Submission to the Alberta Utilities Commission

Distribution System Inquiry Submission Combined Modules 2 & 3 Proceeding 24116

Submission of Energy Efficiency Alberta (EEA)

Submission Date: March 13th, 2020

Jesse Row
Vice President, Corporate Performance
jesse.row@efficiencyalberta.ca

Karen Gorecki
Director, Policy Outreach
karen.gorecki@efficiencyalberta.ca

Energy Efficiency Alberta

Executive Summary

Principles

1. EEA recommends the AUC apply the following principles to the distribution system:

   a) Use an approach that recognizes the **distribution system as part of the broader electricity and natural system** given their connectivity in costs, risks and effects,

   b) Pursue a **least-cost approach**, that **considers all costs and benefits,** including those within the broader electric and natural gas systems, to minimize cost for ratepayers and consumers,

   c) Consider **risk mitigation** alongside the least-cost approach to safeguard against relevant uncertainties,

   d) Apply **technology agnosticism** in a manner that includes resource agnosticism - an impartiality to whether a solution is a supply or demand-side (e.g. demand response, energy efficiency, distributed generation).

   e) Accompany a **preference for market mechanisms** with a recognition that policy intervention may be required to address market barriers or where market access is limited.

   f) Enhance **customer choice**, in part, by addressing market barriers that may distort customer choices. These barriers may be addressed through programs that increase customer knowledge to enable efficient choices.

   g) Use **pricing to influence behaviour** is another element in a least-cost approach that can help to influence consumer choices.

Energy Efficiency Supports a Least-cost Approach

2. Experience shows that energy efficiency programming is an effective cost and risk management tool for the distribution system and the utility system as a whole. Jurisdiction-wide and geotargeted (non-wires alternative[1] (NWA)) energy efficiency programs reduce costs in both the distribution system and for energy consumers. They are also a valuable tool in avoiding future costs that may be incurred by the adoption of new technologies such as electric vehicles (EVs).

3. Evidence shows that EVs are likely to increase the costs of the distribution system depending on how their integration is managed. Studies in other jurisdictions have found that future distribution system costs related to electric vehicle impacts could be mitigated by energy

[1] NWA is used in this submission to describe both non-wire solutions or alternatives in the electricity system and non-pipe solutions or alternatives in the natural gas system.

efficiency, demand response, and smart charging. In addition, EEA recently commissioned a study that demonstrates that a combination of energy efficiency, demand response and managed charging can be more cost-effective than a traditional wires investment (see Appendix A). Under both scenarios modelled, the non-wires portfolio can mitigate overloading of transformers due to EV charging during peak demand periods. This example, as well as growing experience in other jurisdictions, demonstrates energy efficiency programming can act as a cost-effective NWA to traditional wires infrastructure.

4. Energy efficiency offers a no-regrets strategy – saving system costs beyond the distribution system through avoided energy costs, reductions in market-clearing prices for energy, avoided generating capacity costs, reduced transmission costs, avoided line losses and reduced exposure to carbon pricing.

5. Alberta's regulatory framework could better support the principle of "least-cost" through the following considerations:

    a) Take steps to enable the use of NWAs – NWAs are being increasingly assessed and enabled in other jurisdictions to manage costs and risks within utility systems. This is expected to become increasingly important given the expected uptake in new technologies such as electric vehicles.

    b) Integrate energy efficiency into the utility system – Jurisdiction-wide energy efficiency programs are used in nearly all provinces and states in Canada and the U.S. as a cost and risk management tool. These programs are highly complementary with the use of NWAs, smart charging and demand response to help manage the integration of new technologies into distribution systems.

    c) Enable smart charging – Given the impact of even a small number of electric vehicles clustered into a specific area, engaging consumers to enable smart charging technologies and behaviours will become increasingly required to effectively manage distribution system costs.

AUC Questions

1. (i) Principles

AUC Question: During the technical conference for Module One, several parties recommended that the regulatory framework governing the Alberta Interconnected Electric System (AIES) should be technology agnostic and economically efficient. Other principles that also may be applied include customer choice, fairness, efficiency and open competition. In your view, what principles should be applied to implement the regulatory framework necessary to accommodate the economic and technological forces that are transforming the market structure governing energy distribution by public utilities?

7. EEA recommends the AUC apply the following principles to accommodate economic and technological forces that are transforming the market structure governing the distribution system. EEA sees these principles as aligned with other principles outlined in utility system legislation such as the *Hydro and Electric Energy Act*, the *Gas Utilities Act* and the *Electric Utilities Act*.

