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Energy and Environmental Economics, Inc.
(E3)

On behalf of
FortisAlberta

March 2020

Energy+Environmental Economics

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Alberta Utilities Commission

Distribution Inquiry
Proceeding Number 24116

<u>Evidence of Energy and Environmental Economics, Inc. (E3)</u>

1 Introduction

Q1. **PLEASE STATE YOUR NAME, TITLE, AND BUSINESS AFFILIATION.**

A1. My name is Ren Orans. I am the Managing Partner of Energy and Environmental Economics, Inc. (E3), located at 44 Montgomery Street, Suite 1500, San Francisco, California 94104, USA.

Q2. **PLEASE STATE YOUR QUALIFICATIONS AND EXPERIENCE.**

A2. With over 30 years of experience in the electric utility business, I have worked extensively in transmission planning and pricing, integrated resource planning, and wholesale and retail ratemaking. Prior to forming E3 in 1989, I worked at Pacific Gas and Electric Company, which was at the time the largest electric utility in North America, where I was responsible for electric rate design. I received my Ph.D. in Civil Engineering from Stanford University and my B.A. in Economics from U.C. Berkeley. I have more than 25 publications in refereed journals detailed in my attached C.V. My PhD dissertation was on marginal costs in electric distribution and transmission systems and I have worked extensively on the impact of using area and time specific estimates of costs and rates on both planning and investments in DERs.

Q3. **HAVE YOU PREVIOUSLY TESTIFIED ON MATTERS RELATED TO DISTRIBUTION SYSTEM COSTS OR RATE DESIGN IN FRONT OF THE AUC?**

A3. No, I have not.

Q4. **HAVE YOU PREVIOUSLY TESTIFIED ON MATTERS RELATED TO DISTRIBUTION SYSTEM COSTS OR RATE DESIGN IN OTHER JURISDICTIONS?**

A4. I have testified on these matters in front of state or provincial public service commissions in California, Hawaii, Wyoming, Texas, British Columbia, and Ontario.

Q5. **DO YOU HAVE OTHER RELEVANT RATE DESIGN EXPERIENCE?**

A5. I have extensive experience in both wholesale and retail electric ratemaking. While working at Pacific Gas and Electric Company, I had responsibility for retail rate design. As a consultant, I have also worked extensively on the rates of many utilities including both Ontario Power Generation and BC Hydro. My wholesale rate design experience focuses on transmission ratemaking and I was the primary rate design witness in the seminal cases approving the use of open access transmission tariffs in British Columbia, Ontario and Quebec. In each case, the proposed market structures and tariffs were approved by the regulator and by FERC.

2 Overview of Testimony

Q6. **WHAT IS THE SCOPE OF YOUR TESTIMONY?**

A6. The scope of my testimony on behalf of FortisAlberta is to provide a viable roadmap to facilitate the integration of distributed energy resources (DERs) into Alberta and its distribution utilities. The testimony has the following structure:

- In Section 3, I provide the North American context for the growth of DERs as a result of emerging technologies, improved economics, customer choice, and government policy.
- In Section 4, I outline the anatomy of the roadmap, describing the developments that would trigger a distribution utility to evolve from offering its current set of bundled functions to the unbundling of the services necessary for efficient deployment of DERs and the conditions that are required to enable evolution.
- In Section 5, I describe how the functions that distribution utilities perform will evolve with an increase in DERs on the network. I also describe a plausible range of distribution system models/structures that could be deployed to integrate these functions into efficient and well functioning distribution systems.
- In Section 6, I describe the evolutionary process and state of other jurisdictions that are undergoing transformation due to increased DER penetration.
- In Section 7, I distinguish between economic and uneconomic distribution bypass and provide an example rate design structure that

generates efficient levels of DER adoption in any of the distribution systems described earlier.

- Finally, in Section 8, I conclude with a description of common steps that utilities and regulators can take today, regardless of the ultimate end state of the distribution system. I also comment on their relevance to energy markets in Alberta.

3 Context of the Case

Q7. **PLEASE PROVIIDE YOUR DEFINITION OF DERS IN THE CONTEXT OF THIS TESTIMONY.**

A7. In the context of this proceeding I define DERs as any technology that is connected to the distribution grid and affects the supply and/or demand of electricity. At present, DERs generally fit into the following categories:

- Supply side – Technologies that generate electricity and supply it to distribution customers including behind the meter (BTM) generation and distribution connected generation.
- Demand side – Technologies that allow for load shedding and load shifting including electric vehicles or smart hot water heaters.
- Storage – Technologies that allow energy to be stored and used at a later time, for example batteries.

However, 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 and operate like energy storage.

Q8. **CAN YOU BRIEFLY DESCRIBE THE EVOLUTION THAT IS TAKING PLACE IN NORTH AMERICA WITH RESPECT TO DERS?**

A8. At a high level, the costs of DERs have been declining much faster than either total average electricity rates or the costs to build, transport and distribute power from an integrated generation, transmission and disturbed system. If they are used properly, utilities and customers can take advantage of DERs to reduce overall system cost. This value is available from a number of different streams including:

- Provision of energy
- Provision of capacity
- Reliability services
- Avoiding or deferring transmission and/or distribution costs (non-wires alternatives)
- Environmental benefits including reduced local air pollution and reduced carbon emissions.

Over the past decade in particular, the cost of DERs has decreased significantly, which has led to their adoption by consumers in jurisdictions across North America. Figure 1 shows the significant growth in distribution-connected PV installations in the US, indicating how distributed solar is rapidly becoming a valuable resource for electricity consumers. The combination of decreasing costs of solar panels combined with favorable tax incentives and non-cost based rate structures have all contributed to this rapid growth with a large portion of the value attributable to the implicit subsidies in existing rates.

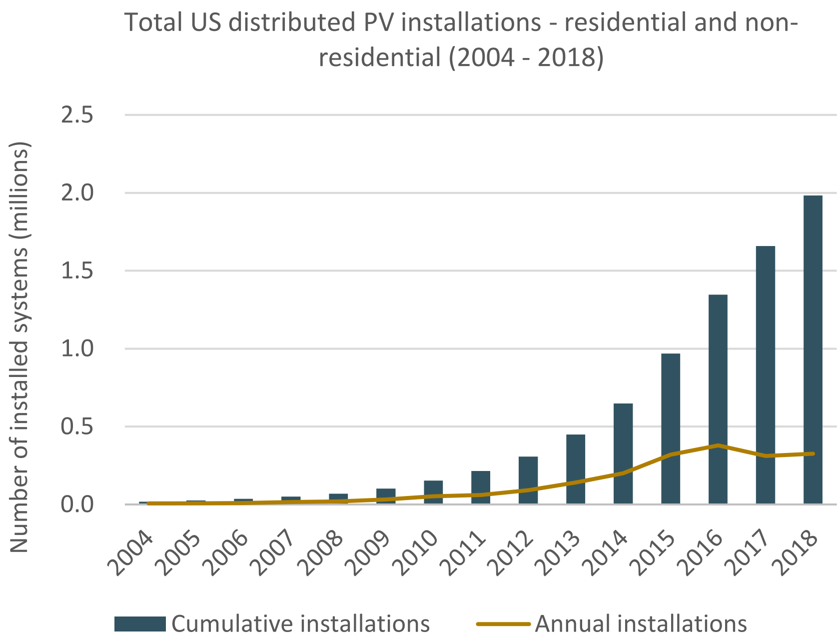

Figure 1. Number of US distributed PV installations from 2004 - 2018 (residential and non-residential). ***Source: LBNL (2019). Tracking the Sun. Pricing and Design Trends for Distributed Photovoltaic Systems in the United States.***

In line with the decrease in solar PV costs, other technologies, like energy storage, are forecast to decline in cost in the coming years, as shown in Figure 2. This cost decrease will make technologies more competitive in more applications, including behind-the-meter (BTM) storage, leading to higher DER adoption levels. Also, because the storage technologies are dispatchable they are particularly well suited to offset demand charges.

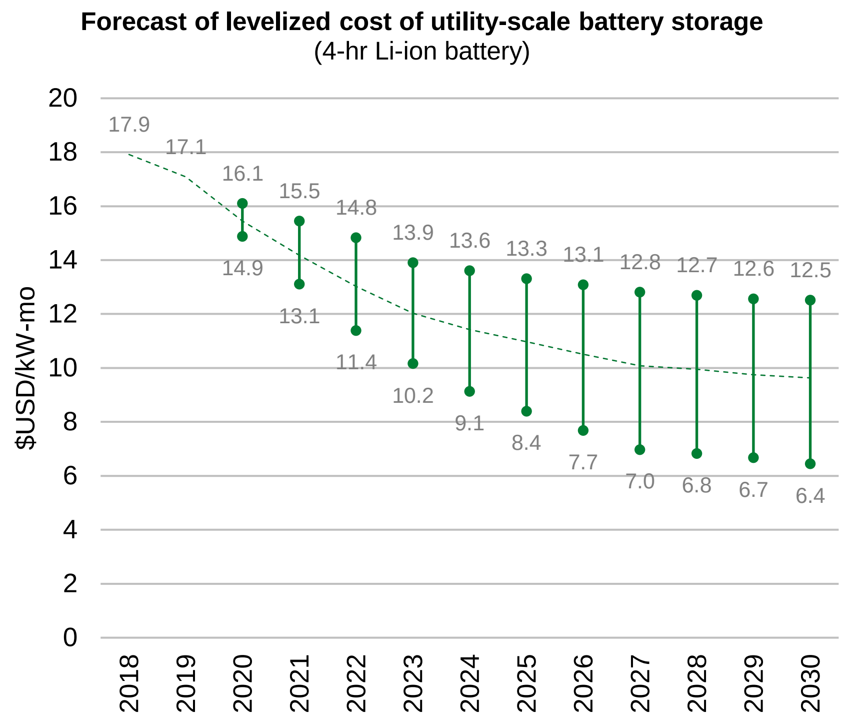

Figure 2. Forecast of utility-scale storage costs. ***Based on Lazard (2019) and E3 projections.***

In some jurisdictions, the adoption of DERs has created challenges for the existing distribution utilities and their consumers. These challenges are described in greater detail in the Jurisdictional Comparison in Section 6.

Q9. **DOES THE COMMISSION HAVE A VIEW AS TO HOW DERS WILL AFFECT THE ALBERTA MARKET?**

A9. Yes. The technological focus of Module One was designed to investigate the impacts of technologies that are currently commercial as well as technologies that are emerging in the Alberta marketplace. Through this process, the commission was able to come to conclusions that it noted in its November 12, 2019 letter[1]:

[1] AUC Letter – Scope and Process for Modules Two and Three – Filing 24116_X0439 – Para. 2

> *Based on the Module One submissions and a technical conference, the Commission concludes that emerging technologies and innovations are creating opportunities for, and challenges, with respect to:*
>
> *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 distribution facility owners 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 competitive markets).*

Q10. **DO YOU AGREE WITH THIS VIEW?**

A10. Yes, I agree that the increasing value of DERs will result in opportunities and challenges for consumers and the distribution system. Specifically:

- Consumers will have increasing choice in all aspects of their electricity consumption.
- More detailed information on consumption and supply will open new markets for different services and providers.
- Falling costs of DERs will lower economic hurdles to adoption for self supply, distribution-connected generation and demand-side management.
- The adoption of these technologies, combined with access to information and increased market participation, could result in a transition from natural monopolies to competitive markets for certain segments of today's distribution system, along with the formation of new markets.

