unable to engage in this practice might incur higher charges.[170] EPCOR submitted that current rate design accurately reflects the actual distribution system costs associated with serving a site, which included sites with DC fast-charging stations. Furthermore, Dr. Orans,[171] EPCOR[172]

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166 For more details, see: https://www.chargepoint.com/files/Make-Ready-Requirements-Specification.pdf.
167 Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 13.
168 Exhibit 24116-X0558, AddÉnergie and ChargePoint Combined Module submission, PDF page 7.
169 Please refer to the following exhibits for parties commenting on time-of-use rates: Exhibit 24116-X0558, AddÉnergie and ChargePoint Combined Module submission, PDF pages 7-8; Exhibit 24116-X0568.02, Energy Efficiency Alberta Combined Module submission, PDF pages 34-35.
170 Exhibit 24116-X0577, EPCOR Combined Module submission, paragraph 45.
171 Exhibit 24116-X0742, E3 concluding remarks, PDF pages 3, 6.
172 Exhibit 24116-X0577, EPCOR Combined Module submission, paragraph 45.

and FedGas[173] commented that time-of-use rates increased the costs borne by small consumers without effecting any real change in behaviour.

207. Fortis, meanwhile, opposed the introduction of EV-specific rates. Instead, it proposed that the definitions of distribution rate classes be revised based on size and interconnection capacity with the grid (discussed in Section 5.2). Under Fortis's proposal, EVs would fit into some of the new capacity-based rate classes thereby providing a better indicator of cost causation. To the extent a DC fast-charging station required more distribution service capacity than a Level-2 charging station, the service cost and the DFO's investment in the service would be higher for a customer of the former, as opposed to the latter, type of charging station.[174]

208. In contrast, ATCO's proposed solution was based on the existing approach to rate classes. Specifically, ATCO proposed a new pilot rate (Price Schedule D23) for EV fast-charging services in its most recent Phase II application. ATCO submitted that this rate would be able to accommodate the unique load profiles associated with DC fast-charging stations. The Commission approved Price Schedule D23 on a pilot basis and directed ATCO to provide a detailed analysis of the EV fast-charging services rate class, which included the uptake of customers in the rate class and the load factors for the rate class. The Commission has previously stated that it will monitor ATCO's D23 pilot rate for DC fast chargers to assess the extent to which there may be merit in separate rate treatment.[175]

209. Based on the approval of ATCO's pilot rate, parties were asked for comments on whether the capacity size requirements and expected load profiles of DC fast-charging stations merited consideration of individual rate classes and tariffs. While most parties appeared supportive of rate classes and tariffs based on unique load profiles, as is the case with DC fast-charging stations, EPCOR and Fortis stated there was no need for a separate rate class. EPCOR offered that DC fast-charging stations could be included in rate classes with customers having similar requirements.

4.5.2 Do EV charging stations require additional regulatory oversight?

210. In this section, issues raised by parties concerning potential regulation of EV charging stations are discussed. Specifically, these issues include whether owners of EV charging stations should be (i) classified as retailers under the *Electric Utilities Act*; (ii) subject to economic regulation in order to monitor the amount an EV customer is billed; and (iii) required to report the location and operation of charging stations.

211. AddÉnergie and ChargePoint submitted that the Commission should provide guidance on whether EV charging station owners would be subject to regulatory oversight in Alberta, particularly if businesses that operate EV charging stations and make their facility available to the public for a fee were subject to regulation pursuant to the *Electric Utilities Act*.

173 Exhibit 24116-X0686, FedGas responses to the Commission's second round of IRs, PDF page 20.
174 Exhibit 24116-X0522, FortisAlberta's responses to the Commission's preliminary IRs, PDF page 42.
175 Decision 24747-D01-2020: ATCO Electric Ltd., 2019 Distribution Tariff Phase II Application, Proceeding 24747, April 30, 2020, PDF page 41, paragraph 189.

212. This uncertainty arises because of how the *Electric Utilities Act* defines an electricity "retailer,"[176] "retail electricity services,"[177] "electricity services,"[178] and "customer."[179] Several parties pointed out that, based on these definitions, an owner of a charging station that bills customers based on consumption or demand to charge EVs could potentially be classified as an electricity "retailer."[180]

213. AddÉnergie and ChargePoint pointed to a recent inquiry initiated by the British Columbia Utilities Commission (BCUC) on the regulation of EV charging services that considered the issue of regulatory oversight. The BCUC found that EV charging stations operated in a developing competitive market, and determined that economic regulation of any aspect of the EV market was not required.

214. AddÉnergie and ChargePoint noted in their combined submission that there is no province, territory or state that actively regulates EV charging and a number of states have found that third-party EV charging station owners are outside the regulatory jurisdiction of utilities commissions. AddÉnergie and ChargePoint also pointed out that the cost and burden of registering with the AUC and tracking and complying with regulation is likely to discourage investment in third-party EV chargers.

215. Additionally, AddÉnergie and ChargePoint submitted that charging station owners should not be classified as retailers, regardless of how they bill customers.[181] Other parties, however, were of the view that under a strict reading of the legislation, owners of EV charging stations that bill customers based on electricity consumption or demand could be regarded as retailers.[182] AddÉnergie and ChargePoint argued that charging stations delivered a service via specialized cords and connectors, specific to EV charging, and operated in a competitive marketplace. They further argued that these services are distinct from the act of electricity retailing contemplated by the *Electric Utilities Act*. The City of Medicine Hat[183] and AFREA[184] agreed with this position.

216. EPCOR's response to this question was more nuanced, stating that the current legislation is unclear whether or not owners of EV charging stations that bill customers based on energy

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176 1(1)(uu) "retailer" means a person who sells or provides retail electricity services and includes an affiliated retailer.

177 1(1)(tt) "retail electricity services" means electricity services provided directly to a customer but does not include electricity services provided to eligible customers under a regulated rate tariff.

178 1(1)(q) "electricity services" means the services associated with providing electricity to a person, including the following: (i) the exchange of electric energy; … ; (vi) billing; (vii) metering; ….

179 1(1)(h) "customer" means a person purchasing electricity for the person's own use.

180 Exhibit 24116-X0502, EPC-AUC-2019NOV29-012(k); Exhibit 24116-X0511, ATCO-AUC-2019NOV29-012(k).

181 ATCO provided the following billing mechanisms that could be used by owners of Level-2 and DC fast-charging stations: (1) pure time rate, (2) demand tiered time rate, (3) session-based, (4) free, (5) charging time only, (6) per kWh, (7) time-of-use layer, (8) proprietary point of sale, (9) normal credit card point of sale, and (10) data link point of sale. For more information on these billing mechanisms, please see PDF pages 73-75 of Exhibit 24116-X0511.

182 Exhibit 24116-X0502, EPC-AUC-2019NOV29-012(k); Exhibit 24116-X0511, ATCO-AUC-2019NOV29-012(k);

183 Exhibit 24116-X0506, CMH-AUC-2019NOV29-012(j).

184 Exhibit 24116-X0561, AFREA-AUC-2019NOV29-012(k).

consumption or demand would be considered as retailers of electricity under the *Electric Utilities Act*:[185]

> EDTI considers that valid arguments can be made on both sides of the issue. In EDTI's view, a more fundamental question is whether such owners *should* be considered to be retailers of electricity under the framework established by the EUA. In this regard, it appears to EDTI that many of the functions, obligations, restrictions, etc. placed on "retailers of electricity" under the EUA and related legislation would be inapplicable, meaningless and even unnecessary hindrances in the context of the owners of charging stations described in this question, whereas the more general scheme established by Alberta's consumer protection legislation may provide a more appropriate framework for these types of businesses.

217. In summary, most parties agree that EV charging stations, similar to electricity storage, are not defined clearly in legislation and their regulatory status within the evolving electricity system is unclear.

218. The inquiry also explored a second aspect of regulating EV charging stations that bill customers for service. Specifically, the Commission inquired whether there should be requirements for price transparency and disclosure to customers, as well as if there needed to be some minimum level of reporting to the Commission on location and operation for consumer protection.

219. Most parties agreed that this type of regulation seemed unnecessary. Energy and Environmental Economics, Inc. (E3) stated that active regulation of charging stations around the world is currently limited. The barrier for charging station owners is lowered when prices are independently set by these owners. Most charging station owners are also small utility customers that provide charging as an additional service to their main business activity.

220. EQUS was the only party that argued in favour of regulating price transparency:

> EQUS supports cost transparency and disclosure, and its participation as an intervener on REA and municipal asset purchase proceedings have echoed and supported this general position. EQUS believes this may not be the realm of the Commission if it does not regulate the activity of EV charging itself. Specifically, EQUS believes this could form part of broader consumer protection legislation and be regulated in a similar way to competitive retailer practices under the *Consumer Protection Act* (formerly the *Fair Trading Act*). In particular, EQUS believes that a difference in flat rates versus time-based rates may lead to confusion on the part of the consumer, and a common expression as a standard cost or a disclosure of the total minimum costs (e.g., total minimum cost of a single charge, or total minimum cost of a 20 minute charge) could benefit the end user and create a level playing field as this infrastructure is built out across the province.[186]

221. AddÉnergie and ChargePoint noted that Measurement Canada regulated many aspects of price transparency and accuracy through the meter specification process and its policies.[187] Additionally, AddÉnergie and ChargePoint pointed out that EV drivers can view the price of

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185 Exhibit 24116-X0529, EDTI-AUC-2019NOV29-012(k).
186 Exhibit 24116-X0705, EQUS-AUC-2020JUN03-011.
187 Exhibit 24116-X0688, AddÉnergie and ChargePoint responses to the Commission's second round of IRs, PDF page 6.

charging services through displays on the charging station or through charging mobile applications, and these services were not provided in a captive, monopolistic environment.

222. Another EV charging station developer, Greenlots, recommended the approach contemplated by the BCUC, where EV charging services provided by entities that are not public utilities should be exempt from regulation as defined in the *BC Utilities Commission Act*, with the exception of parts of certain sections pertaining to safety. Greenlots suggested that some basic level of reporting on location, operation and pricing offered to drivers may be appropriate.[188]

223. Regarding the reporting on location and operation of charging stations, AddÉnergie and ChargePoint submitted that EV registrations were the most effective approach to collecting data on the location of charging stations, since the majority of charging still occurs at home.[189] AddÉnergie and ChargePoint also suggested that distribution utilities may wish to implement programs that distribute smart chargers in exchange for access to customers' utilization data. A good example of such a program is ENMAX's Charge Up pilot program.[190] As such, AddÉnergie and ChargePoint submitted that reporting to the Commission on the location and operation of charging stations should not be required.

224. EV charging is still a nascent market in Alberta, and how customers are billed for these services is still evolving. It appears that a broad range of third parties are installing public charging stations in Alberta, including gas station owners and municipalities, retailers, hotels, universities and other energy service providers. There was little from the information submitted by parties during the inquiry to suggest that vehicle owners do not have access, or would have difficulty obtaining access, to prices for EV charging. In addition, no party suggested that charging station owners have any significant monopolistic advantages that they can exert over drivers.

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188 Exhibit 24116-X0704, Greenlots-AUC-2020JUN03-011.

189 Exhibit 24116-X0688, AddÉnergie and ChargePoint responses to the Commission's second round of IRs, PDF page 7.

190 ENMAX Charge Up pilot program: https://www.enmax.com/ev#:~:text=Charge%20Up%20is%20a%20pilot,within%20the%20City%20of%20Calgary.%20&text=Data%20from%20the%20chargers%20will,charging%20on%20the%20distribution%20grid.

4.6 Energy storage resources[191]

Key takeaways:
Energy storage resources are an emerging, versatile asset that could prove to be highly disruptive to the current regulatory framework. They potentially allow a customer to engage in all three flows of energy. Because they are able to store electricity, they effectively allow customers to create their own microgrid (leaving aside the issue of islanding). Therefore, all the considerations applicable to self-supply with export configurations also apply to energy storage resources. However, energy storage resources present an additional complication. They are able to reliably provide additional services to the grid beyond the delivery of electricity, which services are generally referred to as NWAs. The question arises as to how these assets might be leveraged to promote competition and lower the cost of grid-supplied electricity.

225. Of all the different types of DERs that are being connected to the grid, energy storage resources and, more specifically, battery energy storage resources, appear to have the most potential for disrupting the status quo while, at the same time, facing a number of regulatory and policy barriers to deployment. This is particularly due to the relative novelty of utility-scale battery storage, its flexibility in switching between load and supply, its potential portability, and the multitude of competitive services battery storage is potentially able to supply. As a result, battery energy storage resources appear to have high potential to significantly alter Alberta's existing regulatory framework.

226. This section addresses several of the issues and concerns raised by parties with respect to the potential future uses of energy storage resources.

227. Parties pointed out that declining technology costs are driving the adoption of energy storage. As shown in Figure 3 from Section 2.1, the costs of lithium-ion batteries have dropped significantly over the past 10 years and are forecast to continue falling in the near future.[192]

228. Energy storage resources can range in physical size, electrical capacity, portability and storage volume, and thus can be configured to fit in a variety of applications.[193] Figure 17 below depicts a prosumer[194] with a supply-side DER, demand-side DER, and an energy storage resource installed on their property. While a residential customer is depicted, this image and the ensuing discussion can be generalized to include all types of load and generation customers.

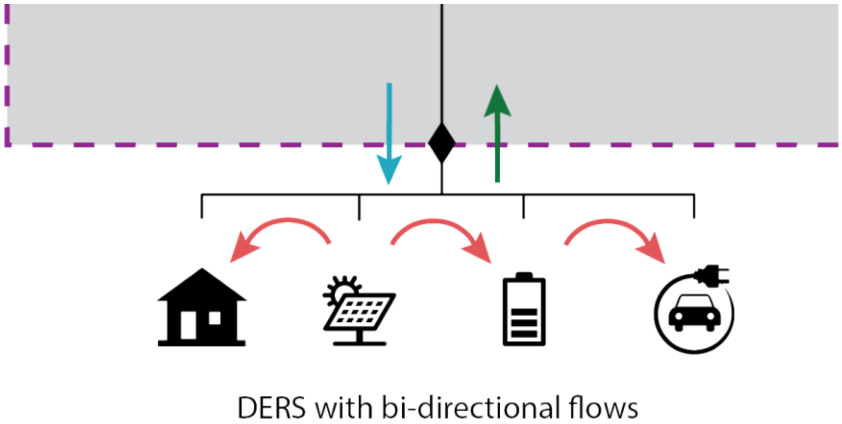
191 Throughout this section and the remainder of the report, the Commission will focus on battery energy storage resources and use the terms "energy storage," "battery energy storage" and "battery" interchangeably.

192 For example, Exhibit 24116-X0159, Energy Storage Canada Module One submission, paragraph 24.

193 Exhibit 24116-X0550, TransAlta Combined Module submission, paragraph 17.

194 While customers able to self-supply electricity are referred to as prosumers, customers that add a battery energy storage system may be referred to as "prosumagers" as they are able to produce, consume and store electric energy.

Figure 17. Illustration of a customer with a supply-side DER, demand-side DER and energy storage resource installed



229. Parties expressed the following concerns about how the current regulatory framework impedes the deployment of energy storage resources:

(i) The absence of a statutory or regulatory definition of energy storage resources within the current legislative and regulatory framework governing the operation of the AIES, and the resulting lack of clarity and certainty in how, when, where and for what purpose such resources can be legally deployed to meet customer wants and needs at market-based prices.

(ii) Limitations on the ability of customers to self-supply and export electricity to the grid.

(iii) The current treatment of energy storage in the AESO and distribution utilities' tariffs.

(iv) Lack of a process for considering energy storage resources as NWAs.

(v) Lack of clarity on how energy storage assets would be treated with respect to a utility's rate base, whether the utility owns the asset or obtains the services under contract with a third-party-owned asset.

230. Each issue will be discussed in turn; however, issues (iv) and (v) will be addressed later at sections 5.5.2 and 5.5.4, respectively.

4.6.1 Definition of energy storage resources

231. Energy storage resources are currently not explicitly defined in legislation and their regulatory status remains unclear. In dealing with the energy storage connection requests received to date, both the Commission and the AESO have had to rely on the broader regulatory framework including such existing definitions and enactments as might reasonably be interpreted to include or apply, however directly or indirectly, to energy storage resources. In addition, the AESO has developed the following working definition, which it provided as part of its energy storage roadmap.

> Energy storage is any technology or process that is capable of using electricity as an input, storing the energy for a period of time and then discharging electricity as an output.[195]

[195] https://www.aeso.ca/grid/energy-storage/ AESO Energy Storage Roadmap, PDF page 8.

232. Parties did not raise any concerns with the AESO's working definition of energy storage during the inquiry.[196]

233. In the absence of a statutory definition of energy storage resources, the Commission, in dealing with the facilities applications involving energy storage resources that have come before it to date, has sought guidance as to legislative intent from definitions of such things as "power plants"[197] and "generating units,"[198] in determining whether, and subject to what conditions, if any, to approve or reject the applications before it.[199] For example, the Commission made the following finding in one of its decisions approving battery storage:

> Although the *Hydro and Electric Energy Act* and *Electric Utilities Act* do not specifically address battery energy storage as a power plant or a generating unit, the Commission considers that **the project, as proposed,** is intended to function as a power plant. Both acts provide that a power plant or generating unit can produce electric energy from any source. All power plants convert energy from one type to another; for example, thermal power plants convert thermal energy to electric energy. A battery energy storage facility, when discharging, converts chemical energy to electric energy. And, if the chemical energy that is stored in a stand-alone battery facility was originally derived from electric energy sourced from the AIES, it does not change the fact that the storage facility, when discharging, is generating or producing electric energy from the battery modules.…[200] [emphasis added]

234. Notwithstanding these approvals, parties recommended that a definition of energy storage resources be added to the legislative framework. Since energy storage is not defined in legislation, there is uncertainty with respect to who may control and operate these assets, when, where, how and for what purposes.

235. Energy Storage Canada expressed the view that the technological progress made in recent years with respect to DERs (including energy storage) requires a fundamental shift in mindset and the existing regulatory framework from segmenting the industry into discrete classifications

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196 Exhibit 24116-X0555, Energy Storage Canada Combined Module submission, paragraph 6; Exhibit 24116-X0437, AUC Module One technical conference notes, September 11, 2020, paragraphs 8, 9 and 44.

197 Under the *Hydro and Electric Energy Act*, " 'power plant' means the facilities for the generation and gathering of electric energy from any source;"

198 Under the *Electric Utilities Act*, " 'generating unit' means the component of a power plant that produces, from any source, electric energy and ancillary services, and includes a share of certain associated facilities that are necessary for the safe, reliable and economic operation of the generating unit, which may be used in common with other generating units: …"

199 To date, the Commission has given approvals to three stand-alone battery energy storage resources, one hybrid gas plant, and one attached to a wind facility. Additionally, the Commission has approved one pumped hydro energy storage resource. The Commission has not received an application to approve an energy storage resource as part of a transmission system.
See Decision 25205-D01-2020: TERIC Power Ltd., eReserve1 Battery Energy Storage Power Plant Project, Proceeding 25205, Application 25205-A001, April 6, 2020; Decision 25691-D01-2020: TERIC Power Ltd., eReserve2 Battery Energy Storage Power Plant Project, Proceeding 25691, Application 25691-A001, August 21, 2020; Decision 25230-D01-2020: Crossfield Energy Centre Battery Addition, Proceeding 25230, Application 25230-A001, February 5, 2020; Decision 24454-D01-2019: Western Sustainable Power Corporation, Summerview Wind Power Plant Alteration - WindCharger Battery Storage Project, Proceeding 24454, Applications 24454-A001 and 24454-A002, November 7, 2019; Decision 22934-D01-2018: Turning Point Generation, Canyon Creek Pumped Hydro Energy Storage Project, Proceeding 22934, Applications 22934-A001 and 22394-A002, August 2, 2018; Decision 26101-D01-2021: FortisAlberta Inc. Waterton Battery Energy Storage System, Proceeding 26101, Application 26101-A001, January 15, 2021.

200 Decision 25205-D01-2020, paragraph 23.

of "generating units," "customers," "electric distribution systems" and "transmission facilities."[201] Instead, it contended that "electrical energy should be allowed to be supplied or withdrawn from the distribution system at any point."[202] Fortis made a similar observation regarding the existing legislative definitions:

> [Fortis] notes that the … definition of "electric distribution service" refers to "customers" where a "customer" means a person purchasing electricity for the person's own use (i.e., a load customer) and distributed generation where "distributed generation" means a generating unit that is interconnected with an electric distribution system (i.e., a DCG customer). The definition of electric distribution service refers to these customers as though they are mutually exclusive, either load-only or generation-only, whereas the nature of DER is that customers may appear on the grid as either. At times, DER customers may be a consumer and at other times they may be a prosumer. As such, these and other definitions will likely require amendments to align with this physical reality.[203]

236. Charles River Associates pointed to a need for the regulatory framework to err on the side of less prescription, rather than more, with respect to defining particular regulatory treatment for certain technologies:

> Our opinion is that, from an initial position, distribution regulation and rate design should be technology agnostic, and not give undue advantage to any particular technology. This is consistent with a principle-driven approach, where regulators rely upon open markets to develop technology choices, while adopting appropriate regulatory frameworks with rates designed to incent the development of economically beneficial technology. We do not believe that any structure that assigns differing values to alternative technologies is warranted.[204]

237. Charles River Associates' position implies that because energy storage resources can look like load and supply, there may be value in structuring the regulatory framework to focus on the activities of drawing electricity from the grid or supplying electricity to the grid rather than prescriptively defining certain assets or customers as "load" or "generation." Similar sentiments were expressed by other parties regarding technology agnosticism. This idea is discussed further in Section 4.7.

238. Heartland Generation also advocated for a legislative solution. It argued that the current legislation limits the Commission's ability to resolve issues relating to energy storage, and a legislative solution "would provide clarity, policy consistency, and decrease the regulatory burden on market participants."[205]

4.6.2 Self-supply with export using energy storage resources

239. There was a strong consensus that the lack of clarity on the definition of energy storage and uncertainties around its treatment under the current regulatory framework is a barrier to the deployment of storage assets in Alberta.

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201 Energy Storage Canada pointed to how these segments of the industry are currently defined in the *Electric Utilities Act*, sections 1(1) (h), (m), (u) and (bbb).
202 Exhibit 24116-X0555, Energy Storage Canada Combined Module submission, paragraph 3.
203 Exhibit 24116-X0578, Fortis Combined Module submission, paragraph 106.
204 Exhibit 24116-X0631, CCA Charles River Combined Module submission, PDF page 6.
205 Exhibit 24116-X0623, Heartland Generation response submission, PDF page 15.

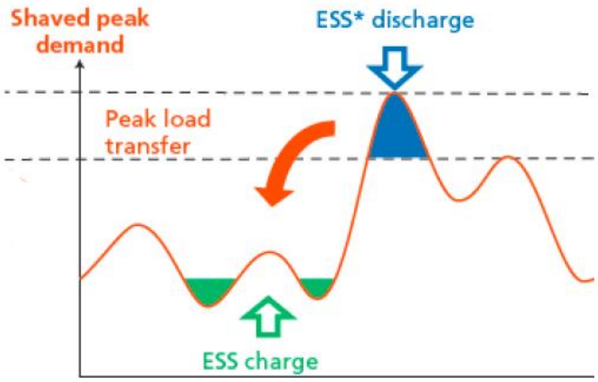
240. One of the defining features of energy storage resources is their ability to charge (acting as a load) and discharge (acting as supply), as well as the fact that they can switch between these two states nearly instantaneously. Because of this unique property, energy storage resources have a high potential to disrupt the current regulatory framework, which is centred around the concepts of load and supply.

241. Using the terminology of this report, having an energy storage resource enables a customer to engage in all three flows of energy. That is, draw energy from the grid when charging and then either consume (self-supply) the stored electricity or supply it to the grid when discharging. For example, adding a battery to what was previously a load-only site can turn that site into either a self-supply, or self-supply with export configuration. From the perspective of the utility meter at the customer's fence line,[206] having a battery is no different than having on-site generation as described in sections 4.3 and 4.4, because only the two flows of energy (inflows from, and outflows to, the grid) are visible through the meter (see Figure 17 above). However, it should be noted that the outflows of electricity from batteries are always smaller than inflows due to "round-trip efficiency" or energy losses incurred over a charge-discharge cycle.

242. As a result, the incentives and issues associated with installing DERs for self-supply with export are equally applicable to energy storage resources. The ability to self-supply creates the opportunity to avoid wires charges, leading to cost shifting between customers and potentially uneconomic bypass. However, energy storage resources potentially exacerbate this problem because they are able to match (and therefore mask) load to a high degree of accuracy during their discharge cycle. Further, because energy storage resources can behave both like supply-side and demand-side DERs, they allow the customer to avoid time-varying utility charges, such as time-of-use volumetric and demand charges. An illustration of this ability is depicted in Figure 18. This could be advantageous or disadvantageous to the grid and society, depending on the extent to which rate structures are set based on the principles of cost causation and the delivery of effective price signals. Accordingly, parties cautioned that the adoption of energy storage resources increases the need for well-designed tariffs, as discussed in Section 5.2.

206 For the purposes of this discussion, and based on current metering practices in Alberta, the Commission assumes that the meter for billing and settlement would at a minimum have two registers, one for electricity consumed from the grid and one for electricity supplied to the grid. However, to fully realize the value of energy storage resources as well as ensure accurate pricing, it would be best if the meter was capable of subhourly interval meter reads. Nevertheless, the current inquiry did not examine the various ancillary services markets and the participation of these resources in gross-to-grid or net-to-grid fashion nor their metering requirements.

Figure 18. Illustrative depiction of an energy storage resource reducing peak loading for a customer's hourly load shape[207]



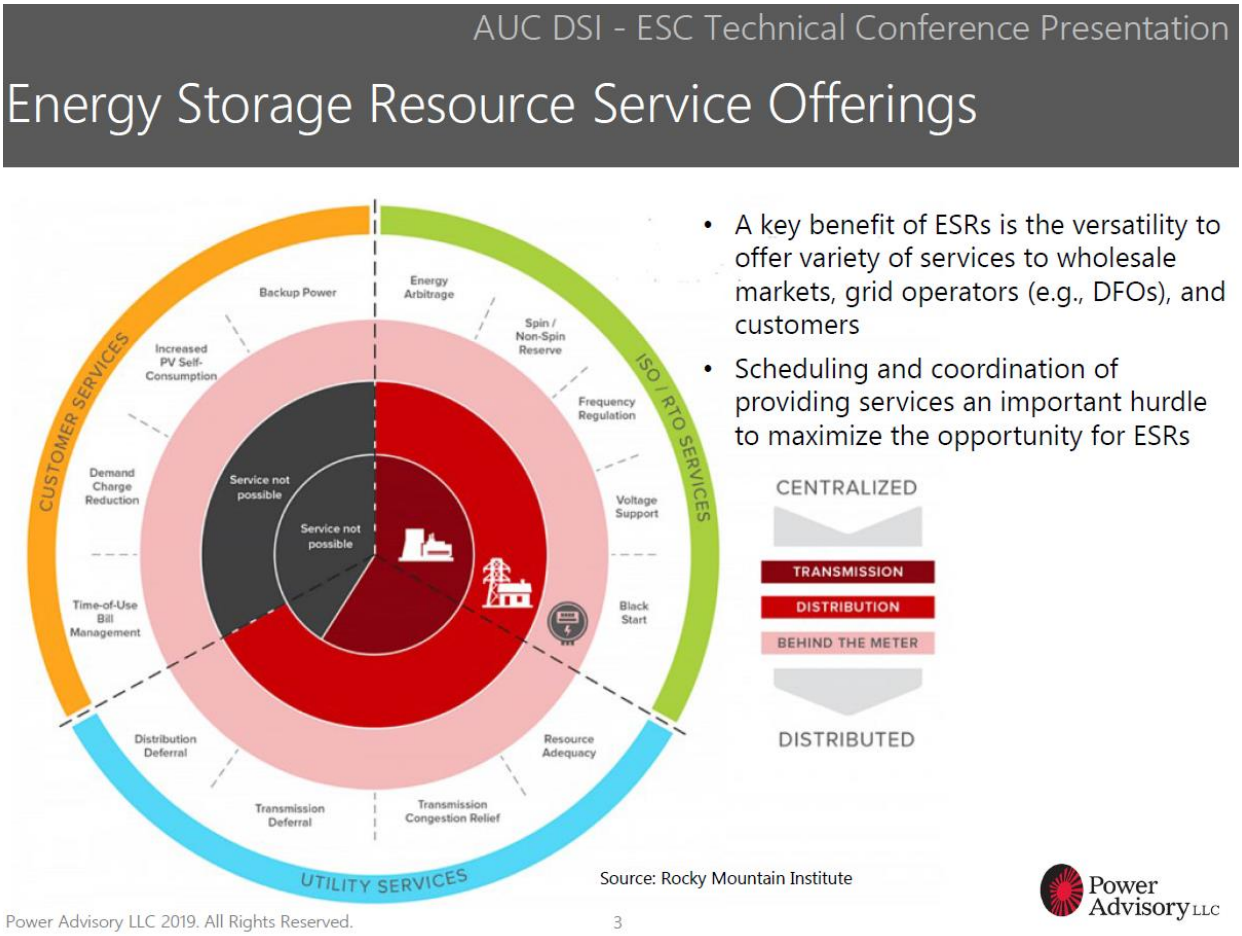
243. As with self-supply with export configurations, the ability to supply electricity to the grid introduces an additional consideration of how the electricity supplied to the grid fits in with, or at the very least does not adversely affect, the fair, efficient and openly competitive operation of the wholesale market. The considerations addressed in Section 4.4.1 are, again, equally applicable to energy storage resources.

244. On this point, AFREA added that energy storage resources should be prevented from price arbitrage (i.e., purchasing at a low price, and then selling at a higher price) in the wholesale electricity market.[208] Pembina[209] and Energy Storage Canada,[210] meanwhile, took the opposite position in pointing out that the ability to engage in price arbitrage is one of the primary benefits of an energy storage resource. In general, the ability of market participants to respond to price signals to consume more or less electricity, or supply more or less electricity into the market is an essential feature of a well-functioning competitive market.

245. An additional, and particularly salient consideration for energy storage resources that goes beyond what might be considered a "typical" self-supply with export configuration, is their ability to provide other services to the grid. Parties explained that if permitted by the regulatory framework, energy storage resources were well positioned to take advantage of multiple value streams, including supplying electricity to the wholesale market, participating in ancillary service markets, as well as providing voltage support. This concept was referred to as "value stacking" and is summarized in Figure 19.

207 Exhibit 24116-X0159, Energy Storage Canada Module One submission, Figure 6.
208 Exhibit 24116-X0556.01, paragraph 91.
209 Exhibit 24116-X0576, Pembina Combined Module submission, PDF page 33.
210 Exhibit 24116-X0615, Energy Storage Canada Combined Module response submission, PDF pages 4-7.