A. Distribution System as Part of Broader Electric System

8. It is important to recognize that the distribution system is one part of a broader electric system that also includes generation, transmission and end-use customers. Many of the resources – especially distributed energy resources – that can be deployed to address distribution system needs also affect other parts of the system. For example, energy efficiency programs do not just reduce demand on localized distribution system infrastructure; they also reduce customers energy costs, reduce market-clearing prices for energy that all customers pay, reduce generation capacity needs and potentially defer generation capacity investments, reduce transmission demand and potentially defer transmission capacity investments, reduce costs associated with compliance with future environmental regulations, etc. Similarly, demand response programs can be deployed to both defer localized distribution system capital investments and to defer system generation and/or transmission capacity investments.

9. The AUC's primary focus is understandably on the regulated components of the electricity and natural gas systems – its principal regulatory responsibility. However, its approach to regulating these components can have important implications for costs, risks and effects on other parts of the electric system. Thus, any regulations established for the distribution system should reflect the "connectedness" of the distribution system to the rest of the grid. For example, energy efficiency programming could cost $3 million to defer a $2 million substation upgrade. If only direct wires cost and benefits were considered, this project would not appear to be cost-effective. However, this narrow perspective misses the $1 million in other avoided system capacity costs and $3 million in avoided energy costs. From a broader "whole system" perspective that includes these avoided costs, all benefits to the project would be $6 million with a cost-benefit ratio of 3.0. As an example, Navigant, calculated the net present value of benefits and costs of Con Edison's 2003-2010 Non-Wires Projects and found that transmission

and distribution (T&D) savings were only roughly a third of the benefits. While these savings were still about $50 million greater than the costs, when considering energy and other savings (in other words, “whole system” benefits), the benefits were approximately $300 million greater than costs.[2]

B. Least-cost Approach

10. Cost management, or pursuing a least-cost approach, should be a prominent consideration at the Distribution System Inquiry given the focus of “developing the necessary regulatory framework to accommodate the evolution of the electric [and natural gas] system[s]”. Any adjusted regulatory framework should ensure an economic and efficient system so that ratepayers are paying the lowest cost for a safe, reliable transmission, and distribution utility system. A balanced regulatory framework would minimize costs for ratepayers and consumers (including avoided energy costs etc. listed in paragraph 11 below) while ensuring fair allocation between customers and securing appropriate distribution system revenue.

Consider all Costs and Benefits

11. A least-cost approach should consider comprehensive, but relevant, costs and benefits when considering appropriate regulatory approaches, and planning processes. This approach often requires that all electric system benefits provided by energy efficiency and other distributed energy resources (DERs) - including avoided energy costs, reductions in market-clearing prices for energy, avoided generating capacity costs, avoided transmission costs, avoided line losses, avoided carbon pricing through regulation, etc. - be recognized and valued in decision-making (see example in paragraph 9). Depending on its interpretation of provincial policy objectives, other societal impacts, such as air quality impacts and increased jobs or economic development, could also be considered.

C. Risk Mitigation

12. While minimizing costs is a vitally important objective, it is also important that risk is considered. For example, it may be preferable to choose option B that is 5 per cent more expensive than option A, if:

    a) option A costs are much more uncertain,

[2] In a 2015 Northeast Energy Efficiency Partnerships (NEEP) report, Navigant calculated the net present value of benefits and costs of Con Edison’s 2003-2010 Non-Wires Projects and found that T&D savings were only roughly a third of the benefits. While these savings were still about $50 million greater than the costs, when considering energy and other savings (in other words, “whole system” benefits), the benefits were approximately $300 million greater than costs. Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments.* https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

b) the load forecast underpinning the need for option A is uncertain, and/or

c) option B insulates customers from other future cost risks.

13. Energy efficiency and some other DERs can mitigate risk in several ways:

a) Localized peak load forecasts underpinning distribution system investment needs are often conservatively high (perhaps understandably, given the importance distribution system engineers need to place on "keeping the lights on"). Deployment of energy efficiency and/or other DERs as part of NWAs can "buy time" to identify such conservatisms and re-calibrate. For example, in discussing its NWA projects from 2003 to 2010, Consolidated Edison stated:

> "…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it *would have installed up to $85 million in capacity extensions that may never be needed."*[3]

b) Efficiency and customer-sited distributed generation can reduce customers' exposure to future fuel price volatility.

c) Efficiency and some other DERs can begin to be acquired within months of decisions to proceed with their acquisition, which is much faster than many supply alternatives. In addition, some efficiency programs self-modulate in ways consistent with system needs. For example, participation in efficiency programs targeting new construction practices will generally be greater when more construction is happening – i.e. when system loads are growing fastest and savings are more valuable – and lower when less construction is taking place – i.e. when system loads are not growing as fast and savings are therefore less valuable. As a result, efficiency resource acquisition can be much more easily modulated (up or down) than most new supply alternatives, either in response to market feedback (e.g. if customer uptake and/or program costs are greater or lower than expected) or to meet evolving assessments of system needs.