Q11. **HOW WILL THESE DEVELOPING TRENDS AFFECT EXISTING DISTRIBUTION UTILITIES IN ALBERTA?**

A11. Some distribution utilities in Alberta are already experiencing a growth of DER connection requests, for instance for utility-scale solar. In addition, new technologies will enable customers to have more flexible electric demands that may provide benefits under the right regulatory structure. However, under the existing market and rate structures, the adoption of DERs could in some cases result in the uneconomic bypass of embedded system costs. Furthermore, the different operational characteristics of DERs, when compared with legacy technologies, could result in potential system reliability risks. With the growth of DERs already taking place in Alberta, I recommend taking immediate steps to address existing issues and to establish a pathway for the efficient adoption and use of DERs that provide value to all electricity consumers.

Q12. **PLEASE DEFINE UNECONOMIC BYPASS.**

A12. Uneconomic bypass describes when a customer bypasses the existing network, resulting in a cost shift to other customers. This is distinguished from *economic* bypass, which results in *reduced* costs for other customers.

Q13. **WHY WOULD UNECONOMIC BYPASS RESULT FROM DERS?**

A13. Current distribution tariff structures in Alberta allocate a number of fixed costs to customers either volumetrically (on a $/kWh basis) or as a function of peak demand ($/kW)[2]. These price signals, which are based on a historical balancing of rate

[2] A more detailed description of rates is included in Q&A51.

design goals, tend to be greater than the marginal costs of distribution service and can improperly incent the installation of DERs. As a result, some DERs will enable customers to underpay for the fixed costs of the network, shifting costs to other customers (an example of uneconomic bypass). This is a common result of DER adoption under traditional rate structures throughout North America and occurs even in DER leading jurisdictions like Hawaii, as described in the Jurisdictional Comparison in Section 6.

Once uneconomic bypass occurs, customers have made long term economic investments that have proven to be difficult to rectify. In order to prevent uneconomic bypass, proper price signals and rate structures must be in place prior to large numbers of customers making significant investments in DERs.

Q14. **ARE THERE ANY KEY PRINCIPLES THAT YOU RECOMMEND THE COMMISSION USE AS GUIDELINES IN CONSIDERING POTENTIAL CHANGES TO THE DISTRIBUTION SYSTEM?**

A14. Yes. This testimony was prepared with the following four guiding principles in mind for a future distribution system vision:

1) Maximize value/benefits and minimize costs of DERs at the distribution and transmission levels.

2) Ensure fair and equitable access to the distribution and transmission systems.

3) Maintain reliability and power quality of the distribution and transmission systems.

4) Maintain affordable access to the distribution and transmission systems.

4 DER Roadmap

Q15. **WHAT IS THE BEST PATH FORWARD FOR ALBERTA GIVEN BOTH YOUR RECOMMENDED PRINCIPLES AND THE MARKET CHANGES YOU DESCRIBE?**

A15. The Commission concluded that emerging technologies are creating opportunities and challenges with respect to customer choice and the improving economics of DERs. Although some developments regarding DER growth are taking shape in Alberta, there is little certainty around which specific technologies will be adopted on a large scale and the market changes they will drive. Further complicating the transition is the lack of certainty around timing. Alberta's adoption of DERs will depend on a number of factors including the costs of DERs, the wholesale price of power, consumer preferences and government policy. Instead of attempting to forecast which technologies will be adopted and when, a more prudent approach would be to identify the signals that indicate that predetermined threshold levels of market changes have occurred and the associated actions that need to take place to support these changes. This approach provides a gradual and natural evolution in both the structural and rate design changes needed. To this end, I recommend the use of a clearly defined *roadmap* that identifies and tracks a number of key metrics to help guide the efficient integration of DERs in Alberta.

Q16. **DOES A ROADMAP SPECIFY AN OUTCOME?**

A16. No. There are many different forms that the distribution system of the future might take, and the road to each is most likely different for each distribution utility in

Alberta. In New York for example, Consolidated Edison is much closer to forming a Distribution System Operator (DSO) than Central Hudson, who is not seeing the value proposition today of forming competitive markets to compensate DERs. In addition, the final distribution model and rate design structure adopted by each utility may be different, and utilities will likely progress down the roadmap at different speeds depending on the rate and type of DER adoption experienced in their service territory. The inherent flexibility of the roadmap allows for regulators, Distribution Facility Owners (DFOs) and market participants to collectively agree on the key metrics and appropriate responses prior to any specific application which would ultimately incorporate the unique realities of DER adoption in each jurisdiction while at the same time providing the certainty required for investment.

Q17. **WHAT IS THE COST OF BEING EARLY OR LATE IN ADOPTING NEW MARKET AND RATE STRUCTURES?**

A17. The costs of being both early or late can be quite large. For example, no jurisdiction in North America has yet to adopt an unbundled cost of service model at the distribution level, let alone separating DER operation from ownership through ringfencing or by forming separate companies. The ideas are quickly evolving in proceedings like this one, but there is no consensus on structures, communications technologies or even the business models and privacy issues tied to releasing customer usage and billing data to third parties. Conversely, although the incentives in Alberta to adopt DERs are lower than in many other jurisdictions, customers will continue to gradually interconnect more resources and dispatchable forms of loads like electric vehicles to the distribution system. Both the adoption levels of DERs as well as estimates of the costs shifted through uneconomic bypass should be tracked by utilities and monitored by regulators as part of implementing a prudent but efficient evolution strategy.

Q18. **PLEASE DESCRIBE YOUR CONCEPT OF A ROADMAP.**

A18. In the context of this preceding, a roadmap is a guiding framework that allows all market participants to generally understand how the distribution system might evolve and what events would trigger evolutionary steps, without taking a position on which technologies will be adopted and when.

Each distribution utility performs several functions as part of its business model. The adoption and integration of DERs will require distribution utilities to evolve some of their existing functions and to perform new ones. Each stage of evolution along the roadmap signifies a change to the functions performed by the utility. These functions are discussed further in Section 5.

In order to guide the evolution of each utility's functions, the roadmap has two key components.

- Triggers – events that will require some level of change in the distribution system model in order to avoid negative consequences.
- Enabling Conditions – conditions that must be in place in order to for the distribution system to successfully evolve and to avert the negative consequences.

All market participants will be able to monitor the triggers that are proposed in this roadmap. If a critical mass of triggers is met, the distribution utility and its stakeholders will then need to enact any enabling conditions to allow for the evolution of the utility and the successful integration of DERs.

Q19. **WHAT ARE THE TRIGGERS THAT MARKET PARTICIPANTS SHOULD BE MONITORING?**

A19. The triggers that should be monitored can be broken down into three categories:

- Technology: The type of DER technologies that are being adopted and their level of adoption in the distribution utility.
- Regulatory: Changes associated with government policy, jurisdictions, and public interest.
- Market: Changes in markets including new markets, market participation, and risk allocation.

As DERs are adopted within each distribution utility, the sequencing of triggers that are met will be different based on the types of technologies adopted and the functions they provide.

A detailed list of triggers and their definitions is given in Table 1 below.

Category	Trigger	Definition
Technology	**Low DER Penetration**	Penetration of DERs remains low and limited to specific locations. Value (and cost) to the system/ratepayers is small.
	Medium DER Penetration	Increasing penetration of DERs across wide areas. Value of DER market is increasing at distribution and/or wholesale level.
	High DER Penetration	High penetration of a diverse range of DERs. Value of DER market is high at distribution and/or wholesale level.

Regulatory	**Jurisdictional Issues**	Elements of utility and/or DER operations may cross jurisdictional boundaries. Under some structures there are boundary issues between the TSO and DSO.
	Fairness/Transparency Concerns	This is a balancing act. Participating customers will want to stack value across the distribution and wholesale levels as quickly as possible, which can lead to double counting of benefits. Non-participating customers want to avoid cost shifting through efficient rate designs, making uneconomic bypass a key metric for utilities and regulators to track.
	Policy Changes	Policy changes are enacted, leading to regulatory/policy pressure to expand DER markets.
Market	**DER Ownership/ Control Issues**	Concerns arise around fairness and transparency of processes for DER ownership, control, or procurement.
	Data Ownership/ Control Issues	Customers don’t have access to their own data, third parties may be unable to compete without data access.
	Business Risks Arise	Aspects of DER ownership and market operation present risk to the utility, e.g. cost recovery, ratepayer impacts, etc.

Table 1: List of triggers and their definitions.

Q20. **WHAT ARE THE ENABLING CONDITIONS REQUIRED TO SUPPORT THE EVOLUTION OF THE DISTRIBUTION UTILITY?**

A20. Similar to the triggers listed above, the enabling conditions can be broken down into four categories:

- Technology: Technologies required to support system operations are in place.
- Regulatory: Successful approval and resolution of triggers requiring government or regulatory input.

- Financial: New distribution rate design is implemented; interaction of wholesale and retail markets is supported.
- Operational: Standards for planning, interconnection, measurement and verification are created.

These enabling conditions ensure that changes to distribution utility business models will be successful in dealing with the challenges caused by the triggering event(s). As I propose at the end of my testimony, utilities and regulators should address some of these enabling conditions before the corresponding triggers are met. Otherwise, these conditions will need to be addressed once the corresponding triggers are met.

A specific list of enabling conditions and their definitions is found in Table 2.

Category	Enabling condition	Definition
Technology	**Technology availability**	The necessary technology is in place to allow for the level of DER control required in this model (e.g., DER Management System, advanced network management, centralized communication network, etc.)
Regulatory	**Resolution of jurisdictional issues**	Questions around regulatory jurisdiction of distribution system assets are resolved.
	Incorporate DERs in system planning	Integrated system planning practices, with consideration of the multi-directional flow of energy that DERs bring and the value that DERs provide, are in place.

Financial	**Customer engagement**	Customers are engaged in DER uptake commensurate with the value of DERs. Customers show willingness to participate in new markets with new technologies.
	Cost recovery and incentives	Regulators provide cost recovery, and potentially incentives, to utilities for programs and technologies related to new distribution system models.
	Wholesale and distribution market prioritization hierarchy	Utilities and regulators create a prioritization hierarchy for distribution level and wholesale level programs and markets, to ensure dispatch signals do not conflict.
Operational	**Planning, interconnection, and operational standards**	Set of standards for planning, interconnection, and operations of the distribution system for higher penetrations of DER is in place. Where necessary, alignment with regional government is incorporated.
	Measurement and verification standards	Set of standards for DER measurement and verification for settlement and billing is in place. Where necessary, alignment with regulators is incorporated (where DER settlement is provided for both wholesale and distribution system).

Table 2: List of enabling conditions and their definitions.

Q21. **HOW DOES EACH DISTRIBUTION UTILITY PROGRESS DOWN THE ROADMAP?**

A21. The roadmap framework allows for utilities to understand how the integration of DERs may lead to evolution of the distribution system, while at the same time providing for the flexibility required to react to the specific changes that manifest. To progress down the roadmap, each distribution utility in Alberta would begin by setting up the ability to monitor for each of the triggers that are described in Q&A19. From that point, the utility will be able to adapt to triggers and provide required functions as they are needed. Each iteration consists of three steps.