Figure 19. Potential value streams of energy storage[211]



246. Customers installing energy storage in Alberta may be able to take advantage of many of the "customer services" identified in Figure 19, including time-of-use bill management for rate classes where it applies. Regarding the "ISO/RTO services"[212] shown in Figure 19, the AESO is moving forward in reviewing and amending certain market rules to set a level playing field for energy storage assets, particularly to enable the provision of ancillary services (see Section 6.2 for more details).

247. Regarding "utility services" shown in Figure 19, the Community Generation Working Group (CGWG) pointed out that the current monopolistic provision of transmission and distribution delivery services limits the extent to which energy storage resources can provide some of these related services and "stack these values" for the optimal use of these assets.[213] This issue is further addressed in Section 5.5 in the context of DERs providing NWAs.

4.6.3 Tariffs for energy storage resources

248. Several parties contended that both the AESO tariff and distribution tariffs should include rate structures designed specifically for energy storage resources. TransAlta suggested that:

211 Exhibit 24116-X0410, Energy Storage Canada presentation, slide 3.
212 Independent System Operator/Regional Transmission Organization.
213 Exhibit 24116-X0561.01, CGWG Combined Module submission, paragraph 65.

> A tariff [for electricity consumption] should only apply to the extent that an energy storage facility charges using distribution or transmission infrastructure. However, the current Demand Transmission Service (DTS) rate should not broadly apply to all battery facilities – this should only apply to batteries that are grid-backed (e.g., cannot self-supply charge) and elect for non-interruptible service.
>
> For energy storage [that does rely on the grid for charging], we recommend at a minimum a special rate class for Energy Storage Opportunity Service be created. Energy storage resources have significant flexibility in managing when they are charged and can operate as interruptible load. This allows these resources to charge when the energy costs are low and/or when the grid has surplus capacity to serve load. In this way, charging can be timed to respond to market and transmission signals which is aligned to the objectives of supporting market efficiency and maximizing efficient utilization of the transmission system.
>
> …
>
> No tariff [for electricity consumption] should apply to a battery storage facility that uses an owner's own generation and behind-the-meter customer-owned wires infrastructure.[214]

249. Several parties took the opposite position. These arguments were well summarized by EPCOR:

> Similar to how load and supply from a site with distribution connected generation is metered, energy flowing to the distribution connected energy storage resource should be metered separately from the energy supplied back to the distribution system.
>
> …
>
> Finally, [EPCOR] disagrees that interruptible rates for commercial energy storage installations could be used as the basis for incenting energy storage development on Alberta's grid. [EPCOR] questions whether energy storage resources could function on a commercially sensible basis in the context of the Alberta wholesale market, in circumstances where the AESO and/or the DFO would have the ability to interrupt supply to the resource or withdrawals by the resource from the grid when the grid needs capacity to address wires constraints. For example, it does not appear to [EPCOR] workable from the perspective of a storage resource owner that [EPCOR] would somehow have the authority to curtail the resource where it has been bid into the merit order and dispatched by the AESO to meet Alberta's energy requirements in a given hour. It is also unclear to [EPCOR] how such an approach would comport with such things as the "must offer, must comply" requirements in the regulatory framework applicable to generation in Alberta.[215]

250. As noted by Lionstooth Energy, most power plants have some on-site load. Heartland Generation also noted that some large TCG have nominal Rate DTS contracts. Therefore, in a certain sense, all "generators" might appear like self-supply with export configurations, just that the export component is much larger than the rest of the energy flows. Accordingly, the notion that the asset could be classified as a "generating unit" does not preclude it from being subject to tariffs for electricity consumption.

214 Exhibit 24116-X0550, TransAlta Combined Module submission, paragraphs 18-19, 21.
215 Exhibit 24116-X0577, EPCOR Combined Module submission, PDF pages 15, 31.

251. EPCOR's first statement quoted above regarding metering energy flows accessing and egressing the grid, combined with Lionstooth Energy and Heartland Generation's observations that all generating units also consume at least some electricity (either from the grid, or self-supplied), raises the issue of "technology agnosticism," which is discussed in the next section.

4.7 Technology agnosticism

Key takeaways:
Technology agnosticism is a useful principle or conceptual ideal for regulation, especially for industries undergoing significant transformation, but may not always be practical, reasonable or even possible, especially when other equally or more important legislative objectives need to be taken into account. Parties highlighted that the meter is agnostic with respect to the technology generating or consuming the electricity; nevertheless, when considering the energy flows of load and generation, it remains the case that not all types of generation are currently treated the same.

252. Several parties expressed the concern that certain approaches to regulation may stifle the adoption of new technologies, as particular rules may not be permissive of new technologies and/or applications that were not previously contemplated. Given this, the majority of parties recommended that the regulatory framework governing the AIES should be "technology agnostic"[216] to ensure a "level playing field" with existing technologies and previously approved solutions.

253. Despite widespread agreement among parties that regulation should be "technology agnostic," there appears to be no standard or widely accepted definition of precisely what is meant by that concept. For example, some parties recommended that generation assets be treated comparably (i.e., subject to the same regulatory framework regardless of the fuel source), while others recommended impartiality between serving customer needs via a traditional wires approach and NWAs (such as demand response, energy efficiency, and distributed generation). Still others argued that ensuring a level playing field requires tailoring regulatory approaches to the specific circumstances of each technology (e.g., interruptible tariffs for energy storage resources; different regulatory treatment based on size of the generating unit, etc.).

254. For the purposes of this report, the following constitutes a workable definition of "technology agnosticism": any situation in which the regulatory framework defines (i) the services that may be supplied to the grid (including those services required for the operation of

216 Exhibit 24116-X0568, Energy Efficiency Alberta Combined Module submission, paragraph 1; Exhibit 24116-X0571, Charles River for the CCA Combined Module submission, PDF page 6; Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 8; Exhibit 24116-X0595, Lionstooth Combined Module submission, PDF page 4; Exhibit 24116-X0575, InterGroup for UCA Combined Module submission, PDF page 6; Exhibit 24116-X0598, Enel X Combined Module submission, PDF page 2; Exhibit 24116-X0551, City of Calgary Combined Module submission, PDF page 5; Exhibit 24116-X0549, Alberta Energy Efficiency Alliance Combined Module submission, PDF page 11; Exhibit 24116-X0569, ATCO Combined Module submission, paragraph 7; Exhibit 24116-X0554, IPCAA Combined Module submission, PDF page 3; Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 45; Exhibit 24116-X0576, Pembina Institute Combined Module submission, PDF page 6; Exhibit 24116-X0577, EPCOR Combined Module submission, paragraph 15; Exhibit 24116-X0599, Kalina Power Combined Module submission, paragraph 28.

the grid itself); or (ii) the services that may be consumed from the grid, without regard to the resource or technology that will provide the service to the grid or consume the service from the grid.

255. The current regulatory framework treats technologies differently on many fronts, including, but not limited to, climate policy and carbon pricing; interconnection requirements and market rules specific to the size and/or fuel source of the generating unit and the entity that owns the generating unit, as well as its intended use and purpose. To some extent, the same applies to transmission and distribution facilities – technology providers are limited in their ability to provide services to customers that would normally be provided by the incumbent utilities (e.g., transmission and distribution of electricity, metering, voltage regulation). These differences in regulatory treatment have historically arisen for a variety of reasons.

256. In terms of load and generation, the current regulatory framework tends to treat load more "agnostically" than generation. This distinction becomes more important as the lines between load and generation become increasingly blurred due to the deployment of DERs (which, as has already been noted several times in this report, are defined as technologies that affect both the supply of, and demand for, electricity). Distribution-connected load customers are generally placed within rate classes based on load profiles and/or end-use classifications. After being placed within a given rate class, loads tend to be treated agnostically. For example, distribution utilities explained that they generally have no way of knowing why any customers' load may have increased (for example, from the installation of an EV charger or a hot tub) or decreased (for example, from installing more energy efficient appliances or using existing appliances less).

257. Generation, by comparison, is typically treated much less agnostically. For example, EPCOR observed that "the Micro-generation Regulation is not even-handed regarding technology. The Micro-generation Regulation also is not agnostic regarding the scale of generation of particular technologies."[217] Such observations and objections notwithstanding, other parties have noted that there may well be valid reasons, both historically and presently, for treating different technologies and activities differently depending on circumstances. The extent to which that is the case, and the reasons therefor are beyond the scope of this report. While technology agnosticism may be a useful principle or conceptual ideal for regulation, especially for industries undergoing significant transformation, it may not always be practical, reasonable or even possible, especially when other equally or more important legislative objectives need to be taken into account.

[217] Exhibit 24116-X0577, EPCOR Combined Module submission, paragraph 14.

5 Tools and considerations for addressing the issues

5.0 Summary of Section 5

258. Of the various issues examined in this inquiry, few received as much attention from parties as the panoply of new and emerging DER technologies and potential connection configurations. It was also clear from the record of this inquiry that the principal issue or concern underlying each DER connection configuration is self-supply resulting in cost shifting among consumers, potentially leading to uneconomic bypass. However, parties also recognized that the impact of DERs on the distribution and transmission systems can be positive or negative, depending on how they are integrated into the grid and how energy flows are priced. With proper price signals and grid planning, DERs have the potential to offer value to the grid. Indeed, the value proposition offered by DERs is potentially available from a number of different streams including:[218]

- Provision of energy.
- Provision of system capacity.
- Provision of reliability services.
- Avoiding or deferring transmission and/or distribution costs through the use of NWAs.
- Environmental benefits such as reduced local air pollution and lower carbon emissions.

259. In order to harness the value of DERs to the benefit of all Albertans, a combination of the following regulatory and industry-led initiatives and undertakings were recommended including: (i) continued emphasis on promoting the goals and objectives of the existing legislative framework governing the Alberta electricity industry including, especially, encouraging fair, efficient and openly competitive electricity markets; (ii) implementation of cost-based tariff and rate design; (iii) deployment of modern metering functionality in the form of AMI systems; (iv) facilitating broader access to information, while protecting personal privacy; and (v) development of an open, transparent, non-discriminatory mechanism for cost-effectively integrating DERs onto the AIES. This section addresses each of these policy, regulatory and grid management approaches.

260. With the exception of a handful of policy issues that various parties believe would benefit from new or amended legislation – because they are neither mentioned, nor even contemplated in existing legislation – there was widespread consensus among inquiry participants that, for the most part, the current legal framework governing Alberta's electricity industry appears sufficiently robust and flexible to accommodate such adjustments or modifications as might be required to allow distribution utilities to efficiently integrate DERs into the AIES for the benefit of all Albertans. Legislative goals and objectives, together forming a set of fundamental principles that will help guide the transition of the industry to greater competition and customer choice, are discussed in Section 5.1.

261. Parties emphasized during the inquiry that, ultimately, what customers care about is their total electricity bill, and not the individual bill components. Thus, it is the total bill that drives

218 Exhibit 24116-X0579, E3 Combined Module submission, PDF page 7.

customer decisions while the “price signal” to which a customer responds (e.g., to draw electricity from the grid, consume self-supplied electricity, or curtail consumption) is really a combination of the prices of all components of the bill.

262. Regarding the distribution and transmission tariffs that form part of the total bill, there was general consensus among parties that they will need to be updated to meet the exigencies of a modern grid. Of all rate design principles, cost causation and economic efficiency become paramount if the objective is to avoid the negative consequences attending uneconomic bypass arising from the growth of DERs. To accomplish this, parties agreed that distribution rate design should involve both (i) non-avoidable charges to recover the embedded costs of the existing infrastructure; and (ii) variable, avoidable charges to send a forward-looking price signal capable of affecting future system costs by altering current behaviour. In tandem, these two components incent customers to make economically efficient decisions in their consumption of electricity (including the choice between electricity drawn from the grid and self-supplied).

263. The Commission heard that, to the extent that the transmission tariff is cost-based and sets effective price signals, it may be useful to explore ways to harmonize the transmission charges collected in the distribution tariffs with the AESO tariff. Doing so would ensure the intended price signal is passed through to end-use customers. This will contribute to increased efficiency in using both the existing distribution and transmission systems.

264. Regarding the commodity portion of the total bill, once more advanced metering technology is fully deployed, there will be an opportunity to leverage the competitive forces present in the Alberta wholesale electricity market to promote economically efficient outcomes, including enhanced retail competition and customer choice. This could be done by settling retailers on the actual hourly usage of their customers, thus creating incentives for retailers and customers to respond to energy market price signals. Cost-based tariffs and rate design are dealt with in Section 5.2.

265. The widescale deployment of AMI systems is an essential element and primary enabling technology of grid modernization as it will allow for enhanced rate design and improved access to information. Currently in Alberta, the decision to deploy AMI rests with the distribution utility. This decision is typically made on an internal cost-benefit basis unique to each utility, particularly given the age and capability of the utility’s existing meters. As a result, distribution utilities are at various stages of deploying AMI systems. While these systems offer many potential benefits to customers, these benefits may not be explicitly included in such cost-benefit calculations, introducing a potential market failure. Indeed, almost all jurisdictions that have deployed AMI systems have done so pursuant to at least some regulatory oversight and involvement. There was broad agreement among parties that distribution utilities should continue replacing their old meters with interval-capable AMI meters that can be used for an AMI system once a critical number of meters has been replaced and back-end data processing infrastructure has been installed. The benefits of deploying AMI systems are considered in Section 5.3.

266. An essential step towards improving price signals in electricity markets is making information and data more accessible. Such information and data is necessary for customers and investors to understand the extent to which DERs could meet energy needs (including their own energy needs in the case of self-supply, or system needs in the case of DCG). A lack of clarity and consistency in the requirements to connect DERs raises their cost, creates needless uncertainty, and raises barriers to investment. Enhancing access to this and other relevant

information promotes economic efficiency. The role of enhanced access to data and information in making the supply of electricity more competitive and in lowering costs to consumers is discussed in Section 5.4.

267. A number of parties argued that DERs have the potential to assist in mitigating system reliability concerns and in reducing overall system costs, provided their dispatch is coordinated and/or controlled. For this reason, utilities should consider DERs in their planning practices and assess them alongside traditional wires solutions whenever system expansion is being considered. It follows that with the growth of DERs, a more integrated approach to system planning and operation will be required. Several DER proponents argued that this integrated approach must work towards improved coordination between the AESO, utilities, load customers and third-party developers, as well as consideration of NWAs alongside traditional wires solutions in handling system constraints. The AESO has already indicated its readiness to consider a more integrated approach as part of its ongoing consultations on current system planning and operational practices. However, some parties noted that this would require changing certain aspects of the existing regulatory framework to ensure that Alberta's distribution utilities are incented to arrive at the lower cost solution by making efficient decisions when choosing between traditional wires solutions and relying on DERs to meet future system needs. DER integration into the grid is discussed in Section 5.5.

5.1 Guiding principles for the ongoing development and optimal use of electric distribution systems

Key takeaways:
The current statutory framework governing Alberta's electricity industry, through its focus on economic efficiency, competition and customer choice, is sufficiently flexible and robust to accommodate such adjustments or modifications to the regulatory framework as might be required to allow distribution utilities to efficiently integrate DERs.

268. Nearly every party to this inquiry agreed that a set of principles is necessary to guide the regulatory framework as it evolves to accommodate the economic and technological forces transforming energy distribution by public utilities. This will be particularly important in assessing the need for and scale of future investments in the modernization and expansion, as well as ongoing operation, of distribution facilities given the potential future role of DERs and the ease or difficulty with which they can be integrated into the grid.[219] A number of parties referred to the principles embedded in the *Electric Utilities Act* and *Hydro and Electric Energy*

[219] Exhibit 24116-X0730, CGWG concluding remarks, paragraph 3; Exhibit 24116-X0734, AltaGas concluding remarks; Exhibit 24116-X0740, ATCO concluding remarks, paragraph 32; Exhibit 24116-X0741, Fortis concluding remarks, paragraph 21; Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 10; Exhibit 24116-X0556.01, AFREA Combined Module submission, paragraphs 1-7; Exhibit 24116-X0575, UCA Combined Module submission, PDF pages 5-6; Exhibit 24116-X0595, Lionstooth Energy Combined Module submission, PDF pages 4-5; Exhibit 24116-X0574, Greenlots Combined Module submission, PDF page 2; Exhibit 24116-X0552, Heartland Generation Combined Module submission, PDF page 3; Exhibit 24116-X0579, E3 Combined Module submission, page 12; Exhibit 24116-X0547, QUEST Combined Module submission, page 2; Exhibit 24116-X0551, City of Calgary Combined Module submission, page 4.

Act and expressed the view that the current statutory and regulatory framework established by the Alberta legislature is no less relevant, robust and adaptable today than it was when first enacted, even as the industry undergoes significant transformation.[220] While they are not specific to electric distribution systems or DERs, those sections of these acts in which the purposes and objectives of the legislation are expressly set out, simultaneously encapsulate the principles that the legislature intended should govern Alberta's electricity industry. These include:[221]

(i) Providing for the economic, orderly, efficient and safe development and operation of the generation, transmission and distribution of electricity in the public interest.[222]

(ii) Providing for a fair, efficient and openly competitive electricity market.[223]

(iii) Maintaining a flexible framework so that decisions on the need for and investment in generation of electricity are guided by competitive market forces.[224]

(iv) Enabling customers to choose from a range of services in a competitive electricity market, and to receive satisfactory service.[225]

(v) Minimizing the cost of regulation and providing incentives for efficiency.[226]

(vi) Providing assistance to the government in controlling pollution and ensuring environmental conservation in the generation, transmission, and distribution of electric energy.[227]

(vii) Providing for the collection and dissemination of information regarding the demand for and supply of electric energy that is relevant to the electricity industry in Alberta.[228]

269. In addition to these Alberta-specific statutory objectives governing the regulatory framework for the industry, there is another vital and centuries-old principle applicable to the regulation of all monopolies. It is expressed in the *Electric Utilities Act* in the following terms:

(viii) Ensuring customers receive distribution service that is not unduly discriminatory,[229] and the tariff for that service is just and reasonable.[230]

220 Exhibit 24116-X0635 EPCOR Combined Module submission; Exhibit 24116-X0518, AESO response to Combined Module preliminary IRs; Exhibit 24116-X0576, Pembina Combined Module submission; Exhibit 24116-X0554, IPCAA Combined Module submission, PDF page 3; Exhibit 24116-X0599, Kalina Power Combined Module submission, pages 6-17; Exhibit 24116-X0562, Capital Power Combined Module submission, PDF page 2; Exhibit 24116-X0568, Energy Efficiency Alberta Combined Module submission, paragraph 7; Exhibit 24116-X0555, Energy Storage Canada Combined Module submission, paragraphs 7-8; Exhibit 24116-X0580, ENMAX Combined Module submission, PDF pages 8-9.

221 The order in which the principles are listed is not a ranking in terms of importance.

222 *Hydro and Electric Energy Act*, Section 2(a)-(b); *Electric Utilities Act*, Section 5(a); see also Section 105(1)(b)-(c).

223 *Electric Utilities Act*, Section 5(b)-(c).

224 *Electric Utilities Act*, Section 5(d).

225 *Electric Utilities Act*, Section 5(e).

226 *Electric Utilities Act*, Section 5(h).

227 *Hydro and Electric Energy Act*, Section 2(c).

228 *Hydro and Electric Energy Act*, Section 2(d).

229 *Electric Utilities Act*, Section 105(1)(a).

230 *Electric Utilities Act*, Section 121(2)(a).

270. Further, Section 105(1)(k) of the *Electric Utilities Act* requires distribution utilities to connect and disconnect customers and distribution-connected generators in accordance with the approved tariffs and with "principles established by the Commission regarding distributed generation."

271. The legislative principles highlight such fundamental avenues as competition and customer choice to achieve economic efficiency. Further, given that wires owners (that is, distribution and transmission utilities) are, and will likely remain for some considerable length of time, regulated monopolies, effective regulation is an important contributor to economic efficiency, as regulation serves as a proxy for the forces of competition.

272. Customer choice is integral to fostering robust competition. The Commission observed earlier in the inquiry that emerging technologies and innovations are creating opportunities for, and challenges with respect to:[231]

(a) Greater customer choice and control over what, when, where and how much electricity customers consume.

(b) New and/or improved service offerings based, at least in part, on more timely and detailed information on customer consumption and demand. These service offerings could be provided by DFOs or third parties, depending on the extent to which information is available to these parties.

(c) Lowering economic barriers to market entry, including self-supply.

(d) Changes to industry structure (from natural monopoly to an as yet undetermined state of greater self-supply and new competitive offerings).

273. The changes being driven by emerging technologies are serving to enhance, or have the potential to enhance, customer choice and competition in all segments of Alberta's electricity industry, including generation, transmission, distribution and retail.

274. When the Alberta legislature passed the *Electric Utilities Act* to restructure Alberta's electricity market, it made a number of changes to the regulatory regime. A defining feature of the enactment was the use of competitive market forces to set the wholesale commodity price of electricity and to allow for retail choice.

275. However, it is likely that regulation of monopoly services, including distribution utility services, will continue well into the future in order to ensure that the public interest remains protected. Therefore, as forms of competition and customer choice offerings enter, or attempt to enter, Alberta's electricity market, it will be important to assess whether such competitive inroads actually improve economic efficiency and overall social welfare. The need to achieve such a balance was expressed by ENMAX:[232]

> Technology has the potential to change the nature of services offered by competitive and regulated service providers. The regulatory framework should not be a barrier to the adoption of new products and services provided by competitive entities and DFOs.

[231] Exhibit 24116-X0439, AUC letter – Scope and process for Modules Two and Three, November 12, 2019. Note that the quoted portion in part (d) was slightly amended after the Combined Module.

[232] Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 8.

> At the same time, the regulatory framework must continue to recognize the statutory obligation of the DFO to serve within a defined service territory. It is in the public interest to ensure the continued supply of safe, reliable, and cost-effective access to energy for all customers, including for those who either cannot or do not wish to self-supply. Therefore, competition should continue to be supported where it already exists and DFOs should have the ability to invest in competitively procured services to enable customers to make efficient investments and economic choices.

276. For those services where regulation remains necessary in the public interest, fostering regulatory efficiency is important because it assists in promoting economic efficiency. This is recognized in the *Electric Utilities Act*, which stipulates that "the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency."[233] The Government of Alberta's recent focus on reducing red tape and improving regulatory efficiency provides further recognition of the importance of fostering regulatory efficiency.[234]

5.2 Improved tariff and rate design

277. Parties emphasized during the inquiry that, ultimately, what customers care about is their total electricity bill, and not the individual components thereof.[235] Thus, it is the total bill that drives customer decisions while the "price signal" to which a customer responds (e.g., to draw electricity from the grid, consume self-supplied electricity, or curtail consumption) is really a combination of the prices of all components of the bill. At the same time, when customers decide what actions to take to reduce their bill, the decision is at least partly based on which components of the bill are easiest for them to lower. This implies that individual bill components are still important, even if customers do not expressly say so.

278. As was set out in Section 3.3, in the Alberta deregulated environment, the three main components of the electricity bill, representing three distinct segments of the industry, are retail charges, distribution charges, and transmission charges. Even if the price signals for each of these components were designed in the most efficient manner, they may not always be aligned as they are measuring scarcity for each of those segments. For example, retail prices may be low (incenting higher electricity consumption, all other things being equal) at the same time as the distribution system is constrained (calling for a reduction in consumption, all other things being equal); or the transmission system may be constrained when the distribution system has abundant available capacity.

279. Parties pointed out that even though this inquiry focused on the distribution system, transmission and retail charges make up a significant share of a customer's total bill. They recommended that a comprehensive approach be taken to address all aspects of a customer's bill when considering more efficient tariff design for electricity consumed from the grid.[236] They also offered suggestions on how to improve pricing (by making it align better with cost causation) for the other two components of the bill.

233 *Electric Utilities Act*, Section 5(h).
234 *Red Tape Reduction Implementation Act*, 2020, SA 2020, c 2.
235 Exhibit 24116-X0716, Transcript, Volume 1, page 26.
236 Exhibit 24116-X0570, Brattle Group Combined Module written submission for ATCO, PDF page 25.

280. With this in mind, this section is organized as follows. Section 5.2.1 focuses on addressing shortcomings in the distribution tariff. Section 5.2.2 presents parties' comments on how to improve price signals from the transmission tariff. Finally, Section 5.2.3, presents parties' comments on the importance of passing through to customers the price signals for energy.

5.2.1 Improving the distribution tariff

Key takeaways:
Distribution tariffs will need to be updated to meet the exigencies of a modern grid. Of all rate design principles, cost causation and economic efficiency become paramount if the objective is to avoid the negative consequences attending uneconomic bypass arising from the growth of DERs. The majority of parties supported transitioning to rates that better reflect the costs of providing utility service; cost causation is accounted for both (i) in the division of cost recovery among customers; and (ii) in how the allocated costs are recovered from customers, that is, rate design.

On rate design, parties agreed that distribution rate design should involve both (i) non-avoidable charges to recover the embedded costs of the existing infrastructure; and (ii) variable, avoidable charges to send a forward-looking price signal capable of affecting future system costs by altering current behaviour. In tandem, these two components incent customers to make economically efficient decisions in their consumption of electricity (including the choice between electricity drawn from the grid and self-supplied).

5.2.1.1 Shortcomings of existing rate frameworks and the problem of uneconomic bypass

281. Parties highlighted that distribution tariffs[237] will need to be updated to meet the exigencies of a modern grid. As Brattle pointed out:

> Rates are not merely a blunt tool for recovering costs. They provide customers with proper price signals that enable adoption of the emerging energy technologies that are most beneficial to the grid, while still fully recovering the costs that they impose on the grid from those customers. Ultimately, this alignment of customer incentives with the optimal operation of the power grid will reduce costs for all customers.[238]

282. Utility ratemaking, more commonly referred to as rate design, is a complex process that typically requires balancing of competing objectives and principles.[239] For example, designing

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237 The term "tariff" is defined in the *Electric Utilities Act* and comprises both the rates (i.e., prices, rates, tolls and charges;) as well as terms and conditions for service. The price paid for electric distribution service include connection charges (grid entry), ongoing rates (grid connected), and termination charges (grid exit). This report focuses on the ongoing rates for obtaining service while being grid connected, as this portion of the tariff often receives the most attention in rate cases because they are the most persistent and visible for customers. However, observations in this report equally apply to all aspects of the tariff (grid entry, grid connected and grid exit costs, as well as the accompanying terms and conditions of service).

238 Exhibit 24116-X0570, Brattle Combined Module submission for ATCO, PDF page 6.

239 These principles were categorized and summarized by Professor Bonbright in his seminal book on utility regulation and are often referred to in the industry as "Bonbright's rate design principles." These are often summarized as: fair apportionment of costs (cost causation), recovering the cost of service (revenue

rates that allow the utility to recover its full revenue requirement, while being simple for customers to understand and avoiding excessive bill impact (or "rate shock") may not always be easy or even possible, with the result that difficult (and partially, if not wholly, incompatible) choices will have to be made between competing objectives.

283. Currently, rate design for distribution utilities exemplifies just such a balancing act. One result is that while distribution system costs are predominantly fixed and sunk,[240] a significant portion of these costs is recovered through variable charges (on electricity consumption or peak demand). For example, Dr. Orans pointed out that, on average, Alberta residential customer rates (which he considered to be "the least reflective of system costs and therefore most relevant to use as an example") recover 60 per cent of wires costs (distribution and transmission) through volumetric charges and 40 per cent through fixed charges.[241]

284. Charles River Associates, on behalf of the CCA, observed that in the past such an approach to rate design was generally accepted for the provision of electric distribution system service because it was widely perceived to achieve a balance of cost and non-cost considerations. The proliferation of DERs is nearly certain to disrupt this balance.[242]

285. As set out in Section 3.4 dealing with uneconomic bypass, economists would call current utility pricing "inefficient" because rates are not based on the costs incurred in providing the service. In response to such inefficient prices, customers will consume either too little or too much distribution system services as compared to the optimal level. It bears mentioning, however, that there may be only a very low (social) cost associated with such inefficient pricing if the utility faces no competition for its service. Where a customer's choice is electricity or no electricity, pricing distribution network services on a average cost basis induces only a small reduction in demand. However, with the option to install DERs, there is a potentially large efficiency loss resulting from uneconomic bypass, as described in Section 3.4. Efficient pricing becomes even more important to the extent that incumbent utilities currently face, or are likely to face, competition from DERs, a probable outcome for the vast majority of parties.

286. Parties to this proceeding pointed out that of all rate design principles, cost causation and economic efficiency become paramount if the objective is to avoid the negative consequences attending uneconomic bypass arising from the growth of DERs. Charles River Associates offered an explanation of what economically efficient rates are in terms of balancing cost causation, recovering the cost of service and setting price signals that encourage efficient use.

> Economically efficient utility rates are ones that discourage wasteful investment and encourage efficient consumption of utility services. Rates set to provide these goals help to diminish the risk of excess utility investment relative to consumer demands (leading to stranded costs) and guide investment in long term assets up to where consumers' demand is met (with sufficient capacity reserves). For instance, rates that are set below marginal

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requirement), customer understanding and acceptance, price signals that encourage efficient use, practicality of implementation, and rate and bill stability. See *Principles of Public Utility Rates*, James C. Bonbright, 1961.

240 The NARUC manual indicates that most distribution system costs are either capacity related or customer related, with limited dependence on system throughput. The majority of parties, including experts at the virtual technical meeting, agreed that costs to provide distribution system services are predominantly fixed at least in the near term.

241 Exhibit 24116-X0579, E3 Combined Module submission for Fortis, PDF page 47.

242 Exhibit 24116-X0571, Charles River Associates Combined Module submission on behalf of the CCA, PDF page 40.

> costs will only encourage wasteful investment by encouraging consumers to use services that are priced below their cost-based value. This, in turn, creates losses at the utility level that must be recovered from all consumers. Although marginal-based costs are the most efficient way to incentivize economically efficient buying behavior, setting rates entirely on a marginal cost basis will not provide a sufficient level of cost return for the utility and, in turn, will violate capital attraction need. Marginal costs, however, can be used as a guide in pricing.[243]

287. The above excerpt contains several important concepts that warrant further examination and discussion. Pricing based on marginal costs provides the most efficient price signals, because the cost of producing the next incremental unit of service will be equal to the willingness of consumers to pay for the last unit they consume, with the outcome that units of "goods or services are consumed by whoever benefits most from them"[244]

288. However, as virtually all parties (including Charles River Associates in the excerpt above) pointed out, rates for regulated utilities cannot be entirely based on marginal costs, because they will not recover the utility's embedded costs, as is required under the regulatory compact.[245] To achieve full cost recovery, utility rates are set on the basis of average embedded costs; however, using average cost rates instead of marginal cost rates obscures the true value of the next increment of service offered for consumption.[246]

289. Charles River Associates concluded that utility rates should continue to be set on an average cost basis, recognizing that doing so preserves some level of inefficiency. However, according to Charles River Associates, to achieve more economically efficient outcomes, and mitigate the issue of uneconomic bypass, these rate frameworks should still strive, to the extent possible, to allocate costs to consumers based on cost-causative factors. The majority of parties to the inquiry supported transitioning to rates that better reflect the costs of providing utility service.

