Alberta Transmission Policy - Direct Energy

Overall Comments

DE appreciates the opportunity to respond to the Government of Alberta's Transmission Policy. As the Government is contemplating changes, Direct Energy agrees that the fundamental principles of affordability, reliability, and decarbonization should form the basis of future transmission policy and regulation. Direct Energy understands that the Government is also looking at broader market principles and structure (Revisions to the Regulated Rate Option, the AESO Net-Zero Pathways project, AUC Inquiry into the Development of Electricity Generation, and MSA making recommendations on market design) however the engagement processes are not linked. As the comments below demonstrate, the market design for the generation, retailing, and transmission of electric power in Alberta are linked and need to be evaluated holistically. Changes in one area could greatly impact the other parts of the sector. Direct Energy has concerns that not only could there be a duplication of efforts, but that key aspects that are discussed and considered when looking at the individual components will be missed by not having an integrated discussion with all market participants.

Policy Considerations

Generating Units Contribution

Proposed Government Direction

- Remove the prescribed maximum GUOC rate, set the minimum GUOC rate to $0/MW, make GUOC non-refundable, and allow determination of rates based on transmission capability.

DE Response

- No comments

Line Loss Calculation

Proposed Government Direction

- Shifting the loss factor calculation methodology to a system-wide average approach that would apply similarly to each generator regardless of their location and operating profile

DE Response

- No comments

Non-Wires Alternatives (NWA) [Section 6(c) in paper]

Proposed Government Direction:

- This option would expand the use of non-wires solutions and ensure that additional wire solutions are not the default solution to reliability challenges. Non-wires solutions would be procured as a service or as a regulated asset.

DE Response:

Direct Energy supports AESO's continued ability to identify opportunities within its planning process where NWAs may substitute for TFOs' wires-based regulated transmission under the circumstances as they are currently defined. Our view is that NWAs have been *under-utilized*. Direct Energy also supports that part of the Green Paper's "anticipated direction" that would permit "the AESO [to] competitively procure the transmission attributes of non-wires solutions from market participants operating in the market via short-term contracts." The market participants included in this opportunity should include both generation and also retailers.

Direct Energy does not support allowing TFOs and DFOs to own NWAs themselves. Instead, NWAs should be sourced by AESO exclusively from the competitive market, because the distributed-generation, storage, and demand-response resources that provide NWA service have predominant use cases within the competitive markets for generation and retail supply. Notably, the State of Texas recently codified in state law the prohibition on regulated utilities' ownership of storage in its ERCOT market, which resembles Alberta as closely as any other jurisdiction in North America, and the same law provided only limited abilities to lease storage as an NWA (up to 100 MW in an 80,000+ MW system) through utility cost recovery.

The Green Paper suggests that "the energy-only market is mature" for the resources that would provide the foundation of NWAs. Direct Energy disagrees in an important respect with this observation. Advanced metering infrastructure ("AMI") still is not widely deployed in the province, and even where it is, it is frequently not used to settle actual customer loads on a granular time interval for the purposes of billing. The result of this is a market for the distributed generation, demand response, and customer-sited storage resources that is *not* mature, and indeed is being inhibited from developing in the first place, because the metering platform simply does not exist to accommodate the compensation of those devices for their load-shifting activities (the same activities that constitute NWA service) when retail customers willingly adopt them.

In time, once AMI and complementary billing systems are widely deployed in the province, retailers will be able to market distributed energy resources ("DERs") to customers and optimize them as part of their retail rate plans, offered to customers through the competitive market. The evidence from other markets shows that the vast majority of resources that provide NWA are otherwise expected to enter service through the competitive market, not regulated distribution and transmission utilities. Many of the plausible non-wires alternatives that could be used in Alberta will and should be optimized through retail offerings in the province's competitive retail market.

While it is appropriate that these retailers should be able to compete in a limited AESO solicitation to provide a NWA sourced from their base of their customers, allowing the systematic rate-basing of DERs by TFOs and DFOs will crowd out the competitive market for generation and retail rate plans in this important space. This risk can be staved off by allowing AESO to conduct limited procurements for NWAs, which would constitute a revenue stream to partially offset the cost of DERs emerging from the competitive generation and retail space, without allowing local monopoly TFOs and DFOs with entry into this market.

To the extent that AESO's procurement would assign certain costs to the customers of a particular TFO, those costs should be passed by AESO to a TFO and recovered without additional markup or intermediation by the TFO, consistent with applicable cost allocation and rate design of that utility.