Step 1 – Track and Report on Triggers

I recommend that all distribution utilities track and report key metrics on triggers that would be accessible to both regulators and key stakeholders. It is possible that individual triggers could be met without the need for changes to the utility's functions because the existing functions can already manage the implications of the trigger. However, if one or more triggers cause the need for changes or additions to the utility's functions, then the utility would progress to understanding the enabling conditions required to evolve.

Step 2 – Enabling Conditions

The enabling conditions required in each evolutionary step will be dependent on the triggers that have been met and the functions that need to be modified or added. Using the enabling conditions from Q&A20, the utility and its regulators will ensure that all appropriate changes have been made.

Step 3 – Iterate

Once the enabling conditions have been satisfied and the new and modified functions/rate designs are in place, the utility will again begin monitoring for further triggers to be met and the gradual system evolution will progress at a speed that is consistent with the progression of the market conditions and the value proposition posed by each step along the restructuring and ratemaking roadmap.

Q22. **HOW WILL THE FINAL STRUCTURE OF EACH UTILITY BE DETERMINED?**

A22. Each utility has a number of functions that they currently perform and their business model is comprised of how they execute these functions. The integration of DERs into distribution utilities will drive some of these functions to evolve as well as new functions to be created. Which of these functions manifest, and the way that they are organized, will inform the business model of the distribution system of the future.

Q23. **WILL UTILITIES PROGRESS DOWN THE ROADMAP AT THE SAME RATE?**

A23. No. The rate of progression will be determined by how rapidly the triggers manifest for each utility. Today, for example, some utilities have negligible DER adoption in their service territory while others may already be experiencing a level of DER adoption that already requires investments to maintain reliability. The second utility in this example should already be considering the enabling conditions necessary to progress down the roadmap.

5 Distribution System of the Future: Functions and Models

Q24. **WILL THE FUNCTIONS OF THE DISTRIBUTION SYSTEM BE DIFFERENT IN THE FUTURE?**

A24. Yes. Among the existing functions performed by distribution utilities today, some are likely to change and others will remain fundamentally the same. In addition, entirely new functions will arise.

Q25. **WHY WILL THE FUNCTIONS OF DISTRIBUTION SYSTEM CHANGE?**

A25. As DER costs continue to fall and new technologies become available, customers will increasingly interconnect these technologies on the distribution system. Some changes to system functions will enable DERs to provide more value to the system, i.e. to minimize total system costs. Other changes may be needed to provide fair access to the system. Finally, some changes may be needed in order to ensure reliability as DER penetration grows.

Q26. **PLEASE OUTLINE THE FUNCTIONS OF UTILITIES TODAY AND IN THE FUTURE.**

A26. Figure 3 provides a simplified description of key existing, evolving and new functions that are likely to become necessary as DERs become more integrated in Alberta (regardless of who is responsible for those functions).

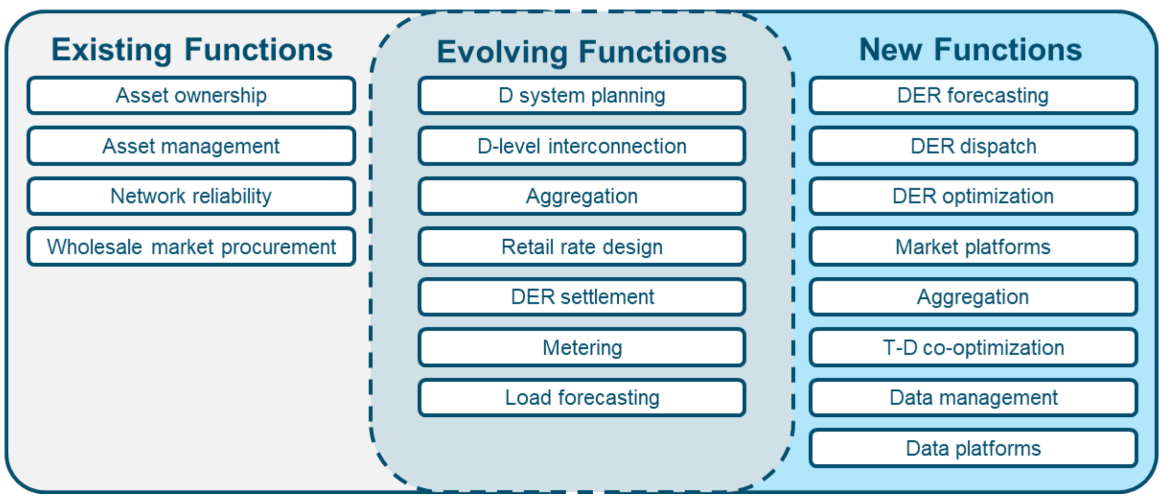

Figure 3: Functions of future distribution systems, detailing existing functions, evolving functions, and new functions.

Q27. **PLEASE DESCRIBE THE FUNCTIONS THAT ARE LIKELY TO REMAIN UNCHANGED.**

A27. Functions that are likely to remain unchanged as DERs grow are described in Table 3:

Function	Description
Distribution asset ownership	Procurement, construction, and ownership of traditional distribution assets, including meters, wires, and substations.
Distribution asset management	Operation and management of traditional distribution assets described above.
Network reliability	Services to provide system reliability and power quality, such as fault management and system restoration and voltage and reactive power control.
Wholesale market procurement	Using load forecasts and real-time information to procure energy in wholesale markets.

Table 3: List of existing distribution system functions and their definitions.

Q28. **PLEASE DESCRIBE THE EVOLVING FUNCTIONS AND HOW THEY MAY CHANGE OVER TIME.**

A28. A number of existing functions will evolve over time as DER adoption increases. It is not possible to predict the timing or the order of these changes, as changes will occur based on the adoption of different DER technologies along with developing system and customer needs. Table 4 defines the different functions and gives a description of how the changes associated with these functions could manifest.

Function	Description
Distribution system planning	In order to meet capacity or reliability needs, system planning will balance traditional “wires” solutions with DER-based “non-wires alternatives.”
Distribution-level interconnection	To support connection requests, clear rules and protocols for interconnection will be developed and utilities will publish hosting capacity maps to communicate key information to customers.

Aggregation	In today's distribution systems, DER aggregation is done passively by DFOs, which then report net loads to the TSO. In future systems, aggregation will be an active function to provide specific services at both the bulk power and distribution levels.
Retail Rate Design	Rate design will change to provide multi-part tariffs capable of collecting fixed costs over the long-lived grid assets as well as short-term and efficient price signals suitable for DER dispatch and compensation.
DER settlement	Today, DERs are effectively settled by modifying net load, which subsequently informs wholesale market prices. DER settlement will evolve as DERs begin to participate directly in markets or to participate via aggregators.
Metering	In order to provide better price signals and increase the value of DERs, the penetration of advanced metering infrastructure (AMI) will likely grow along with corresponding services to manage the additional data generated by AMI.
Load forecasting	Distribution-level load forecasting will separate out gross loads from DER services to better inform DER investment and dispatch.

Table 4: List of evolving distribution system functions and their definitions.

Q29. **PLEASE DESCRIBE POSSIBLE NEW FUNCTIONS AND HOW THEY MIGHT BE REALIZED.**

A29. Similar to the evolving functions, it is not possible to predict the timing or order in which new functions will be required. It is however possible to give a general overview of functions that are likely to arise as DER adoption grows. The following Table 5 describes these possible new functions.

Function	Description
DER forecasting	DER forecasting will become an increasingly important part of distribution system operations. Some DERs can modify demand, including battery storage, demand response, and flexible loads. These resources can provide reliability and/or capacity services, but optimal dispatch will be contingent on the availability of forecasts for both load and distributed generation.

DER dispatch	DER resources will not be treated as "must-take." Instead, they will be dispatched subject to market bids and/or optimization processes that could exist at the bulk power level (TSO) or at the distribution level (DSO)
DER optimization	Some DERs provide demand services, as described above. These DERs can be dispatched subject to optimization processes. In addition, the optimization processes may indicate the need to curtail some DERs for reliability purposes.
Market platforms	Distribution-level markets for a number of different services will be needed in order for DERs to provide their full value. These services may include energy, capacity, regulation, and others. These markets may be locational.
Aggregation	An aggregator may pool many DERs in order to bid for a single service. Aggregation will benefit customers who do not want to schedule or bid their own DERs. In addition, groups of DERs may be able to provide services that individual DERs cannot, for example by combining solar and storage resources to provide some degree of firm capacity.
Transmission-Distribution co-optimization	To reduce system costs, system assets may be co-optimized across the Transmission-Distribution interface.
Data management	Distribution systems will generate large amounts of data including historical loads, historical DER operations, DER forecasts, load forecasts, and market prices. Questions will arise regarding who owns this data and who should be able to access it. New policies on data access will be necessary in order to ensure that parties can only access the data they are privileged to, thus maintaining customer privacy.
Information platform	Data access will be key to participating in DER markets. Utilities will need to provide system-level data to all market participants. In addition, customers and DER owners will need the ability to share their data with parties of their choosing, for example in order to sign up with an aggregator. An information platform will be required to facilitate this data sharing.

Table 5: List of new distribution system functions and their definitions.

Q30. **IN TODAY'S SYSTEM, WHAT PARTIES ARE RESPONSIBLE FOR DIFFERENT DISTRIBUTION SYSTEM FUNCTIONS?**

A30. In today's system in Alberta, the DFO, i.e.: the distribution utility, is responsible for most of the existing and evolving functions, with Competitive Retailers (CRs) responsible for some customer-facing functions like retail rate design. With the evolution of many existing distribution functions and the rise of new functions related to DERs, the appropriate integration of newer distribution functions into either the utility or a separate independent entity can be determined using the evolutionary process described earlier.

Q31. **HOW IS THE DISTRIBUTION SYSTEM MODEL CURRENTLY STRUCTURED IN ALBERTA?**

A31. In Alberta, DFOs (including FortisAlberta) are responsible for most distribution system functions. These functions include asset management and distribution reliability as well as functions related to network planning and interconnection. In today's system, the operation of DERs is not coordinated by any entity. The Transmission System Operator (TSO) has access to some data, including real-time generation data from large Distribution-Connected Generation (DCG) and net loads from the DFOs. However, no entity is responsible for optimizing dispatch of DERs or for coordinating participation in existing wholesale markets. The current system is illustrated in Figure 4.