290. As applied to utility ratemaking, cost causation is accounted for both (i) in the division of cost recovery among customers; and (ii) in how the allocated costs are recovered from customers, that is, rate design. The first component, allocation of costs to customers, is addressed in Section 5.2.1.2 below. Parties recommendations on how to improve the design of distribution rates are set out in Section 5.2.1.3.

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[243] Exhibit 24116-X0571, Charles River Associates Combined Module submission on behalf of the CCA, PDF page 14. Exhibit 24116-X0570, Brattle Combined Module submission for ATCO, PDF page 25.

[244] Exhibit 24116-X0650, CEER paper, PDF page 9.

[245] In general terms, the regulatory compact represents the understanding that utilities are given an exclusive franchise territory (i.e., monopoly status to provide a public utility service in a given area), but in exchange must accept economic price regulation. The utilities also understand that linked with the exclusive franchise is an obligation to serve all customers on a non-discriminatory basis in their service area for which the utility is granted an opportunity both to earn a reasonable return on its prudent investment and to recover its prudently incurred expenses.

[246] Exhibit 24116-X0571, Charles River Associates Combined Module submission on behalf of the CCA, PDF page 15.

5.2.1.2 Allocation of costs to customers

291. In so far as the allocation of costs to customers is concerned, cost causation means that, to the degree that a particular customer or set of customers is responsible for imposing costs on the system (e.g., by driving the need for system upgrades), that set of customers should be responsible for paying those costs. In their submissions to the inquiry, parties offered several ideas on how to improve (from the perspective of economic efficiency) the allocation of distribution system costs to customers.

292. Fortis explained that, in its most recent cost allocation study, it undertook a sub-functionalization of distribution costs into three components: shared system, local facilities and service components. Fortis explained that by "unbundling distribution costs" this way, it allowed for greater precision in setting rates:[247]

> Breaking down the Company's total distribution costs into these three components will provide greater transparency and detail to Customers, which should assist Customers in understanding the services and charges they are allocated and billed by the distribution utility. This more detailed breakdown will also allow each of the three components to be charged and recovered differently based on how each component is classified (as either: non-coincident peak (NCP) demand (annual or monthly), energy, Customer Service, or distance related). In other words, each cost component may be recovered according to its own rate structure, or billing determinant, such that the billing determinant provides an effective price signal to Customers that best reflects cost causation.

293. Several parties pointed out that the grouping of customers into rate classes[248] may need to be adjusted as the grid is modernized. In this regard, some parties recommended creating a separate rate class specific to some of the DERs. For example, AddÉnergie and ChargePoint recommended a separate rate class for DC fast chargers (i.e., Level-3 chargers) because of unique capacity requirements and utilization profiles. This particular issue was discussed in Section 4.5.1. Energy Storage Canada and TransAlta recommended a separate rate class for energy storage assets, stating that applying the same rate as that applied to all other load for drawing electricity from the grid constitutes a barrier to the deployment of stand-alone energy storage resources. This was discussed in Section 4.6.3.[249] Other parties were generally opposed to such an approach because technology-specific rates do not align with cost causation.[250]

294. Still other parties advocated a totally different approach to how rate classes are created. They proposed that they be based on capacity rather than on end-use (e.g., residential, small commercial, irrigation), as is currently the case.[251] According to Fortis, defining rate classes on the basis of end-use may no longer closely correspond with costs attributable to or associated with unbundled transmission and distribution wire services and, as a result, defining rate classes and the associated rate structures on an end-use basis is unlikely to be sustainable in the long

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247 Exhibit 24116-X0578, Fortis Combined Module submission, paragraphs 124, 145, 147.

248 Distribution utilities group customers into "rate classes," which typically are a group of customers with similar load profiles, consumption patterns and cost of service. Doing so simplifies cost allocation studies, rate design, and customer billing. Most commonly, customers are divided into residential, commercial, and industrial rate classes often with some granularity within each group (e.g., small commercial, large commercial, etc.).

249 Exhibit 24116-X0693, ESC-AUC-2020JUN03-007; Exhibit 24116-X0550, TransAlta Combined Module submission, PDF page 9.

250 Exhibit 24116-X0635, EPCOR Combined Module reply submission, paragraph 46.

251 Exhibit 24116-X0699, EDTI-AUC-2020JUN03-007; Exhibit 24116-X0706, UCA-AUC-2020JUN03-007.

term.[252] Fortis explained that the disassociation with cost causation occurs as a result of the prevalence of DERs:

> As a more distributed grid model evolves and customers have an increased ability to utilize DER to offset their net load, or generate and export surplus energy to the grid, it will become increasingly difficult to assign customers to defined rate classes based on an end-use consumption attribute. Consequently, FortisAlberta anticipates that definitions of distribution rate classes will necessarily evolve to being based on size of their interconnection capacity with the grid, since this attribute is a better indicator of the resulting costs and benefits of the services provided by the distribution system as a whole.[253]

295. The idea of adjusting rate classes to conform to system capacity requirements was not universally supported. For example, AFREA[254] and Pembina[255] both indicated that farm or irrigation-use rates should be maintained because of their seasonal nature and inability to load shift. The Brattle Group, retained by ATCO, supported continuing to define rate classes by end-use, but with an improved rate design.[256]

296. ENMAX pointed out that the City of Lethbridge currently uses capacity-based rates, and stated that both approaches (end-use or capacity-based) may make sense, depending on the needs and characteristics of the distribution utility:

> Charging customers based on end-use is a historically proven approach. As long as the rate classes adequately reflect their respective customers in that each customer uses the distribution system in approximately the same manner as others within its rate class, customers will be charged for the costs they impose on the distribution system, maintaining cost-causation.
>
> Depending on the unique characteristics of the utility, either capacity-based rates or end-use rates could make sense. Currently, EPC does not have the necessary metering infrastructure to move to capacity-based rates across its entire system.[257]

297. E3, retained by Fortis, supported re-evaluating the use and functionality of existing rate classes, but suggested that it be undertaken as rate designs become more cost-based and as AMI penetration increases across a distribution utility's service territory.[258]

298. Mr. Cowburn, an informed citizen and former employee of EPCOR, proposed yet another approach under which rate classes would be completely eliminated in favour of charging individual rates for each customer. He suggested that EPCOR's current approach of setting customer-specific rates for distribution access service for a number of its large industrial customers could be a model for all rates, given the state of technology and data availability. These rates are consumption-independent "flat" rates (i.e., fully fixed charges specific to each customer). He argued that to implement such rates requires "a customer site specific asset inventory, integrating what the asset is, where it is (electrically) located, when it was put in

252 Exhibit 24116-X0578, Fortis Combined Module submission, PDF page 56.
253 Exhibit 24116-X0578, Fortis Combined Module submission, PDF page 57.
254 Exhibit 24116-X0685, AFREA-AUC-2020JUN03-007.
255 Exhibit 24116-X0687, Pembina-AUC-2020JUN03-007.
256 Exhibit 24116-X0697, Brattle-AUC-2020JUN03-007.
257 Exhibit 24116-X0698, EPC-AUC-2020JUN03-007.
258 Exhibit 24116-X0701, E3-AUC-2020JUN03-007.

service, who it serves and how much it originally cost."[259] According to Mr. Cowburn, Fortis appears to have carried out this calculation for every individual customer on its distribution system. The distribution utilities dismissed Mr. Cowburn's approach as impractical, costly and administratively burdensome with very little benefit.[260]

299. In sum, most parties were supportive of improving the allocation of distribution system costs to customers to better reflect the principle of cost causation. One approach to improving cost allocation is for the distribution utilities to undertake a more granular analysis ("mapping out") of their system, and an examination of the underlying drivers of system costs, as was done by Fortis as part of its sub-functionalization and classification initiative. Another approach offered by some parties was to redefine the way customers are grouped together into rate classes, to more precisely allocate costs to a set of customers that are responsible for imposing those costs on the system. This may mean exploring the merits of transitioning from end-use-based to capacity-based rate classes, as suggested by Fortis and EPCOR. From the perspective of economic theory, the reason for grouping customers into rate classes is to engage in what economists refer to as third-degree price discrimination. This involves charging certain groups of customers higher prices to recover a greater percentage of fixed and common costs from them because they have a higher willingness to pay for the services in question than other customers. Because rate classes are based on observable customer characteristics, customers cannot switch to a more favourable rate class. But for this difference in the willingness of some customers relative to other customers to pay for services consumed, it would not be possible for regulated utilities to recover their full revenue requirement since some costs (e.g., fixed and common costs) are impossible to allocate based strictly on cost causation alone.

300. To this end, E3 suggested that reconsideration of rate class definitions should be done in concert with improved rate design and reflect the current and expected realities facing each particular distribution utility. This, in turn, further reinforces the need, as expressed by many of the parties to this inquiry, for a comprehensive distribution utility roadmap that would take all these factors into account when considering grid modernization. This is further discussed in Section 6.1.

301. According to the distribution utilities, eliminating existing rate classes in favour of customer-specific rates is not feasible at this time. It was their view that in addition to the high cost and burden of administering so many individual rates, there is an equity issue as customers with similar characteristics currently expect to be charged the same rate by their utility. According to the distribution utilities, grouping customers into rate classes based on certain characteristics (including on end-use, capacity, or willingness to pay for distribution service) continues to represent a reasonable trade-off between the ratemaking principles of cost causation, practicality of implementation, and fairness.

259 Exhibit 24116-X0611, Combined Module submission by Mr. Cowburn, PDF page 2.

260 Exhibit 24116-X0619, ENMAX Combined Module response submission, PDF pages 8-9; Exhibit 24116-X0635, EPCOR Combined Module response submission, PDF page 51.

5.2.1.3 Rate design

302. In the inquiry, the issue of how to improve distribution rate design featured prominently in the submissions of the four independent experts retained by parties: E3 for Fortis, represented by Dr. Orans; Charles River Associates for the CCA, represented by Mr. DesLauriers; InterGroup Consultants for the UCA, represented by Mr. Friesen; and the Brattle Group for ATCO, represented by Dr. Faruqui. These representatives took part in the virtual technical meeting, where the issue of rate design was one of the two main topics. Other parties, in their reply submissions and concluding remarks, have generally aligned with one, or several, of these independent experts and, as such, this section will focus primarily on the submissions of the four independent experts.

303. In addition to the submissions by these parties, the Commission placed on the record of the inquiry the Council of European Energy Regulators (CEER) *Paper on Electricity Distribution Tariffs Supporting the Energy Transition*[261] that provides a comprehensive overview and background for the tariff-related issues discussed in the inquiry. The Commission presented to parties, through IRs and questions at the virtual technical meeting, some of the concepts set out in that paper, and the four independent experts, for the most part, have agreed with them.

304. As discussed in Section 5.2.1, most parties agreed that an effective way to design rates that support economically efficient outcomes (i.e., prevent uneconomic bypass), and simulate the results of a competitive market, is to set rates based on the costs to deliver the distribution network service. When it comes to rate design, this means that rates should be designed to better reflect the way that costs are incurred in providing distribution system services.

305. Distribution system costs can be divided into three broad groups. The first group consists of costs associated with delivering grid supplied electricity to a consumer. These are primarily line losses between where the electricity is produced and where it is consumed, and they depend on both the distance and amount of electricity delivered.[262] In the second group there are costs associated with operating and maintaining the distribution network. These costs do not generally vary with the volume of electricity delivered, but simply reflect the fact that the distribution network must be repaired if a component fails, trees must be trimmed to avoid damage to the system and other prospective maintenance activities performed to limit the amount of outages. The third group consists of the costs of building and upgrading the distribution network. Up to the capacity of the network, these costs do not scale with the volume of electricity flowing through the distribution network.

306. The way in which the costs of distribution system services are incurred implies that the vast majority of distribution network costs cannot be causally assigned to specific market participants. It is theoretically possible that the marginal cost of delivering an additional kWh of electricity can be assigned to a specific delivery of electricity; however, the other two groups of costs must be incurred in order for the distribution utility to provide service to any customer. In the language of economics these are called common costs.

307. The four independent experts all favoured a shift from rate structures that place an emphasis on variable rate components to those that recover a larger portion of distribution utility

261 Exhibit 24116-X0650, CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition.

262 Because of these losses, more than 1 kWh of energy must be injected into the transmission and distribution networks from a generation unit in order for a customer to consume 1 kWh of energy.

costs through corresponding fixed or demand charges. In their respective submissions and answers to Commission IRs, they have presented their recommendations on rate design. E3 and Charles River Associates favoured a three-part rate design that includes fixed, demand and volumetric (cents per kWh) charges.[263] InterGroup Consultants indicated that it also supports these three-part rates.[264] The Brattle Group favoured two-part rates that include fixed and demand charges based on the view, reiterated by Dr. Faruqui at the virtual technical meeting, that "there is no theoretical justification for having variable volumetric charges to recover fixed costs of distribution."[265]

308. At the virtual technical meeting,[266] Dr. Orans and Mr. DesLauriers recommended using volumetric charges to primarily recover the cost of energy (i.e., cost of generation) and this component would not be a part of the distribution utility costs in Alberta's unbundled environment. Mr. Friesen indicated that there is a place for volumetric charges in the distribution rates, for example, to recover variable costs such as line losses. Dr. Orans agreed that some of the distribution system costs such as line losses and a portion of operation and maintenance costs are variable; however, because these are likely to be quite small, it does not matter whether they are recovered through fixed or variable charges. Overall, the four experts concluded that the distinction between two-part and three-part tariffs "is a difference without any significance"[267] as they basically recommended the same approach to distribution rates.

309. Fundamentally, the four experts agreed that the largest portion of total distribution system costs, being the costs related to all historic investment in the distribution system, consists of embedded, or sunk, costs. These costs do not change with the use of system services by customers and, therefore, by principles of cost causation and economic efficiency, should be recovered by way of charges that cannot be bypassed (avoided), or at least that are difficult to bypass, such as fixed charges (e.g., fixed monthly charges) or non-bypassable demand charges (e.g., monthly capacity fee, NCP[268] charge or ratcheted demand charge[269]). The CEER paper provides some further theoretical background on this issue:

> How residual costs are covered by the tariff structure is a matter of economic efficiency (minimising economic distortions) and a collective and fair remuneration from all users. This basically implies an optimal lump-sum charge, i.e. a fixed rate paid collectively by all users of the network (e.g. some kind of subscription fee), in cases where costs cannot be linked with a specific network user.[270] [271]

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263 Exhibit 24116-X0571, Charles River Associates Combined Module submission for CCA, PDF page 9.

264 Exhibit 24116-X0706, UCA-AUC-2020JUN03-004(c).

265 Exhibit 24116-X0697, Brattle-AUC-2020JUN03-004(c).

266 Exhibit 24116-X0716, Transcript, Volume 1, pages 21-23 and 27.

267 Exhibit 24116-X0716, Transcript, Volume 1, page 50.

268 A NCP or "non-coincident peak" demand charge is also referred to as the highest metered demand of a customer in a billing period. It is the peak demand of a customer, regardless of whether the peak was measured at a time coincident with the system peak (i.e., non-coincident).

269 A ratchet is a feature of certain demand charges, which commonly has two components: a percentage and a time period. A ratcheted demand charge would take the highest metered demand from previous bills and use it in the demand charge for a current month. A common ratchet used in Alberta is a 90 per cent, 11-month ratchet, whereby the demand charges a customer faces depends on either the current month's highest metered demand, or 90 per cent of the highest metered demand from the last 11 months, whichever is higher.

270 Exhibit 24116-X0650, CEER paper, pages 10-11.

271 From the perspective of economic theory, common and fixed costs should be allocated based on the willingness of customers to pay. Essentially, this amounts to allocating such costs to the customer least likely to distort their behaviour to avoid them.

310. During the virtual technical meeting, the four independent experts repeatedly emphasized the concepts addressed throughout this report. Whenever an attempt is made to recover embedded or sunk costs (also referred to as "residual costs" in the quote above) through charges that customers can avoid (such as volumetric charges or CP demand charges[272]), improper incentives (i.e., incentives contrary to the public interest in the least cost provisioning of electricity) arise to invest in self-supply, resulting in (i) under-recovery of fixed system costs; (ii) cost shifting to other customers; and (iii) uneconomic bypass.

311. However, the four experts also agreed that while distribution costs are mostly fixed in the short term, they are variable in the long term. This is because meeting the increased capacity needs of customers (including needs arising from new technologies such as EVs) eventually necessitates system upgrades. Therefore, distribution rates should contain a variable component to provide a forward-looking price signal to customers to manage their use of distribution system services that will affect the future costs of the network. This forward-looking component is based on variable charges (volumetric charges or avoidable demand, such as CP charges).[273]

312. Without such a forward-looking component (i.e., in the situation where all utility costs are recovered through fixed charges as was advocated by some parties), distribution rates would mute effective price signals, to the extent that consumption decisions influence the cost of the distribution system in the longer term. In addition, a fully fixed rate design may not account for the short-term variable distribution system costs, such as line losses. Therefore, fully fixed rates would not only reduce uneconomic bypass, but also economic bypass where reduction in use of system services by a customer would result in lower system costs for other customers.

313. The CEER paper presents the same conclusion that rate design should contain the two main components:[274]

> In order to have cost-reflective tariffs, it is important to be aware of the cost structure of distribution networks in the short term (losses and congestion costs) and over the long term (infrastructure costs). Tariff design should reflect that electricity networks have high fixed costs and low variable costs in the short-term. Customers should be exposed to forward-looking price signals to reflect changes in their utilisation of the grid affects future network costs. The tariff design should be targeted at reducing system peak and individual peaks.

314. In this regard, Charles River Associates pointed out that incentives should not necessarily be designed to reduce capacity requirements (i.e., "system peak and individual peaks") in the long term. CRA indicated there is nothing wrong with increased capacity requirements as long as they are economic. Therefore, rather than focusing on the reduction of long-term capacity requirements, efficient levels of investment and efficient consumption of utility services should be the ultimate goals.[275] For example, the economically optimal usage of the shared system might entail one customer shifting its use to off-peak hours (e.g., night time) when there is excess installed wires capacity to handle additional load. Another customer may place a greater value of their use of the shared system during peak hours, opting to pay higher rates. Effective pricing

272 A CP demand charge is the measure of a customer's demand on the system coincident with when the system reaches its peak demand (i.e., coincident peak or CP).

273 Exhibit 24116-X0716, Transcript, Volume 1, page 47.

274 Exhibit 24116-X0650, CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition, PDF page 5.

275 Exhibit 24116-X0571, Charles River Associates Combined Module submission, PDF page 14.

frameworks would allow customers to make decisions based on their preferences, leading to economic efficiency.

315. In summary, the four experts agreed at a conceptual level that distribution rate design should involve both (i) non-avoidable charges to recover the embedded costs of the existing infrastructure; and (ii) variable, avoidable charges to send a forward-looking price signal capable of affecting future system costs by altering current behaviour. In tandem, these two components incent customers to make economically efficient decisions in their consumption of electricity (including the choice between electricity drawn from the grid and self-supplied).

316. The four experts echoed the words of the CEER paper that "the link between present distribution tariffs sending price signals for future infrastructure network costs is necessarily of a theoretical nature, and can be interpreted in different ways across different jurisdictions."[276] The experts have expressed the same view and contended that their proposed rate structures would allow for a balance to be attained between the objectives of recovering embedded costs and sending a forward-looking price signal.

317. Several other approaches to rate design that might achieve a similar or even better balance between objectives were explored in the inquiry. They included marginal cost-based pricing (including some form of dynamic pricing)[277] and varying distribution rates by either location, time, or both. The four independent experts pointed out that while prices based on marginal costs may be theoretically preferable, such pricing mechanisms are costly to implement and may not be feasible at this time. Similarly, experts indicated that while there may be merits of locational pricing on the transmission system, there probably is much less value in locational pricing on the distribution systems, at this time. The experts agreed that rate frameworks can be improved by introducing time variant rates – that is, charging different rates for certain days (weekends versus weekdays), or times of the day (such as morning and/or evening peak hours) when the system is expected to experience constraints.[278] In addition, Dr. Orans strongly urged the Commission to consider engaging DERs through NWA procurement to address local distribution needs rather than to rely on locational pricing signals.[279]

318. Another area that was explored was the wide range of possible applications for demand charges, as they can come in many variations, measuring different aspects of customer demand.[280] The experts agreed that demand charges may play a greater role in future but cautioned that each proposed form of demand charge needs to be evaluated against its intended purpose to ensure that it sends the price signal required to achieve it.

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[276] Exhibit 24116-X0650, CEER paper, page 11.

[277] Dynamic pricing refers to setting the price signal at shorter notice periods, possibly close to real time, so that it varies with the marginal cost of distribution and transmission system delivery to the customer, in terms of both time and location. Fully dynamic pricing is different from time-differentiated static tariffs, which are characterized by offering different price signals for energy and power, based on discrete time periods (or "time-bands"). A full description of dynamic pricing was presented in Exhibit 24116-X0650, CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition.

[278] In its submission, the Brattle Group explained there are quite a few different designs to time-differentiate rates, of which critical peak pricing (CPP) is perhaps the best known arrangement. See Exhibit 24116-X0570, Brattle Group Combined Module submission, PDF page 12.

[279] Exhibit 24116-X0716, Transcript, Volume 1, pages 56-57.

[280] Exhibit 24116-X0570, Brattle Group Combined Module submission for ATCO, PDF page 10.

319. There was agreement that improving existing rate design based on the concepts presented in this section, coupled with setting up an effective regulatory framework for NWAs procurement (addressed in Section 5.5.2), would adequately accommodate the needs of distribution utilities and their customers, at this time, as they prepare for a future featuring a much higher penetration level of DERs.

5.2.1.4 Other considerations

320. Parties pointed out that while principles of cost-causation and economic efficiency should take precedence when redesigning distribution tariffs, they should not completely overshadow other rate design considerations. Dr. Faruqui emphasized that "customer understandability … is absolutely the key to rate design success" and any contemplated changes to rate design should be "customer-centric," as customers will not respond to even the most thought-through price signals they do not understand.[281] On this point, Dr. Orans countered that new technologies in DERs themselves (the "smart devices" that adjust energy consumption or production based on programming or machine learning) will enable customers to understand and take advantage of more complicated rate structures.[282]

321. Charles River Associates pointed out that limiting the amount of a customer bill that can be avoided reduces incentives for conservation, investments in energy efficiency, and deployment of DERs that may be policy priorities of a given jurisdiction. Accordingly, Charles River Associates offered that "a regulator acting in line with a policy priority may elect to limit the extent to which rates are shifted to truly reflect fixed vs. variable costs, but should do so understanding the incentives and distortions they are creating."[283] The Brattle Group countered that rates should accurately reflect costs, and policy goals such as promoting clean energy "are ideally accomplished through initiatives independent of rate design, in order to avoid distorting the incentives that customers have to make economically efficient decisions."[284]

322. Balancing of various rate design principles is important and echoes the words of the CEER paper, which concluded that "there is not a one-size-fits-all tariff model that is appropriate for all [distribution utilities] when it comes to distribution tariffs. Rather, tariff design should take a number of principles into account. Cost-reflectivity [i.e., cost causation], leading to economic efficiency, is the key principle, while the additional principles are non-distortion, cost recovery, non-discrimination, transparency, predictability and simplicity. [Rate design] should seek to find a balance between these principles."[285]

323. Finding this balance is particularly important before a large number of customers make significant investments in DERs, guided by the existing price signals from utility rates encouraging self-supply and uneconomic bypass. If a significant amount of DER investment is premised on tariff avoidance, moving to cost-based rates could result in considerable customer frustration in the short term despite promoting efficient outcomes longer-term.

324. Some parties recommended measures such as transition periods, gradual implementation, grandfathering and load retention rates to minimize the impacts of rate design changes to customers that can be materially affected by switching to cost-based rates. Charles River

281 Exhibit 24116-X0716, Transcript, Volume 1, page 85.
282 Exhibit 24116-X0579, E3 Combined Module submission, PDF page 50.
283 Exhibit 24116-X0571, Charles River Associates Combined Module submission for the CCA, PDF page 39.
284 Exhibit 24116-X0570, Brattle Group Combined Module submission for ATCO, page 25.
285 Exhibit 24116-X0650, CEER paper, PDF pages 5, 29.

Associates also recommended that customers that do not have DERs (including EVs) should be allowed access to legacy rates. The transition should be done in a measured and thoughtful way, having regard to customer bill impacts, and some of the proposed measures, such as the transition periods and gradual implementation, involve less harm. However, measures such as grandfathering may distort the level playing field, be administratively burdensome to implement and reduce overall economic efficiency.

5.2.2 Improved price signals from transmission tariffs

Key takeaway:
The issue of uneconomic bypass may also arise on the transmission system, as a result of the transmission tariff incenting more and more customers to install on-site generation and thus engage in self-supply. However, the resolution of this, and other issues related to the AESO tariff raised in the inquiry are best addressed in the AESO's tariff proceedings. Aligning the rate design for the transmission costs portion of the distribution tariff with the AESO rate design, as part of Phase II proceedings, would ensure the intended price signal is passed through to end-use customers. This will contribute to increased efficiency in utilizing the existing distribution and transmission systems.

325. Parties indicated that the issue of uneconomic bypass may also arise on the transmission system, as a result of the transmission tariff incenting more and more customers to install on-site generation and thus engage in self-supply. AltaLink pointed out that under the current AESO tariff, bulk transmission system costs that account for approximately 50 per cent of the total transmission system revenue requirement are collected through a 12 Coincident Peak (12 CP) demand charge.[286] This charge sends a price signal to customers to reduce their billable load at the time of the transmission system coincident peak, thus incenting the installation of on-site generation or energy storage. AltaLink argued that the 12 CP charge no longer reflects the underlying cost drivers of the transmission system, thus avoiding this charge does not reduce the costs of the transmission system and simply allows self-supply customers to avoid paying for a large portion of transmission system costs, resulting in cost shifting to other customers. To minimize or potentially eliminate this opportunity for uneconomic bypass, AltaLink recommended moving away from the 12 CP charge to a rate framework with more fixed and demand-based charges.[287]

326. During the virtual technical meeting, both Dr. Orans[288] and Mr. DesLauriers[289] agreed that the current 12 CP charge contributes to uneconomic bypass of the transmission system. Dr. Orans noted that the current 12 CP charge in Alberta sends a price signal of approximately \$10/kW to avoid that one hour in a month, and exclaimed that this is "… an astronomically high number on the order of things, and it pays for a customer to install a CT [combustion turbine] to

[286] A 12 CP demand charge is the measure of a customer's demand on the system coincident with when the system reaches its peak demand (i.e., coincident peak or CP). The 12 refers to the 12 months in a year, whereby the customer's contribution to the system peak is measured and billed each month. See ISO Tariff – Rate DTS 3(2).
[287] Exhibit 24116-X0597, AltaLink Combined Module submission, paragraphs 111-112.
[288] Exhibit 24116-X0716, Transcript, Volume 1, page 88.
[289] Exhibit 24116-X0716, Transcript, Volume 1, pages 89-90.

bypass a bulk system that is largely built and largely has no variable cost in the short-run going forward."[290]

327. Parties expressed their concerns with other aspects of the AESO tariff as it relates to the matters discussed in the inquiry. Energy Storage Canada and TransAlta, for example, opined that the AESO's current DTS rate for drawing electricity from the grid acts as a barrier to the deployment of stand-alone energy storage resources.[291]

328. Most parties acknowledged that uneconomic bypass of the transmission system and other issues related to the AESO tariff, while not irrelevant to the inquiry, are better addressed in the AESO's tariff proceedings. The AESO noted, in this regard, that it is currently working on optimizing price signals in its tariff.[292] The Commission is also aware the AESO has launched a tariff modernization initiative and is currently consulting on bulk and regional tariff redesign.[293]

329. Parties also called for the harmonization of distribution and transmission tariffs from several perspectives. The Canadian West Ski Areas Association (CWSAA) explained that transmission system costs are recovered from distribution customers through a part of the distribution tariff called "System Access Service" (SAS). CWSAA observed that the four regulated distribution utilities design their SAS rates using their own tailored methodologies, which differ considerably among the companies, and recommended aligning among the distribution utilities how the AESO's transmission tariff is flowed through to customers. CWSAA clarified that its proposal is to standardize (i) the method by which SAS rates are determined among the four major distribution utilities; and (ii) the timing of the flow-through, not the rates themselves, to respect the differences in metering infrastructure and existing rate class definitions.[294]

330. From another perspective, AltaLink and IPCAA recommended that distribution rate design for the SAS portion of the tariff align with transmission rate design to ensure that the intended price signal is passed through to end-use customers. AltaLink stated:

> The distribution tariffs need to be more closely aligned with the transmission tariff. This is especially true as the distribution rates recover the transmission costs as part of their tariff structure. If efficient price signals are set as part of the transmission rate design process, the effectiveness of these price signals will be lessened or nullified if the distribution tariffs do not have similar price signals.
>
> …
>
> The effectiveness of having correct pricing signals in the transmission tariff is diminished if distribution tariffs are not aligned with these price signals. If it is determined that grid charges should be collected via a fixed charge in the transmission tariff, the DFO should also be collecting these charges through a fixed charge.[295]

290 Exhibit 24116-X0716, Transcript, Volume 1, page 88.
291 Exhibit 24116-X0693, ESC-AUC-2020JUN03-007; Exhibit 24116-X0550, TransAlta Combined Module submission, PDF page 9.
292 Exhibit 24116-X0594, AESO Combined Module submission, PDF page 7.
293 https://www.aeso.ca/rules-standards-and-tariff/tariff/tariff-modernization/
294 Exhibit 24116-X0642, CWSAA Combined Module response submission, PDF page 10.
295 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraphs 102 and 115.

331. IPCAA argued that aligning the rate design for the SAS portion of the distribution tariff with the AESO rate design would contribute to increased efficiency in utilizing the existing distribution and transmission systems and may help defer the need for future builds, ultimately resulting in lower costs of delivering electricity.[296] If all distribution utilities were to align their SAS rate designs with the AESO rate design (which applies throughout Alberta), it would lead naturally to the harmonization among DFOs, addressing CWSSA's concern.

332. However, in the short term, there are obstacles to such harmonization. As AltaLink observed, some of the rate components in the current AESO tariff do not reflect the underlying cost drivers of the transmission system.[297] Therefore, customers' response to such price signals will not optimize the use of the existing infrastructure and avoid future builds. As noted previously, the AESO appears to be aware of these concerns and is currently working on optimizing price signals in its tariff.

333. Another potential obstacle is the constraint on distribution rate design options arising from available billing units for some rate classes fully or partly driven by existing metering infrastructure. Parties referenced an extreme case of a residential rate that recovers all of the SAS charges though a volumetric ($/kWh) levy. While the majority of the AESO's charges are based on demand, straight mirroring of these charges to residential customers is not possible as their demand is not measured. The Commission considers that aligning distribution rates (including the SAS portion) with underlying system costs, with more emphasis on fixed, time-of-use or demand charges, as applicable (as was discussed in Section 5.2.1), will help to mitigate this obstacle. This also underscores the need for more metering data which, in turn, further supports AMI installation.

