June 17, 2020

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue SW
Calgary, AB T2P 0G5

Attention: Randy Lucas, Application Officer

Re: Proceeding 24116 Distribution System Inquiry

Dear Mr. Lucas,

Energy Storage Canada ("ESC") submits the following responses to the Distribution System Inquiry Round 2 Information Requests ("IRs"). ESC has not responded to all IRs. In the case of questions 001, 002 and 003, ESC believes other parties are in a better position to inform the Commission of the issues of advanced metering. In the case of questions 005 (i) and (j), 006 (b), 008, 010, and 011, we have collaborated with the Community Generation Working Group ("CGWG") and The Pembina Institute and refer the Commission to the responses provided by them. For 006(a), ESC has provided a response that we believe extends the response provided by CGWG.

The attached report on Evaluation of Storage Utilization Scenarios that was prepared by our consultants as our response submission to proceeding 24116.

Sincerely,

J Rangooni

Justin Wahid Rangooni, LL.B.
Executive Director
Energy Storage Canada

Energy Storage Canada Responses to Alberta Utilities Commission, Distribution System Inquiry, Round 2 Information Requests

Prepared by Olien Consulting and DePal Consulting for Energy Storage Canada

ESC-AUC-2020JUN03-004

Issue: Rate designs that provide for effective price signals

Request:

(a) Please comment on the preamble, which concludes that the principle of economic efficiency should be of prominent importance in designing distribution and transmission rates. To what extent can and should distribution and transmission rates be based on the underlying costs to deliver service, so that effective price signals are communicated to the customer?

(b) Do you agree with the statements in the InterGroup Consultants' evidence and the CEER paper (both quoted above) that a wires tariff should balance the need to recover the costs for capacity, which are largely fixed in the short term (arguing for more fixed charges), with the need to provide customers with effective price signals incorporating incentives to reduce their capacity requirement in the long term (arguing for some form of variable charges)? Please provide your views on "balancing" of these objectives, and any rate design challenges in achieving this balance.

(c) **For InterGroup Consultants and Brattle Group only:** Please provide your recommendation on the characteristics of a distribution tariff that would send effective price signals; that is, a tariff that provides incentives to pursue least cost alternatives for (i) price responsive load; (ii) self-supply; and (iii) grid scale generation resources. If you do not have a recommendation, please comment on the merits of the respective tariff recommendations offered by Charles River Associates, E3 and the CEER paper, as quoted above.

(d) Please explain how your recommended tariff design characteristics would balance recovering the infrastructure costs already incurred with sending price signals that will promote efficient, least cost future system infrastructure choices.

(e) Please provide your view on what kinds of information a customer should receive, and with what frequency, to create effective price signals.

(f) Does the mechanism by which price signals are communicated matter? What mechanism would you recommend and why?

(g) Please explain how your responses to (d)-(f) may depend on the state of deployment of: (i) AMI; or, if AMI is already in place, (ii) back-end data processing infrastructure.

(h) Please explain if your responses to (d)-(f) might change if the adoption of DERs was expected to increase.

Response:

a) In the view of ESC, economic efficiency is the most important factor in cost recovery of distribution tariff rates. That is, in a regulated system, the costs that a customer creates on the system should be reflected in rates, as you would expect in a competitive market. However, optimal efficiency amongst different types of consumers is more difficult to achieve. Principles of simplicity, transparency, and predictability[1] also deserve consideration when determining tariff charges for small DFO customers, which constitute the majority of customers by number.

With regards to energy storage, an efficient rate outcome would produce utility rates that enable customers to build storage facilities and connect to the grid. The AESO and distribution firms' storage tariffs must reflect what would happen in a competitive market. It would be inefficient if utility rates were so high as to discourage storage investment.

b) ESC agrees that balancing cost recovery of residual (sunk)[2] costs with price signals to encourage effective distribution system capacity usage now and in the future is required. Consumer actions that reduce consumption, such as installing micro-generation or installing efficient appliances, may not result in a reduction in residual DFO system costs in the short term. However, effective price signals are required to encourage more efficient use of the system in the longer term, and these efficiency gains will reduce future system costs.