14. The risk profiles of different resource options can theoretically be captured in cost-effectiveness analyses. For example, regulators in Vermont have historically reduced the cost of efficiency resources by 10 per cent when conducting cost-effectiveness analyses as a conservative way of reflecting their risk-mitigating benefits relative to supply alternatives.[4]

[3] Gazze, C., Mysholowsky, S., & Craft, R. (2009). *Con Edisons's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction*. https://www.aceee.org/files/proceedings/2010/data/papers/2059.pdf
[4] Vermont Public Service Board. (1990). *Decision in Docket No. 5270: Investigation into Least-Cost Investments, Energy Efficiency, Conservation and the Management of Demand for Energy*.

D. Technology Agnostic

15. A technology-agnostic regulatory framework would be unbiased with respect to which type of technology solves a distribution system related issue/problem. Rather than prescribing specific technologies, the framework would focus on maintaining flexible approaches to meet the intended objective(s). For example, any technology should be able to contribute towards a non-wires alternative(s) (NWA) project if it is deemed more cost-effective than a traditional transmission and distribution (T&D) or “wires” investment and it meets the required load reduction objective(s).[5]

16. EEA recommends technology agnosticism also encompasses a resource agnostic approach. This principle would, therefore, guide regulatory framework and planning processes to be agnostic on whether a solution is on the supply or demand-side solutions (e.g. demand response, energy efficiency, distributed generation) as long as it best met relevant objectives.

17. It is important to recognize that not all technologies interact with the system the same way even though they can bring similar services and multiple benefits. Demand-side solutions, for example, cannot participate in the market the same way supply-side resources or T&D resources participate. Therefore, intervention should occur in one of two ways: 1) the market is adjusted to provide a value stream to demand-side management, or 2) introduce programs or regulation that address barriers to market participation.

E. Preference for Market Mechanisms

18. Whenever possible, there should be a reliance on markets or market processes. A preference for reliance on market mechanisms can still support intervention, through regulation or programming, where the range of market mechanisms do not recognize the value of environmental, and/or social interests (consistent with the AUC’s mandate as described in paragraph 10 above) and/or there are market barriers that must be addressed outside of the market. This requires a recognition that there are circumstances where markets fail to provide the least-cost option due to a lack of market access.

19. Regulation or other policy intervention is also appropriate when there is no vehicle for compensation of all desired value streams provided by a resource. Energy efficiency programming can provide energy, capacity, transmission & distribution cost savings and risk mitigation, as well as emission reductions, enhanced economic development, amongst other social and economic objectives, but it is often not adequately compensated for these values it provides. Moreover, energy efficiency programming faces barriers (e.g. information asymmetry, split incentives) that reduce its uptake to a level that is less than economically efficient. There is, therefore, justification to address these barriers through planning processes and programming to increase uptake to a cost-effective level.

[5] A least-cost and technology agnostic NWA approach would rank and select DERs and other technologies contributing to the NWA project according to their cost-effectiveness.

F. Customer Choice

20. This principle is aligned with the concept of competitive markets; customers should have the freedom to make choices about their energy retailer, supply, end-uses, etc. However, maintaining customer choice must remain consistent with each customer or rate class bearing an appropriate cost burden for their impacts on the transmission and distribution systems.

21. This principle should also be guided by an understanding that market imperfections that may skew customer choices (e.g. lack of information on energy efficiency impacts of a particular end-use choice can lead to suboptimal decision-making). Rates and programs can enable understanding and provide incentives for consumers to make more efficient choices.

22. A demand-side management (DSM) program administrator[6] helps maintain customer choice in multiple ways. For example:

    a) Helping to make efficient products and services available – and appropriately accessible - in the market when they otherwise may not be;

    b) Helping to educate consumers on the trade-offs between up-front cost and longer term-energy savings and other benefits of efficiency measures so that their choices are informed choices;

    c) Helping to educate and train builders, developers, contractors, retailers and other trade allies on elements of efficiency design and the benefits of efficiency so they can more effectively offer "efficiency choices" to their customers; and

    d) Ensuring there is a level playing field for all market participants:

        i. Ensuring all efficiency products that meet a specific standard are included in programs,

        ii. Forming a trade ally network open to all contractors (if they adhere to specific standards), which also increases consumer understanding of the choice in contractors they have in the market; and

        iii. Administering small consumer managed/smart charging and demand response (heat, water heating, appliance etc.) programs that are agnostic to product brand while ensuring they offer adequate services (e.g. ability to respond to utility communication requirements).