334. Most distribution utilities indicated that they intend to give additional consideration to harmonizing their SAS rates with the AESO tariff as part of their next Phase II tariff applications. These are most likely the appropriate venues to deal with such harmonization and other distribution rate design matters discussed in this report.

335. On a broader level, AltaLink and the AESO[298] called for a coordinated approach to the design of transmission and distribution tariffs to promote efficiency and reduce tariff shopping. AltaLink made its point as follows:

> As discussed above, there is a general interest in ensuring a level of harmonization between distribution and transmission tariffs so that inequities are minimized. Harmonization of the transmission and distribution tariffs allow customers to choose between a distribution and a transmission connection on the basis of appropriate technical and financial considerations as opposed to being incented to choose a certain connection on the basis of perverse price signals.
>
> …
>
> Generally, a holistic view to the AESO and DFO tariff designs needs to be incorporated as much as possible with an aim at achieving harmonization between the transmission and distribution tariffs. This will lead to more cost efficient outcomes, reduce cross-

[296] Exhibit 24116-X0554, IPCAA written submission - Combined Module, PDF page 7.
[297] Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 79.
[298] Exhibit 24116-X0594, AESO Combined Module written submission, PDF page 7.

> subsidization and diminish the possibility of tariff shopping between transmission and distribution tariffs.[299]

336. Advancing alignment between transmission and distribution tariffs is more of a long-term objective and may not always be possible for a variety of reasons, including physical and engineering realties, as well as policy and regulatory considerations. The venue to pursue such alignment is in the AESO's and distribution utilities' respective tariff applications.

337. Lionstooth took the idea of harmonization of the distribution and transmission tariffs one step farther and suggested developing a single, province-wide set of rates for access to the entire integrated system (i.e., the entire AIES) across all electricity customers and services. Lionstooth conceded, however, that its proposal is complex and would require significant additional analysis.

5.2.3 Price signal for the retail component (i.e., commodity charges)

Key takeaways:
When more advanced metering technology is fully deployed, there will be an opportunity to leverage the competitive forces present in the Alberta wholesale electricity market to promote economically efficient outcomes. This could be done by settling retailers on the actual hourly usage of their customers, thus creating the incentive for retailers and customers to respond to total bill price signals.

338. As set out in Section 3.1, the wholesale and retail prices for electricity in Alberta are generally not regulated by the Commission, but, rather, are determined in competitive markets. Customers can currently choose a retail product from among a number of competitive offerings.

339. All of the experts in the virtual technical meeting appeared to agree that the cost to supply the actual commodity of electric energy is highly variable (e.g., because of fuel availability and cost), and the most efficient price signal for this portion of the bill would be exposure to a time-varying rate that corresponds to the wholesale price of electricity.[300]

> (Mr. Friesen) So you have an energy pool in Alberta, and it is a time-varying rate, an hourly time-varying rate, and that price signal is largely absent from your market, at least in terms of the residential consumer or the small C&I consumer.…
>
> (Mr. DesLauriers) I believe that the variable charge … should be tied as closely as possible to the energy market. We know that that varies by time based upon the fuel costs of the source of generation. And so we do think that there's a time-based component to fuel and to energy charges, and that's obviously clearing in the energy markets today through the AESO. And so, you know, our statement was that energy charges correctly priced should reflect those price signals and most likely a time-varying energy charge would be better than one that aggregates it all and averages out across time.

299 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraphs 103 and 105.
300 See Exhibit 24116-X0716, Transcript, Volume 1, pages 194-196, for the full discussion.

340. The Commission agrees that the ability of customers to receive efficient price signals, and respond to them, generally promotes economically efficient outcomes. This applies equally to the commodity component of their bill. With advances in metering technology, there is an opportunity to leverage the competitive forces present in the Alberta wholesale electricity market, by passing onto customers with DERs dynamic price signals for electricity.

341. However, on this point, it is important to clarify that receiving efficient price signals for a commodity (electricity) does not imply that all customers should be directly exposed to the hourly wholesale market price. Customers in Alberta can choose among many competitive retail offerings that include fixed and floating rates for electricity. Ultimately, it should be the retailers that are financially accountable for the difference between the market and contract prices as they are in the best position to manage the exposure to the hourly wholesale market. For this to happen effectively, retailers would need to be settled based on the actual hourly usage of their customers. Dr. Faruqui observed that where other jurisdictions have taken similar approaches this has resulted in innovative retail offerings to the benefit of customers.[301]

[301] Exhibit 24116-X0570, PDF pages 5 and 24, provided the following examples:
"Thus far, there has been relatively little innovation in variable distribution charges in the industry, even though the idea has been entertained in several U.S. jurisdictions and also in Australia and New Zealand. Additionally, some vertically integrated utilities with TOU [time-of-use] rates have indicated that their distribution costs are being collected on a time-varying basis under these rates, in recognition of the fact that distribution capacity is largely a peak demand-driven cost.
There has been significantly more innovation in variable charge design on the generation side of the bill. A number of utilities have collected generation costs through dynamic pricing rates, such as Baltimore Gas & Electric and Pepco in Maryland (PTR), Oklahoma Gas & Electric (CPP), and Commonwealth Edison (RTP). These rates were introduced to reduce utility costs through demand response, in some cases leveraging the presence of smart thermostats and in-home energy information displays and therefore enhancing the customer's ability to respond to the dynamic price signals."

5.3 Advanced metering infrastructure systems

Key takeaways:

An essential element and primary enabling technology of grid modernization is the widescale deployment of AMI systems, as they allow for enhanced rate design and improved access to information. The data and information collected by AMI systems is potentially very useful in that it can increase the benefits the grid makes available to all consumers while simultaneously lowering the aggregate costs of delivering services to those same consumers. In particular, the types of information AMI systems can generate will enable distribution utilities to design rates in ways that are more aligned with cost causation and, at the same time, send more effective price signals to both producers and consumers of electricity. This is because AMI enables customers to be billed not only on any element of cost attributable to or associated with the delivery of service to them (e.g., volumetric or usage-based and demand or capacity-based charges) but also in different time periods (interval or time variant pricing), and is an absolute must if any form of dynamic pricing is being considered.

Currently in Alberta, the decision to deploy AMI rests with the distribution utility. This decision is typically made on an internal cost-benefit basis unique to each utility, particularly given the age and capability of the utility's existing meters. As a result, distribution utilities are at various stages of deploying AMI systems. While these systems offer many potential benefits to customers, these benefits may not be explicitly included in such cost-benefit calculations, introducing a potential market failure. Indeed, parties explained that almost all jurisdictions that have deployed AMI systems have done so pursuant to at least some regulatory oversight and involvement. There was broad agreement among parties that distribution utilities should continue replacing their old meters with interval-capable AMI meters that can be used for an AMI system once a critical number of meters has been replaced and back-end data processing infrastructure has been installed.

342. Parties agreed that more access to information and data will promote competition and customer choice in Alberta's electricity market (see Section 5.1). As well, rate design for grid-supplied electricity would need to be improved to recover the costs of existing infrastructure while, at the same time, providing price signals to manage future costs, as discussed in Section 5.2. Parties noted that progress on these two issues would be significantly aided through widescale deployment of AMI. This section summarizes why AMI systems are an important enabler to delivering the benefits of DERs investments.

343. AMI systems consist of metering devices (often referred to as "smart meters") that are capable of being read remotely at an hourly, or more frequent, interval for electricity consumption (that is, kWh) and demand (kW or kVA) using communications and back-end data processing infrastructure. It is important to understand that a basic back-end data processing infrastructure is required to make smart meters functional. This infrastructure usually includes

data collection and communication systems, head-end systems, meter data management systems, data storage systems and customer billing systems.[302]

344. Several parties explained that not all AMI systems are alike. While at a fundamental level AMI systems have the same basic functionality – two-way communication between the utility and the meter installed at the customer's site – many of the benefits provided by AMI often depend on the system's configuration to meet specific functional requirements.[303] Potential benefits AMI can provide, as identified by the U.S. Department of Energy (and summarized by the UCA), include:[304]

- Reduced costs for metering and billing from labour savings, more accurate and timely billing, fewer customer disputes, and improvements in operational efficiencies.
- Greater customer control over electricity consumption, costs and bills from greater use of new customer tools (e.g., web portals and smart thermostats) and techniques (e.g., shifting demand to off-peak periods).
- Lower utility capital expenditures and customer bill savings resulting from reduced peak demand and improvements in asset utilization and maintenance.
- Lower outage costs and fewer inconveniences for customers from faster outage restoration and more precise dispatching of repair crews to the locations where they are needed.
- Enables use of time-based rates and enhances the capabilities of demand-side management programs.
- Improved integration and billing for DERs and EV charging.

345. Parties stated that many of these benefits arise from being able to leverage the interval data on electricity consumption and demand. Once installed, were AMI systems used to read customer meters at hourly (or more frequent) intervals, high volumes of very granular data sets would be generated. For example, rather than one data point for one customer's billing based on monthly cumulative consumption, approximately 730 data points would instead be needed to facilitate monthly billing based on hourly interval consumption; even more may be needed if demand charges are also applied. Storage, validation and use of these data would require additional IT-related infrastructure. AMI systems installed in Alberta today are not configured to make meter reads for the majority of customers at intervals greater than the monthly billing cycle.

346. EPCOR is one of the few distribution utilities in Alberta with interval-capable meters installed across its entire service territory as part of its AMI system. EPCOR explained that it is actively analyzing opportunities to leverage its AMI system to improve the planning and operation of its distribution system in the following ways: (a) optimize voltage to control it in a more narrow band on all of its circuits to improve how grid-connected load devices operate; (b) enhance demand response and price signals provided to customers; (c) integrate its AMI system with its advanced distribution management system (ADMS) to better understand and

[302] Exhibit 24116-X0699, EPCOR's responses to the Commission's second round of IRs, EDTI-AUC-2020JUN03-001, PDF page 14.
[303] Exhibit 24116-X0699, EDTI-AUC-2020JUN03-001.
[304] Exhibit 24116-X0706, UCA-AUC-2020JUN03-001.

respond to loading patterns and conditions; and (d) provide additional data analytics to optimize the use of existing infrastructure.[305] In other words, AMI systems allow for a better understanding of location, timing and sources of peak loads on the distribution system, and enhanced granularity and accuracy of load forecasting.[306]

347. The data and information collected by AMI systems is potentially very useful in that it can increase the benefits the grid makes available to all consumers while simultaneously lowering the aggregate costs of delivering services to those same consumers. In particular, the types of information AMI systems can generate will enable distribution utilities to design rates in ways that are more aligned with cost causation and, at the same time, send more effective price signals to both producers and consumers of electricity. AMI is an essential component of the infrastructure required for effective and comprehensive rate design. This is because AMI enables customers to be billed not only on any element of cost attributable to or associated with the delivery of service to them (e.g., volumetric or usage-based and demand or capacity-based charges) but also in different time periods (interval or time variant pricing), and is an absolute must if any form of dynamic pricing is being considered.

348. In addition, retailers and DER proponents may also be able to analyze customer usage data, creating opportunities to develop differentiated products and services, communicate with clients and provide more effective price signals to customers.[307] The City of Medicine Hat pointed out that AMI offers the ability to collect, settle and bill customers for bi-directional interaction with the grid at hourly intervals when customers have installed DERs.[308] This allows the electricity supplied to the grid from DERs to be settled at the hourly wholesale price of electricity. This promotes more robust competitive market outcomes, rather than relying on approximations or non-market mechanisms for pricing certain products. This issue is further discussed in Section 4.4.2.

349. The confluence of enhanced distribution planning and operation, distribution rate design, and retail offerings, all three of which are facilitated by AMI systems, can promote grid optimization through market mechanisms.

350. For example, a distribution utility could introduce time variant charges for residential and small commercial customers and levy higher rates during a certain time of day based on expected or actual system constraints. Customers could receive real-time communications either from their retailer (e.g., by way of a cellphone app) or directly from their AMI meter (connected to their Home Area Network via a third-party communication device) alerting them that their current load may attract peak pricing charges. Their "smart devices" can also be pre-programmed to reduce consumption when peak pricing is in effect. Such a scenario, although still hypothetical in Alberta, would provide customers with a clear price signal allowing them to determine whether their marginal benefit of consumption of grid-supplied electricity during that time exceeds the marginal cost to them, or whether they would prefer to shift their consumption to off-peak hours.

351. The adoption of AMI systems was examined by the Commission in 2011 through the Alberta Smart Grid Inquiry.[309] In the final report, the Commission recommended that the

305 See Exhibit 24116-X0170, EPCOR Module One submission, paragraphs 52-70, for more details.
306 Exhibit 24116-X0512, Pembina response to Commission's preliminary IRs, PDF page 9.
307 Exhibit 24116-X0154, ENMAX Module One submission, PDF page 17.
308 Exhibit 24116-X0142, City of Medicine Hat Module One submission, PDF page 6.
309 Alberta Smart Grid Inquiry, Proceeding 598, January 31, 2011.

province allow AMI to be adopted according to a "natural evolution" (that is, conventional meters being replaced with AMI meters as they reach the end of their operating life) in large part because industrial and large commercial customers consumed the majority of total electrical energy in the province, and they were already equipped with interval meters. However, the Commission also proposed a cost-benefit methodology that would allow the government to model a range of roll-out scenarios to determine whether mandating widespread deployment of interval-capable AMI systems would be in the public interest. While no such roll-out was ever mandated, Alberta's largest distribution utilities have begun to integrate AMI meters into their distribution systems to varying extents.

352. Currently in Alberta, the decision to deploy AMI rests with the distribution utility. This decision is typically made on an internal cost-benefit basis unique to each utility, particularly given the age and capability of the utility's existing meters.

353. EPCOR completed installation of its AMI system in 2017, replacing 99.9 per cent of its conventional meters with AMI meters. EPCOR's AMI system cost approximately $76 million (roughly $61 million for the installation of 372,996 meters and $15 million for back-end systems).[310] Its system includes the infrastructure required to remotely read the AMI meters and perform billing and settlement functions in accordance with the requirements under the current regulatory framework. Based on a preliminary analysis, EPCOR estimated that to generate bills based on hourly data for all customers currently being billed on a cumulative basis would require additional capital investment of at least $10 million.[311]

354. ATCO Electric utilizes automatic meter reading (AMR) devices in its service territory. In its Phase II application, ATCO received approval to implement a time-of-use residential rate in the Grande Prairie region, where ATCO plans to install approximately 2,000 AMI meters. ATCO's proposal was a pilot program to examine customer usage.[312] ATCO initiated planning for a meter data management system enhancement to handle the required volume of data produced by an AMI system.[313]

355. ENMAX advised that it was replacing existing meters with AMI meters only if they failed a test or were more than 24 years old. ENMAX indicated that of its 517,702 installed meters, 4,229 were interval meters and 84,693 were AMI meters[314]; the remaining meters are traditional (i.e., non-AMI) cumulative meters.[315]

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310 Exhibit 24116-X0743, EPCOR concluding remarks, paragraph 33. EPCOR also noted that the Commission's utility asset disposition (UAD) policy created an additional barrier and cost to deploying its AMI system. EPCOR stated this policy presented a potential financial disincentive for investing in AMI technology, and presented its own case where EPCOR's shareholder incurred a loss of $8.96 million on the undepreciated meters that were replaced by AMI meters. UAD is a complex subject and is beyond the scope of this report.

311 Exhibit 24116-X0699, EDTI-AUC-2020JUN03-002(c).

312 Decision 24747-D01-2020: ATCO Electric Ltd., 2019 Distribution Tariff Phase II Application, Proceeding 24747, April 30, 2020, PDF page 37, paragraph 170.

313 Exhibit 24116-X0511, ATCO's responses to the Commission's preliminary IRs, PDF page 58.

314 Interval meters measure consumption in intervals, but do not communicate the interval data back to the service provider as do AMI meters. As such, interval meters still need to be manually read or have their information downloaded.

315 Exhibit 24116-X0502, ENMAX's responses to the Commission's preliminary IRs, PDF page 45.

356. Fortis characterized its base of installed meters as a fully deployed AMI system.[316] However, Fortis's meters for residential and small commercial customers are not capable of performing meter reads at hourly intervals – a capability that is presently not required, but may be beneficial in the future as described above. Fortis explained that it plans to exchange all current cumulative meters with new generation meters, capable of sub-hourly measurement, over the next 10 years on a lifecycle replacement schedule. Fortis currently has no plan to configure these meters to provide sub-hourly or hourly information, as these enhancements would require upgrades to communications systems, meter data management systems and processes, and billing and load settlement systems.[317] During the technical conference, Fortis mentioned that all of its meters may need to be replaced by 2044 to meet Measurement Canada's E-31 policies and specifications on having meters that were capable of interval readings. Measurement Canada's guidelines in this respect have not yet been announced.

357. As for the other distribution utilities in the province, EQUS reported it was working to install a fully functioning AMI system across its service territory by the end of 2020 or the beginning of 2021.

358. The City of Medicine Hat has replaced all of the meters for electricity (approximately 32,500 meters), natural gas (approximately 34,000 meters) and water (approximately 24,000 meters) in its service area with AMI meters. The new meters comprise an interconnected metering and billing system. The City explained that one of the main benefits of deploying this technology across all the utilities it operates under a single system allows customers to see their own detailed consumption data (near-real time) and provides for enhanced customer engagement. The City began installing these meters in 2012 and completed the deployments in 2018.[318]

359. AFREA reported that its member REAs are strongly opposed to deployment of AMI systems across their service territory, particularly due to concerns of cost and what they viewed as an absence of measurable benefits. AFREA submitted that AMI was not necessary, and was not a prudent cost in rural settings and for small customers.[319] AFREA also expressed its view that AMI was not required for the safety and reliability of the grid as a whole, and was not required to integrate DERs into the grid.[320]

360. In general, parties did not support the idea of a mandated widespread deployment of AMI systems throughout the province. While mandated AMI system deployment would accelerate the modernization of the grid and increase access to information for a wider range of customers, this functionality would come at a cost, as seen by EPCOR's experience. Some parties argued that before AMI systems are mandated, a cost-benefit analysis should be conducted to evaluate the prudence of such an initiative.[321] Other parties considered that the technology is mature and most

316 Exhibit 24116-X0741, Fortis concluding remarks, paragraph 6.
317 Exhibit 24116-X0522, Fortis' responses to the Commission's preliminary IRs, PDF page 33.
318 Exhibit 24116-X0142, City of Medicine Hat Module One submission, PDF page 6.
319 Exhibit 24116-X0732, AFREA concluding remarks, PDF page 8.
320 Exhibit 24116-X0732, AFREA concluding remarks, PDF pages 4-5.
321 Exhibit 24116-X0697, Brattle Group's responses to the Commission's second round of IRs, PDF pages 4-7; Exhibit 24116-X0701, E3's responses to the Commission's second round of IRs, PDF pages 3-5; Exhibit 24116-X0706, UCA's responses to the Commission's second round of IRs, PDF pages 9-13. Exhibit 24116-X0708, the AESO's responses to the Commission's second round of IRs, PDF page 4.

distribution utilities are in various stages of deploying their AMI systems; therefore, additional analysis on costs and benefits of AMI is not needed at this time to facilitate the roll-out.[322]

361. The inquiry explored the possibility of distribution utilities deploying interval-capable AMI systems to serve particular customers in response to market forces, rather than widespread deployment in response to regulatory intervention. Most parties appeared to agree that limited or select deployment of AMI meters would not realize the operational benefits of AMI systems. This point was emphasized by Dr. Faruqui of the Brattle Group, who indicated that if the deployment of AMI systems were left up to market forces, it would likely be unsuccessful.[323]

362. As stated above, the decision to deploy AMI currently rests with the distribution utility based on the benefits and costs that accrue to the utility. While many of these will be shared with the customer, some will accrue only to customers and not the utility (e.g., the benefits resulting from enhanced access to data and information). Many of these benefits are summarized in Section 5.4 dealing with enhanced access to information.

363. The UCA explained that many of the benefits of AMI are highly dependent on the capabilities of the installed communications and back-end data processing infrastructure.[324] Even if a distribution utility deploys an AMI system, there is currently no incentive for that utility to install the back-end data process infrastructure for hourly interval meter reading for their residential and small commercial customers. Current settlement and billing rules do not require distribution utilities to bill customers based on their actual hourly consumption.[325] [326] However, these requirements are a reflection of the current accepted approach to rate design, and may be revisited if a more economically sophisticated pricing structure were to be adopted in the future.

364. Given that AMI systems are widely expected to be the cornerstone of grid modernization in the future, the expectation is that, at a minimum, interval-capable AMI meters will be deployed through the natural evolution and replacement cycle of meters as part of the prudent planning and operation of the distribution system. These AMI meters, installed over an extended period of time, will need to be compatible with each other to be used for an AMI system once a critical number of meters has been replaced and back-end data processing infrastructure is in place. Such considerations related to the eventual development of the AMI system for each utility may need to be considered as part of a distribution utility's roadmap, as recommended by several parties.[327]

322 Exhibit 24116-X0741, Fortis concluding remarks, PDF page 7, paragraph 6.

323 Dr. Faruqui mentioned that leaving deployment of AMI systems to market forces has not succeeded in other jurisdictions because the benefits to the customers of installing an AMI meter are not clear to them. Selective deployment is difficult because customers and retailers show relatively little interest in AMI meters. See Exhibit 24116-X0716, Transcript, Volume 1, pages 121-125, for more details.

324 Exhibit 24116-X0706, UCA-AUC-2020JUN03-001.

325 See Section 3.4 of Rule 021.

326 Rule 021, Section 3.3, PDF page 20.

327 Exhibit 24116-X0579, E3 written submission, PDF pages 17-18; Exhibit 24116-X0638, UCA response submission, PDF pages 20-21; Exhibit 24116-X0741, FortisAlberta concluding remarks, PDF page 7; Exhibit 24116-X0743, EPCOR concluding remarks, PDF pages 19-22; Exhibit 24116-X0735, AESO concluding remarks, PDF pages 8-9.

5.4 Enhanced access to data and information

Key takeaways:
Moving to a grid of the future requires more accessible information and data. Such information and data is necessary for decision makers (e.g., customers and investors) to understand the extent to which DERs could meet energy needs (including their own energy needs in the case of self-supply, or system needs in the case of DCG). This can be considered as part of the benefit of installing DERs. A lack of clarity and consistency in the requirements to connect DERs raises their cost, creates needless uncertainty and raises barriers to investment. Enhancing access to this and other relevant information promotes economic efficiency.

365. The costs of installing DERs include not only the "hard" (i.e., directly related) costs of sourcing the technology and installing it, but also "soft" (indirect) costs such as regulatory and connection costs. These soft costs often increase when barriers to obtain information are present, both for predominantly load customers and for DER proponents. Parties commented that, in addition to raising the cost of DERs, the lack of access to relevant information creates barriers to entry and otherwise weakens competition and customer choice. Each will be discussed in turn.

5.4.1 Customer access to information

366. As discussed above in Section 3.3, at the margin, a customer's choice between consuming grid-supplied electricity and electricity supplied by a DER will depend on the price for each. The value DERs provide to customers often consists of avoiding the need to purchase grid-supplied electricity and some wires charges. To understand what this value might be, customers must be able to discern how much of their load could be self-supplied through DERs (e.g., electricity generated by DERs at a time that coincides with their load); or in the case of demand-side measures, how much of their load could be reduced. For example, Pembina pointed out that it is difficult for a customer interested in installing a DER to estimate the potential avoided costs of grid-supplied electricity without easy access to data.[328]

367. Having access to their real-time (or near-real-time) load information empowers customers of all types (including residential, commercial and industrial) to manage their consumption better. AMI systems, appropriately configured, are necessary to achieve this.

368. To the extent that customers are exposed to demand charges or time-varying rates, having access to their interval consumption data better enables them to respond to these price signals. This, in turn, can potentially reduce system peaks and, consequently, the number of required distribution system upgrades. If more sophisticated pricing mechanisms are employed (for example, those that price distribution system constraints in real or near-real time), customer access to both pricing and consumption information becomes essential for such price signals to operate effectively. Simply put, customers cannot respond to even the most carefully designed price signals if they cannot see these signals or their consumption data, especially during those periods when prices are most volatile (i.e., subject to significant swings).

328 Exhibit 24116-X0687, Pembina's responses to the Commission's second round of IRs, PDF page 8.

369. Although customers are currently able to manage their consumption of grid-supplied electricity, they have little incentive to do so unless the potential savings are high enough to warrant the effort. This, in turn, depends on the extent to which customers have access to more granular and near-real-time data. For example, one of the current limitations in sending effective price signals to customers is that their consumption is not measured on an interval basis (i.e., cumulative meters and not AMI meters are installed, as discussed in Section 5.3). In this inquiry, the four largest distribution utilities provided a summary in Table 6 of the amount of energy that was delivered to customers in metered rate classes with cumulative meters. It is evident from Table 6 that a significant proportion of customers purchasing electricity from the grid receives only a muted price signal.[329]

Table 6. Percentage of delivered volumes to metered profiled rate classes of the four major distribution utilities in 2018[330]

Distribution utility	ENMAX	Fortis	ATCO Electric	EPCOR
Percentage of delivered volumes to metered profiled rate classes	51.6	40.7	38[331]	50.35[332]

370. Mr. Friesen, appearing on behalf of the UCA, explained that if interval-capable AMI were installed, Alberta's existing wholesale electricity market, which currently settles hourly, could be leveraged to set the price signal:

> So you have an energy pool in Alberta, and it is a time-varying rate, an hourly time-varying rate, and that price signal is largely absent from your market, at least in terms of the residential consumer or the small C&I consumer.…
>
> So, you know, there's an opportunity there, I believe, to introduce customers to time-varying rates within a market mechanism that you already have in place. You don't have to invent a new market mechanism.[333]

371. It is important to recognize in this regard that, even if interval-capable AMI meters were installed, settlement of consumption on an hourly basis would first need to occur at the retailer

329 For example, the Commission is not aware of any residential and small commercial customers in Alberta that receive price signals or communications from electricity market participants to reduce load during times of system constraint. Instead, during times of system constraint, the AESO issues a press release and posts it on its website and Twitter account requesting customers to reduce consumption of grid-supplied electricity. In this example, only customers paying attention to these news sources receive this information, and any associated load reduction from customers occurs as a result of their desire to respond to the AESO's call-out for help and their own personal inclination to be civic-minded, and not because of any price signal to consume less. This approach has been sufficient in Alberta in the past because of Alberta's high load factor (because of its large commercial and industrial customer demand relative to residential demands); however, at some future point, particularly as the penetration of DERs increases, a more advanced approach may be needed.

330 Exhibit 24116-X0502, ENMAX's responses to the preliminary IRs, EPC-AUC-2019NOV29-011(c)(v), PDF page 49; Exhibit 24116-X0522, Fortis's responses to the preliminary IRs, FAI-AUC-2019NOV29-011(c)(v), PDF page 36; Exhibit 24116-X0511, ATCO's responses to the preliminary IRs, ATCO-AUC-2019NOV29-011(c)(v), PDF page 62; Exhibit 24116-X0529, EPCOR's responses to the preliminary IRs, EDTI-AUC-2019NOV29-011(c)(v), PDF page 56.

331 ATCO's response included unmetered lighting in its response, noting that less than 1% of the 38% reported was for unmetered lighting customers.

332 50.35 = 28.51 + 9.30 + 12.54 in Column B, Rows 1-3 of Exhibit 24116-X0529.

333 Exhibit 24116-X0716, Transcript, Volume 1, page 196, lines 3-23.

level (on an aggregate basis for all individual customers served by each retailer). Afterwards, each retailer would need to settle its customer's hourly consumption and be able to bill its customers on that basis. As it stands now, neither retailers nor their residential and small commercial customers have any incentive to respond to hourly price signals from the wholesale energy market because of the current practice of load profiling for these customers.[334] Currently, customers who decrease their consumption of electricity during high-priced hours, or at times of system constraint, will receive little benefit for doing so. This is because, in the absence of actual hourly consumption data, for settlement purposes, customers' energy consumption in a given hour is assigned a pro-rated portion (based on a pre-determined load profile) of their total consumption for that billing period (typically a month).

372. Similarly, retailers themselves may or may not be exposed to price volatility in those hours because the load settlement agent (which in most cases is the distribution utility) assigns electricity consumption for a given hour to the retailer based on the pro-rated portion of their customers' total consumption, as determined by the load profile. IPCAA observed that even if price signals were adjusted, and interval metering were installed, settling customers based on load profiles rather than actual hourly usage mutes the incentive to respond to those price signals:

> Smaller distribution-connected loads that are currently billed using a load profile would not notice a significant change in cost. However, over time some of these smaller loads may determine that with a new rate design installing an interval meter and actively managing their demands will yield returns in excess of the cost of the interval meter.[335]

373. Enel X took the position that if AMI were installed, access to the customer's hourly consumption data should not be limited to retailers. Customers themselves and DER proponents should also have access to this information (in the case of the latter, however, only if the customer grants permission or the data is provided in a sufficiently aggregated format to protect customer privacy). According to Enel X, expanding access to customer data in this way would create new market opportunities, increase competition in various electricity markets (including potentially ancillary services, retail and provision of NWAs) and enhance customer choice.[336]

374. Another potential disadvantage of unduly restricting the types of customer information that might be made available and the industry participants to whom such information might be disclosed is as follows. If the type of customer data to which access is permitted is restricted to individual monthly consumption patterns and, moreover, this data is made available only to residential and small commercial customers themselves, there will simply be insufficient information to allow these customers or their retailers to quantitatively assess the value DERs might be able to provide them, particularly in terms of matching their load with the output of the DER to maximize the value of the DER.

375. In cases where the data exists, EPCOR stated that, based on its own experience, customers have little or no interest in obtaining detailed information on their individual

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334 Load profiles are used for both ratemaking (e.g., setting rate classes and establishing billing determinants of rate classes) and for assigning energy consumption to specific hours to customers with cumulative meters for the purposes of billing and load settlement because actual hourly consumption data does not exist for these customers. References to load profiles here only refers to the latter.

335 Exhibit 24116-X0554, IPCAA Combined Module submission, PDF page 11.

336 Exhibit 24116-X0282, Enel X responses to Module One IRs.

consumption. At the same time, EPCOR filed evidence in the inquiry explaining the results of a pilot study undertaken in Alberta that demonstrated a correlation between the availability of real-time electricity consumption information and reduced energy consumption. EPCOR further noted that AMI meters are only one among several devices that can be used to obtain this information.[337] Even with access to this level of data, there is a lack of incentive for the customer (or retailer) to act because of the practice of load profiling and the absence of effective price signals that reflect the actual marginal cost of delivered electricity.