Broader Policy Considerations

Zero-congestion policy (Section 7(a))

Should Alberta's zero-congestion policy be considered in light of the objectives outlined in this paper? If so, do you support one of the options proposed above? Which one and why? Should other options be considered?

Yes. The policy of zero congestion is not a tenable situation in a network where power supply is motivated to located in resource-rich locations, often far from load. Already the province is seeing a substantial rate of increase in congestion as demonstrated by the out-of-market payments made to generators under must-run and redispatch protocols of AESO, though the absolute value of these payments remains low for the time being. (See pages 39-42: https://www.aeso.ca/assets/Uploads/market-and-system-reporting/2022_Annual_Market_Stats_Final.pdf) These statistics should be understood to be a leading indicator of the problem ahead. If the policy of zero-congestion is maintained, the changing resource mix in the province will ensure significant increases in transmission costs and the possibility of substantial moral hazard for those making siting decisions, who should incorporate in their development decision-making the optimization of resource siting on both the vitality of the natural resource and its proximity to load or capacity on the transmission system.

Direct Energy supports an optimal planning approach. The alternative is to adopt an arbitrary percentile figure for acceptable levels of congestion. However, it may be possible that high levels of congestion are economically efficient in certain locations (e.g., where it would be extremely expensive to build out a transmission line), and *vice versa.*

If an optimal transmission planning approach were implemented, what would the implications be on other interconnected policies discussed in this paper and otherwise?

A system that is designed to tolerate incidences of congestion would require a corresponding alteration to the market design of AESO's existing energy-only market by undertaking at least three reforms:

1. The implementation of a nodal pricing model to calculate locational marginal prices.
2. The introduction of a financial product that represents the property right to congestion rents, commonly called a Financial Transmission Right or Congestion Revenue Right in electricity market design.
3. The introduction of meaningful and binding market power mitigation that counteracts the likely increase in the exercise of unilateral market power that could accompany the introduction of congestion on the transmission grid.

See our answers to Question 7(b) for further details on these three reforms.

If an optimal planning approach were implemented, what benefits and costs should be considered when determining the need for new transmission?

Direct Energy urges caution on over reliance of any multi-decade planning study for making transmission investments due to the inherent uncertainty of a study with such a long planning horizon. The electric grid is facing significant change. Past long-term planning studies have done a questionable job at forecasting future needs, even in the presence of variables that were arguably not as uncertain and volatile as the ones grid planners face today. Direct Energy is not opposed to the voluntary use of 20-year planning studies to inform shorter-term transmission decision-making but does not believe that reliance on 20-year transmission planning to drive investment decisions will lead to just and reasonable outcomes. A shorter-term assessment of 10 years would be more certain, fit within the planning horizon necessary to make transmission investment decisions, and still reflect regional policy goals. Longer-tenor expectations can and should be made by state policymakers or private actors, taking on transmission as part of energy-project development costs and priced into power purchase agreements.

The changes the Government is considering through this and other government-contemplated changes (revisions to the Regulated Rate Option, the AESO Net-Zero Pathways project, AUC Inquiry into the Development of Electricity Generation, and MSA exploring changes to market design) need to be considered holistically not in isolation of each other.

Cost allocation (Section 7(b))

Should Alberta's load-pays policy be considered in light of the objectives outlined in this paper? If so, do you support one of the options proposed above? Which one and why?

Direct Energy does not believe that Options 1 and 2 are strictly mutually exclusive, as the Green Paper suggests. In general, transmission does support load in terms of reliability and access to competitive supplies of energy. In most electricity markets, Load pays for all or most of the transmission revenue requirement, and load also consequently owns the property right to congestion rent on the transmission system that it has paid for. This property right is productized in electricity markets through Financial Transmission Rights or Congestion Revenue Rights. Load-serving entities should receive an allocation of FTRs or CRRs based on the load they serve, and they should be free to hold or sell those FTR or CRR allocations at auction, or to trade them bilaterally. Typically, generators, virtual market participants (financial traders), and other load-serving entities (competitive retailers) will have an interest in buying FTRs and CRRs in order to hedge the value of the generation they own or contract with, to lock in a cost structure for their retail supply obligations, or to take positions on the economic value of energy arbitrage. In summary, the trade in FTRs and CRRs should produce a revenue stream that is credited back to load, which pays for most transmission in the first instance.