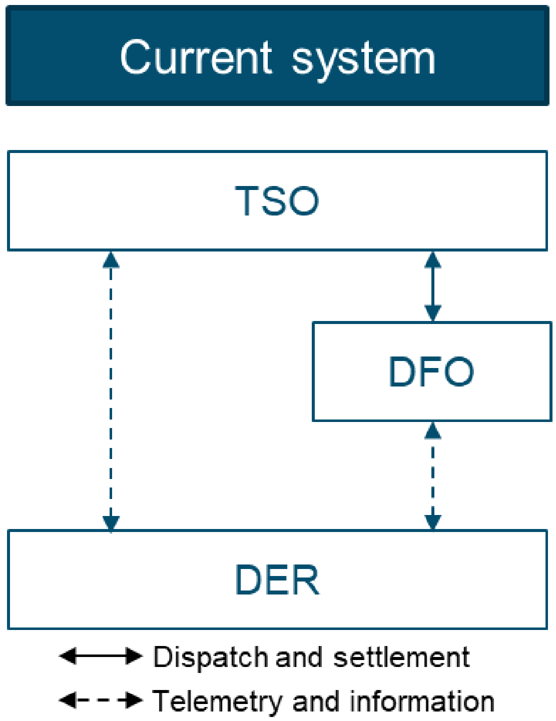

Figure 4: "Current system" model.

Q32. WHAT WILL HAPPEN IF DER GROWTH OCCURS WITH NO STRUCTURAL CHANGES TO THE DISTRIBUTION SYSTEM MODEL?

A32. Increasing levels of DER adoption are likely to go hand in hand with the arrival of independent aggregators: service providers operating on behalf of groups of customers to aggregate the services of many DERs. In the current distribution system model, there is no active coordination of either the DERs, nor of the aggregators. Consequentially, in a "Business as Usual (BAU)" model with increased levels of DERs, aggregators may provide retail services to the DFO as well as participate in the TSO market directly, and they may do so simultaneously. This model is illustrated in Figure 5.

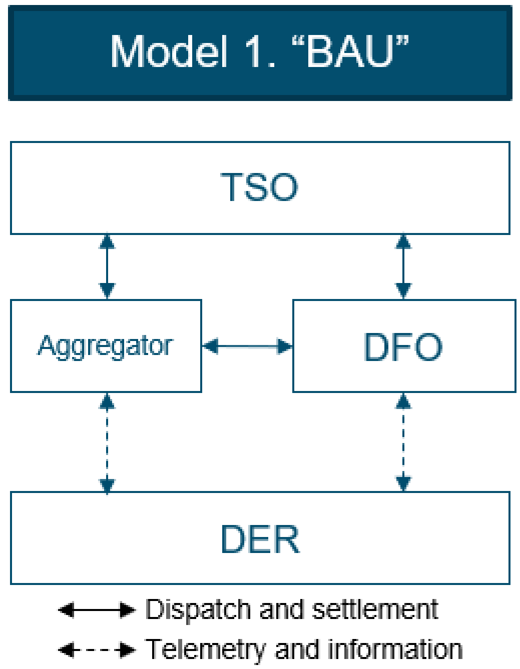

Figure 5: “BAU” model.

Q33. WILL CHANGES TO THIS MODEL BE REQUIRED WITH THE GROWTH OF DERS?

A33. Even though the “BAU” model currently used in Alberta is the industry standard today, there are a number of issues with the BAU system that will materialize as the penetration of DERs grows. The first issue is that no single entity is coordinating the procurement or dispatch of DERs, which can lead to inefficiencies and/or cost shifts. In addition, aggregators are free to provide distribution and bulk system services and could sign conflicting service contracts. This has the potential to lead to either a double counting of benefits or a degradation of reliability when the resource is unavailable to be simultaneously used in both markets. While jurisdictions like New York and California have rules in place to avoid these conflicts, the rules may reduce DER value below its optimal level.

Finally, dispatches made by aggregators and the TSO would be opaque to the DFO, potentially jeopardizing distribution reliability.

Q34. **WHAT DISTRIBUTION SYSTEM MODELS SHOULD BE CONSIDERED IN THE DISTRIBUTION SYSTEM OF THE FUTURE?**

A34. A number of different models can be considered in this context. The models as described here are differentiated based on which entity is responsible for which functions in the distribution system of the future. The main distinguishing feature is which entity is responsible for coordinating DERs.

It is important to note that these models represent potential end states in the distribution system of the future, although transitions may be possible from some models to other ones. As established in the roadmap framework in Section 4, the transition process leading from today's system to any one of these models is expected to be gradual and evolutionary.

DFO as primary coordinator

In these models, the DFO takes on new functions related to coordinating the procurement and dispatch of DERs. The DFO will dispatch DERs to manage local constraints and meet TSO requirements at the interconnection. In these models, concerns over preferential treatment may arise if the DFO intends to own DERs. Two models can be distinguished based on their treatment of aggregators:

- *Model 2. "DFO Lite"*. In this model, the DFO coordinates the market participation of DERs, but aggregators can still choose to access TSO markets directly. If they do so, they cannot simultaneously participate in retail markets. Compared to "BAU," the "DFO lite" model enables DERs to contribute more value to the system, but forgoes the opportunity to achieve both system and local benefits from the same DER.

- *Model 3. "DFO Plus".* In this model, the DFO functions as a "super aggregator" responsible for optimization of all DER and aggregators in retail and wholesale markets. In this model, aggregators cannot access TSO markets directly and must go through the DFO.

These models are illustrated in Figure 6.

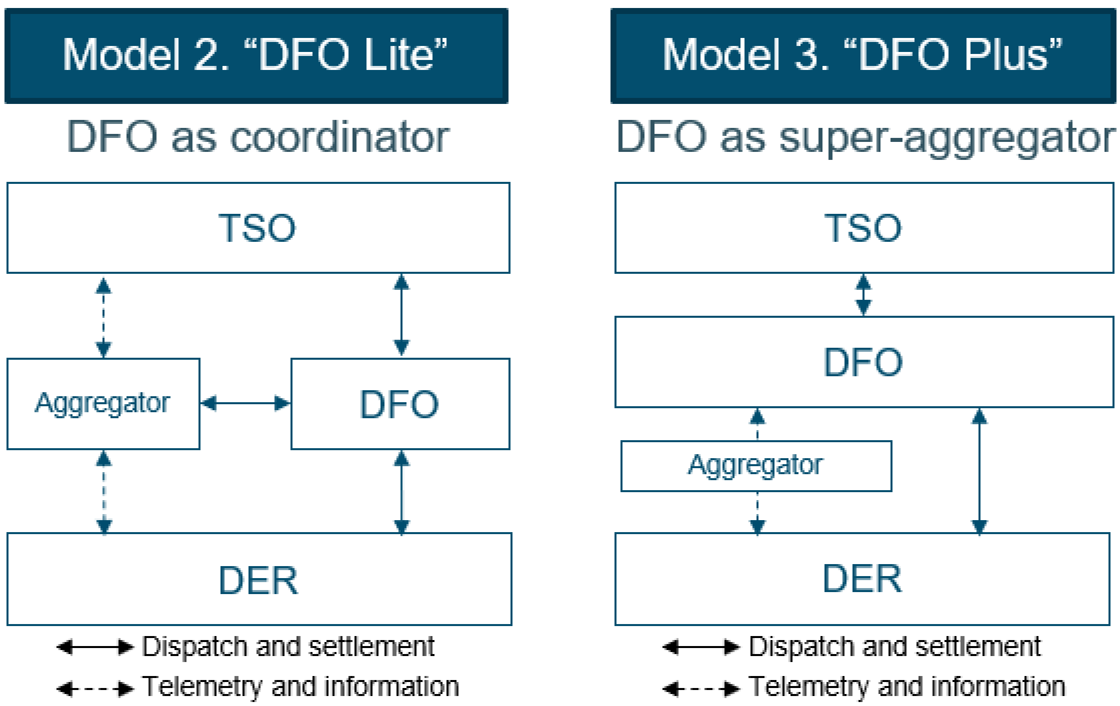

Figure 6: "DFO Lite" and "DFO Plus" models.

DSO as primary coordinator

In these models, a new entity called the Distribution System Operator (DSO) is responsible for the procurement and optimization of DERs and management of the interface with the TSO. The DSO can either be a functionally unbundled part of the DFO or can be an independent entity.

- *Model 4. "DFO/DSO".* In this model, the DSO is responsible for optimization of all DERs and aggregators. Thus, the DFO and aggregators can solely access markets through the DSO. The DSO manages the interface with the TSO and the operations of the distribution system. In this model, the DSO and DFO are functionally separated, i.e.: they are two parts of the same organization with a firewall between them.
- *Model 5. "iDSO".* This model is similar to "DFO/DSO" in structure but positions the DSO as a fully independent entity rather than as a separate unit of the DFO. This structure may lead to more efficient investments, although there may be complications related to reliability as the responsibilities are separated for system planning (DFO) and procurement (DSO).

These models are illustrated in Figure 7.

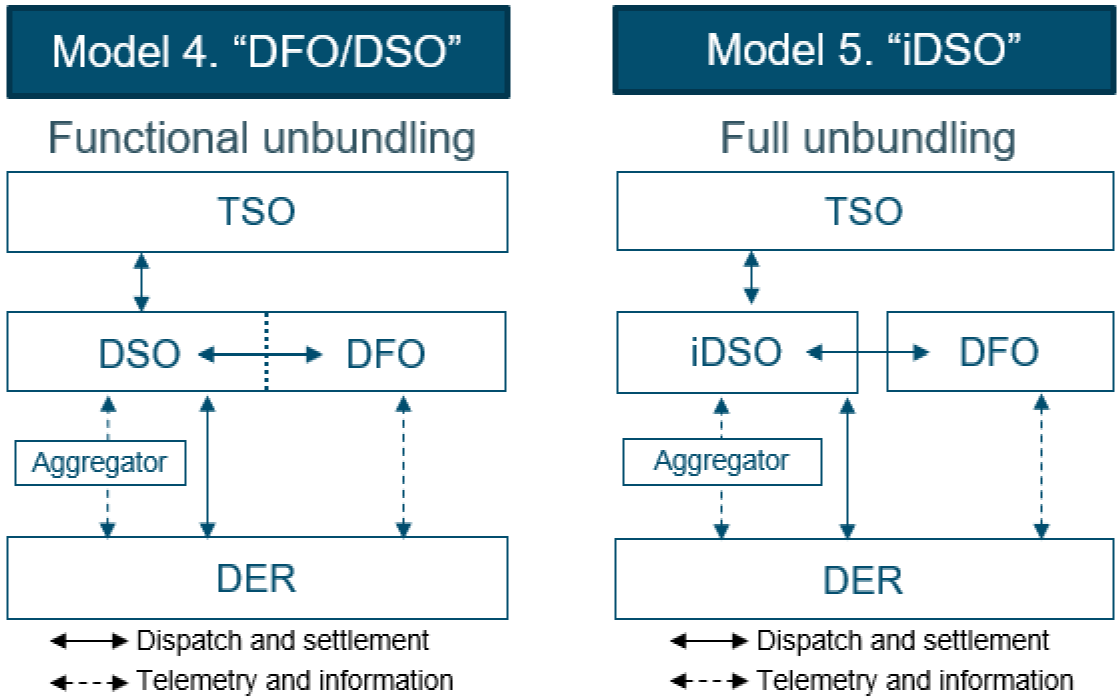

Figure 7: "DFO/DSO" and "iDSO" models.

TSO as primary coordinator

In this model, the DSO functions are managed by the TSO. In other words, the TSO is responsible for coordination of all DER participation in markets.