376. Other jurisdictions in North America that have widely deployed AMI systems have also adopted policies on customer data access where customers have the right to access individual smart metering data collected by a utility. In the United States, it is common for utilities to participate in what is known as the Green Button initiative, which allows AMI customers to download their own detailed energy usage from a distribution company's website.[338] Customers with access to their consumption data can release this information to third-party service providers to help them identify measures to reduce electricity bills, including possibly installing DERs. The Green Button program is also used in Ontario, with 60 per cent of customers having access to their data.[339]

377. Dr. Faruqui explained that by sharing data with third-party entities, a customer may receive energy solutions that are tailored to their specific circumstances. For example, a distributed solar company can rely on energy consumption data to evaluate the payback time and overall economic benefits for a potential customer. Similarly, an energy-efficiency company can review energy usage pattern to propose the most cost-effective measure for customers to reduce their bills.[340]

378. InterGroup noted that existing legislation and regulation pertaining to customer data is silent on the issue of data ownership, and expressed the view that ownership of customer data resided with the distribution utility.[341] The majority of parties emphasized the importance of *access* to data as opposed to *ownership* of data. Initiatives such as the Green Button are valuable because they lower the cost of, and barriers to, a customer and/or energy service provider obtaining data and information that could potentially increase competition, enhance customer choice and retail offerings, and promote the optimal use of the existing grid. Such initiatives require the installation and configuration of AMI systems capable of reading meters on an hourly, if not more frequent, basis. As previously observed in Table 6, this is not yet the case for the majority of customers in Alberta.

5.4.2 Access to information for DER proponents

379. Providing access to relevant data and information to DER proponents can enhance competition in the electricity market. One of the simplest ways of effecting this is for customers to share access to their individual data with third parties, as explained in the previous section. Accessing information and data on aggregate consumption patterns or loading patterns on the grid can also support competitive outcomes. For example, increased availability of data allows

337 Exhibit 24116-X0170, EPCOR Module One submission, PDF page 29; Exhibit 24116-X0172, Alberta Innovates, Alberta Real-Time Electricity Consumption Monitoring Study.

338 Exhibit 24116-X0701, E3's responses to the Commission's second round of IRs, PDF page 7; Exhibit 24116-X0697, Brattle Group's responses to the Commission's second round of IRs, PDF pages 8-9.

339 Exhibit 24116-X0697, Brattle Group's responses to the Commission's second round of IRs, PDF page 9.

340 Exhibit 24116-X0697, Brattle Group's responses to the Commission's second round of IRs, PDF page 9.

341 Exhibit 24116-X0706, InterGroup's responses to the Commission's second round of IRs, PDF page 16.

alternative service providers to identify market gaps and assess the commercial viability of different products and business strategies.[342]

380. The AESO stated that open and transparent access to relevant non-private data is an important factor in lowering barriers to market entry, facilitating a fair, efficient and openly competitive market, and permitting market participants to compete on a level playing field. However, the AESO drew a distinction between static transmission system-related data and dynamic transmission system flow data. The AESO explained that static transmission system-related data[343] could facilitate market entry by providing data to inform customers' decisions about the location, timing and size of their planned facilities. Dynamic transmission system flow data, on the other hand, had limited value for the purposes of facilitating market entry decisions or competition in real time. Accordingly, the AESO concluded that making transmission system flow data (whether hourly, sub-hourly, or otherwise publicly available), was of insufficient value to warrant further consideration.[344]

381. Lionstooth, an installer of DCG, expressed the view that there are no market entry barriers or limits to competition that can be attributed to a lack of access to data today. However, it added that it would welcome increased access to both existing data, and the future data that becomes available once AMI systems are deployed. Increased data access (i) supports competition; (ii) allows DCG to better determine where to site their projects to maximize benefits to the system; and (iii) will improve future collaborative integrated planning processes.[345]

382. In general, making certain aggregate load and flow data more accessible may support competitive market outcomes. However, ensuring consumer interests are respected, including having their privacy protected as new services and technologies are developed and marketed, will be important to monitor as consumers participate in DERs. The jurisdictions in North America that have attempted to address this issue have taken a variety of approaches.[346]

383. The Commission acknowledges and commends distribution utilities that have proactively made interactive hosting capacity maps publicly available. Specifically, ATCO Electric, ENMAX and Fortis released and updated their hosting capacity maps over the course of the inquiry for their respective systems. Hosting capacity maps provide an estimate of the DER capacity that may be accommodated without adversely affecting power quality or reliability under current configurations and without requiring infrastructure upgrades. The creation of hosting capacity maps by these utilities is both a useful and welcome step in providing DER proponents with more accessible information. Figure 20 below provides an illustration of what a hosting capacity map looks like:

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342 Exhibit 24116-X0697, Brattle Group's responses to the Commission's second round of IRs, PDF page 9.

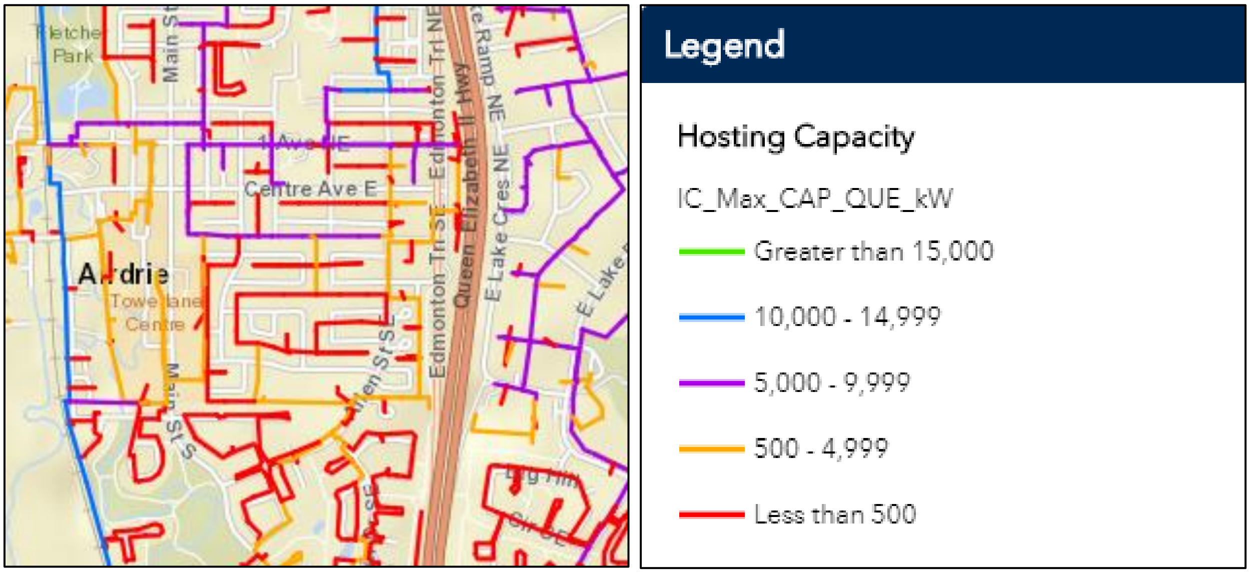
343 This includes the AESO's long-term transmission development plans and information about transmission system characteristics, such as available capability, historical congestion, and the costs associated with transmission constraint rebalancing, transmission must-run and dispatch down service.

344 Exhibit 24116-X0708, AESO's responses to the Commission's second round of IRs, PDF pages 5-6.

345 Exhibit 24116-X0710, Lionstooth's responses to the Commission's second round of IRs, PDF page 8.

346 Douris, Constance, Lexington Institute, "Balancing Smart Grid Data and Consumer Privacy," June 2017: One example is the approach taken by Illinois, where aggregated customer information must comply with the 15/15 rule – meaning that the information from at least 15 customers must be included and that no single customer's load can account for more than 15 per cent of the total. This paper is not on the record of the inquiry but is provided for additional information on jurisdictional approaches to permitting access to data.

Figure 20. Screenshot of Fortis's hosting capacity map



384. This important initiative notwithstanding, hosting capacity maps still have their limitations. The CGWG pointed out that while existing hosting capacity maps help to identify areas of low congestion that are amenable to interconnection, they do not provide information identifying important system needs that DERs could help to address. The CGWG also claimed that hosting capacity maps have not aided DER proponents in connecting their DERs to distribution systems, due to the uncertain timelines and costs. This contributing factor to the cost of DERs is discussed in the next section.

5.4.3 DERs interconnection process

385. Part of the information and data needed for (i) customers to assess the difference in prices and costs for grid-supplied electricity versus installing DERs (described in Section 4.2.1); and (ii) DER proponents to determine optimal siting (described in Section 4.2.2), is an understanding of the "soft" costs to connect the DER to the distribution system. These "soft" costs are addressed in this section.

386. As part of the inquiry, distribution utilities were asked to provide their current processes for interconnecting various DER configurations, including small micro-generating units, large micro-generating units, DCG with no associated load, grid customer with generation for own use, and industrial systems designations. Each of the four largest distribution utilities that the Commission regulates has its own process for assessing interconnection applications. In general, the utilities conduct an analysis with similar objectives and results, but follow different processes to complete it. Members of the Allied Community Renewable Energy Interests (ACREI)[347] stated that this creates uncertainty in terms of how long it may take to interconnect and at what cost.

387. For example, ATCO explained that it performs several specific studies as part of its interconnection process.[348] Fortis stated that it generally performs technical assessments (rather

[347] ACREI is composed of the following individual parties: Action Surface Rights Association, Alberta Surface Rights Federation, St. Mary's Irrigation District, the County of Taber, 3B Energy Ltd., Determination Drilling, the Southern Alberta Investment Co-Op for Renewable Energy, Iron and Earth, the Orphan Well Association, and SkyFire Energy.

[348] Exhibit 24116-X0511, ATCO's responses to the Commission's preliminary IRs, PDF pages 28-29.

than specific studies) to ensure that the DCG unit output capacity does not exceed the capacity rating of other infrastructure within the distribution system and power quality is maintained within standard limits.[349] Fortis added that it is amenable to modifying its process as the penetration of DERs increases.[350] EPCOR[351] and ENMAX[352] also described their specific processes for interconnection.

388. The distribution utilities explained that the costs for studies performed for micro-generation units are borne by the utility (and recovered through rates), in accordance with the *Micro-generation Regulation*. However, the costs for interconnection-related studies performed for DCG that are not covered under the *Micro-generation Regulation* are borne by the specific project proponent. Several DER proponents highlighted this inequity under the existing regulatory framework, as it is possible that very similar generation units may end up paying very different connection costs.

389. DER proponents have voiced several concerns about how long it takes to connect DERs to the distribution system. ACREI members pointed out that many of the small-scale and community generation projects on which they have been working were hampered by delays and uncertainties in navigating the distribution utility's interconnection process.[353] In its preliminary IR responses, ACREI stated that small-scale or community generation projects must go through a seven-step process, with costs up to $60,000 and application evaluation periods of up to two years. ACREI explained, moreover, that this process is invariant with project size. Small and large projects take the same amount of time to be evaluated before being approved or rejected.[354]

390. In E3's concluding remarks, Dr. Orans recommended that a set of transparent standards be developed to streamline the interconnection process as the integration of DERs accelerates. Customers and developers should have access to all relevant non-confidential operating or planning information, including information regarding available capacity and standards used to evaluate requests. He added that this standardized and transparent interconnection process should have a fast turnaround time and be technology-agnostic.[355]

391. Under the 2020-2021 AUC Operational Plan, the Commission stated that one of its goals was to review and update interconnection practices to create a standard and transparent process that provides for consistent and non-discriminatory access and treatment by incumbent utilities.[356]

392. There is considerable merit in standardizing the interconnection process, to the extent practical and reasonable, and to keep it transparent for all stakeholders, especially as the rate of DERs penetration continues to increase. Most importantly, making distribution system information easily accessible can improve the interconnection process for both the distribution utilities and new entrants (be they third parties or individual customers). When all parties have

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349 Exhibit 24116-X0522, FortisAlberta's responses to the Commission's preliminary IRs, PDF page 18.
350 Exhibit 24116-X0578, Fortis Combined Module submission, PDF page 31.
351 Exhibit 24116-X0529, EPCOR's responses to the Commission's preliminary IRs, PDF pages 9-10.
352 Exhibit 24116-X0502, ENMAX's responses to the Commission's preliminary IRs, PDF page 5.
353 Exhibit 24116-X0581, ACREI Combined Module submission.
354 Exhibit 24116-X0507, ACREI's responses to the Commission's preliminary IRs, PDF page 16.
355 Exhibit 24116-X0742, E3 concluding remarks, PDF page 7.
356 2020-2021 Operational Plan: https://www.auc.ab.ca/Shared%20Documents/2020-2021-OperationalPlan.pdf, PDF page 3.

access to information, third parties can optimally locate their DERs more quickly and distribution companies can set measures to handle any system constraints.

5.5 Integration of DERs

Key takeaways:

DERs have the potential to assist in mitigating system reliability concerns and in reducing overall system costs, provided their dispatch is coordinated and/or controlled. For this reason utilities should consider DERs in their planning practices and assess them alongside traditional wires solutions whenever system expansion is being considered. It follows that with the growth of DERs a more integrated approach to system planning and operation will be required. This integrated approach must work towards improved coordination between the AESO, utilities, load customers and third-party developers, and consideration of NWAs alongside traditional wires solutions in handling system constraints. The AESO has already indicated its readiness to consider a more integrated approach as part of its ongoing consultations on current system planning and operational practices. However, some parties noted that under the existing regulatory framework, Alberta's distribution utilities have an incentive to continue adding new capital expenditures to their regulated rate base instead of relying on DERs to meet future system needs even when reliance on DERs is a lower cost solution.

For providers of DERs solutions to realize the true value of their investments, a better understanding is required of the potential locational advantages and benefits associated with DERs (including energy storage), what services these assets can provide, how they could be compensated for those services, and how need should be identified and priced.

393. As previously noted, there was widespread agreement among parties that if DERs are used properly and are the least cost solution compared to a traditional wires approach to system upgrades, then utilities and customers should be able to take advantage of them to reduce overall system cost. Indeed, the value proposition offered by DERs is potentially available from a number of different streams including:

- Provision of energy.
- Provision of system capacity.
- Provision of reliability services.
- Avoiding or deferring transmission and/or distribution costs through the use of NWAs.
- Environmental benefits such as reduced local air pollution and lower carbon emissions.[357]

[357] Exhibit 24116-X0579, E3 Combined Module submission, PDF page 7.

394. The first point, the ability of DERs to provide energy and the potential benefits this creates for customers and the system, was introduced in sections 4.2, 4.3, 4.4 and 4.6. The last consideration, environmental benefits of DERs, is outside the scope of this report.

395. This section describes how DERs can provide system capacity, reliability services, and avoid or defer transmission and/or distribution costs through the use of NWAs, as these are all related benefits potentially resulting from the deployment of DERs. It must be emphasized that while DERs can provide these benefits, they can also bring about negative results (that is, reduce system capacity, diminish reliability and create a need for system upgrades) and increase overall system costs if not integrated properly into the distribution system.

396. As Fortis put it, "NWAs have locational and temporal variability of both need and value."[358] AltaLink filed on the record of the inquiry a report by the Electric Power Research Institute (EPRI) that sets out a framework to systematically evaluate the costs and benefits of DERs across the full power system. EPRI described the potential benefit of DERs to provide capacity as follows:

> A potential benefit of integrating DER into the distribution system is reduced net feeder demand that relieves capacity on existing distribution infrastructure, potentially deferring distribution capacity upgrades. For a resource to provide distribution capacity relief, it must be available during peak load periods when feeder assets are most constrained and capacity becomes the limiting factor. The ability for intermittent DER, such as [solar] PV, to reduce feeder peak demand may abate at high penetration levels if the load peak shifts outside the time of PV.[359]

397. The ability of DERs to provide system capacity also depends on the DER and system operating constraints; existing and future load; DER size and capacity, availability and location; and controllability by the system operator.

398. The EPRI report also listed other potential benefits DERs can provide to the system, most of which can be categorized as reliability services. These are summarized in Table 7.

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358 Exhibit 24116-X0640, Fortis response submission, paragraph 11.

359 Exhibit 24116-X0180, EPRI, "The Integrated Grid: A Benefit-Cost Framework Final Report," February 2015, PDF page 68.

Table 7. Reliability services that may potentially be provided by DERs[360]

Reliability service	Description
Voltage support	Poorly regulated voltage has a number of undesirable effects that can be mitigated by improved voltage regulation. Some of these undesirable effects include increased energy consumption without additional output, and reduced customer equipment operational efficiency and/or lifespan. DERs can regulate active power, reactive power or both, and mitigate many of the voltage issues that arise on a circuit. For example, the response time of an inverter-based generator (a type of DER) can regulate output much more quickly than traditional voltage control devices (such as line regulators or switched capacitor banks). If the DER output is coordinated with existing utility voltage control and provides voltage support when needed, adverse impacts are reduced or eliminated.
Energy losses	DERs have the potential to reduce distribution losses since the generation is provided closer to where the energy is actually consumed. When sited closer to the customer, the electrical resistance between the generation source and customers is decreased, thereby reducing the resistive losses. However, if the DER is not coincident with the feeder's load (i.e., does not provide energy when load is consuming) or isn't located near loads, losses can increase.
Reliability	DERs have the potential to improve reliability, but the technology must be dependable and sited in a location where it can effectively deliver power during system failure events. During these events, utilities switch the affected feeders to alternate feeds; occasionally, there is insufficient capacity in the alternate feed to supply the load required to restore service. Supporting some of the load from local DERs could improve feeder reliability. DER output must be available at the time of need to improve reliability.

399. The ability of DERs to potentially provide system capacity and/or reliability services creates the opportunity for distribution utilities to avoid or defer costs through the use of NWAs. As can be seen from the description of system capacity and/or reliability services above, these costs can be avoided or deferred by the distribution utility if it is able to leverage DERs to obviate the need for new or upgraded infrastructure (such as feeders or transformers), provided that utilizing DERs is the least cost solution. One widely cited example of this is the Brooklyn Queens Demand Management Program (BQDM program), where in place of a $1 billion USD system build-out, Consolidated Edison employed an innovative suite of non-traditional customer-side and utility-side solutions, coupled with traditional measures, addressing the issue at a total cost of one-half that of the original budget. Appendix 5 provides a summary of the BQDM program, which exemplifies many of the concepts discussed throughout this section.

400. The BQDM program is just one example among a growing list across the globe of how DERs are being leveraged to lower system costs and, ultimately, the customer's total electricity bill. However, as with most things of significant value, it is "easier said than done." Using DERs as NWAs represents a fundamental shift in how distribution utilities approach planning for system upgrades, development and growth. If DERs are to be better integrated into distribution system grid planning and operations, then a number of practical, engineering and regulatory (and possibly other administrative) steps and processes will need to be reconsidered, augmented, modified, replaced and/or discarded to accomplish this. Other unique aspects of the Alberta legal framework point to further changes that may be required if the full potential of DERs is to be realized in delivering the most reliable supply of electricity services to Albertans, under the safest conditions, and at the lowest possible cost and price. For example, in Alberta, unlike in

360 Exhibit 24116-X0180, EPRI, "The Integrated Grid: A Benefit-Cost Framework Final Report," February 2015, PDF pages 63-69.

many other jurisdictions, distribution line losses are paid for by retailers; therefore, distribution utilities have little incentive to use DERs to mitigate these costs.

401. Despite the examples provided of other jurisdictions using DERs as NWAs to lower system costs, with the BQDM program being the most prominent one, distribution utilities called into question this potential value. They submitted that at least some DERs provide energy intermittently, without visibility to the system planner and operator, with limited control by the system operator, and at times other than during the system peak demand. This view was succinctly advanced by EPCOR:

> Generally speaking, DERs do not reliably or even predictably reduce the loading on distribution infrastructure during peak demand, which in turn means that DERs do not actually reduce distribution system costs. Even over the very long term, many factors will come into play in determining whether distribution system costs are actually reduced by customer adoption of DERs. Put simply, it is not in any sense a "given", as some parties espouse, that all DERs will reduce distribution costs. And it is incorrect to claim, for example, that because a customer's total annual consumption of electricity from the distribution system at a site will be reduced by a DER at the site, the costs of the distribution system will be reduced.[361]

402. Parties brought forward three considerations related to obtaining the maximum benefit from the use of DERs. The first consideration was the need for an enhanced and more integrated approach to grid planning and operation. This issue is addressed in Section 5.5.1. The second consideration related to ownership and control of DERs and is explored in sections 5.5.2 and 5.5.4.

403. At a theoretical engineering level, the potential to reduce distribution system costs by relying on DERs as NWAs exists in a variety of ownership and control scenarios. That is, DERs should be able to provide value to the system regardless of whether it is a distribution utility or a third party that owns and/or controls the DER. At a practical level, however, whether DERs can provide system capacity and/or reliability services depends on the ownership and control structure of DERs and also on the governing regulatory framework. These issues are also explored in Section 5.5.2.

404. The third consideration related to the kinds of price signals required to maximize the value DERs can deliver to the AIES. Parties supportive of DCG credits see them as a possible mechanism to advance the provision of NWAs. The Commission addresses this in Section 5.5.3.

5.5.1 Integrated grid planning and operation

405. Several parties agreed that to maximize the value of DERs and ensure they lower costs for all participants, system planning and operation needs to adapt. Parties advocated moving towards an integrated approach to system planning and operation, which would not only see improved coordination between the AESO and transmission and distribution utilities, but would also create an avenue for customers and/or DER proponents to provide input. As the penetration of DERs continues to increase, consideration of DERs as NWAs alongside traditional wires solutions for addressing system needs would be an essential part of such an integrated approach.

[361] Exhibit 24116-X0635, EPCOR response submission, PDF page 9.

406. The duties and responsibilities of the AESO, transmission utilities and distribution utilities regarding grid planning and operation are largely established in the *Electric Utilities Act* and the *Transmission Regulation*. The AESO is the sole party responsible for planning the transmission system.[362] For the distribution system, distribution utilities have a duty "to make decisions about building, upgrading and improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy having regard to managing losses of electric energy to customers in the service area served by the electric distribution system."[363]

407. The AESO indicated that, traditionally, it has had limited involvement in distribution system planning since distribution load growth forecasts provide sufficient information at the transmission-distribution interface for transmission planning activities.[364] As such, the interaction between the AESO and the DFOs in terms of coordinated system planning has generally been limited to considering the distribution utilities' requests for transmission upgrades to serve their needs. These requests are based on distribution utilities' planning criteria and, generally, do not occasion much scrutiny from the AESO. The need for a more integrated approach to planning between the two systems ultimately stems from how distribution systems are evolving (from being the conduit of the one-way flow of electricity from the transmission system to load, to more variable flows of energy in terms of volume and direction).

408. Fortis provided an example of how its distribution planning currently works. Fortis identifies distribution system capacity needs and reliability needs based on metered peak loads and solutions for these needs are determined through a local area study. The local area study considers distribution and transmission solution alternatives, or a combination thereof, and these alternatives are compared to arrive at the most cost-effective solution. When meeting the needs of the distribution system calls for upgrades to the transmission system, Fortis makes an application to the AESO, by way of a SAS request. The AESO, through a collaborative process with the DFO and TFO, determines the preferred transmission alternative to address the identified system need.[365]

409. The system is also designed using deterministic planning, which identifies the worst-case contingency and consequences from that contingency. When planning its distribution system, EPCOR stated it must account for worst-case scenarios and ensure there is sufficient distribution capacity so all customer demand can be met.[366]

410. DERs are not currently considered in system planning and operation in terms of their ability to provide system capacity or reliability services. This largely has to do with a distribution utility's lack of visibility of a particular DER's actual operation and performance, the lack of control over the asset, and its potential intermittency due to its fuel source.

411. The absence of an integrated planning process that takes DERs into account can have negative consequences as the penetration of DERs increases. AltaLink provided two dramatic

[362] *Electric Utilities Act*, Section 17(j); *Transmission Regulation*, Section 10.
[363] *Electric Utilities Act*, Section 105(1)(b).
[364] Exhibit 24116-X0176, AESO Module One submission, PDF page 22.
[365] Exhibit 24116-X0578, FortisAlberta Combined Module submission, PDF pages 23-24.
[366] Exhibit 24116-X0577, EPCOR Combined Module submission, PDF page 26.

examples where insufficient coordination with DERs jeopardized safety and reliability, and resulted in significant costs:[367]

- In Germany, DER penetration has been significant for the past decade and distributed PV generators were connected with little consideration for effective integration. Prior to the introduction of more robust connection requirements, PV generators were not required to respond to grid operating requirements or to be equipped to provide grid support functions. Lack of coordination resulted in serious power issues and drove the need to retrofit 400,000 PV systems with smart inverters at a significant cost to customers (approximately $300 million USD).

- In August 2019, approximately one million customers lost power in the United Kingdom. A lightning strike on a 400-kV line initiated a series of events that resulted in the loss of 1,878 MW of generation. Approximately 500 MW of this generation loss came from DCG, which were tripped due to mis-operation of anti-islanding protection.[368] In order to remedy this anti-islanding deficiency, the National Grid implemented a three-year program that would pay for the cost of upgrading the protection of all DCG. The cost of managing the risk posed by these problematic protections exceeded £100 million, which was covered by customers.

412. The CGWG provided steps that distribution utilities could use in handling the increasing penetration of DERs, which included establishing a baseline capacity of the distribution system to host DERs and identifying planning data necessary for distribution planners to collaborate with other stakeholders.[369]

413. The CGWG supported a requirement for distribution utilities to open system planning processes to broader stakeholder involvement, and stated that DER developers and owners can provide information to assist distribution utilities in identifying the value DERs can provide as NWAs and where they are not the best option.[370] The UCA explained that this data and information could be efficiently provided through an appropriately configured AMI system (as was discussed in Section 5.4).[371]

414. In Decision 23943-D01-2020, the Commission recommended that the AESO and DFOs consider operational measures, such as NWAs, to alleviate system needs rather than solely relying on traditional wires solutions:

> … The Commission advises against the practice of over-relying on transmission solutions and encourages the AESO and DFOs to attempt to find innovative means to delay the need for transmission projects … the Commission requires a full analysis of what operational measures were considered and why such measures were eliminated in favour of new infrastructure as a solution.[372]

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367 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF pages 8-9.

368 Anti-islanding protection is implemented to ensure a DCG unit will stop supplying power to the grid when there is a problem with the electric system.

369 Exhibit 24116-X0561.01, CGWG Combined Module submission, PDF pages 21-22.

370 Exhibit 24116-X0561.01, CGWG Combined Module submission, PDF page 28.

371 Exhibit 24116-X0706, UCA-AUC-2020JUN03-001, PDF page 6.

372 Decision 23943-D01-2020: Alberta Electric System Operator, EPCOR Distribution & Transmission Inc. – West Edmonton Transmission Upgrade Project, Proceeding 23943, Applications 23339-A001 to 23339-A006,

415. Fortis indicated it could dispatch or control DCG and energy storage to optimize the use of existing assets and facilitate the bi-directional flow of electricity.[373] Fortis stated that DFOs must be given the duty to consider DERs in the planning, development and operation of the distribution system, similar to how the AESO and TFOs consider centralized transmission-connected generation in their processes.[374] Fortis remarked that real-time power flows will need to be provided to the AESO for both generation and load to have visibility of masked loads during disturbances.[375] Fortis does not currently have the means to gather sufficient real-time information to determine possible DER impacts on its system.[376]

416. AltaLink, on the other hand, supported a model that would grant the AESO more responsibility. It recommended that a framework be implemented for integrated system-wide planning conducted by the AESO and that a cost-benefit framework for DERs and DER-enabling investments also be developed.[377]

417. It is clear that depending on how the system evolves, the roles and responsibilities of stakeholders will likely change or evolve as well, and this will require extensive industry engagement and consultation. Even though Fortis and AltaLink had different visions of this aspect of the future evolution of the grid, both recommended that such evolution be guided by a roadmap, to be developed through a stakeholder process that includes proactive analyses, has regard to best practices in multiple jurisdictions, and identifies trigger points to guide successive steps in the transition to a more fully integrated and transparent system.

5.5.2 Barriers to including DERs in planning and operation and potential solutions

418. In the transmission context, the use of NWAs (referred to as "non-wire solutions" in the regulation) is currently limited to the circumstances described in Section 15(3) of the *Transmission Regulation*. The AESO indicated that removing this limitation may serve as a possible avenue to manage system costs and perform integrated grid planning and operation:[378]

> Legislative change to broaden and align the permitted use of non-wires solutions, at both a distribution and transmission level, may therefore be appropriate to fully enable the contracting of reliability services as a means of optimizing and deferring the need for distribution or transmission infrastructure.

419. At the same time, the AESO pointed out that, if not carefully managed, the use of NWAs (either at the transmission or distribution system levels) may negatively affect the fair, efficient and openly competitive energy-only and ancillary services markets.[379]

> The framework governing non-wires alternatives – including ownership, use, and cost recovery – should be structured in a manner consistent with the FEOC principle, with

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March 12, 2020, PDF page 40, paragraph 155. Please also see Decision 23105-D01-2019: Alberta Electric System Operator – Rycroft 730S Substation Voltage Support Needs Identification Document, Proceeding 23105, Application 23105-A001, May 3, 2019, PDF page 34, paragraph 133, where the Commission acknowledged the viability of energy storage in alleviating system constraints.

373 Exhibit 24116-X0578, FortisAlberta Combined Module submission, PDF page 70.
374 Exhibit 24116-X0578, FortisAlberta Combined Module submission, PDF page 46.
375 Exhibit 24116-X0578, FortisAlberta Combined Module submission, PDF page 27.
376 Exhibit 24116-X0578, FortisAlberta Combined Module submission, PDF page 30.
377 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF pages 5-7.
378 Exhibit 24116-X0594, AESO Combined Module submission, PDF page 10.
379 Exhibit 24116-X0594, AESO Combined Module submission, PDF page 9.

> particular emphasis on avoiding market distortions and ensuring a level playing field for market participants. For this reason, the AESO is of the view that any asset capable of supplying energy (e.g., energy storage) is not, and should not be considered to be, a wires alternative, and should not be permitted to be included in a rate base or otherwise be used to earn a regulated rate of return on the underlying investment. The AESO supports the use of reliability services procured from supply assets, where appropriate, as non-wires alternatives. For example, while the AESO can in certain cases enter into contracts with the owner of a generating unit for the provision of transmission must-run ("TMR") service, the AESO cannot direct or propose the construction of a generator.

420. The issue of ownership of NWAs, particularly energy storage resources, is addressed in Section 5.5.4.

421. In the distribution system context, given the current legislative and regulatory framework, distribution utilities do not have the same restrictions as those faced by the AESO in planning and operating their systems.[380] Beyond the important practical, safety and reliability considerations mentioned above, an additional important barrier to leveraging DERs to reduce distribution system costs is the lack of incentive to do so on the part of distribution utilities. The CGWG made this point succinctly:

> The reason that DCGs and other DERs in Alberta are not providing NWA and other real-time services to the AIES is due to a lack of integrated planning, price signals, procurement, and market design and the lack of an enabling regulatory framework from the AUC rather than an issue with reliability or technical capability.[381]

422. The lack of a fully integrated planning process and cost-based price signals has already been discussed. The remainder of this section explores what the CGWG characterized as a lack of procurement, market design, and an enabling regulatory framework.