Deployment of DERs and energy storage going forward will increase efficient use of the distribution systems on which they are installed. Customers with on-site generation, energy storage or both will have a lower impact on system usage during peak hours than other customers, and therefore any shift to greater fixed costs in DFO tariffs needs to include careful consideration of the benefits derived from these efficiency gains.

ESC suggests that, before significant changes to DFO rate designs are implemented, DFOs be required to present studies that identify the potential for efficiency gains, specify the potential reduction in cross-subsidization, detail how tariff changes will reduce undesirable impacts and determine a reasonable balance between short and longer term objectives.

[1] Exhibit 24116-X050, PDF page 12.
[2] "infrastructure costs already incurred (i.e. residual costs)." Exhibit 24116-X0650, PDF page 11.

In any event, the efficiency benefits from energy storage will only be possible if storage is economical. Tariff designs that impede efficiency gains, including the benefits presented by energy storage, should not be implemented.

c) – h) ESC has no comment.

ESC-AUC-2020JUN03-005

Issue: Dynamic tariffs

Request:

(a) Please comment on the quoted passages from the CEER paper in the preamble above. In particular, please comment on its applicability and relevance to pricing distribution systems in Alberta.

(b) Please comment on the feasibility of dynamically pricing the costs of the electric distribution and transmission systems at this time. Please specify if dynamic pricing can be reasonably implemented either temporally (i.e., prices based on the system-wide marginal cost of delivering an additional kWh during a specific time interval), locationally (i.e., prices based on the marginal cost of delivering an additional kWh to a location) or both (i.e., prices based on the marginal cost of delivering an additional kWh to a location during a specific time interval).

(c) Please provide your view on whether it is more important to vary prices over time or across locations for distribution and transmission tariffs. Please explain the extent to which your view is affected by the feasibility of implementation, and why.

(d) Please comment on the feasibility of dynamically pricing (either temporally, locationally or both) the costs of the electric distribution and transmission systems based on demand charges, rather than volumetric charges.

(e) Please comment on whether volumetric-based dynamic prices are preferable to demand-based dynamic prices, or if the two approaches may be complementary.

(f) Please provide any relevant examples of jurisdictions that price distribution and transmission systems dynamically, and for which customer classes.

(g) Would you recommend dynamic pricing for distribution and transmission tariffs for all customer classes in Alberta? If so, please explain your recommendation in the context of the spectrum of possible options provided by the Brattle Group (quoted above).

What is missing is an analysis of how dynamic pricing would improve economic efficiency and what is the relative improvement compared to procuring flexibility. ESC suggests that DFO planning processes be expanded to include an assessment of dynamic pricing and flexibility procurement options.

(h) As an alternative, should dynamic pricing be contemplated only for large commercial and industrial customers that already have the necessary metering infrastructure installed?

(i) If full dynamic pricing were adopted (i.e., real-time pricing of distribution and transmission systems temporally and locationally), would this remove the need for any investigation into the "value proposition of DERs," as has been recommended by several parties?**5** Why or why not?

(j) Please compare the effectiveness and desirability of different tariff approaches, including dynamic pricing, as an alternative to contracting for grid services from DERs for the provision of grid services and non-wires alternatives.

Response:

a) The Council of European Energy Regulators states that "in order for price signals to work in an efficient manner, two requirements must be met. First, consumers must be able to observe the price signal and, even more importantly, be able to react to the price signal."[3] At this time, in Alberta, responding to dynamic tariffs requires an action on the part of the customer. In the future, technology may allow some responses to become automated, but that is not currently the case. ESC submits that most customers today are unlikely to make significant efforts to respond to DFO rate price signals. First, because of the general lack of elasticity in residential electricity demand,[4] and second is the low relative consumer savings available should action be taken.

AESO evaluated potential demand response as part of the evaluation of the current energy market price cap.[5] The AESO identified 300 MW of load reduction in 2018 that responded at prices below $1,000/MWh and the potential for an additional 40 MW of load reduction at higher prices. Given the average 2018 pool price of $50.35/MWh, and peak load of 11,205 MW[6], it follows that a price increase of almost 2,000% results in a demand change of 3%. The question for dynamic DFO pricing becomes: What level of price increase would be required to actually induce material load customer behaviour and/or incent DER installation, and is that

[3] Exhibit 24116-X0650, PDF page 9.
[4] Exhibit 24116-X0571, 4.3.4 Demand Side Management, PDF page 56.
[5] https://www.aeso.ca/assets/Uploads/Session-2-April-9-2020-REVISED-FINAL-v2.pdf, PDF page 26 and 28
[6] AESO 2018 Annual Market Statistics, PDF page 4.

level of price increase politically palatable at this time? ESC believes that this price level would need to be excessive since the AESO viewed only 40 MW of new price responsive load if the price cap moved above $1000/MWh.