- *Model 6. "TSO+"*. In the TSO+ model, the TSO dispatches DERs alongside large generators using data from the DFO. Importantly, the DFO does not bilaterally procure DERs. In addition, the responsibility for distribution system reliability is split between the DFO (planning) and the TSO (procurement). In this model, DERs would likely be dispatched to first serve transmission system needs, and subsequently serve needs on the distribution system.

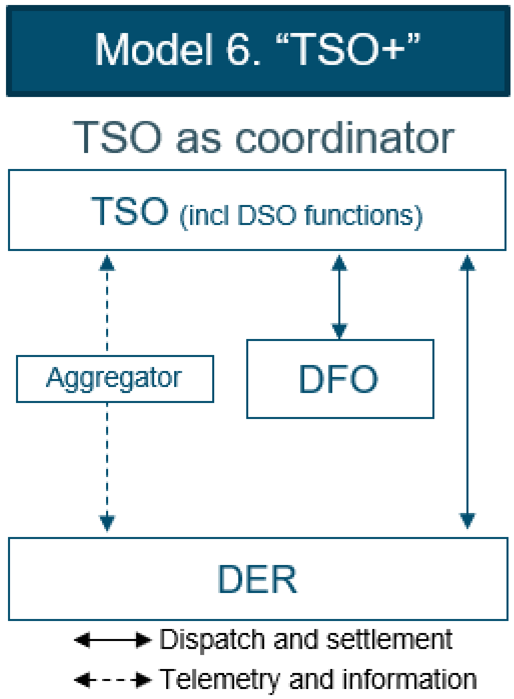

Figure 8: **“TSO+” model.**

Q35. **GIVEN THE CURRENT WHOLESALE POWER MARKET IN ALBERTA, IS THE TSO + MODEL A LOGICAL END STATE FOR ALBERTA?**

A35. Not necessarily. There are pros and cons to the each of the models presented. For example, with the AESO as the current market operator at the bulk level, the TSO+ model may have an advantage in the organization and management of new markets. Moreover, the centralization in this model may result in cost savings and efficiency benefits. However, the TSO+ model would require the AESO to take on many new responsibilities at the distribution level, where the DFOs have more experience in planning and operations. Also, adopting a DFO or DSO model rather than a TSO model may give more flexibility in the rate at which each distribution utility progresses toward the end state.

Q36. **ARE YOU PROPOSING THAT EACH OF THE DFOS BE ALLOWED TO INDEPENDENTLY DETERMINE THEIR OWN APPROPRIATE MARKET STRUCTURES?**

A36. No. I am proposing that the AUC codify the process for each utility to develop their own roadmap which would include a common set of terms, operating requirements and standards across all the Alberta DFOs.

Q37. **IS THERE ANOTHER JURISDICTION THAT HAS FOLLOWED THE PROCESS YOU ARE RECOMMENDING?**

A37. Yes. The New York Public Service Commission and the DFOs in New York are following a similar process that allows different utility roadmaps, but also defines common protocols that would be used by each DFO. Part of this process entailed the implementation of a joint working group of the DFOs in New York. The experiences of New York are described in more detail in Q&A45. My recommendations on forming a working group are included in Q&A63.

Q38. **IS A DECISION AMONG THESE SYSTEM MODELS REQUIRED AT THIS POINT?**

A38. No, a decision among these models is not required at this point. Aside from the BAU model, any of these models could potentially be end points in a high DER future and might be the most suitable for a jurisdiction depending on that jurisdiction's unique circumstances. The most suitable model will depend on numerous factors including the organization of existing entities, the ease of creating new system participants such as a DSO, and stakeholder preferences. It is, however, important to understand the trade-offs between these models and to consider which system entities may be best suited to coordinate DERs.

The experiences of other jurisdictions provide useful examples that may inform future decisions of utilities and regulators in Alberta. A jurisdictional comparison is presented in the following section.

6 Jurisdictional Comparison

Q39. **ARE OTHER JURISDICTIONS EXPERIENCING SIMILAR DEVELOPMENTS RELATED TO DER GROWTH?**

A39. Yes. Their significant cost decrease over the past years has led to the adoption of DERs by consumers in jurisdictions across North America, as well as other parts of the world. A confluence of technology, policy, and customer trends has driven a reconsideration of utility programs and planning for DERs, which are in different stages of development in different jurisdictions. Rapid growth of DERs in some jurisdictions has led to challenges related to rate design and peak load management, motivating jurisdictions to adopt new functions and policies. In Hawaii and California for example, a combination of factors led to the rapid growth of distributed solar, which required the implementation of changes in rate design and DER interconnection. In New York, on the other hand, the incorporation of DERs in the distribution system was the result of a more proactive approach set by regulatory proceedings and policy initiatives. In Europe, the experiences of Germany and Great Britain also provide informative examples. An estimated overview of where each jurisdiction stands with regard to the level of DER adoption and the implementation of regulatory changes, compared to the situation in Alberta, is shown in Figure 9. These jurisdictions do not necessarily illustrate best practices or success stories, but each provides an example that can inform future steps in Alberta.

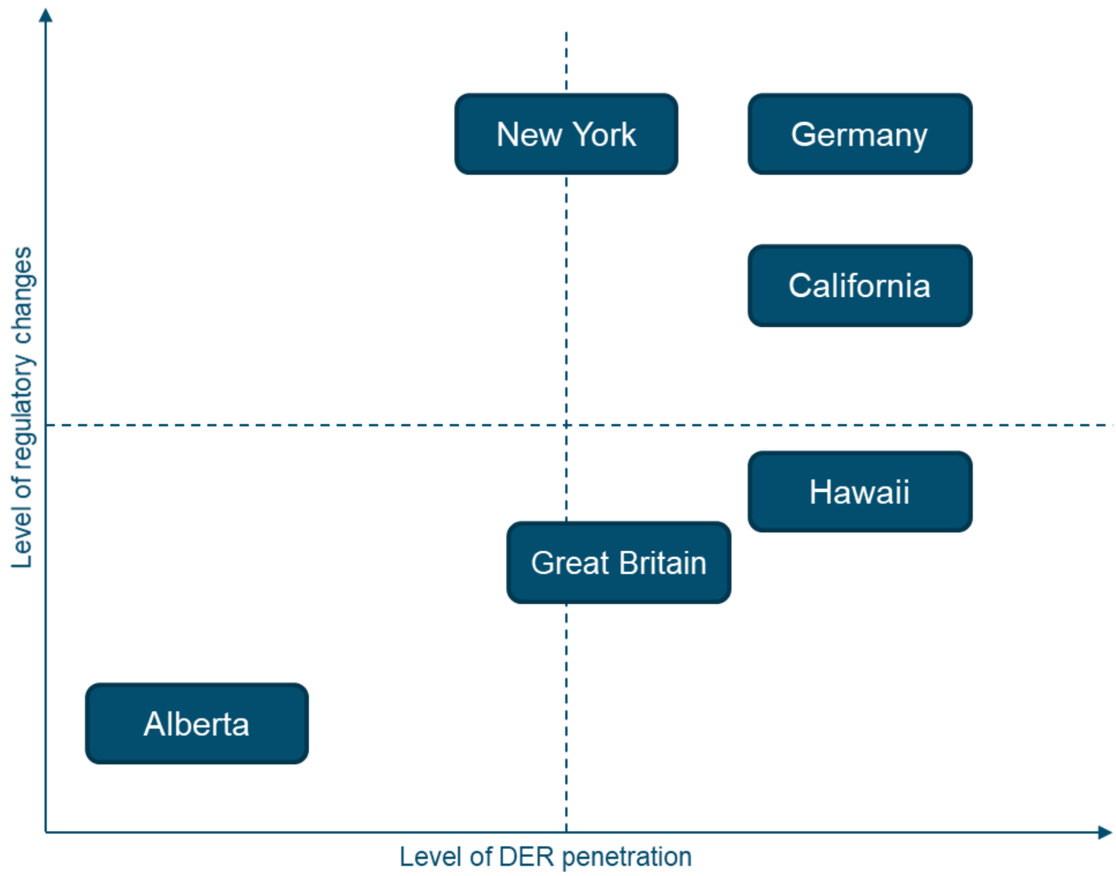

Figure 9. Overview of jurisdictional comparison based on level of DER penetration and level of regulatory changes.

Q40. **CAN YOU PROVIDE A SUMMARY OF HAWAII'S EXPERIENCE AND RESPONSE TO VERY HIGH LEVELS OF DER PENETRATION?**

A40. In Hawaii, the combination of state policy (100 percent renewable portfolio standard, or RPS, by 2045), good solar resource, very high electricity costs, rate design and land constraints has led to the rapid growth of BTM solar installations.

Starting in 2010, distributed solar customers were eligible for a feed-in tariff, providing a direct incentive for these DERs. In the years after the tariff was closed to new applications, rooftop solar customers had access to "net metering," in which consumers are charged based on their monthly net consumption of energy (i.e.: monthly grid energy demand less monthly exports of solar energy). Net metering enabled customers to reduce the volumetric component of their bill to zero, even though these customers rely on electricity from the utility when their rooftop solar is not producing. This has led to substantial uneconomic bypass: a large cost shift from customers with rooftop solar to customers that have not installed these DERs. In addition, the interconnection of a large amount of uncurtailable solar has also led to system reliability concerns.

To address these issues, two significant changes are being pursued. The first is to change rate structures in order to reduce uneconomic bypass. In the short term, Hawaiian Electric has adopted rate structures that reduce credits for exports to the grid, reducing the amount of cost shifting but not alleviating the fundamental mismatch between rate design and system costs. Going forward, Hawaiian Electric is considering multi-part rates that can fully collect embedded costs via customer and demand charges along with dynamic rates for energy that better reflect system costs. The second change is meant to improve reliability: new rooftop solar installations will be required to have smart inverters that will allow the utility to directly curtail solar generation when necessary for system reliability.

Q41. **WHAT ARE THE KEY LESSONS LEARNED FROM HAWAII?**

A41. Hawaii would have been in a better position if they had anticipated the rapid uptake of rooftop PV and had planned ahead in order to quickly modify the incentives for distributed solar. There is approximately a two-year lag to process a rate case through the public service commission and, as a result, rate design changes have lagged substantially behind DER adoption rates, which has led to higher rates and subsequently more DER adoption. If Hawaii had a roadmap in place prior to implementing its feed-in tariff, they could likely have adapted more quickly to the effects of DER adoption and avoided some of the cost shifting that has substantially increased rates for customers without rooftop solar. Now that such a large portion of customers have made long term investments based on existing incentives and tariff designs, the transition to more cost-based rate structures is going to be very gradual.

Q42. **HAS HAWAII PURSUED ANY OF THE MARKET STRUCTURE CHANGES YOU DESCRIBE?**

A42. No. Hawaii is a very small market and I am not aware of any proceedings that consider restructuring opportunities. The vertically integrated utility continues to provide all energy resources and be the main purchaser of DER services. The utility has an unregulated sister company, which currently finances but might want to own and operate DERs throughout Hawaii.[3] This may eventually lead Hawaii toward a DFO/DSO or iDSO model, as concerns about ownership of DERs may lead to calls

[3] See www.pacificcurrenthawaii.com (visited 3/6/2020)

for DER procurement and operations to be run by a functionally unbundled or fully independent DSO.