423. A number of parties made a similar point that distribution utilities may have a disincentive to rely upon NWAs to meet their regulatory obligation to serve, since there is a potential for NWAs to be considered as operational expenses and not capital expenditures. This distinction is important because utilities earn a return on rate base (i.e., the capital asset base) and not on operational expenses. Therefore, the financial incentives facing regulated utilities are such that utilities have an inherent preference for capital investment over solutions financed by operational expenses, and this is true under both cost-of-service and PBR frameworks.[382] Another disincentive unique to the PBR framework arises from the fact that NWAs often require investments, the useful life of which exceeds the average duration of the PBR term. The result is that benefits will only be realized years after the costs were incurred. Indeed, costs and benefits are likely to accrue in different PBR terms. Dr. Orans emphasized this issue in response to questioning from the Commission during the virtual technical meeting:[383]

> I think one of the problems with the benefits [of NWAs] is they're back-ended and long term and the costs are short term, and your PBR is short term. But just one idea is, you know, if you're convinced that over 10 or 20 years the benefits are bigger than the costs,

380 Decision 23943-D01-2020, paragraph 143.
381 Exhibit 24116-X0634, CGWG Combined Module response submission, paragraph 26.
382 The incentive to invest in capital is present under PBR because of the periodic rebasing, when rates are reset based on the utility's costs.
383 Exhibit 24116-X0716, Transcript, Volume 1, pages 184, 188-189.

> you can make an adjustment to the baselines in the five-year time frame to re-adjust the baseline framework in your PBR, and perhaps then you could get that in place as a long-term glide path and way to implement this under your PBR framework.

424. A number of parties, including Fortis[384] and InterGroup on behalf of the UCA,[385] suggested that future PBR plans will need to be forward-looking and be flexible enough to accommodate and incent longer-term investments in innovative and cost-effective ways of providing service, while at the same time sharing the risks and rewards of innovation with customers. ENMAX expressed the concern that utilities have minimal innovation incentives within the existing PBR framework and that the rebasing mechanism should be revised to allow them to better adapt to the future and to customers' needs.[386]

425. Parties brought forward a number of approaches taken by other jurisdictions including New York,[387] California,[388] Illinois,[389] New Hampshire,[390] Michigan,[391] Rhode Island,[392] the United Kingdom,[393] Australia[394] and New Zealand[395] as possible examples of how the PBR framework could be modified to encourage distribution utilities to more seriously consider NWAs and operational strategies, compared to traditional wires solutions, with the goal to more efficiently use existing infrastructure and lower system costs. These alternative approaches included:

- Altering the treatment of capital and operational expenditures at rebasing so utilities are indifferent between the two.
- Allowing contracts for DERs and NWAs to be capitalized.
- Creating an "innovation factor" (sometimes generally referred to as "performance incentive mechanisms"[396]) within the PBR formula that pays for performance based on a defined set of criteria to incent desirable behaviour, particularly related to accommodating new entrants, technologies and competition.
- Requiring DFOs to put a certain amount of grid replacements or upgrades out for competitive tender via NWAs and to report to the Commission periodically.

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384 Exhibit 24116-X0578, Fortis Combined Module submission, PDF page 51.
385 Exhibit 24116-X0716, Transcript, Volume 1, PDF pages 180-183.
386 Exhibit 24116-X0580, ENMAX Combined Module submission, PDF pages 2-4.
387 Exhibit 24116-X0568, Energy Efficiency Alberta Combined Module submission, PDF pages 26, 30 and 39; Exhibit 24116-X0571, Charles River Associates Combined Module submission for the CCA, PDF page 33; Exhibit 24116-X0578, Fortis Combined Module submission, PDF pages 34-35; Exhibit 24116-X0580, ENMAX Combined Module submission, PDF page 43; Exhibit 24116-X0576, Pembina Combined Module submission, PDF page 33.
388 Exhibit 24116-X0568, Energy Efficiency Alberta Combined Module submission, PDF pages 25, 30.
389 Exhibit 24116-X0716, Transcript, Volume 1, page 182.
390 Exhibit 24116-X0571, Charles River Associates Combined Module submission for the CCA, PDF page 33.
391 Exhibit 24116-X0619, ENMAX response submission, PDF page 4.
392 Exhibit 24116-X0619, ENMAX response submission, PDF page 4.
393 Exhibit 24116-X0571, Charles River Associates Combined Module submission for the CCA, PDF page 20; Exhibit 24116-X0576, Pembina Combined Module submission, PDF page 37.
394 Exhibit 24116-X0570, Brattle Combined Module submission for ATCO, PDF page 24.
395 Exhibit 24116-X0570, Brattle Combined Module submission for ATCO, PDF page 26.
396 Exhibit 24116-X0742, E3 response submission, PDF page 4; Exhibit 24116-X0730, CGWG response submission, PDF page 5.

426. Several parties recommended the use of pilot projects and "regulatory sandboxes"[397] to, in a very limited capacity and based on certain criteria, approve projects that might fall outside typical regulatory approvals. Parties suggested that such an approach provides a path forward for these new technologies and innovations to be deployed, creating the opportunity for investment, innovation and experimentation, while reducing the regulatory burden and the inherent risks for all parties involved. ATCO pointed to the testimony of Dr. Faruqui, who discussed how pilot projects have been used in other jurisdictions to test customer engagement and collect data for the purposes of estimating future benefits, and concluded:

> Expedited and more frequent approvals for new rates and services should be considered to ensure utilities have the flexibility to respond promptly to customers' needs. For example, new Commission processes for accepting limited-scope applications and/or evaluating pilot projects should be investigated. The goal should be fair, accurate, and efficient rates in order to avoid duplicative investments, cross-subsidies and other negative unintended consequences resulting from customer behaviors.[398]

427. EPCOR took a different position with respect to barriers limiting, if not precluding, the participation of DERs in system planning and operational processes under the current PBR framework. It asserted that many of the specific actions proposed by parties would "unnecessarily and harmfully limit and constrain the authority and discretion [distribution utilities] are currently provided under the regulatory framework," and "would unnecessarily undermine the public interest by constraining the distribution system owner's ability to make decisions that are necessary to achieve a safe, reliable and economic system."[399] EPCOR continued:

> Forcing distribution system owners to procure from third parties distribution infrastructure or services that are integral to the safe, reliable and economic delivery of electricity would severely and unnecessarily erode the owner's ability to control the design, implementation, operation and maintenance of the distribution system which in turn would erode the owner's ability to operate its system safely, reliably and efficiently.[59] Further, giving the distribution system owner the necessary level of control over third party service providers or third party owned facilities would, for example, increase the level of cost and administrative burden on the owner immensely, driving substantial increases in distribution utility costs for no meaningful benefit.
>
> By contrast, the current regime of financial regulatory oversight of the distribution system owner by the Commission based on the prudent cost recovery standard (whether by way of the previous cost of service rate regulation regime or the current PBR plan under which distribution system owners are powerfully incented to minimize cost) and the Commission's authority to hold distribution owners accountable for meeting their duties imposed under the legislation, is a far more efficient and sensible approach, and ensures that distribution system owner decision-making is objective, economic and in the public interest. Any potential for "capital bias" or a purported need for modification of the incentives of distribution system owners as argued by a number of parties, is

397 QUEST Canada advanced the concept of using "regulatory sandboxes," which have been used in other jurisdictions, to "cope with the uncertainties created by these profound infrastructural and economic transformations." QUEST argued that regulatory sandboxes create a tool for a regulator to "be reactive, nimble, and flexible to quickly adapt existing regulations and address unforeseen regulatory, economic and technical challenges and barriers. See Exhibit 24116-X0547, QUEST Combined Module submission, PDF pages 2-3.

398 Exhibit 24116-X0740, ATCO concluding remarks, paragraph 8.

399 Exhibit 24116-X0635, EPCOR Combined Module response submission, paragraph 35.

effectively and appropriately addressed by the current regulatory framework, and none of the parties' proposed changes are necessary or warranted from that perspective.

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59 While [EPCOR] notes that the current regulatory framework provides a distribution system owner with discretion to make arrangements under which other persons perform the duties or functions of the owner under the EU Act and the regulations, it also states clearly that no such arrangement "affects or reduces the responsibility or liability of the owner to carry out those duties or functions" (EU Act, S. 104).[400]

[all other footnotes omitted]

428. As noted in this section and throughout this report, there is widespread agreement among parties that DERs are growing in importance as competitive sources of supply; as mechanisms, processes and/or technologies for load-management; and as potential NWAs. Given the issues associated with their continued growth and widespread adoption, the question of how best to maximize the potential contribution of DERs to efficient, whole system solutions will continue to occupy the energy and attention of industry participants, the agencies regulating them and government policy-makers for some time to come.

5.5.3 DCG credits

429. Having addressed key aspects of efficient tariff design, the value of broad-based and convenient access to information, and the benefits and costs of integrating DERs on the system, particularly with respect to their ability to provide NWAs, the issue of DCG credits, which was first mentioned in Section 4.2 as contributing to a non-level playing field between DCG and TCG, is now discussed further. The latter concern notwithstanding, this section examines to what extent DCG credits reflect the system benefits (including improvements in system efficiency) that some parties attribute to DCG acting as NWAs.

430. Fortis explained that the introduction of DCG credits was rooted in a change in transmission metering practice, and the public policy objective of incenting flare-gas generation to reduce flaring.[401] DCG credits are the payments that some distribution utilities provide to DCG units (both stand-alone and as part of self-supply and export configurations)[402] located in their service territories. The credits are calculated based on the electrical energy delivered by the DCG to the distribution system, and are the difference between the AESO transmission charges (Rate DTS and Rate STS) to the distribution utility (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. The calculated credits are then allocated to, and recovered from, all load customers of that distribution utility.[403]

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400 Exhibit 24116-X0635, EPCOR Combined Module response submission, paragraphs 39-40.

401 Exhibit 24116-X0578, Fortis Combine Module submission, PDF page 61.

402 Fortis gives its DCG credits via a mechanism called Option M, available to all DCG except micro-generation; ATCO Electric and ENMAX enable their DCG credits via rate classes; ENMAX's rate class restricts to sites with 1 MVA of export or greater.

403 The reader is referred to Decision 22942-D02-2019 and the final report for the DCG inquiry for a comprehensive description of the DCG credit mechanism.

431. Table 8 shows that in 2018 and 2019, ATCO, ENMAX and Fortis paid DCG approximately $28 million in credits based on the AESO DTS rate portion of the DCG credit mechanism. This dollar amount has grown each year since 2012.

Table 8. Payments of DCG credits by ATCO, ENMAX and Fortis[404]

			Sum of DCG credits	
	Number of DCG units [# of generators]	Total DCG energy [MWh]	Based on reduced DTS [$ million]	Based on STS flow-through [$ million]
2012	53	390,677	5.2	0.00
2013	51	473,404	8.8	0.00
2014	58	343,786	5.3	-0.01
2015	67	562,654	10.9	-0.01
2016	73	747,576	15.8	0.00
2017	75	720,486	23.0	0.16
2018	77	902,552	28.2	0.38
2019 (Jan-Oct)	79	909,973	28.2	0.43

432. The reduction in transmission charges that distribution utilities experience from the presence of DCG on their systems arises from the netting of distribution system load with coincident generation on the distribution system. Under the AESO's previous metering practice, this netting took place at the high-voltage side of the substation (POD), thus resulting in the netting of all DCG and load on that substation. Under the AESO's recently approved adjusted metering practice, this netting would take place on the low-voltage side of the substation, resulting in a netting on an individual feeder level.[405]

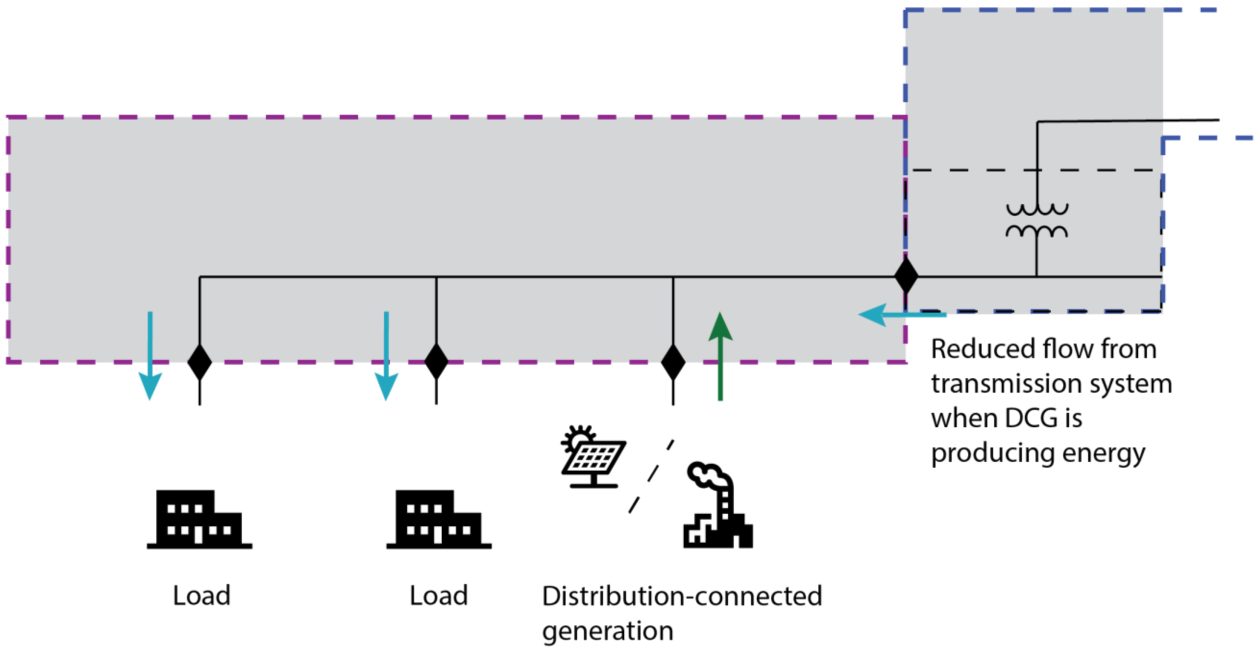
433. Absent the presence of DCG, the total load connected to a substation could be accurately inferred by measuring the incoming power from the transmission grid. The presence of DCG, however, results in its production offsetting load. This, in turn, means that any attempt to measure the incoming power from the transmission grid would only detect the net load on the substation. That part of load supplied by DCG on the same feeder would be "masked."

434. To further explain this mechanism, Figure 21 provides a simplified illustration of how the coincident flows of energy corresponding to load and generation are netted before reaching the metering point for the transmission system, thus masking load from the perspective of the AESO in its calculation of Rate DTS and Rate STS charges.

404 Exhibit 24116-X0502, EPC-AUC-2019NOV29-009; Exhibit 24116-X0522, FAI-AUC-2019NOV29-009; Exhibit 24116-X0511, ATCO-AUC-2019NOV29-009.

405 See Decision 22942-D02-2019, paragraph 844, and Decision 25848-D01-2020.

Figure 21. Illustration of energy flows affecting the calculation of DCG credits



435. By supplying electricity onto the distribution system, DCG masks coincident load, lowering the billing determinants measured at the POD, and thus lowering the AESO charges billed to the distribution utility, most significantly the 12 CP demand charge that comprises half of the transmission revenue requirement and currently stands at $11,085/MW/month.[406] Because of the presence of the DCG credits and the way they are calculated, there is an incentive for DCG owners to locate generation units near sufficient load to offset as much of it as possible, thus reducing transmission charges as much as possible to maximize the value of the credit. If a DCG operator can predict the time of the coincident peak during the month and dispatch its energy during that time, the DCG owner stands to receive a credit for that one hour, approximately 11 times higher than the maximum possible price in the wholesale electricity market (which has a price cap of $999.99/MWh), and likely many times more than an average market price.[407] It bears noting that the DCG unit will still fetch the wholesale price of electricity for its gross generation, in addition to the amounts received for DCG credits.

436. DER proponents emphasized the value of DCG credits, stating that they provide a locational price signal for generation because they create a powerful financial incentive for DERs to offset load (as measured by reduced POD billing determinants) by locating on distribution feeders and freeing up capacity for other users.[408] SkyFire Energy emphasized that DCG credits provided an important incentive to private developers to assist in reducing the use of and stress on the transmission system.[409] Additionally, Kalina pointed to expert evidence filed

406 https://www.aeso.ca/rules-standards-and-tariff/tariff/iso-tariff/, approved in Decision 26054-D01-2020: Alberta Electric System Operator, 2021 Independent System Operator Tariff Update, Proceeding 26054, December 18, 2020.

407 In 2019, the average pool price was $54.88/MWh, AESO 2019 Annual Market Statistics, March 2020.

408 Exhibit 24116-X0561.01, CGWG Combined Module submission, PDF page 16.

409 Exhibit 24116-X0589, SkyFire Combined Module submission, PDF page 3.

in this proceeding suggesting that the system incurs fewer costs (and, hence, greater savings are realized for the utility and customers) when a DCG unit provides electricity.

> While [DCG] can be integrated at relatively little cost, carefully planned [DCG] integration into the grid can also result in long-term avoidance, deferral or reduction of costly future transmission system costs as confirmed by the Electric Power Research Institute ("EPRI") as follows: "These included benefits from the deferral of T&D investment, reduced line losses, and reduced congestion." Kalina's expert calculated that for each one (1) megawatt (MW) of [DCG] injected in the transmission system, transmission system usage was reduced by approximately 6.9 MW for bulk transmission, 2.9 MW for local transmission and 1.7 MW for point of delivery systems. [footnote omitted][410]

437. The Community Generation Working Group (CGWG) argued that one of the potential benefits DCG credits provide is the locational price signal for DCG to operate at a particular location on the system. As described above, it is clear that DCG credits create a highly effective incentive to locate where load exists, and to match generation capacity to local load levels. CGWG underscored this point by explaining that while information on where DCG *can* connect is important, it is more valuable to all actors on the system if it is communicated where DCG *should* connect. Adhering to the principles set out in Section 5.1, these communications are best effected by way of transparent prices.

> While hosting capacity is useful in identifying locations where DERs "can" be connected it doesn't provide information regarding where there is system need that DERs could support. For example, in areas of the grid where local voltage support or volt-var optimization, constraint minimization or power quality could be improved by siting DERs, information is required by DER developers to optimally site project investments at these locations. This information could come from planning processes or from dynamic, granular and time variant pricing signals.[411]

438. The CGWG further submitted that the focus should not be on how to limit credits in order to maximize cost recovery for transmission assets, but how to improve upon what already exists to develop and implement an efficient locational value signal.[412]

439. AltaLink did not agree that DCG may provide locational benefits. It pointed out that system planners and operators currently do not rely on DERs to provide system capacity (as explained previously in Section 5.5.1). In AltaLink's view, this means that adding DERs to the system will do nothing to avoid capital outlays on existing or future transmission infrastructure.[413]

440. Notwithstanding these DCG units receiving payments for avoided transmission charges, as Fortis explained, there is no actual reduction to transmission infrastructure or the AESO's revenue requirement as a result of DCG units directly supplying electricity to the distribution system because the infrastructure is already built.[414] Since avoiding these charges does not lower

410 Exhibit 24116-X0644, Kalina response submission, PDF pages 6-7; see also Exhibit 24116-X0599.01, Kalina Combined Module submission, PDF page 29; Exhibit 24116-X0643, Kalina expert evidence.
411 Exhibit 24116-X0561.01, CGWG Combined Module submission, PDF page 16.
412 Exhibit 24116-X0561.01, CGWG Combined Module submission, PDF page 17.
413 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF page 18.
414 Exhibit 24116-X0578, Fortis Combine Module submission, PDF page 61.

the cost of the transmission system, the AESO is forced to collect the missing portion of its revenue requirement from other customers. In other words, one of the consequences flowing from the payment of DCG credits is cost shifting from one group of customers to another. In Decision 22942-D02-2019, the Commission made similar observations, stating "there is evidence on the record of this proceeding on the cross subsidy created by DCG credits and the resulting transfer of transmission costs to load customers without a corresponding reduction in the actual cost of the transmission grid, requiring recovery in the ISO tariff."[415] As such, the issue of DCG credits effectively raises the same concern as the uneconomic bypass that may occur in self-supply configurations.

441. Furthermore, as Fortis and AltaLink explained, the uneconomic bypass in this case is aggravated by the fact that the cost of providing DCG credits is recovered from all load customers of that distribution utility.[416] Therefore, the cost to load customers at best remains the same and, in most cases, increases. The AESO must collect the shortfall in revenues from all customers through increased fees to all customers in subsequent periods, including those who paid the DCG credits. From this perspective, the DCG credits represent a net loss to society. Alberta load customers as a whole pay an amount equal to the DCG credits twice – once to the DCG owner and a second time to the AESO.

442. Parties offered several solutions to address the cost shifts and double-charging of Alberta load customers resulting from DCG credits. AltaLink pointed out that the AESO's adjusted metering practice – pursuant to which substation load will be measured at the distribution feeder level rather than on a total POD level – will substantially reduce the amount of netting taking place and, therefore, will correspondingly lower the extent to which transmission charges to distribution utilities will decline as a result of the locational decisions of DCG.[417] This, in turn, will reduce the DCG credits. However, any anticipated benefit from the AESO's adjusted metering practice will at best be temporary. If the transmission price signal persists, new generation will still be incented to connect (and existing DCG may find ways to reconfigure their connection) to the feeders with load customers, and the total quantum of DCG credits may go up again.

443. To resolve this issue, AltaLink suggested moving the metering point even closer to the DCG – to each customer's fence line. That is, to further adjust the metering practice such that these energy flows would be gross metered.[418]

444. As discussed in Section 5.2, the most efficient solution to the uneconomic bypass issue is to set rates based on the costs to produce and deliver network services. In this regard, E3 concluded that "the issues raised by the Commission regarding DCG credits may only be fully resolved through developing transmission access charges that reflect the underlying system costs."[419]

445. Nearly every party suggested that a further detailed review of DCG credits should be undertaken, especially as the integration of DERs into the system planning and operation process

415 Decision 22942-D02-2019, paragraph 787.
416 Exhibit 24116-X0578, Fortis Combine Module submission, PDF page 61; Exhibit 24116-X0597, AltaLink Combined Module submission, PDF page 17.
417 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 110.
418 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 110.
419 Exhibit 24116-X0742, E3 concluding remarks, PDF page 6.

accelerates. Parties further submitted that any such review should focus on the purpose of the credits, desired customer behaviours, the value DCG may actually provide to the system and, ideally, on how to achieve greater consistency across all distribution utilities in Alberta on whether, and to what extent, if any, there should be continued reliance on the use of DCG credits.[420]

5.5.4 Who can own energy storage

446. As discussed in Section 4.6, since energy storage is not explicitly defined in existing legislation, there is some uncertainty regarding who may operate and control these assets, as well as how, and in what scenarios. As also described in that section, energy storage resources can provide multiple system services, through what is known as “value stacking” (see Figure 19). These services range from providing energy for a customer’s own use (i.e., self-supply), to supplying the wholesale electricity or ancillary services markets (i.e., as a generator or by way of self-supply with export), and providing system capacity and/or reliability services (i.e., by acting as an NWA as described earlier in Section 5.5.2).

447. No party to the inquiry took the position that energy storage resources should be precluded from providing services to the distribution and transmission systems. Parties pointed out that, if employed correctly, energy storage resources with their multiple system services can lower system costs and thus benefit all customers. What was contentious, however, was whether regulated utilities should be permitted to own, operate and/or provision services from energy storage resources and, if so, how those assets should be permitted to be used. Furthermore, if regulated utilities are permitted to own and/or control energy storage resources, determining how these assets should be paid for (i.e., allowing costs to be recovered from customers through regulated rates or receiving competitive market prices) also becomes critical.

448. The inquiry revealed that there is no consensus among parties on the question of ownership. In general, parties were divided along the following lines:

(i) No regulated utility ownership, but contracts for grid services permissible.

(ii) Regulated utility ownership permitted.

449. The remainder of this section summarizes the views of parties and the reasons underlying their recommended options. As existing legislation is silent on whether, how and, if so, to what extent the owners of energy storage resources should be regulated, the Commission, the Market Surveillance Administrator (MSA), and the AESO – each within their respective jurisdictional domain – will be required to rely on the existing legislative framework to arrive at their own determinations unless this matter is expressly addressed by policy-makers.[421]

Option 1: No regulated utility ownership, but contracts for services permissible

450. The AESO, AFREA, Capital Power, Heartland Generation, Lionstooth and TransAlta strongly opposed the ownership of energy storage resources by regulated utilities. Their

420 See for example, Exhibit 24116-X0646, Lionstooth Combined Module response submission, PDF pages 11-13; Exhibit 24116-X0569, ATCO Combined Module submission, PDF page 9; Exhibit 24116-X0573, EQUS Combined Module submission, PDF page 13.

421 The Market Surveillance Administrator raised several related regulatory issues that many need to be considered, depending on the high-level option pursued. See Exhibit 24116-X0160 for more details.

opposition is best described in the context of the following two scenarios in which a regulated utility might be permitted to own an energy storage resource: (i) the energy storage resource is able to operate to its full capability (by providing energy, system capacity and/or reliability services); and (ii) use of the energy storage resource is restricted to the provision of system capacity and/or reliability services (i.e., the energy storage resource is barred from the wholesale electricity and ancillary services markets). Each will be considered in turn.

Energy storage resources able to operate to their full capability (by providing energy, system capacity and/or reliability services)

451. Lionstooth argued in favour of this scenario. It submitted that although there are many scenarios under which energy storage resources could be used as an alternative to traditional wires infrastructure, under all of these scenarios energy storage resources are still acting as generators, and the *Electric Utilities Act* prohibits regulated utilities from owning generating units. Lionstooth added that in the scenario in which energy storage resources are exclusively engaged to ensure safe and reliable electric service for the AIES, these operations could be characterized as being consistent with the principles of transmission must-run (TMR).[422] Lionstooth noted that generators providing the TMR function today are facilities not owned by the regulated utilities, consistent with the principles outlined in the *Electric Utilities Act*.[423]

452. Parties suggested that while regulated utilities should not be permitted to own energy storage assets, utilities and the AESO should be free to enter into contracts for system capacity and reliability services with third-party owners of energy storage resources (i) to defer the need for additional distribution or transmission infrastructure or, simply, (ii) whenever it is cost-effective to do so. Such contracts would be similar to contracts the utilities or the AESO are free to enter into for services from pure-play generation or load (i.e., demand response) customers to provide NWAs or ancillary services. Parties argued that such a service should be competitively procured where possible, to ensure it is the least cost alternative. It was further argued that such contracts could be structured to still allow for value stacking. That is, the owner of the energy storage resource would be required to reserve a portion of the energy storage asset's discharge capability to meet the terms of the contract, but a portion of the discharge capability might remain to allow for participation in the wholesale energy or ancillary services markets. The reasonable costs of such a service would be recoverable through the applicable tariff structure.

453. The AESO stated that such a competitive procurement process should expressly bar the participation of non-regulated affiliates of regulated utilities.[424]

454. With respect to procurement processes for NWAs to support transmission systems, EPCOR[425] and ATCO[426] submitted that only the transmission utility for the relevant franchise service territory should provide transmission service, including through the use of an energy storage resource.

[422] TMR is generation that is required to be online and operating at specific levels in parts of the province's electricity system to compensate for insufficient local transmission infrastructure relative to local demand. TMR is used to ensure reliability until adequate transmission infrastructure is built in that local area. See https://www.aeso.ca/market/ancillary-services/transmission-must-run-service/

[423] Exhibit 24116-X0528, LION-AUC-2019NOV29-013, PDF page 49.

[424] Exhibit 24116-X0518, AESO-AUC-2019NOV29-013, PDF page 42.

[425] Exhibit 24116-X0577, EPCOR Combined Module submission, PDF page 18.

[426] Exhibit 24116-X0531, AML-AUC-2019NOV29-013, PDF page 55.

455. Heartland Generation argued that a competitive procurement process would facilitate overall efficient investments. Heartland added that if such a procurement were to take place, the merchant-owned energy storage resource should be able to participate in both the competitive wholesale electricity and ancillary services markets, while at the same time fulfilling the NWA contract with the same asset. Heartland explained that the ability to stack these values allows both services (provision of energy and provision of NWA) to be offered more cheaply because they are subsidizing each other.

> The competitive alternative identified by Heartland would also facilitate overall efficient investments through revenue stacking of the monies earned in the competitive procurement as well as the energy and/or ancillary services markets. Ratepayers benefit from merchant owners retaining the market participation of storage assets, as this will serve to reduce the competitive bids to provide non-wires solutions in the RFP. For example, suppose a wires solution costs $100 million and an NWA costs $70 million. The merchant owner may submit a bid for $60 million (less than the cost of the NWA) because the merchant owner will be able to earn additional revenues in the [wholesale] energy and ancillary services markets.[427]

456. Heartland pointed to Texas as an example of a jurisdiction moving towards such a model.[428] It is important to note that the structure Heartland proposed above (i.e., the same storage asset receiving competitive and regulated revenue streams) appears in many respects to be similar to that proposed by ATCO and AltaLink, and this example will be also be referenced later in this section when describing their views.

Energy storage resources providing system capacity and/or reliability services are excluded from the energy markets

457. Several parties not only opposed the ownership of energy storage resources by regulated utilities, but suggested that energy storage resources owned by non-regulated entities providing system capacity and/or reliability services should not be allowed to participate in the energy markets. The general argument against energy storage resources participating in the wholesale electricity and ancillary services markets was that it does not accord with one of the *Electric Utilities Act*'s stated purposes: "to provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages…."[429]

458. Parties argued that if any entity owned and operated an energy storage resource where it was able to earn both regulated and unregulated (energy market) revenues, this would harm or otherwise distort market outcomes by virtue of the unfair advantages it possesses. These parties concluded that energy storage resources should be restricted to either the provision of system capacity and/or reliability services, or serving the wholesale electricity and ancillary services markets, but not both.

427 Exhibit 24116-X0523, Heartland-AUC-2019NOV29-013, paragraph 44.
428 Exhibit 24116-X0690, Heartland response submission, PDF page 15.
429 *Electric Utilities Act*, Section 5(c).

459. Capital Power further explained that:

> … because regulated entities are eligible for cost recovery and a regulated rate of return on investments, allowing them to simultaneously collect a rate-based revenue on ratepayer-backed investments and participate in the energy or ancillary services markets would be in direct violation of this purpose. Not only does this create an unlevel playing field and interferes with competitive market forces, but the electric energy being supplied or withdrawn from the grid will distort energy price formation.[430]

460. TransAlta further submitted that this scenario would:

- Create stranded asset risks due to technology obsolescence.
- The non-market incentives for regulated utilities could drive the inefficient proliferation of storage assets because their focus is on reliability and not cost competitiveness.
- Competitive markets are better at allocating risk and benefiting customers by driving down costs.[431]

461. With respect to this second scenario (where energy storage resources are restricted to the provision of system capacity and/or reliability services, and barred from the wholesale electricity and ancillary services markets), parties argued that this would be an inefficient allocation of resources, since a perfectly capable asset would be sitting idle due to regulation instead of being used to its full potential.