Alberta transmission and distribution planning is based on the AESO, TFOs and DFOs building a robust wires system that minimizes congestion.[7] Therefore, there is little need to try to change customer behaviour if system planning continues under its current zero-congestion practices. These planning practices have created robust, yet expensive, wires systems in Alberta.

In fact, in a recent AESO study, the AESO forecasts that current wires costs have helped to increase total grid and energy costs such that Industrial customers, in all service territories, should now be motivated to install on-site generation.[8] This creates the risk of a “death spiral” characterized by a cycle of increased wires costs and decreased system participation since industrial load makes up a significant portion of Alberta’s total load.

Dynamic pricing seems appropriate in areas where significant congestion exists, and expensive wires solutions may need to be implemented if load growth is not reduced. This is not currently the case in Alberta where we have spent significant funds on wires and the grid.

A better approach for Alberta at this time is to encourage efficiency in grid use to mitigate future wires solutions through the procurement of flexibility, including the installation of, and DFO contracting with, energy storage resources. Based on the discussion above, ESC submits that it is currently more effective for DFOs to procure flexibility and other grid services from energy storage or DERs than to introduce dynamic tariff pricing.

Further, to minimize costs to consumers, ESC submits that DFOs and the AESO should be required to demonstrate consideration of NWAs for new infrastructure projects.

Consistent with Commission direction,[9] ESC has collaborated with CGWG in our IR responses. CGWG, in their response to IR 005 (i) and (j), present constructive ideas on the use of dynamic and location-dependent price signals. ESC suggests that the Commission, AESO, DFOs and stakeholders create a set of indicators that would proactively identify the need to evaluate the more sophisticated pricing structure described by CGWG. Examples of such indicators could include:

- a certain penetration level of consumer DERs,
- a certain adoption rate of AMI, and

[7] Transmission regulation – 100% of the time in merit, 95% of the time N-1.
[8] https://www.aeso.ca/market/market-and-system-reporting/delivered-cost-of-electricity/, PDF page 43.
[9] Exhibit 241160-X0487, paragraphs 15 and 25.

- a certain predicted rate of increased congestion on a given distribution system.

ESC-AUC-2020JUN03-006

Issue: Distribution-connected generation (DCG) credits

Request:

(a) To the extent you are familiar with the DCG credits offered by the DFOs to DCG in Alberta, please provide your view on whether you agree or disagree with the Commission's prior observation on the current design of DCG credits.

(b) Based on your knowledge of other jurisdictions, please provide any relevant examples where DCG is compensated for avoiding distribution or transmission system upgrades or replacements, based on their location, that you would recommend Alberta consider.

Response:

(a) ESC agrees with the Commission's observation that existing fixed system costs (residual costs) may not be directly reduced by the addition of new DCG capacity in the short term. However, non-wire benefits provided by a DCG or storage can delay or displace future investments in both the transmission and distribution systems if these services are considered in system planning. Therefore, in the view of ESC, some level of DCG credit is appropriate.10 The key question is the level of the credit.

The DCG credit is determined by taking the actual DFO Transmission invoice for a substation and determining the amount that would have been paid without the DCG. The difference between the actual substation tariff invoice and the re-calculated amount is provided to the DCG through the credit mechanism. The determinant on the level of the credit is the structure of the ISO tariff and currently, one key determinant is the AESO bulk charge.

The current ISO tariff bulk charge reduces the substation tariff costs if the substation minimizes its load during the system coincident peak. If this ISO tariff rate structure is appropriate, then the level of DCG credit is also appropriate.