Meanwhile, for certain transmission facilities with particular characteristics—for example, lines that are principally designed to accommodate an expansion of renewables in a remote area, or interties between markets—it may make sense for the province to expect the cost of those lines (and thus the rights to them) to be paid for by interconnecting generators. Those generators then will build these costs into their models to justify the development of their project, and the sales or offtake agreements they make on a forward basis in order to obtain project financing. (Very few if any renewable projects are entirely exposed on a purely merchant basis to the AESO's real-time energy pricing.) If generators pay for lines, they should have the right to the capacity they have paid for, and to the FTRs/CRRs that are associated with that transmission.

Should other options be considered?

In addition to cost allocation, the province should carefully consider the retail rate design of transmission rates in Alberta. To the extent transmission investments are predicated on increasing demand for electricity (as opposed to accommodating new remotely located sources of supply), then it is appropriate to try to obviate the need for an overbuild of transmission investment to the extent possible by sending price signals through transmission rates that are charged at times of high and increasing demand. At present, only the largest customers are exposed to transmission rates that have exposure to such rates, and as discussed earlier in our response to (6)(c), the lack of AMI poses practical barriers to understanding other customers' contribution to demand peaks. However, it should be considered that AMI, once deployed, should convey time-of-use price signals associated with transmission as a default rate design—subject to retailers willingness to bear that exposure onto themselves (and thus have an incentive relative to minimizing that transmission cost to flex their consumers demand through DERs). An active demand side that is more capable of load shifting (and being paid for that service) will help reduce the costs of transmission in general, and thus reduce pressure on sensitive questions of cost allocation.

If transmission rights are implemented, what would the implication be on other interconnected policies in this paper and otherwise?

Here we expand on the three essential policies that relate to the presence of transmission congestion which are:

1. Nodal pricing through LMPs
2. FTRs and CRRs to represent the property right to congestion rent
3. Market power mitigation

First, without *nodal* pricing, the presence of transmission congestion will create uneconomic dispatch of generation that consumers will ultimately pay for. In a well-designed electricity market, transmission constraints should be reflected in the pricing that faces supply, because those transmission constraints limit the amount of supply that can be exported from a place rich in supply to a place that is more demand-heavy. The locational marginal pricing that results from a nodal market design is a logical and economically efficient representation of this natural phenomenon.

Other markets have tried a *zonal* approach to supply pricing, but this would perpetuate inefficient siting decisions and cause an increase in the must-run, redispatch, or uplift payments needed to pay out-of-market generation to relieve the actual transmission constraints (which are more prevalent than a zonal model would represent in its pricing scheme). Meanwhile, in recognition of the implausibility of having significantly different costs to serve customers in the competitive retail market, load can and should continue to be priced zonally, at the average of LMPs within the zone. The only other energy-only market in North America, ERCOT, has adopted this nodal-supply/zonal-load settlement approach in its market design.

Second, as we describe above, if nodal locational marginal prices influence the dispatch of supply and the long-term decisions to develop new generation (or not) in a particular location, then FTRs and CRRs represent the congestion rent between two points on the transmission system. Whoever paid for transmission should be entitled to this rent, and they should be able to resell that right to congestion rent through an FTR/CRR auction or in bilateral trading.

Third and finally, Alberta already has a relatively concentrated sector for power generation, which is capable of exercising unilateral market power relative to the pool-wide price resulting from the "no congestion" policy. Market power would become further concentrated in the presence of substantial transmission congestion at particular nodes, and it would be necessary to implement a meaningful regime of market power mitigation. Alberta is the only organized wholesale electricity market in North America without a comprehensive approach to market power mitigation. A variety of approaches in markets in the United States was recently sampled here: (pages 8-39: https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/MPM_Review_GPQW.pdf)

Ancillary Services

Questions:

- Should cost causation be a driving principle in the assignment of ancillary services costs?
- Are ancillary services costs substantial enough to warrant the regulatory changes that would be associated with assigning them to be based on cost causation principles?

Response:

- Moving to a nodal framework with congestion would make ancillary services more efficient, so the regulatory application of cost causation principles would not be required.

Interties

Questions:

- What changes to intertie policy are required to ensure sufficient levels of timely restoration and expansion can be achieved to meet government's goals?
- What are the principles that should be considered in balancing intertie policy with the integrity of Alberta's competitive market and system reliability?
- To what extent should the competitive process be maintained as it relates to the development of new, or upgrade of existing, regulated and merchant interties?
- What mechanisms, if any, are required to ensure a level playing field for imports in Alberta's electricity market if interties were to be restored or expanded?

Response:

Direct Energy is supportive of merchant-built interties and allowing economic bids/offers on the interties. We are also supportive of broader coordination with the WECC and participation in the Western Energy Imbalance Market.