Option 2: Regulated utility ownership permitted

462. AltaLink, ATCO, Energy Storage Canada, ENMAX, EPCOR, Fortis, IPCAA and the UCA supported a model where the regulated utilities would be allowed to own and operate energy storage resources. These parties were of the general view that energy storage resources are another "tool in the toolbox" to resolve grid issues and, in some cases, may be the least cost alternative, but their operation and control is best coordinated by grid operators. According to ATCO:

> For example, energy storage might be used to solve capacity issues, power quality issues, and/or defer costly upgrades to the grid. In isolated communities, batteries can be used to supplement intermittent renewable power. Utility use of battery technology would be subject to prudency testing in the respective rate applications – i.e. the battery should be the right solution to a problem.[432]

463. Arguments in support of regulated utilities owning energy storage resources can be considered in the context of the same two scenarios discussed earlier: (i) the energy storage resource is able to operate the asset to its full capability with some limitations; and (ii) the energy storage resource is restricted to the provision of system capacity and/or reliability services (i.e., is barred from the wholesale electricity and ancillary services markets). In this case, however, the arguments related to the latter will be examined first.

[430] Exhibit 24116-X0562, Capital Power Combined Module submission, PDF page 2.
[431] Exhibit 24116-X0550, TransAlta Combined Module submission, paragraphs 9-14.
[432] Exhibit 24116-X0511, ATCO-AUC-2019NOV29-013, PDF page 82.

Energy storage resources providing system capacity and/or reliability services are excluded from the energy markets

464. EPCOR argued that whenever an energy storage resource is installed because it is the most economic option for ensuring the safe, reliable and cost-effective operation of the system, it follows that such energy storage asset is a necessary component of that system, and thus the utility should be permitted to own it.[433]

465. Fortis suggested that all NWAs, including energy storage resources, "have locational and temporal variability of both need and value." It then argued that the utility is in the best position to manage the risk associated with these variations because it has better access to the information to make this business decision.[434] AltaLink expressed a similar view:

> Utility ownership also allows maximum flexibility to manage the uncertainty and the value of [a] Transmission-Only energy storage [resource] as a long-term asset. As highlighted previously by AltaLink in this Inquiry, the future of electricity system has significant uncertainty given the development and use of new technologies that have a profound impact on the grid use.[435]

466. AltaLink also suggested that the energy exchanged with the grid under this scenario would be minimal, similar to the modest line losses that can be attributed to other wires assets. AltaLink argued that excluding these assets from participating in the wholesale electricity and ancillary services markets would leave the operation of the FEOC market unaffected by out-of-market payments associated with utility ownership of energy storage resources functioning purely as an NWA. This is because its configuration would preclude its being able to serve in competitive electricity markets given the primary requirement for delivering reliability.[436]

467. AltaLink asserted that concerns that utility ownership of energy storage resources could distort price formation in competitive electricity markets is misplaced, particularly if non-regulated entities are also able to own energy storage resources that are able to enter into NWA contracts and concurrently participate in the competitive electricity markets.

> … an NWA contract is still an "out-of-market" payment and can have negative implications on the FEOC operation of the market. More specifically, a NWA provider can use its regulated stream of revenue to subsidize its market participation causing impacts to the market which could lead to market distortion and inaccurate price signals. The FEOC market impact of such an arrangement is particularly a concern if a NWA contract is long-term and becomes a large part of the business case driver of an energy storage facility that provides regulated services in exchange for contracted revenue while participating in competitive markets. A similar concern arose with Transmission Must Run (TMR) contracts. To alleviate these concerns, the 2003 Transmission Development Policy paper from Alberta Energy stated that TMR arrangements should be short term solutions.[437]

468. AltaLink concluded that regulated utility ownership of energy storage assets, used exclusively as NWAs, would have a much less distortionary effect on competitive electricity

433 Exhibit 24116-X0577, EPCOR Combined Module submission, PDF pages 14-21.
434 Exhibit 24116-X0640, Fortis response submission, PDF page 6.
435 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 145.
436 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 146.
437 Exhibit 24116-X0597, AltaLink Combined Module submission, paragraph 152.

markets than if utilities were required to procure these services from third-party entities. Furthermore, if these third-party-owned assets were excluded from operating in competitive electricity markets because they held NWA contracts, then there is little difference between utility ownership and third-party ownership, except in the latter case there is reduced operational efficiency resulting in a suboptimal outcome.

469. IPCAA submitted that "DFOs should not be permitted to own [energy storage resources] unless they can show that the installation of an [energy storage resource] will lead to a reduction in the distribution system revenue requirement by avoiding a more expensive investment in distribution infrastructure."[438]

470. Parties also pointed out that if this option was permitted, some thought would also need to be given to how to allocate the cost of energy lost as part of round-trip efficiency from charge-discharge cycles of the energy storage resource.[439]

Energy storage resources being able to operate to their full capability (by providing energy, system capacity, and/or reliability services)

471. ATCO stated that energy storage resources providing non-regulated services such as participating in the wholesale electricity and ancillary services markets should generally be owned by non-regulated entities. However, ATCO stated that, in some cases, regulated utilities should be able to use their own storage in those markets to maximize the benefit to the local system and utility customers.

> With respect to DFO-owned energy storage, while its primary purpose is to address and resolve grid issues identified at the time of implementing the asset, if opportunities exist where it can also be utilized for ancillary services (at no detriment to its primary purpose), the DFO should not be precluded participation. Any revenues received for services provided to the ancillary market for DFO-owned storage would be treated as a revenue offset.[440]

472. AltaLink also identified a scenario where it may be beneficial for a utility-owned energy storage resource to participate in competitive electricity markets. In this scenario, the grid operator would determine that a regulated energy storage asset has surplus capacity and is capable of providing energy into electricity markets in addition to meeting the requirements of providing regulated services. AltaLink noted that in this scenario, measures are required to ensure such activities are consistent with the FEOC operation of the electricity market and will not unfairly disadvantage other market participants. AltaLink further suggested that in this scenario it may be beneficial if energy offered into competitive electricity markets be provided through an arm's-length third party (such as the Balancing Pool) and that any benefits realized from such activities should be returned to ratepayers, as ratepayers are paying for the storage facilities through regulated tariffs.[441]

473. Pembina advanced a similar scenario where distribution utilities could be allowed to own and retain operational control over storage resources but must issue long-term contracts for

438 Exhibit 24116-X0516, IPCAA-AUC-2019NOV29-013, PDF page 5.
439 See, for example, Exhibit 24116-X0529, EDTI-AUC-2019NOV29-013(b); Exhibit 24116-X0561.01, CGWG Combined Module submission, paragraphs 68-70.
440 Exhibit 24116-X0511, ATCO-AUC-2019NOV29-013, PDF page 83.
441 Exhibit 24116-X0531, AML-AUC-2019NOV29-013, PDF page 54.

commercial operation of those resources. Under this scenario, distribution utilities would be allowed to maximize the system benefits of storage and integrate storage assets into their regulated rate base, but would be precluded from profiting from the deployment of such assets in competitive markets. Pembina pointed out that this scenario is being piloted in several jurisdictions, including New York state, the United Kingdom and Australia.[442]

5.5.4.1 Parties' recommendations on clarifying the regulatory framework for energy storage

474. Fortis suggested that energy storage-related ownership issues should be addressed in the broader context of developing a holistic approach to NWAs and distribution utility roadmaps (discussed further in Section 6.1):

> In the Company's submission, FortisAlberta identified and continues to purport the need for a holistic NWA process that addresses, and is not limited to, the following topics: (1) procurement, (2) evaluation methodology, (3) market compensation mechanisms, (4) DFO and third party ownership, (5) cost recovery, (6) legislative changes, (7) DFO incentives (revenue sharing), and (8) operational agreements. The recommended solutions by other DSI stakeholders that address a specific or individual NWA topic should be vetted in a stakeholder workgroup assigned to solution a holistic NWA process.[443]

475. Heartland Generation engaged Mr. Tom Rose to provide Texas' experience in addressing this issue. He recommended that the following actions be taken in Alberta to resolve issues associated with the use of energy storage resources:

> 1. Clearly define ownership and operational policy for energy storage systems.
>
> 2. Establish efficient technical interconnection requirements and rules to ensure worker safety and grid reliability.
>
> 3. Establish a competitive contracting (RFP) process for electric utilities to enter into agreements with competitive energy storage, including operational requirements for power quality services.
>
> 4. Allow electric utility cost recovery with return on competitive contracts providing electric energy storage services for power quality purposes, ensuring storage is evaluated on "par" with other traditional technologies.
>
> 5. Require electric energy storage "pilot projects" for each distribution utility to minimize technology and contracting risks.
>
> 6. Establish state oversight person(s) to ensure both electric utilities and competitive storage service providers negotiate in good faith.[444]

476. As a general proposition, the rules and compensation schemes that govern Alberta's energy market were designed for resources with different characteristics than those associated

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442 Exhibit 24116-X0512, Pembina-AUC-2019NOV29-013, PDF page 13.
443 Exhibit 24116-X0640, Fortis response submission, PDF page 6.
444 Exhibit 24116-X0552, Tom Rose, Public Policy Report: Use of Electric Energy Storage in the Alberta Electricity Market, PDF page 4.

with energy storage. Because energy storage resources are capable of performing a range of services and, hence, of delivering multiple value streams simultaneously, the potential issue of double compensation (from both regulated and non-regulated revenue streams) and market distortion inevitably arises. Parties emphasized the importance of a level playing field to allow storage markets to develop without distortion, to remove barriers to new market entrants and to provide the distribution utilities the right incentives for efficient investments.

6 Parties' recommendations for next steps

Key takeaways:
Many, if not all, of Alberta's distribution utilities and other stakeholders are taking steps to modernize the grid, either proactively or in response to issues raised over the course of this inquiry. In this regard, almost all parties supported, to a greater or lesser extent, the creation of distribution utility roadmaps that would identify those specific circumstances (or "triggers"), the occurrence of which would signal to the Commission and the utilities that further steps must be taken to either enable the integration of DERs or to bring such integration closer to being realized, as market or other relevant conditions then permit. However, before roadmaps can be explored, there is a need for an objective assessment of the value DERs may actually offer the grid both in terms of avoidable costs and other deliverable benefits.

477. As a practical matter, addressing the full range of issues identified by parties during the inquiry will require a suite of coordinated actions by all electricity industry stakeholders. Parties recommended leveraging existing regulatory processes, convening additional regulatory and/or stakeholder consultation processes led by the Commission, and supporting initiatives led by other stakeholders (including the AESO, distribution utilities and potentially the provincial government) with such additional input and assistance from the Commission as may be necessary. This section highlights some of these recommended actions.

478. The AESO recommended that the best way to capitalize on the results of the inquiry is to have the Commission undertake two processes: "(1) address the opportunities and objectives it can achieve in the short term through immediate, targeted and discrete processes; and (2) initiate building a longer-term roadmap for issues and challenges that are broader in scope, or less defined. These latter, more complex issues are better addressed within a longer-term process, once industry has … carefully considered the implications of the Inquiry's findings and the Commission's final report."[445] Other parties generally supported this approach, at least implicitly, by dividing up recommendations as to next steps between those that should be taken immediately and those that will likely require more time to complete.

6.1 Distribution utility roadmaps

479. Given that the future pace and scale of DER deployment is presently unclear, Dr. Orans recommended that the Commission lead a process of establishing roadmaps for the evolution of the distribution utilities. A roadmap would offer a guiding framework that allows all market participants to better understand how the distribution system might evolve and what events would trigger evolutionary steps, without taking a position on which technologies will be adopted or when. Simply put, a roadmap would identify what actions will be needed when specified triggers are met.

480. Dr. Orans recommended that a roadmap contain two main elements: triggers and enabling conditions. He suggested that all market participants would be able to monitor the triggers. When a particular trigger, or a set of triggers, is met, the distribution utility and its stakeholders would then need to give effect to any enabling conditions to allow for the evolution

[445] Exhibit 24116-X0735, AESO concluding remarks, PDF pages 4-5.

of the utility and the successful integration of DERs.[446] Dr. Orans gave the following high-level examples of what may constitute triggers:

- Technology concerns: the level of adoption of DERs in the utility's service territory.
- Regulatory concerns: changes associated with government policy; DERs control and ownership; data access and control (for customers and third parties); scale of cost shifting due to uneconomic bypass; and regulatory uncertainty for new technologies.
- Market concerns: changes in markets including new markets; market participation (including value stacking); and new risks and costs (DER ownership and market operation risk to DFO).

481. He also provided high-level examples of what some of the enabling conditions might include:

- Technology: technologies required to support system operations are in place to allow for the level of control of DERs required (e.g., AMI, ADMS, DERMS, centralized communication network, etc.).
- Regulatory: resolve jurisdictional issues (between DFOs, the AESO, TFOs, etc.); and incorporate DERs in system planning.
- Financial: implement new distribution rate design; support interaction within wholesale and retail markets with clear rules for all connection configurations; customer engagement commensurate with DERs adoption; and cost recovery for DFOs (and potentially incentives) for implementing enabling technologies.
- Operational: create standards for planning, interconnection, measurement and verification (for higher penetration levels, as well as settlement and billing).

482. Among the enabling conditions offered by Dr. Orans were potential new distribution system functions that relate to managing and coordinating DERs. Dr. Orans also suggested six different possible business evolutionary models for distribution utilities that contemplate what entity (for example, the AESO, the distribution utility, or some other entity) might be responsible for the potential new roles and functions to manage DERs. These appear to be a type of "end-state" that might be provisionally agreed upon at the time the roadmaps are created, and which are then tentatively approached as triggers and enabling conditions are met. ENMAX noted it was important for stakeholders to come to a consensus on the desired end state, which may require policy direction and legislative change from the government.[447] A summary of the potential new distribution system functions and six different possible models offered by Dr. Orans is provided in E3's written submission.[448]

483. Nearly every party supported the idea of creating distribution utility roadmaps; however, parties differed on how this concept should be implemented.

484. AltaLink submitted that it was important to develop distribution utility roadmaps that would allow for a properly paced response of the distribution system to new technologies and

446 Exhibit 24116-X0579, E3 Combined Module submission, PDF pages 15-16.
447 Exhibit 24116-X0733, ENMAX concluding remarks, PDF page 9.
448 Exhibit 24116-X0579, E3 written submission, PDF pages 27-33.

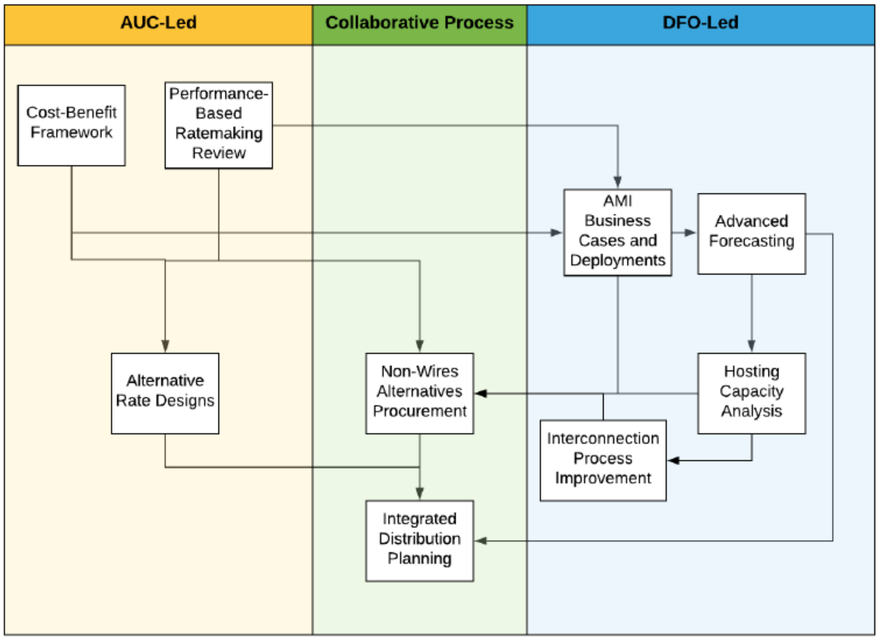
would help avoid overbuilding infrastructure to accommodate the deployment of DERs.[449] AltaLink[450] and ATCO[451] indicated that roadmaps need to be developed with broad consultation and must involve engagement from utilities, the Commission and the government. Similarly, Fortis stated that all parties need to agree on the key metrics and appropriate responses prior to any specific application of DERs.[452]

485. The UCA was supportive of the roadmap concept, insofar as it aids in distribution system planning, load forecasting, identifying solutions in cost-effectively integrating DERs, and energy efficiency policies. The UCA recommended that to implement the roadmaps, more visibility into distribution system planning is required in order to verify that the utilities are considering all relevant factors when planning their upgrades to the grid, including load forecasts, trends in technology and DER adoption.[453]

486. In voicing its support for the roadmap concept, Pembina recommended the Commission consider examining the approaches taken in other jurisdictions, and pointed to Minnesota and Oregon as possible examples.[454] Pembina further recommended a comprehensive approach to developing distribution utility roadmaps, laying out its view of the various sequential steps that would need to be taken, reproduced as Figure 22. It recommended starting with developing a transparent cost-benefit framework for assessing the value DERs can provide to the system, and ending at the ultimate goal of an integrated distribution planning process.

449 Exhibit 24116-X0727, AltaLink concluding remarks, PDF page 4.
450 Exhibit 24116-X0727, AltaLink concluding remarks, PDF page 6.
451 Exhibit 24116-X0740, ATCO concluding remarks,. PDF page 11.
452 Exhibit 24116-X0741, Fortis concluding remarks, PDF page 5.
453 Exhibit 24116-X0744, UCA concluding remarks, PDF page 7.
454 Exhibit 24116-X0737, Pembina concluding remarks, PDF page 14; see footnote 17 in Pembina's submission for references and links to these provided examples.

Figure 22. Pembina's recommended process to developing distribution utility roadmaps and integrating DERs[455]



487. The regulated distribution utilities all favoured utility-specific roadmaps. For example, EPCOR stated that each distribution utility's specific circumstances must be considered carefully and the differences in the service territories must be reflected in any utility-specific roadmap developed.[456] ATCO,[457] ENMAX[458] and Fortis[459] expressed similar views.

488. Considering energy storage resources specifically, Energy Storage Canada submitted that a Commission-initiated process is required to develop a common DER roadmap structure for utilities to ensure regulatory consistency across all service territories.[460] Energy Storage Canada indicated that having a common roadmap structure would simplify and reduce the regulatory burden for distribution utilities and customers. Although Energy Storage Canada was generally supportive of Pembina's recommendation of a cost-benefit analysis of the value of DERs, it suggested that before investing significant time and effort in developing roadmaps, the Commission should address the following enabling conditions that, in its view, have already been triggered:[461]

- Tariffs specific to energy storage resources, (this issue was discussed in Section 4.6.3).
- Harmonization between distribution and transmission tariffs for transmission delivery charges (this issue was discussed in Section 5.2.2).

455 Exhibit 24116-X0737, Pembina concluding remarks, PDF page 16.
456 Exhibit 24116-X0743, EPCOR concluding remarks, PDF pages 18-19.
457 Exhibit 24116-X0740, ATCO concluding remarks,. PDF page 11.
458 Exhibit 24116-X0733, ENMAX concluding remarks, PDF page 7.
459 Exhibit 24116-X0741, Fortis concluding remarks, PDF page 5.
460 Exhibit 24116-X0728, Energy Storage Canada concluding remarks, PDF page 3.
461 Exhibit 24116-X0728, Energy Storage Canada concluding remarks, PDF pages 5-6.

- Procurement processes for energy storage resources and other DERs to provide NWAs (this issue was discussed in sections 5.5.2 and 5.5.4).

489. Once these enabling conditions have been addressed, Energy Storage Canada stated that distribution utilities will be prepared to tailor the base roadmap structure to meet the needs of their distribution systems. Energy Storage Canada recommended each utility's roadmap be finalized and approved by way of a regulatory proceeding.[462]

490. ENMAX recommended that the Commission move forward with a consultation on guidelines for utility-specific roadmaps, which would include consideration of NWAs in distribution system planning and the future roles of distribution utilities in a high-DER future.[463]

491. While some parties have posited cost savings for DERs, EPCOR stated that this could not simply be presumed. EPCOR explained that many factors would have to be considered in determining whether costs are actually reduced by the adoption of DERs.[464] Therefore, EPCOR indicated that prior to designing or implementing triggers or enabling conditions based on cost-saving impacts of DERs, it was important to determine the extent to which different types of DERs would affect distribution system costs and the timing of such impacts.

492. While Dr. Orans suggested that distribution utilities should monitor the type of DERs being adopted and the level of adoption, EPCOR indicated that not only was this impossible for devices installed behind the meter, but also that simply knowing the DER penetration level was not informative.[465] EPCOR found it more helpful to investigate the potential of its AMI system to observe impacts of actual customer behaviour on the distribution system, which did not require information about the technology installed behind the meter. Observing customer behaviour by improving data gathering, tracking and analysis efforts could assist the distribution utilities in evolving their system planning over time in appropriate and timely ways.[466] As such, EPCOR submitted that distribution utilities should assess the costs and benefits of investing capital and operating expenditures into data gathering, tracking and analysis efforts.

493. Given the widely held view that the grid is shifting from a system-centric model to a customer-centric model, and connecting distribution utilities to their customers in new ways, Fortis and ATCO similarly recommended conducting a wide-ranging customer engagement process to determine customer needs and expectations moving forward. Fortis argued that such an undertaking is critical to understanding the opportunities, barriers and challenges experienced by industry in the current market structure.[467]

494. Customer data gathering may include the implementation of a more advanced AMI system that could be used to gather the data, as EPCOR indicated. This is a principal reason why, as discussed in Section 5.4, AMI systems are widely expected to be the cornerstone of grid modernization. Regarding customer engagement, it appears that utilities (through their

462 Exhibit 24116-X0728, Energy Storage Canada concluding remarks, PDF page 10.
463 Exhibit 24116-X0733, ENMAX concluding remarks, PDF page 7.
464 Exhibit 24116-X0635, EPCOR reply submission, PDF page 9.
465 Exhibit 24116-X0743, EPCOR concluding remarks, PDF pages 20-21.
466 Exhibit 24116-X0743, EPCOR concluding remarks, PDF page 21.
467 Exhibit 24116-X0578, Fortis Combined Module submission, paragraph 174.

participation in the Alberta Smart Grid Consortium[468]) are already taking steps in that direction, and they look forward to seeing the results of those efforts.

495. The AESO was supportive of Commission-led distribution roadmaps, stating that the Commission was well-positioned to apply a holistic lens to the transformations occurring on the distribution systems, to make principled decisions on topics within its mandate that are in the best interests of the public and industry, and to coordinate with the AESO, government and market participants.[469] The AESO suggested that such a roadmap process should define a list of issues and actions requiring resolution and identify areas where coordination between the AESO, the Commission and government will be required. The AESO suggested the following topics first need to be addressed in implementing the roadmap concept: principles, establishing common terminology, distribution utility rate design, AMI, distribution utility planning criteria, and leveraging DERs as NWAs on the distribution system.[470]

496. The Rocky Mountain Institute's (RMI) advice (referenced by the Pembina Institute) is relevant to the roadmap concept:[471]

> Unfortunately, there is no "single, one-time decision or regulatory proceeding that establishes the end state for the electricity market." Nor is there likely a single perfect or best business model for distribution utilities, for achieving the desired system outcomes.
>
> …
>
> … all decisions (do not) need to be known in advance, with the exact form and functions of the utility predetermined. Still, regulators and utilities have an important strategic choice to make at the outset: whether to pick off decisions one by one and see over time where they end up, or to set a vision in advance then let decisions follow from that. Clearly, the latter is the better approach. [footnotes removed]

497. As identified throughout this report, the continued evolution of the electric system will require thoughtful planning and actions on the part of the distribution utilities, the Commission, and other stakeholders to address issues surrounding rate design, information availability, implementation of AMI systems, DERs integration, as well as grid planning and operation in general. Many of these actions are of varying urgency, and may also be utility specific. However, it is generally recognized that action on these issues will eventually be required to ensure that economically efficient outcomes are achieved and grid modernization continues to proceed in the public interest.

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468 The Alberta Smart Grid Consortium consists of Alberta Innovates (a Provincial Crown Corporation), Alberta Energy and the Alberta DFOs, including ATCO, ENMAX, EPCOR, Fortis, AFREA, EQUS and the Cities of Lethbridge, Medicine Hat and Red Deer. "The Consortium works collaboratively to understand the impacts and opportunities of grid modernization solutions by enabling the development, deployment and use to meet the current and evolving needs of their electricity consumers."

469 Exhibit 24116-X0735, AESO concluding remarks, PDF page 4.

470 Exhibit 24116-X0735, AESO concluding remarks, PDF pages 8-9.

471 Exhibit 24116-X0576, Pembina Combined Module submission, PDF page 5, quoting: Dan Cross-Call, et al., *Reimagining the Utility* (RMI, Jan. 2018), page 19, https://rmi.org/insight/reimagining-the-utility/.

6.2 Processes led by other industry participants

498. Many, if not all, of Alberta's distribution utilities and other stakeholders are taking steps to modernize the grid, either proactively or in response to issues raised over the course of this inquiry. This section highlights several notable examples.

499. ATCO Electric, ENMAX and Fortis either released or updated hosting capacity maps for their respective systems during the course of this proceeding. In its most recent Phase II application, ATCO Electric applied for and received the Commission's approval to implement a pilot rate for EV fast-charging services and a pilot AMI project. EPCOR undertook joint research with the University of Alberta on potential DERs impacts to urban utilities. Fortis is conducting a number of internal and external initiatives, studies and pilots to cost-effectively integrate DERs. ENMAX launched an EV pilot program called Charge Up where ENMAX helped offset the cost of charging stations (specifically, Level-2 and DC fast-charging stations) for Calgary homeowners and small businesses in exchange for access to their charging data to monitor changes in electricity load shape.[472]

500. Many of these programs fall outside distribution utilities' regulated activities, or are part of managing the utility's business under PBR and thus may not fall squarely under the Commission's oversight. However, they are examples of utilities using innovative methods to obtain more granular data, model the impact of DERs on their systems, and try various methods on a smaller scale. These efforts by the distribution utilities to leverage the learnings from this inquiry, including this report, in further preparing their distribution systems for the ongoing transformation of the electric grid are notable and encouraging.

501. Over the summer of 2020, a group referred to as the Alberta Smart Grid Consortium engaged The Strategic Counsel, a professional market research firm, to conduct a study among electricity consumers in Alberta to better understand what grid modernization means to them, including their changing needs, expectations in terms of their relationship with their utility, priorities, behaviours and trends. The research study focuses on consumer groups that may have limited engagement with the distribution utilities, including residential, small commercial, and farm operators.[473] It is anticipated that this will be an important and relevant study.

502. Concurrent with the inquiry, the AESO has been leading the following initiatives to address the challenges and opportunities associated with the transformation of the electric grid:[474]

- DER Roadmap.
- Energy Storage Roadmap.
- Transmission and distribution coordinated planning framework.
- Initiatives related to pricing signals and cost allocation, which include the 2020 market-related initiatives and ISO tariff consultations.

503. The AESO explained that the purpose of the DER Roadmap is to facilitate the integration of DERs on the AIES, and the following topics will fall within the scope of the roadmap: DER

472 More information on the program can be found through the following hyperlink: https://www.enmax.com/ev.
473 Alberta Purchasing Connection, reference number AB-2020-03080, https://vendor.purchasingconnection.ca/Opportunity.aspx?Guid=24eb9b7b-b2cb-b95e-128c-39c2ed490000&
474 Exhibit 24116-X0594, AESO Combined Module submission, PDF pages 5-7.

data, visibility and dispatchability, system forecasting and modelling, system planning, real-time operations, and transmission-distribution interconnection requirements.[475] The DER Roadmap was published in June 2020.[476]

504. Similarly, the AESO initiated the Energy Storage Roadmap in August 2019,[477] in which it is working to understand energy storage performance capabilities, potential grid reliability impacts and technical requirements. Alongside this roadmap, the AESO initiated the Energy Storage Innovation and Learnings Forum to explore all aspects of energy storage resources with industry experts.[478] Finally, the AESO is investigating opportunities to utilize NWAs, including energy storage, and indicated it was important to coordinate and align this work with the Energy Storage Roadmap.[479]

505. In an effort to enhance the framework around system access service requests (SASRs) and planning of the transmission system, the AESO developed a framework to support the coordination of transmission and distribution system planning. Elements of its DER and Energy Storage roadmaps will be integrated into this framework. Since May 2020, the AESO has been engaging towards this end with distribution and transmission utilities, as well as some affected stakeholders. The current scope includes, but is not limited to, the following:[480]

- Adjusting the AESO's business practices for DFO-driven SASRs.
- Considering the development of AESO guidelines or criteria for POD-level interconnections.
- Assessing and determining the role of probabilistic analysis in distribution planning and the corresponding transmission infrastructure need decision-making process.
- Considering the development of a load forecasting methodology, format and data requirements that are fit for use in the AESO's evaluation of DFO SASRs.
- Developing processes for the improved coordination of the AESO's Long-term Transmission Plan, system needs identification documents and operational regional plans with the DFOs' plans.