It should be noted that Dual Use AESO customers receive a benefit because the onsite generation at ISD sites results in reduced ISO tariff costs. Currently, the ISD benefit is at the same level as the benefit received by DFO's due to the introduction of DCG generation. Without an DCG credit, such as option M, the DFO would receive an AESO cost reduction that it did not

[10] ESC supports the arguments presented by CGWG in their response to IR 006.

earn because it was caused by the DCG. The DCG credit is therefore just as reasonable as the reduced ISO tariff costs paid by Dual Use ISD sites.

ESC recommends that the Commission continue with DCG credits but evaluate the appropriate ISO Bulk and Regional tariff structure once the AESO files the ISO tariff application which is expected later in 2020.

AUC-2020JUN03-007

Issue: Rate classes

ESC: review and identify potential response

Request:

(a) Please provide your view on whether the current approach to defining rate classes, which is typically based on end-use rates in Alberta (e.g., residential, farm, commercial, industrial), should be reconsidered, as contemplated by Fortis.

(b) Please comment on if (and how) the definition of rate classes might influence the adoption of DERs by certain customers.

(c) Please explain if your response to (a) might change depending on the level of deployment of:

(i) AMI; or, if AMI is already in place,

(ii) back-end data processing infrastructure.

(d) Please explain how your response to (a) might change if the adoption of DERs was expected to increase.

(e) How might concerns such as those raised by ENMAX be addressed if rate classes were restructured based on end-use?

(f) Please provide your view on whether the capacity size requirements and expected load profiles of direct current fast charging stations for EVs (Level-3 chargers) merit consideration of individual rate classes and tariffs, comparable to ATCO Electric's pilot rate of D23, approved in Decision 24747-D01-2020 and referenced in the quote above.

Response:

a) ESC submits that the Fortis existing rate classes were created for a reason. It is likely that at the time they were created, it made sense to charge a specific customer class a specific rate to encourage these types of accounts to connect to the grid. Over time, the need for the distinction in rates has likely been reduced as the businesses these rate classes represent have matured. Therefore, it is reasonable for DFOs to reconsider their rate classes as contemplated by Fortis. However, as new types of business are created, such as energy storage, the AESO and DFO's should create new rate classes to enable connection of these business. As shown by ESC in its reply submission, the AESO's current DTS rate to stand alone storage creates an effective cost to energy storage of $128/MWh.11 This rate level will not allow energy storage to connect on a stand-alone basis. It is important to consider not only efficiency in rate design but also practicality, simplicity, and other rate design principles.

b)-c) ESC has no comment.

d) ESC response to (a) already assumes an expected increase in DERs.

e) ENMAX has a valid concern of allocating large costs to a small geographic area. ESC submits that most system upgrades benefit the reliability of the system as a whole, especially when viewed over a longer time scale when the network infrastructure may change or create dependencies that maybe did not previously exist. Therefore, is it appropriate that, in general, costs for system upgrades in a specific area be collected across the entire distribution system.

f) ATCO identified that EV Level-3 chargers, like energy storage resources, have different load profiles compared to most other load customers[12] and that existing tariff structures are a financial obstacle[13]. ESC agrees that technologies such as EV Level-3 chargers and energy storage that have significantly different withdraw patterns compared to existing load customers deserve separate tariff rate consideration. ESC is interested to see the results of the analysis of the ATCO D23 pilot rate[14] and submits that a similar consideration of appropriate tariff rates for energy storage resources is required at the transmission and distribution levels.

[11] Exhibit 24116-X0615, Table 3, PDF page 9.
[12] 24747-D01-2020, paragraph 185.
[13] 24747-D01-2020, paragraph 184.
[14] 24747-D01-2020, paragraph 18.

AUC-2020JUN03-009

Issue: Markets and regulation

Request:

(a) Please comment on the statements from AFREA quoted above regarding the importance of the location of the meter, and that the custody transfer of energy accessed or egressed from the grid should take place at the customer meter.

(b) Regarding pricing energy exports to the Alberta Interconnected Electric System (AIES), to what extent should the system operator and/or regulator define the desired services (such as energy, reliability and ancillary services) and set a consistent mechanism to price the provision of those services, regardless of the source of the energy or the point (i.e., distribution or transmission) that it enters the AIES?

(c) Please comment on the statements from AFREA quoted above regarding the regulation of various sizes of generators. Can the size of the generator (or the average net export to the AIES if the generator engages in both self-supply and export) result in certain market outcomes that may necessitate regulatory intervention?