Q43. **CAN YOU PROVIDE DETAIL ON THE SITUATION IN CALIFORNIA?**

A43. Similar to in Hawaii, a combination of factors has resulted in the rapid growth of distributed solar in California over the past decade. In addition, California has adopted several policies that explicitly encourage continued DER growth, such as building codes that require rooftop solar on new homes. Regulators have recognized that net metering leads to cost shifts and thus adopted new rate structures under “NEM 2.0.” NEM 2.0 includes time of use (TOU) rates, which reduce export credits during hours of high solar generation, as well as requirements for customers to pay interconnection fees. In addition, NEM 2.0 adds a non-bypassable volumetric charge to electricity delivered by the utility. NEM 2.0 is currently under review and will be replaced with NEM 3.0, potentially resulting in a gradual path towards more cost-based rates.

Q44. **HAS CALIFORNIA PURSUED ANY OF THE MARKET STRUCTURE CHANGES YOU DESCRIBE?**

A44. California is still operating with a BAU structure where aggregators (scheduling coordinators) can participate directly with the CAISO or through the procurement programs offered by the distribution utilities. CAISO has indicated that it does not intend to substantially expand its operations to include the operation of distribution facilities. Instead, CAISO has indicated its preference that California eventually move toward a DFO- or DSO-based model for DER operation[4]. To date, the balance sheets of the large distribution utilities have been used to advance the state's RPS strategy, which for years has been the focus of California's clean energy policy. Utilities have already begun to build and own electric vehicle charging stations, and this model of DER ownership points toward a future DFO/DSO or iDSO model in California.

Q45. **CAN YOU PROVIDE DETAIL ON THE SITUATION IN NEW YORK?**

A45. Unlike in Hawaii and California, New York is addressing DERs not in response to growth of distributed solar, but as a result of proactive policy. In 2014, NY launched Reforming the Energy Vision (REV), a set of regulatory proceedings and policy initiatives intended to encourage investment in DERs and to enable DER integration into the electric grid. These policies included a restructuring of ratemaking and utility revenue models, giving utilities the role of "market operators" to facilitate DER transactions and creating a new term called a Distribution System Platform (DSP), which would be an intelligent network that fosters broad economic activity around DERs. The utilities in NY believe that the platform would include market services, DER integration services and information sharing services which are reflected in Figure 10 below:

[4] https://www.energy.gov/sites/prod/files/2017/04/f34/2_T-D%20Interface%20Panel%20-%20Lorenzo%20Kristov%2C%20CAISO.pdf

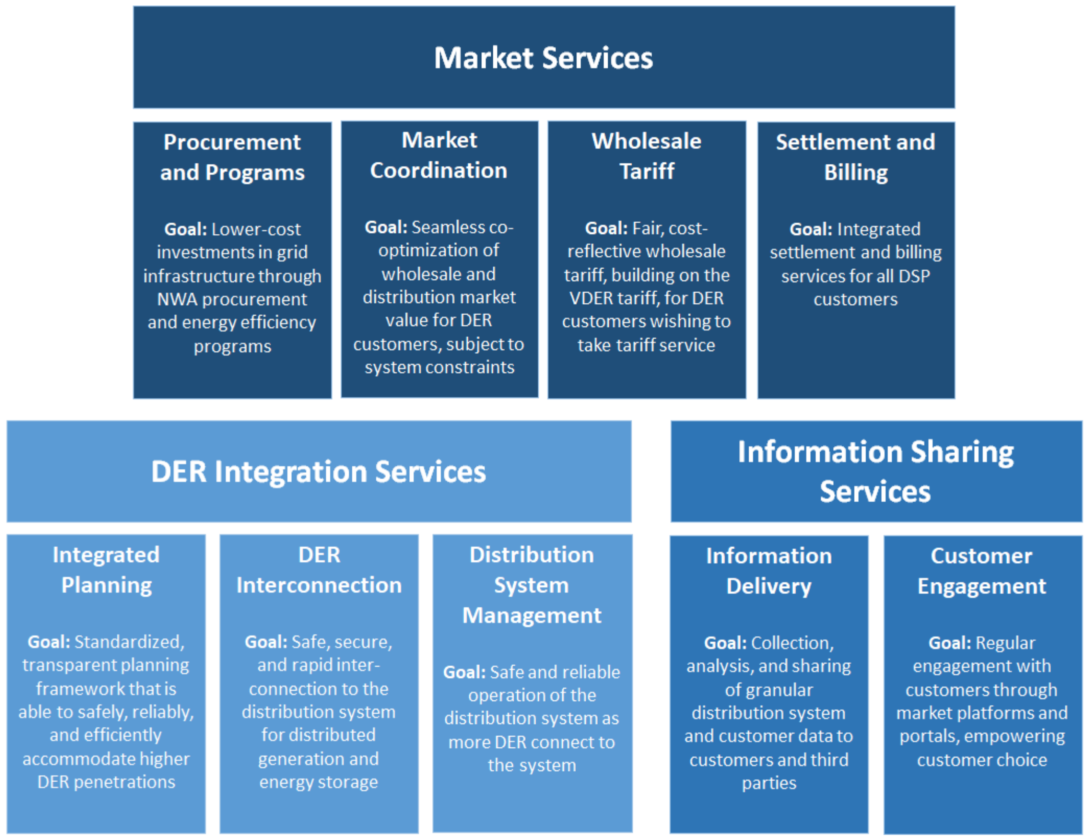

Figure 10: Long-Term Goals for DSP Functions within Each Core DSP Service Area. Source: Consolidated Edison Distributed System Implementation Plan (2019)

As they evolve, DSPs are expected to increasingly bring together suppliers and buyers of electricity services, becoming populated with more information and transactions over time. DSPs will become a marketplace for third-party aggregators and technology vendors to gather data and offer their services (Figure 11). The final framework of the DSPs is not determined and could be one of the models described in Section 5.

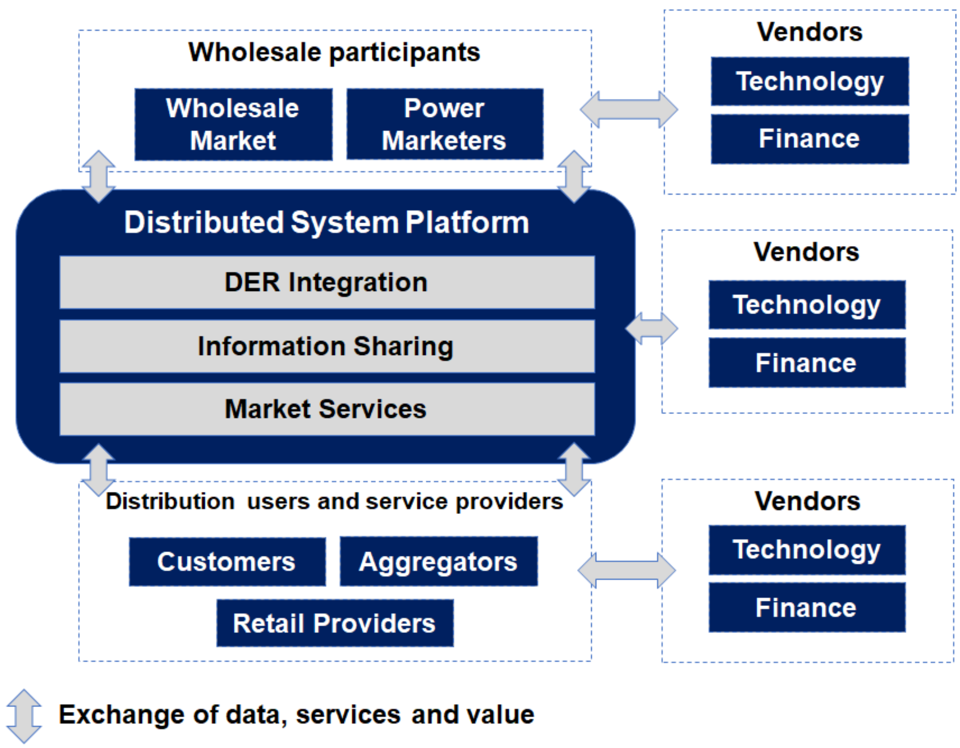

Figure 11: Illustration of the DSP as an energy services marketplace. Source: Consolidated Edison Distributed System Implementation Plan (2019)

Another component of REV is a proposal to replace net energy metering by a mechanism called the Value of Distributed Energy Resources (VDER). VDER would compensate distributed generation using a localized calculation of system benefits. Components of VDER include avoided carbon emissions, cost savings to customers and utilities, and savings from avoided capital investments on the distribution system.

Q46. **HAS NEW YORK PURSUED ANY OF THE MARKET STRUCTURE CHANGES YOU DESCRIBE?**

A46. The REV proceeding, by assigning DSP functions to the incumbent utilities, has essentially ruled out the TSO+ model as a future model for New York's distribution system. However, it is still unclear what the final state will be, with DFO-based and DSO-based models still in play. Today, the functions of the DSP are essentially being implemented under a BAU structure, with each utility progressing along a roadmap similar to the process described above.

Q47. ARE THERE JURISDICTIONS OUTSIDE OF NORTH AMERICA THAT COULD PROVIDE IMPORTANT LESSONS?

A47. Yes. Some countries in Europe are educational as they have experienced similar developments related to DER growth, resulting in challenges for system operators. Two notable cases to highlight are Germany and Great Britain.

In Germany, the top-down implementation of the "Energiewende", which included a ban on nuclear energy and a rapid increase of renewables, was incentivized by the introduction of a feed-in tariff. This tariff was aimed at giving long-term security to renewable energy producers by guaranteeing earnings above the retail or wholesale price. As a result, the share of renewable electricity rose to 46% in 2019, surpassing fossil generation many days of the year although emphasizing coal-fired generation as the main baseload source.[5] Although the average electricity price has not changed significantly as a result of this development, there has been a sharp increase in price volatility. The German electricity system is largely centralized at the transmission level with four large TSOs and highly decentralized at the distribution level with over 700 DSOs. Furthermore, it is challenged with congestion management at the transmission level as well as with balancing issues

[5] Fraunhofer ISE (January 2020). Public Net Electricity Generation in Germany 2019

in incorporating DERs into the system. Given the top-down policy approach, the highly decentralized distribution network and the existing transmission constraints, the German system seems to be moving towards a TSO+ model.

In Great Britain, the electricity system is moving toward DSO-based models, informed by the evolution of the market. Great Britain's electricity grid consists of four TSO operators and a number of regulated Distribution Network Operators (DNOs), whose functions are closely related to the DFO as described in this testimony. Historically, National Grid (the largest TSO) has been responsible for system balancing using a mechanism that allowed for voluntary participation in the market. The end result of this mechanism was a supply portfolio that was largely dominated by a small number of large coal, gas and nuclear power generators. With the recent growth of renewable generation in Great Britain, the voluntary participation of generators is causing challenges for the TSO in balancing the system efficiently, as an increasing part of supply has become opaque at transmission level, transforming one of the first organized energy pools into a balancing market serving the primary resources connected and dispatched at the distribution level. With increased focus on local scale generation and the urge for local coordination as a result of these balancing issues, the DNOs now seem to be on the front line of coordinating DERs.