506. As part of its market-related initiatives, the AESO has been engaging stakeholders on the short-term and long-term market-related implementation activities for energy storage as well as market considerations associated with DERs, such as "must-offer, must-comply," minimum size thresholds, and aggregation. The AESO has been working on advancing these activities throughout the course of 2020. As well, the AESO has launched a tariff modernization initiative to ensure, among other things, that its rate design evolves and adapts to the new realities of the grid (such as proliferation of DERs and energy storage) and sends price signals to incent the efficient use of transmission infrastructure.[481]

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475 Exhibit 24116-X0594, AESO Combined Module submission, PDF page 5.
476 Details on this roadmap can be found through the following hyperlink: https://www.aeso.ca/assets/Uploads/DER-Roadmap-2020-FINAL.pdf.
477 Details on this roadmap can be found through the following hyperlink: https://www.aeso.ca/assets/Uploads/Energy-Storage-Roadmap-Report.pdf.
478 Exhibit 24116-X0594, AESO Combined Module submission, PDF page 5.
479 Exhibit 24116-X0735, AESO concluding remarks, PDF page 9.
480 Exhibit 24116-X0708, AESO's responses to the Commission's second round of IRs, PDF pages 28-29.
481 https://www.aeso.ca/rules-standards-and-tariff/tariff/tariff-modernization/

507. The AESO acknowledged these initiatives were not intended to establish provincial DER-related policy or to redefine industry roles and responsibilities, and that policy matters should be reserved for the provincial government.[482] With this consideration in mind, the AESO recommended the Commission defer any further Commission process on matters that overlapped with the AESO's initiatives until such time as the specific issues requiring resolution are better known and understood.[483]

508. While parties were generally supportive of the AESO's initiatives,[484] AltaLink indicated these initiatives may be somewhat limited in their scope, given the AESO's responsibilities and mandate, and may not fully reflect the issues relevant to the distribution systems. With regard to the DER Roadmap, AltaLink was concerned the initiative would not account for the implications of DERs within the distribution system. AltaLink stated the DER Roadmap needed to take a holistic view of the power system to ensure DERs were properly integrated and system development was appropriately timed to meet the pace, scale and timing of DER adoption.[485] To this point, AltaLink suggested a future proceeding resulting from the consultations on the DER Roadmap was required.[486]

509. Similarly, AltaLink supported the transmission and distribution coordinated planning framework, but stated the process would only be useful if it resulted in a set of recommendations and requirements. AltaLink further stated this process would not consider distribution planning criteria that did not have an interface with the transmission system, and that the process may not result in consensus among participants. Therefore, AltaLink indicated a further process to be conducted by the Commission may be required.[487]

510. AltaLink also remarked that if planning of the grid for new technologies was segmented between transmission and distribution planning, a more optimal, system-wide solution would likely be overlooked in favour of more narrow transmission-only or distribution-only solutions.[488] AltaLink submitted that planning criteria should be established and then robustly tested through a regulatory process to ensure this criterion drives an optimal development of the transmission and distribution system.[489]

511. The AESO further explained that it plans to expand its engagement on the transmission and distribution coordinated planning framework and DER Roadmap, and stated it would invite Commission staff to participate in those engagements. The AESO added that it would also engage the Commission if its guidance or assistance were required to implement recommendations for improving the coordination of transmission and distribution system planning.[490]

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482 Exhibit 24116-X0641, AESO Combined Module response submission, PDF page 9.
483 Exhibit 24116-X0641, AESO Combined Module response submission, PDF page 8.
484 For example, EPCOR indicated its support for the Transmission and Distribution Coordinated Planning Framework in its responses to the Commission's second round of IRs. See PDF pages 60-61 of Exhibit 24116-X0699.
485 Exhibit 24116-X0631, AltaLink Combined Module response submission, PDF page 4.
486 Exhibit 24116-X0727. AltaLink concluding remarks, PDF page 6.
487 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF pages 9-10.
488 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF page 6.
489 Exhibit 24116-X0597, AltaLink Combined Module submission, PDF page 7.
490 Exhibit 24116-X0708, AESO's responses to the Commission's second round of IRs, PDF page 30.

512. The Commission is supportive of the AESO's initiatives and stands ready to participate should such be required by or be of assistance to the AESO. Further, as both the AESO and AltaLink indicated, issues requiring guidance or a determination from the Commission may arise within the AESO's ongoing initiatives and associated stakeholder engagement activities. In these cases the Commission will become directly involved through its decision-making process. Given that most of these initiatives are well underway, the AESO's request to avoid overlap has merit.

513. Nevertheless, AltaLink's observations are also noteworthy – given the AESO's primary focus on the transmission system and electricity market, issues related to distribution systems, or a more holistic view of the electric grid, may not be fully canvassed in the AESO initiatives and may require additional processes. The Commission will await the outcome of the AESO's initiatives and will consider the need for further processes that may build upon the AESO's initiatives, at that time. In doing so, the Commission anticipates being able to leverage the AESO's expertise and knowledge acquired during its own consultations.

Appendix 1 – Glossary and list of acronyms

Acronym or term	Description or name in full
ADMS	advanced distribution management systems
AESO	Alberta Electric System Operator established by Section 7(1) of the *Electric Utilities Act* as the Independent System Operator (ISO) charged with the operation and economic planning of the Alberta Interconnected Electric System as well as the running of a competitive energy market
AIES	Alberta Interconnected Electric System as defined in the *Electric Utilities Act*, Section 1(1)(z)
AMI	advanced metering infrastructure: Technology, including metering technology and network communications and information technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology
CEER	Council of European Energy Regulators
CP	coincident peak demand
DCG	distribution-connected generation
DER	distributed energy resource
DERMS	distributed energy resource management systems
DFO	distribution facility owner, that is, the owner of an electric distribution system
DG	distributed generation. Both an Alberta statutory term as well as a term in other jurisdictions external to Alberta that is synonymous with DCG. The statutory definition: *Electric Utilities Act*, Section 1(1)(j): " 'distributed generation' means a generating unit that is interconnected with an electric distribution system"
DR	demand response
DSI	Distribution System Inquiry, the current inquiry by the AUC under Proceeding 24116
DTS or Rate DTS	demand transmission service, the primary load rate class for service from the transmission system
EPRI	Electric Power Research Institute
EUA	*Electric Utilities Act*
EUB	Alberta Energy and Utilities Board (the Commission's predecessor)
EV	electric vehicle
FEOC	*Fair, Efficient and Open Competition Regulation*
grid	For the context of this report, the Alberta Interconnected Electric System (AIES) and "grid" are synonymous.

Acronym or term	Description or name in full
IR	information request, i.e., the interrogatory process in Commission proceedings
ISD	industrial system designation, as defined under the *Hydro and Electric Energy Act*, Section 1(1)(g)
ISO	Independent System Operator, as defined under the *Electric Utilities Act*, Section 1(1)(w)
IT	information technology
kVA	kilovolt ampere, a unit of power
kW	kilowatt, a unit of power
kWh	kilowatt hour, a unit of energy
LCOE	The levelized cost of energy (LCOE) is a measure of the average net present cost of electricity generation for a generating plant over its lifetime
MG	Depending on context, micro-generation or micro-generating unit
MW	megawatt, a unit of power equal to 1,000 kW
NARUC	National Association of Regulatory Utility Commissioners
NCP	non-coincident peak demand
NWA	non-wires alternative
PSC	New York Public Service Commission
PV	photo-voltaic, referring to solar photovoltaics, a type of generation technology
RRO	regulated rate option, a regulated rate tariff provided by a regulated rate provider
SAS	system access service, as defined under the *Electric Utilities Act*, Section 1(1)(yy)
STS or Rate STS	supply transmission service
TCG	transmission-connected generation
TFO	transmission facility owner

Appendix 2 – Process for the distribution system inquiry

1. The Commission issued Bulletin 2018-17 in December 2018, where it noted that the nature of the electric distribution system in Alberta is changing and launched the Distribution System Inquiry (Proceeding 24116). As part of that bulletin, the Commission initially set out three questions it sought information on in undertaking the inquiry:

- How will technology affect the grid and incumbent electric distribution utilities; and how quickly?

- Where alternative approaches to providing electrical service develop, how will the incumbent electric distribution utilities be expected to respond and what services should be subject to regulation?

- How should the rate structures of the distribution utilities be modified to ensure that price signals encourage electric distribution utilities, consumers, producers, prosumers and alternative technology providers to use the grid and related resources in an efficient and cost effective way?

2. Initially, the Commission intended to undertake the inquiry in a series of three modules, which generally aligned with the three questions posed above. Later in the process, the Commission saw process efficiencies in combining the latter two questions into one module. Thus, the actual process for the inquiry included Module One and the Combined Module. The process for the inquiry was held both in writing and verbally for the two separate modules.

3. After canvassing parties on refining the scope for the inquiry, the information-gathering process began in earnest in July 2019 with parties' Module One submissions on the emerging trends and technologies that have the potential to affect distribution systems. Module One culminated in a technical conference taking place from September 10 to 12, 2019, at the Red Deer College. Other significant process steps for Module One are included in the table below.

Module One process step	**Date**
Written submissions from parties on Module One	July 17, 2019
Information requests (IRs)	August 7, 2019
Responses to IRs	August 21, 2019
Technical conference at Red Deer College	September 10 to 12, 2019
Supplemental submissions	November 11, 2019

4. In November 2019, the Commission moved to the Combined Module,[491] which focused on ensuring a common understanding of how Alberta's electric distribution systems are currently organized (from the perspectives of technology, rates, regulations and legislation), and the efficacy of various rate design approaches to collect the utilities' revenue requirement, promote the user-pays principle (including implications for bypass of regulated facilities), and establish price signals that ensure cost-effective investment in distribution systems. With the realities of the global pandemic caused by COVID-19, the Commission was forced to cancel the in-person technical meeting and hearing; in its place, the Commission provided participants an opportunity

491 As part of a broader initiative to make proceedings more efficient, productive and timely, the Commission combined Modules Two and Three, which was renamed the Combined Module.

to respond to the written submissions of other parties[492] and held a virtual technical meeting on June 24, 2020. During this virtual meeting, Commission members and staff asked questions of four independent consultants[493] that parties had retained for the inquiry, focusing on the topics of public utilities deploying advanced metering infrastructure (AMI) and what the ideal rate design might be.

5. The record development phase for the inquiry was completed in July 2020 with parties' concluding remarks. Other significant process steps in the Combined Module were as follows:

Combined Module process steps	**Date**
Commission preliminary IRs to all parties	November 29, 2019
Submissions for the Combined Module	March 13, 2020
Response submissions	May 13, 2020
Commission IRs to parties	June 3, 2020
Responses to Commission IRs	June 17, 2020
Virtual meeting held by webinar	June 24, 2020
Comments on virtual meeting topics and concluding remarks on the inquiry	July 15, 2020

6. Throughout the inquiry the Commission benefitted from input provided by approximately 90 different parties, representing a diverse and broad set of interested and informed stakeholders based in Alberta as well as abroad.[494] These included rural and urban distribution electric and natural gas utilities, electric transmission utilities, firms specializing in transmission- and distribution-connected generation, technology providers, special interest advocacy groups, rural landowners, and expert consultants. This input was received in the form of written responses to IRs, expert reports and technical meetings. These submissions produced valuable information on: (i) potential emerging technologies; (ii) the current and anticipated impacts of these emerging technologies and trends on grid reliability, existing business models, rate structures and the ability to provide appropriate price signals; and (iii) potential areas of innovation for the Alberta electricity industry in general and the AIES in particular.

492 Response submissions were filed on May 13, 2020.

493 The four independent consultants were David DesLauriers, Charles River Associates; Dr. Ahmad Faruqui, The Brattle Group; Dr. Ren Orans, Energy and Environmental Economics, Inc. (E3); and Dale Friesen, InterGroup Consultants Ltd.

494 For a full list of parties that participated, see Appendix 6.

Appendix 3 – Parties' submissions on natural gas

(return to text)

1. On January 18, 2019, ATCO Electric Ltd. (transmission and distribution divisions), ATCO Gas and Pipelines, ATCO Power and ATCO Energy (collectively, ATCO) requested the Commission to consider expanding the scope of the distribution system inquiry to examine how the matters under review also affect the gas network and gas utilities.[495]

2. The Commission approved ATCO's request and expanded the scope of the inquiry. In the Module One technical conference, the inquiry explored the nature of the gas system and how emerging technological and economic forces might affect the natural gas distribution system.

3. While there have been even more dramatic changes in the technologies for producing natural gas, and some changes in natural gas consumption technologies as well, parties indicated that technological change is not expected to be as pronounced, at least in the near term, for regulated natural gas utilities and their customers. Some of the differences in how new technologies are affecting electric and gas distribution systems are driven by the physical properties of the two energy sources. For example, the real-time operation of the electric markets and electric grid requires that energy be balanced on a nearly instantaneous basis and in tandem with other power systems with which the AIES connects. In contrast, as ATCO explained, on the natural gas network, energy is much easier to store than electricity, and price swings, such as those associated with electricity demand, are not typically observed by the gas utilities.[496]

4. That being said, the industry is seeing early signs of emerging competition between natural gas and electricity, with modern technology enabling customers to substitute one energy source for another. For example, a customer may opt for a heat pump and disconnect from, or significantly reduce, their gas service while another customer may install a combined heat and power (CHP) unit and disconnect from, or significantly reduce, their electricity service.

5. ATCO explained that "Technology exists today that allows for trade-offs between electric and thermal energy at the consumer level, where, for example, electric consumption can be reduced by increasing gas consumption and vice versa."[497] In practice, Mr. Peters, representing Community Generators, stated that this fuel switching was most prevalent among irrigation customers.[498] Fuel switching to produce hot water for residential purposes was also discussed as part of the Module One technical conference.[499] ENMAX stated that in Calgary there is only one micro-CHP unit connected to the electric distribution system and that it was installed in 2017.[500]

6. Nevertheless, the societal mega-trends discussed in Section 2.1 of decarbonization, digitalization and decentralization also have the ability to affect the natural gas system. In particular, since the start of the inquiry, ATCO Gas is planning to blend hydrogen into its natural gas distribution system to reduce the greenhouse gas intensity of the natural gas stream.[501]

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495 Exhibit 24116-X0079, ATCO comments on scope and process, January 18, 2019.
496 Exhibit 24116-X0438, Module One technical conference notes, paragraph 41.
497 Exhibit 24116-X0079, PDF page 3.
498 Exhibit 24116-X0436, Module One technical conference notes, paragraph 126.
499 Exhibit 24116-X0437, Module One technical conference notes, paragraphs 104-106.
500 Exhibit 24116-X0154, ENMAX Module One submission, PDF page 11.
501 https://www.atco.com/en-ca/for-home/natural-gas/hydrogen.html#blend

ENMAX also stated that it currently has larger CHP projects including district energy projects that make more flexible use of natural gas, capturing heat and generating electricity, reducing costs and emissions.[502]

7. The City of Edmonton provided examples of its energy transition plan to support carbon reductions and accelerate advancement to a low carbon economy. The City discussed its encouragement of net-zero buildings, a district energy heating project in its downtown core, as well as a city-owned Blatchford Renewable Energy Utility, which would deploy a large district energy sharing system in the Blatchford community able to serve a thermal load of 44 MW to over 30,000 Edmontonians over the next three decades.[503]

8. Pembina also provided a forecast of potential heat-pump installations, with the technology becoming more cost-effective, especially for new construction scenarios or where customers would be replacing furnaces and air conditioners simultaneously. Pembina also submitted a forecast from the National Energy Board of Canada (NEB), the predecessor to the Canada Energy Regulator, noting that the NEB presumes the installations could be between 40 per cent and 70 percent higher in 2040.[504] QUEST stated that this trend and momentum are clear, that more natural gas and diesel/gasoline end use situations will be replaced with heat pumps and EVs.[505]

9. The Commission asked both regulated gas utilities about defections from their distribution systems. Apex Utilities Inc. (formerly AltaGas Utilities Inc.) provided a full summary of de-energizations that it has experienced dating back to 2014, but noted that it does not typically track the reasons for the disconnections. AltaGas did state, however, that it was aware of a small number of sites that have disconnected from its distribution network and converted to propane, a site that disconnected as a result of electrification, and a site constructed using geothermal energy.[506] ATCO Gas stated that it did not track such metrics and that it finds both disconnection requests from the gas distribution grid as well as the number of sites that have not requested natural gas connections to be immaterial at this time.[507]

10. One reason for the current lack of defections from the gas grid may be the efficiency in delivering large quantities of energy via gas infrastructure. ATCO stated that comparing electricity and natural gas consumption in common units may be helpful. To demonstrate the scale, ATCO provided an example of a typical Alberta homeowner that uses 7,500 kWh of electricity every year, but 30,000 kWh worth of natural gas. If such a homeowner were to try to electrify everything, that individual would need to consume four times as much electricity to replace the energy that the natural gas supplied. ATCO stated that, in Alberta, the electric grid delivers roughly 250 GWh per day and the natural gas grid delivers 2,000 GWh worth of energy per day. Viewing the comparison in the same units, ATCO noted, was helpful in understanding what each energy system is capable of delivering.

502 Exhibit 24116-X0154, ENMAX Module One submission, PDF page 10.
503 Exhibit 24116-X0141, City of Edmonton Module One submission, PDF pages 7-8.
504 Exhibit 24116-X0175, Pembina Module One submission, PDF pages 25-26.
505 Exhibit 24116-X0134, QUEST Module One submission, PDF page 17.
506 Exhibit 24116-X0322, AltaGas response to Commission IRs, MULTIPLE-AUC-2019AUG07-003(a).
507 Exhibit 24116-X0329, ATCO-AUC-2019AUG07-003(a).

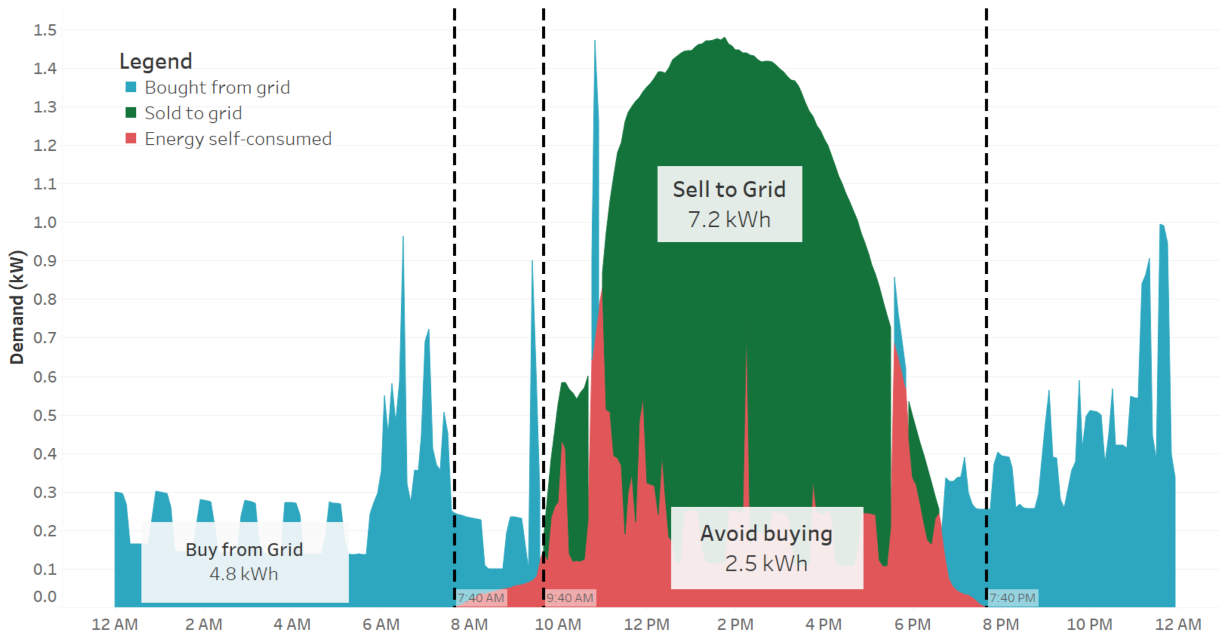
Appendix 4 – Detailed calculations for avoided cost mechanism for small micro-generation

(return to text)

1. The following provides supporting information and calculations related to sections 3.2 and 3.3. Those sections assessed the value proposition for energy purchased from the grid, energy self-supplied, and energy sold to the grid, including the prices for each of these three flows of energy.

2. The example billing determinants are from Figure 6, reproduced below. The customer needs (4.8 kWh + 2.5 kWh =) 7.3 kWh on this day. The customer produced (7.2 kWh + 2.5 kWh =) 9.7 kWh of energy. Of this amount, 2.5 kWh of produced energy was consumed on-site.

Flows of energy for a small micro-generation self-supply with export customer: from the customer's point of view



3. These billing determinants are presumed to be repeated for 30 days for a given month.

4. Applicable charges are as set out in Table 2 from Section 3.3.3, reproduced below:

Billing components for consumption for a small micro-generation customer under a hypothetical residential rate class[508]

	Charges for energy **drawn from** the grid (i.e., blue area in Figure 6)					Effective value of energy consumed on-site* (i.e., red area in Figure 6)	Energy sold to the grid (i.e., green area in Figure 6)
	Commodity	Retail administration	Distribution	Transmission	Miscellaneous		
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Energy charge	$0.07/kWh		$0.01/kWh	$0.04/kWh	$0.02/kWh	$0.14/kWh	$0.05/kWh[509]
Customer charge		$6/month	$20/month				

* Note: The effective value of energy consumed on-site is the sum of all charges avoided by self-consuming the DER-generated electricity.

5. In total for the 30-day month, for all energy, the customer:

- Consumed [(4.8 + 2.5) kWh/day × 30 days =] 219 kWh
- Produced [(7.2 + 2.5) kWh/day × 30 days =] 291 kWh
- Self-supplied and consumed [2.5 kWh/day × 30 =] 75 kWh

6. Under the **"buy-all sell-all" or gross metering practice**, no offsetting of energy flows is allowed. In other words, the customer would buy all 219 kWh from the grid. Their bill would be $26 + 219 kWh × $0.14/kWh = $56.66 for the month. The customer would also sell all of its produced energy to the grid, and receive the pool price from the power pool for hours when energy is exported, e.g., $0.05/kWh, for a total of 291 kWh × $0.05/kWh = $14.55. Thus, a customer's total bill under the buy-all sell-all metering practice would be $42.11.

7. In contrast, under the **net billing and net metering practices**, a customer is allowed to offset their consumption with energy produced on-site and the customer only buys their net requirements from the grid. Most often these practices are driven by the location of the meter. Physically offsetting flows of energy behind the customer meter prevents the grid from seeing the total energy consumed by the customer, i.e., masking 2.5 kWh of load every day. Referring to the above figure, and assuming a 30-day month, under those two metering approaches:

- The grid only sees (4.8 kWh/day × 30 days =) 144 kWh purchased from it.
- The grid only sees (7.2 kWh sold × 30 days =) 216 kWh sold to it.

508 These hypothetical rates were obtained by averaging the discrete elements of ATCO Electric's D31, ENMAX's D300, EPCOR's medium commercial rate, and Fortis's Rate 61. While such an averaging does not constitute a representative rate for a typical residential customer in Alberta, it provides a useful illustration of the concepts discussed in this report.

509 For simplicity, it is assumed that the customer gets credited at the wholesale market rate in all scenarios. As explained in Section 4.4.2, small micro-generation customers would get credited at their retail rate under the net billing arrangement.

8. The offsetting of consumption with energy produced on-site has the financial benefit of the avoided cost of purchasing energy, in this case, $0.14/kWh. This value represents the retail price of energy as well as volumetric components of the tariff.

9. As noted in Section 3.3.2, under the net metering practice, energy is sold to the grid at $0.14/kWh, which represents the sum of the retail rate for electricity and all of the utility's volumetric charges. Under the net billing practice, energy is sold to the grid at $0.05/kWh, that is, the price of electricity alone. Table 9 below presents the calculation of a customer's bill under the net billing and net metering approaches.

Table 9. Comparison between net billing and net metering

Charges under net billing		**Charges under net metering**	
Billing determinants seen by utility:	30 days	Billing determinants:	30 days
	144 kWh bought		144 kWh bought
	216 kWh sold		216 kWh sold
Fixed charges	$26.00	Fixed charge	$26.00
Energy charges ($0.14/kWh)	$15.96	Energy charges ($0.14/kWh)	$15.96
Credit for sold energy ($0.05/kWh)*	($10.80)	Credit for sold energy ($0.14/kWh)	($30.24)
Extra value not metered		**Extra value not metered**	
75 kWh not metered @ $0.14/kWh avoided cost	$10.50	75 kWh not metered @ $0.14/kWh avoided cost	$10.50
Total bill (charges + credit)	**$31.16**	**Total customer bill (charges + credit)**	**$11.72**
Total value to customer of DER (avoided cost + credit)	$21.30	Total value to customer of DER (avoided cost + credit)	$40.74

*Note that the above table and calculations presume a wholesale-price credit of $0.05/kWh for energy sold, and not the $0.07/kWh retail rate for energy, as used for compensating small micro-generation.

10. Table 10 below summarizes the customer's bill under all three metering practices. It should be noted that this comparison only focuses on the effect on the customer's bill and omits an important parameter – the cost of the installed DER. Thus, it cannot be viewed as an indicator of the total value proposition of DERs.

Table 10. Summary of total bill for three metering practices

	Buy-all sell-all	**Net billing**	**Net metering**
Charges for energy drawn from the grid	$56.66	$41.96	$41.96
Credits received for energy supplied to the grid	($14.55)	($10.80)	($30.24)
Value of energy self-consumed	$0	$10.50	$10.50
Total bill	$42.11	$31.16	$11.72
Total benefit of DER	$14.55	$21.30	$40.74

Appendix 5 – Case study: Brooklyn Queens Demand Management Program[510]

(return to text)

1. Consolidated Edison (ConEd) originally proposed constructing a new distribution substation, expanding an existing 345-kV switching station and constructing a sub-transmission feeder to mitigate reliability concerns resulting from rising electricity demand in Brooklyn and Queens. The estimated cost of this solution was $1 billion USD. The New York Public Service Commission (PSC) directed ConEd to look at non-traditional investments to manage demand growth and offered innovative incentives to adopt these alternatives. ConEd proposed to reduce demand by 69 MW through the combined use of DERs (as NWAs) and traditional solutions. This included:

- 41 MW of customer-side electricity demand reduction solutions (such as energy efficiency, DCG and energy storage).
- 11 MW of non-traditional utility-side electricity demand reduction solutions (energy storage and conservation voltage optimization).
- 17 MW of traditional capacitor and load transfer solutions.

2. This revised solution was expected to defer the need for traditional infrastructure investment for at least seven years. In 2014, the PSC approved this plan on a $200 million budget for the combined demand reduction solutions (customer-side and utility-side), plus $305 million for the traditional solutions. In 2017, the PSC extended the Brooklyn Queens Demand Management Program (BQDM program) beyond the initial three-year scope with no termination date and without additional funding. As of ConEd's Q2 2020 project update, $116.64 million of the $200 million budgeted for demand-side reductions has been spent ($93.45 million on the customer side and $23.2 million on the utility side). Through these expenditures, ConEd reported achieving over 58 MW of peak hour load relief (40 MW via customer-side load relief and 18 MW via utility-side).

3. The customer-side load relief was achieved through providing customer incentives to install, or directly installing, energy efficiency measures and upgrades in the residential, multi-family, commercial and public building sectors. It also included customer programs to install DERs (such as fuel cells, combined heat and power facilities, and energy storage) to contribute toward the program's load relief goals.

4. By implementing the BQDM program, ConEd was unable to put into rate base the majority of the originally proposed $1 billion. This means that ConEd stood to earn less return because of the BQDM program. To compensate for this, the PSC approved innovative incentives for ConEd to adopt these alternatives. This included:

- Earning an authorized rate of return on BQDM program costs.

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510 Exhibit 24116-X0159, Energy Storage Canada Module One submission, paragraph 40; Exhibit 24116-X0634, CGWG Combined Module response submission, PDF page 12; UtilityDive, BQDM program demonstrates benefits of non-traditional utility investments, March 11, 2019, accessed at: https://www.utilitydive.com/news/bqdm-program-demonstrates-benefits-of-non-traditional-utility-investments/550110/; ConEd BQDM Q2 2020 Expenditures and Program Report, accessed at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800

- The potential to receive up to 100 basis points in performance incentives above its authorized rate of return on BQDM program investments: 45 basis points tied to achieving the proposed 41 MW demand reduction with alternative measures; 25 basis points tied to increasing diversity of DERs in the marketplace; and 30 basis points tied to achieving a lower $/MW value than traditional investments.
- Customer-savings sharing mechanism. ConEdison proposed an additional savings sharing mechanism that was rejected, in which it would receive 50 per cent of the annual net savings, as calculated as the difference between the annual carrying cost of the original $1 billion traditional investment package and the total annual collections for the BQDM program. ConEd revised the proposal, which was subsequently approved, for future NWA projects (including in the extension to the BQDM program), allowing the utility to receive 30 per cent of the annual net benefits.
- Accelerated depreciation (10 years) for investments under the BQDM program compared with traditional capital investments, thereby increasing their working capital.

5. This project is ongoing and ConEd continues to provide quarterly updates on the BQDM program to the PSC.

Appendix 6 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
AddÉnergie Technologies Inc.
Alberta Electric System Operator (AESO)
Alberta Federation of Rural Electrification Association (AFREA) Hawk's Aerial & Technical Solutions Inc Russ Bell & Associates Inc.
Alberta Direct Connect Consumers Association (ADC)
Alberta Energy Efficiency Alliance
Alberta Innovates
Alberta Irrigation Districts Association Alberta Sugar Beet Growers Potato Growers of Alberta
Alberta Utility Billing Inc
Alliance for Transportation Electrification
Allied Community of Renewable Energy Interests (ACREI) 3B Energy Action Surface Rights Association Alberta Surface Rights Federation Coreman Consulting Inc. County of Taber Determination Drilling Elemental Energy Inc. Iron and Earth My Landman Group, Inc. Orphan Well Association SkyFire Energy Inc. Southern Alberta Investment Co-op for Renewable Energy St. Mary's Irrigation District
AltaLink Management Ltd. (AltaLink)
Apex Utilities Inc.
ATCO group of companies (ATCO) ATCO Electric Ltd. ATCO Gas The Brattle Group Inc.
Aura Power Renewables Ltd.
Calgary Micro Generators
Canada West Ski Areas Association (CWSAA)
Canadian Geothermal Energy Association
Capital Power Corporation (Capital Power)
Towns of Cardston and Ponoka
ChargePoint Inc.
City of Edmonton
City of Medicine Hat
Community Generation Working Group (CGWG) Alberta Co-operative Energy Canadian Solar Industries Association (CanSia) Enerstrat Canada Inc. First Nations Power Group Peters Energy Solutions Inc. Power Advisory LLC
Consumers' Coalition of Alberta (CCA) Charles River Associates (CRA)
Direct Energy Marketing Limited
Dual Use Customers

Name of organization (abbreviation) Company name of counsel or representative
Edmonton Public School Board
Enel X
Energy Efficiency Alberta
Energy Storage Canada DePal Consulting Oilen Consulting Power Advisory LLC
Enernoc Ltd.
ENMAX Power Corporation (ENMAX or EPC)
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI)
EQUS REA LTD. (EQUS) ReWatt Power Inc.
Federation of Alberta Gas Co-ops Ltd.
FortisAlberta Inc. (Fortis) Energy and Environmental Economics, Inc. (E3)
Greenlots
Heartland Generation Ltd. Tom Rose Consulting
Industrial Power Consumers Association of Alberta (IPCAA)
Kalina Distributed Power (Kalina)
Larry Gibson
Lionstooth Energy (Lionstooth)
Market Surveillance Administrator (MSA)
NPS Industrial Power
Office of the Utilities Consumer Advocate (UCA) InterGroup Consultants Ltd.
Pembina Institute for Appropriate Development (Pembina) Big Spruce Law Dr. Josh Keeling / Caedo Group LLC Rocky Mountain Institute (RMI)
QUEST Canada (QUEST)
Rick Cowburn
The Canadian Western District of the Christian and Missionary Alliance
The City of Calgary (Calgary)
TransAlta Corporation (TransAlta)

Alberta Utilities Commission

Commission panel
B. Romaniuk, Acting Commission Member

Commission technical expert
Dr. F. Wolak
Director, Program on Energy and Sustainable Development
Co-Director, Stanford Natural Gas Initiative
Holbrook Working Professor of Commodity Price Studies
Department of Economics
Stanford University

Commission staff
D. Reese (Commission counsel)
R. Lucas
O. Vasetsky
A. Ayri
G. Bourque
C. Fuchshuber