(d) Considering your response to the previous set of questions, what metering configuration would you recommend? Some examples may include:

> (i) One bi-directional interval meter for tariffs and settlement for those connected to the grid, regardless of whether they are considered “load” or “generation” or a combination of the two.
> (ii) One interval meter for tariffs and settlement dedicated to on-site load and a separate meter dedicated to generation, regardless of whether they are considered “load” or “generation” or both.
> (iii) One bi-directional interval meter for tariffs and settlement for those connected to the grid, regardless of whether they are considered “load” or “generation” or both, but a second meter dedicated to gross generation for visibility purposes for the system controller and other market participants.

(e) With respect to your response to (d) above, please comment on how the installation and operating costs of the meters factor into your recommendation. How should the costs of your recommended option be recovered?

(f) Do your answers to (a)-(d) above depend on the type of load or generation resource that is connected? Please consider in your response energy storage projects in any configuration, including those connected to load, other generating assets, or as stand-alone resources.

(g) If a customer pairs an energy storage resource with any other generation assets, what are the benefits and drawbacks for different stakeholders to treating the resources separately in terms of metering, instead of requiring only one bi-directional interval meter for the customer that would recognize only that energy is flowing past the meter, but not the source from which it was generated?

(h) Several parties commented on how rules concerning who is permitted to own storage projects might affect the wholesale electricity market. Please provide your views on how energy storage ownership rules might affect the ancillary services market, including market power issues that may arise.

Response:

(a) ESC supports the position expressed by AFREA that the custody of energy should change at the meter. In the case of an energy storage resource, the energy stored by the resource should be in the custody of the facility owner.

(b) The mechanism for pricing energy and ancillary services delivered to the AIES should be consistent regardless of source. We make a distinction in the case of a distribution connected micro-generation facility that is providing energy to the distribution system. The energy provided to the distribution system by a micro-generator should be priced according to the current rules.

(c) The AFREA point is valid in that a regulatory or operating condition that is placed on a large generator may be unnecessarily burdensome on a smaller generator. The current requirement for market participation for facilities above 5 MW is appropriate and should not be reduced. The threshold of 150 kW for pricing for micro-generators would ideally be raised by the Government to 500 kW to encourage more efficient deployment of micro-generation facilities.

(d) In principal, ESC supports providing visibility to the system controller (DFO or AESO). However, adding a second meter for smaller installations could be financially onerous and may not provide materially relevant information. This is an important question for discussion among DFOs, facility owners and the AESO before DER penetration increases to a level where DER generation becomes material to system reliability.

Before requiring a second meter dedicated to generation, the DFO should provide analysis to indicate how the cost of collecting and processing the additional information will result in more efficient and more reliable operation of the distribution system.

(e) A key concern for metering will be the net impact on cost allocation for wires charges. If net metering is allowed, then the rate structure for net metered sites may need to be evaluated to ensure that other customers, that do not have net metering, will not be unfairly allocated wires costs.

If an additional meter is requested by the DFO, then the cost should be recovered by the DFO as an operating cost. The benefit of the meter is to aid in the operation of the distribution system and is therefore a benefit to all customers.

f) Our answers apply to stand-alone energy storage resources and are applicable to other load/generation/storage resource configurations as well.

g) In general, there will not be a negative impact on non-storage customers from allowing only one bi-directional interval meter if rates are properly designed. It will be reasonable for a DFO to perform analysis to indicate the necessity of installing a second generation-only meter at some locations and for resources of sufficient size.

h) ESC is not opposed to allowing DFOs to own energy storage resources for the provision of grid services if these storage facilities have minimal amount of charging and discharging and therefore minimal impact on the energy market. ESC agrees that regulated entities should not be permitted to participate in competitive markets, including the ancillary services market, and acknowledges that prohibiting DFO ownership of energy storage is a simple solution. However, prohibition of DFO ownership may not be the optimal solution. Should DFO ownership of energy storage resources be permitted, ESC is not concerned about impacts to the ancillary services (AS) market. The provision of AS occurs on a day ahead basis and therefore precluding

DFO participation in the AS market is straight forward and activities related to grid services are unlikely to impact the need for or delivery of AS.