Q48. **CAN YOU SUMMARIZE WHICH JURISDICTIONS ARE LIKELY TO EMPLOY WHICH MODELS?**

A48. A comparison of the types of models that are likely outcomes in Hawaii, California, New York, Germany and Great Britain is shown in Figure 12.

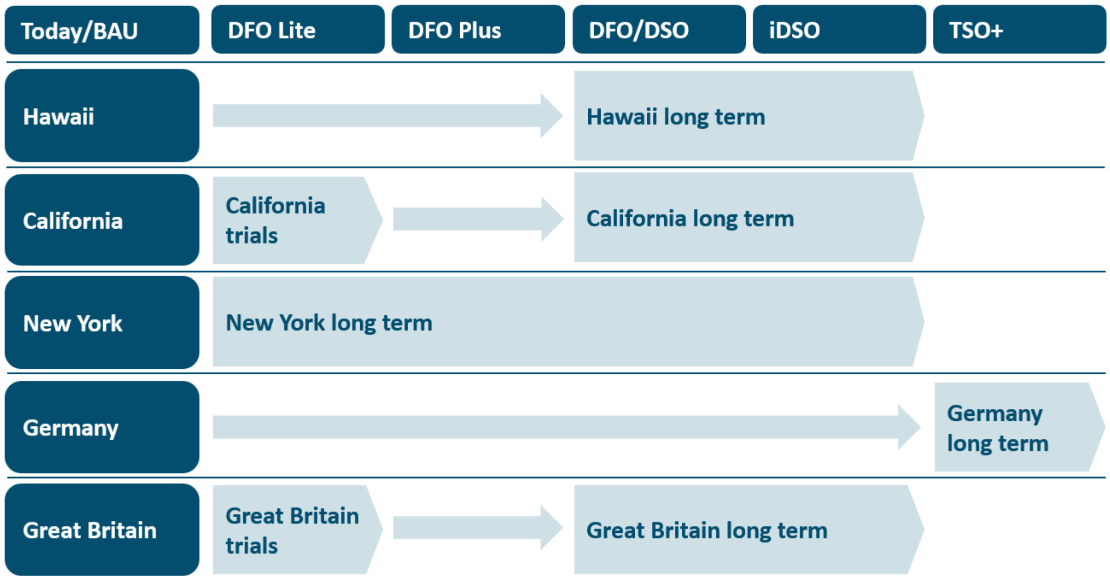

Figure 12: Distribution system models under consideration in different jurisdictions.

Q49. **WHAT CAN THE ALBERTA MARKET LEARN FROM EXAMPLES IN OTHER JURISDICTIONS?**

A49. Although responding to DER growth will require a customized approach in each jurisdiction, the examples in other jurisdictions provide three main take-aways for Alberta.

First, the jurisdictions have shown how the foresight to develop a long-term vision for the distribution system of the future – even without knowing the exact nature of DER adoption – can result in the ability to reduce issues stemming from uneconomic bypass and to provide value for DERs on the grid. The roadmap as described in this testimony provides guidance to that end.

Second, jurisdictions are moving to different distribution system models based on their own unique circumstances. A number of factors play a role in this outcome, including the existing structure of the system, the interest among entities such as utilities and the TSO in taking on new distribution system functions, preferences of policymakers and utility interest in owning and operating DERs.

Third, the adoption of new rate structures and the progression toward cost-based rates is consistent across all jurisdictions that are evolving. As the stage of DER adoption in Alberta evolves, specific attention to rate design can help prevent uneconomic bypass and maintain reliability without damaging the market for DERs.

7 Rate Design

Q50. **HOW IS THE EXISTING DISTRIBUTION TARIFF CURRENTLY STRUCTURED IN ALBERTA?**

A50. In Alberta, transmission and distribution charges for residential customers consist of a fixed charge ($/day) for the recovery of facilities and service costs (metering, billing, etc.) and a volumetric energy-based charge ($/kWh) for the overall usage of the distribution and transmission system. Although the structure of the rates is aligned for all DFOs, the proportion of the rate recovered through fixed or variable charges may vary from DFO to DFO. Despite the varying ratio of fixed to variable charges, DFOs in Alberta generally recover a significant portion of fixed system costs through volumetric charges on residential customers. An overview of system costs recovered through fixed and variable components for a household with a demand of 600 kWh per month is given in Table 6. I specifically show rates for residential customers in this table as these are the least reflective of system costs and therefore most relevant to use as an example.

	Volumetric		Fixed	Total
	Distribution costs	*Transmission costs*		
FortisAlberta	$13.80	$23.80	$24.50	$62.20
ATCO Electric	$41.20	$23.50	$37.40	$102.00
ENMAX Power Corporation	$6.50	$11.70	$15.90	$34.10
EPCOR Distribution & Transmission	$6.00	$20.20	$20.40	$46.60
Average across 4 DFOs	**$16.90**	**$19.80**	**$24.60**	**$61.20**
Proportion	**60%**		**40%**	**100%**

Table 6. Recovery of system costs from residential customers for 4 Alberta DFOs. Costs assume a consumption level of 600 kWh/month.[6] Note: this table does not include energy costs.

For other customer classes, rates in Alberta are less reliant on volumetric charges and may include a demand/capacity charge as well as a fixed service charge.

Q51. **DOES DER GROWTH LEAD TO ISSUES WITH VOLUMETRIC RATE STRUCTURES?**

A51. Yes. There are two major issues that arise as DER penetration grows in a system with rates that are largely volumetric. The first issue is that these rate structures encourage uneconomic bypass, i.e. cost shifts. The second issue is that volumetric rates do not reflect the value of DERs to serve multiple system needs including capacity and regulation.

[6] Derived from electric rate schedules (2020) for FortisAlberta, ATCO Electric, ENMAX Power Corporation and EPCOR Distribution & Transmission. Available via: http://www.auc.ab.ca/Pages/current-rates-electric.aspx

Q52. **PLEASE PROVIDE AN EXAMPLE OF UNECONOMIC BYPASS.**

A52. Net metering (or net billing) of rooftop solar is a classic example of uneconomic bypass. By self-generating, customers can reduce their monthly energy demand to zero and thus pay nothing for the volumetric component of their bill. These solar customers are under-paying for the fixed costs of the grid, as they continue to use the grid extensively to balance their solar generation and load. 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 (uneconomic bypass).

Q53. **CAN YOU EXPLAIN THE ISSUE REGARDING DERS SERVING MULTIPLE SYSTEM NEEDS?**

A53. DERs can provide a number of services to electric systems including energy, capacity, and reserves and regulation. In order to provide these services, customers need rates/tariffs that reflect these different components of electric systems. For example, a customer on volumetric rates would have no incentive to reduce their peak load, which may provide capacity services to the system.

Q54. **DOES YOUR EVOLUTIONARY ROADMAP APPLY EQUALLY TO CHANGES IN RATE DESIGN AS IT DOES TO BUSINESS MODELS AND MARKET STRUCTURE?**

A54. Yes, it does. Most rate design experts agree that an efficient multi-part rate design, which has fixed and variable components, based on the fixed and variable costs of the services provided, will encourage efficient adoption and use of DERs. However, there is substantial disagreement about how best to transition from the rates jurisdictions have in place today to more efficient cost-based structures. Again, we recommend that the roadmap process be used to move Alberta incrementally towards efficient rate designs. Unlike our discussion of market structures, there is a clear winner on the most efficient rate design.

Q55. **ARE THERE EXAMPLES OF JURISDICTIONS WHERE THESE ISSUES HAVE ARISEN?**

A55. The issue of DERs leading to uneconomic bypass has occurred in a number of US states, leading to changes in rate structures or proposals for such changes. Hawaii and California are the prime examples of this, as described in Q&A40 and Q&A43. In these jurisdictions, rate design has been a key approach toward addressing these issues.

Q56. **WHAT PRINCIPLES ARE GENERALLY CONSIDERED IN RATE DESIGN?**

A56. Traditional rate design considers a number of principles that may be in competition with each other. These principles include fair apportionment of costs ("cost causation"), customer understanding and acceptance, price signals that encourage efficient use, practicality of implementation, and rate and bill stability.

Q57. **WHAT PRINCIPLE(S) SHOULD BE STRESSED IN DESIGNING NEW RATE STRUCTURES THAT ARE COMPATIBLE WITH DER GROWTH?**

A57. To design rate structures that are compatible with DER growth, the focus should be on the principles of cost causation and appropriate price signals, especially as this applies to customers with DERs. In practice, this means designing rates that are cost-based, e.g. rates that reflect the costs of providing interconnection, energy, and capacity services and that reimburse customers who can provide these services themselves.

Q58. **ARE COST-BASED RATES IN CONFLICT WITH THE PRINCIPLE OF CUSTOMER UNDERSTANDING?**

A58. Historically, there has been a perception of conflict between the principles of efficiency (designing rates that reflect the cost of service) and simplicity (designing rates that are easy for a customer to understand). However, as DERs continue to grow, new technologies will enable customers to understand and take advantage of more complicated rate structures. For example, electric vehicles can be programmed to charge during off-peak times, so customers will not need to micromanage charging around time-of-use rates. As another example, battery storage can be programmed to reduce peak demands, so customers with batteries could benefit from capacity charges without significant effort on their part. In addition to new technology in the DERs themselves, aggregators, making use of smart technology and machine learning, may become increasingly responsible for DER scheduling, further reducing the need for customers to interpret their own rates.

Q59. **ARE COST-BASED RATES IN CONFLICT WITH THE PRINCIPLE OF RATE AND BILL STABILITY?**

A59. The move to cost-based rates may lead to changes in customer bills. Thus, cost-based rates may be adopted gradually in order to reduce the abruptness of these changes. However, once adopted, these rates will support rate and bill stability. In contrast, status quo volumetric rates will increasingly lead to uneconomic bypass, and the associated cost shift onto customers who do not adopt DERs will have a negative impact on rate and bill stability for these customers.

Q60. **CAN YOU PROVIDE AN EXAMPLE OF COST-BASED RATES?**

A60. One example is "three-part rates," as illustrated in Figure 13. The three different parts are meant to recover the costs of serving customer interconnection, capacity and energy. The interconnection component corresponds to the costs of transformers, wires, meters, and other interconnection services and forms a monthly customer charge. The capacity component corresponds to the costs of meeting peak energy demand and is priced as $/kW using a peak capacity allocation methodology. It typically collects the fixed costs of distribution facilities. The energy component corresponds to the costs of providing energy and is priced as $/kWh, ideally with a time-varying rate that reflects the time-dependent costs of generation.

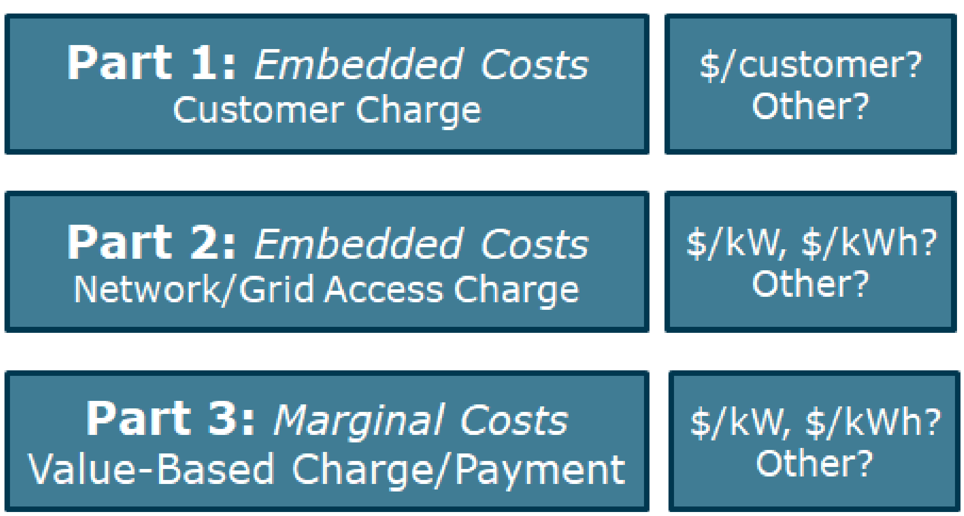

Figure 13: "Three-part rates," an example of cost-based rates.

Q61. **IF ALBERTA DOES NOT IMMEDIATELY MOVE TOWARD COST-BASED RATES, ARE THERE OTHER IMPORTANT CHANGES IN RATES OR COST RECOVERY?**

A61. Yes. Decoupling utility revenues from sales removes some of the perverse incentives that may discourage DFOs from supporting DERs. Hawaii, California and New York all have revenue decoupling mechanisms. Although decoupling was initially implemented to support energy efficiency, it will also create better incentives for DFOs to interconnect and procure DERs in order to support customer choice and help meet system needs.

8 Next Steps and Conclusion

Q62. **BEYOND THE ADOPTION OF A ROADMAP, ARE THERE ANY COMMON STEPS THAT DISTRIBUTION UTILITIES CAN TAKE TODAY TO PREPARE FOR THE FUTURE INTEGRATION OF DERS?**

A62. Yes. As utilities progress along the roadmap described in Section 4, the following are several steps that utilities can take that will benefit the distribution system and consumers as DER penetration grows. These steps are informed by the discussion of distribution system functions and models in Section 5, the discussion of other jurisdictions in Section 6, and the discussion of rate design in Section 7.

- *Reforms to interconnection policies.* Other jurisdictions, including Hawaii, New York and California, have implemented reforms to interconnection policies in order to facilitate timely and more efficient interconnection and to recover the costs of interconnection (Section 7).

Key reforms include standardization of methodology, data transparency and regular updating of utility hosting capacity analyses, which detail the amount of DERs that can be accommodated at specific locations on the distribution system without requiring significant upgrades. These analyses provide key information to consumers and developers. In addition, utilities can implement a clear schedule of fees for interconnection of different DERs, which will enable fair recovery of interconnection costs.

- *C&I Advanced Metering Infrastructure (AMI).* Advanced metering will be an evolving system function and will be key to providing efficient price signals, enabling DERs to provide greater value to the system (Section 5). AMI should commence with C&I customers since they have large energy demands and may be more sophisticated in their approach to energy management. AMI for these customers will enable efficient price signals, evolving rate structures, and higher value for DERs. Also, opt in strategies, where participants pay for the incremental costs of metering and infrastructure, until a threshold number of customers is reached, and it becomes cost-effective to implement interval meter for all customers.
- *Sensors on the distribution system.* Sensors offer granular, real-time information on distribution feeders that can support enhanced planning in both evolving and new system functions described in Section 5, including hosting capacity analysis and the evaluation of non-wires

alternatives. In addition, these sensors will enable more efficient operations and improved system reliability. This improved situational awareness will enhance DER utilization, regardless of the distribution system model that is ultimately established.

- *Consider changes in rate structure.* Other jurisdictions provide useful examples of changes in rate structure, as described in Section 7. As Hawaii and California have illustrated, significant growth of DERs under legacy rate structures can lead to both uneconomic bypass and system reliability concerns. In contrast, New York is taking proactive steps to enact more cost-based rates before DER adoption has reached a high level. In future rate cases, regulators should be cognizant of the issues that may arise with volumetric rates and should consider moving toward rate structures that can reduce cost shifts and provide efficient price signals, as described in Section 7.
- *Consider decoupling distribution utility revenues from electric sales*. As described in Q&A61, the decoupling of utility revenues from sales will improve the incentive structure for utilities to interconnect and utilize DERs. Decoupling is not a replacement for cost-based rates, as it does not address the issues relating to uneconomic bypass. However, decoupling can be implemented immediately, even while changes in rate structure may proceed gradually.
- *Closely related transmission rate design issues.* To some extent, Alberta is already experiencing uneconomic bypass on its transmission system,

as large industrial customers have installed BTM generation that is expressly dispatched to avoid the monthly coincident peak. As a result, it is worth reconsidering transmission rate design and/or considering rate structures more holistically.

- *Continued awareness and monitoring of other jurisdictions*. Other jurisdictions may be farther along the DER roadmap due to differences in policy, rate structure, DER value, or other factors. By monitoring the experiences of these jurisdictions, Alberta can learn from successful examples and potentially avoid some of the pitfalls that other jurisdictions have encountered. While Section 7 provides an introduction, Alberta should continue to monitor the progress of these and other jurisdictions going forward.

Q63. **DO YOU HAVE OTHER RECOMMENDATIONS FOR NEXT STEPS IN THIS REGULATORY PROCESS?**

A63. Yes. In this context, it is worth considering the formation of a working group among the DFOs. This working group can define the common terms and structural elements needed across the province to achieve the maximum value of DERs, minimize costs to ratepayers and maintain safe and reliable operations and comparable access to both transmission and distribution services. In New York, a Joint Utilities working group was tasked by the state Public Service Commission to define a standard set of technical and market terms and rules that would be used by each DFO in development of their respective distribution capital plans, along with how the DFOs intend to facilitate the efficient use of and integration of DERs into both the distribution system and bulk system services provided by the NYISO. As a result of the working group, each of the DFOs adopted the common set of roadmap proposals but offered their own views as to what made sense for their own customers. I recommend that Alberta form a DFO working group to propose a similar common set of rules and standards suitable for use by all DFOs in Alberta.

Q64. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A64. Yes.

9 Appendix: Curriculum Vitae

Ren Orans

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC.
San Francisco, CA
Managing Partner

Dr. Orans founded Energy and Environmental Economics, Inc. (E3) in 1989. An economist and engineer, he has focused throughout his career on the challenges facing the electricity industry. He is a trusted advisor to a broad range of clients that have included government agencies, utilities, system operators, regulators, independent power producers, energy technology companies, public interest organizations, and investors. He has led E3 teams on numerous high-impact and high-profile projects that have required both rigorous technical analysis and the ability to effectively distill actionable insights to help E3's clients make informed decisions as they develop innovative projects, programs, or policies.

Dr. Orans' pioneering work in utility planning has centered on the design and use of area and time-specific (ATS) marginal costs for both pricing and evaluation of grid infrastructure alternatives. This seminal work has led to detailed area costing applications in pricing, marketing, and planning for many utilities throughout North America. He is an expert in designing wholesale transmission tariffs and has served as an expert witness in regulatory proceedings on retail rate design and wholesale transmission pricing, including for Canada's three largest utilities: BC Hydro, TransEnergie, and Ontario Power Generation.

In a recent forward-looking study, Dr. Orans provided his expertise to California's energy and environmental regulators in evaluating the operational challenges, feasibility, and cost consequences of a higher Renewables Portfolio Standard (RPS) in California by 2030.[7] This assessment included technical input from the California Independent System Operator (CAISO) as well as independent reviews from a distinguished four-member advisory panel and utilized E3's best-in-class Renewable Energy Flexibility (REFLEX) model. Additionally, in consultation with advisors to California's Governor and principals and staff from the energy agencies and the CAISO, Dr. Orans and E3 staff developed a set of technology deployment scenarios that meet California's goal of reducing greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050.[8] This analysis leveraged E3's California PATHWAYS model, an economy-wide, infrastructure-based GHG and cost analysis tool that captures interactions among the buildings, industry, transportation, and electricity sectors in a low-carbon future.

[7] https://www.ethree.com/projects/modeling-californias-50-percent-renewables-portfolio-standard/
[8] https://ethree.com/public_projects/energy_principals_study.php

Dr. Orans has also guided E3's national deep decarbonization analysis, most notably in the influential report *Pathways to Deep Decarbonization in the United States*.[9] Co-authored with Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest National Laboratory (PNNL), its principal finding is that multiple pathways exist to achieving deep decarbonization by midcentury at manageable cost. The report was published for the Deep Decarbonization Pathways Project (DDPP), an initiative led by the United Nations Sustainable Development Solutions Network (SDSN) and the Institute for Sustainable Development and International Relations (IDDRI) to explore how countries can transform their energy systems by 2050 to achieve needed greenhouse gas reductions.

Dr. Orans is a respected thought leader who is often asked to share his expertise and vision for the energy industry. He regularly publishes in refereed journals and has taught a graduate course on electric utility planning at Stanford University. He received his Ph.D. in Civil Engineering from Stanford University and his B.A. in Economics from the University of California at Berkeley.

DEPARTMENT OF ENERGY Washington, DC
NATIONAL RENEWABLE ENERGY LABORATORY 1992 – 1993
ELECTRIC POWER RESEARCH INSTITUTE
Lead Consultant

Dr. Orans developed new models to evaluate small-scale generation and DSM placed optimally in utility transmission and distribution systems.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Research and Development Department 1989 – 1991

Dr. Orans developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can in some cases be less costly than larger generation alternatives. He also developed the evaluation methodology that led to PG&E's installation of a 500kW photovoltaic (PV) facility at their Kerman substation. This is the only PV plant ever designed to defer the need for distribution capacity.

ELECTRIC POWER RESEARCH INSTITUTE Palo Alto, CA
Consultant 1988 – 1992

Dr. Orans developed the first formal economic model capable of integrating DSM into a transmission and distribution plan; the case study plan was used by PG&E for a $16 million pilot project that was featured on national television**.**

DEPARTMENT OF ENERGY Washington, DC
Lead Consultant 1989 – 1990

[9] http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf

Dr. Orans was the lead consultant on a cooperative research and development project with the People's Republic of China. The final product was a book on lessons learned from electric utility costing and planning in the United States.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Corporate Planning Department 1989 – 1992

Dr. Orans was the lead consultant on a joint EPRI and PG&E research project to develop geographic differences in PG&E's cost-of-service for use in the evaluation of capital projects. Developed shared savings DSM incentive mechanisms for utilities in California**.**

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Rate Department Economist 1981 – 1985

As an economist at PG&E, Dr. Orans was responsible for the technical quality of testimony for all electric rate design filings. He was also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the first and largest residential time-of-use program in California and a variety of innovative pricing and DSM programs.

Education

Stanford University Palo Alto, CA
Ph.D., Civil Engineering

Stanford University Palo Alto, CA
M.S., Civil Engineering

University of California Berkeley, CA
B.A., Economics

Citizenship

United States

Refereed Papers

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