[6] EEA's submission most frequently uses the term "energy efficiency program administrator" given that, of all demand-side solutions, energy efficiency is most often the least-cost, common, and well-understood of all demand-side solutions. As programs evolve, micro-generation and small consumer demand response are often included in these administrators' program portfolios. Consider the terms "demand-side management" or "energy efficiency program administrator" to be synonymous in EEA's submissions whereas the former is more accurate, and the latter is better understood.

23. These consumer choices can have an impact on energy infrastructure for many years (e.g. construction of a large commercial building), therefore it is important to address market imperfections in a timely way to encourage more efficient consumer choices.

G. Pricing to Influence Behaviour

24. Many customer investment decisions have implications that can last between 10 and 50 years. If price signals are based on the short-run as opposed to the long-run, inefficient choices will be made. Careful rate design can simultaneously recover utility costs, equitably determine how rates should be collected, and send customers appropriate price signals to reduce total utility system costs. Rate structure should send price signals to conserve energy and reduce the need for future infrastructure to be built along with appropriately recovering utility costs.

25. If price signals are based on the short-run as opposed to the long-run, inefficient choices will be made. Careful rate design can simultaneously recover utility costs, equitably determine how rates should be collected, and send customers appropriate price signals to reduce total utility system costs. Rate structure should send price signals to conserve energy and reduce the need for future infrastructure to be built along with appropriately recovering utility costs.

26. For example, already, 33 to 45 per cent of a residential annual bill consists of fixed charges in Alberta.[7] Also, without the variable charge being made explicit on the bill, some consumers perceive fixed charges to be even higher than this. The implications of increasing fixed costs should influence rate redesign coming out of the Distribution System Inquiry:

    a) Many utility costs are fixed over the short and medium-term, but variable over a long-term planning horizon. Therefore, economically efficient price signals should inform rate setting along with cost-of-service studies. Cost-of-service allocates historical costs to customer classes and indicates how much revenue to collect, but prices should attempt to reflect future marginal costs to influence customer behaviour.[8]

[7] Average detached home in 2016. See the MSA report to the Minister of Energy, Market Surveillance Administrator (MSA). 2017. *Options for Enhancing the Design of the Regulated Rate Option.*
[8] Whited, M., Woolf, T., & Daniel, J. (2016). *Caught in a Fix, The Problem with Fixed Charges for Electricity*. https://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf

b) A high proportion of fixed charges are widely considered to negatively impact low electricity users.[9] Low-income customers tend to consume less electricity than residential customers on average.[10]

c) Fixed charges reduce a customers' ability to respond to price signals regarding capacity and distribution constraints, thus decreasing a customers' ability to lower their bill by consuming less energy. It, therefore, reduces the incentive to invest in energy efficiency and other DERs. These customer decisions can influence whether future investment in utility infrastructure is necessary and a lack of price signals can result in higher costs for the distribution system.[11]

d) While price signals should be in place to influence behaviour, it should be recognized that market barriers exist that prevent efficient behaviour. It is common for programs and regulations to be used to compliment pricing in order to achieve efficient outcomes.

[9] Chernick, P., Colgan, J.T., Gilliam, R., Jester, D., & LeBel, M. (2016). *Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers*. https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf;
Whited, M., Woolf, T., & Daniel, J. (2016). *Caught in a Fix, The Problem with Fixed Charges for Electricity*. https://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf;
Advanced Energy Economy (AEE). 2018. *Rate Design for a DER Future, Designing rates to better integrate and value distributed energy resources*. https://info.aee.net/hubfs/PDF/Rate-Design.pdf;
Lazar, J., Allen, R., & Schwartz, L. (2011). *Pricing Do's and Don'ts: Designing Retail Rates As if Efficiency Counts*. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-pricingdosanddonts-2011-04.pdf
[10] In nearly every state, most low-income customers have a level of energy consumption below the median. Nationally, as gross income rises so does average electricity consumption. See Whited, M., Woolf, T., & Daniel, J. (2016). *Caught in a Fix, The Problem with Fixed Charges for Electricity*. https://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf; and Energy Information Administration (EIA). (2009). *Residential Energy Consumption Survey 2009*. https://www.eia.gov/consumption/residential/data/2009/
[11] Baatz, B. (2017). *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*. https://www.aceee.org/sites/default/files/publications/researchreports/u1703.pdf

1. (ii) Principles as Applied to the Regulatory Framework

AUC Question: When considering the various load and generation connection schemes summarized in the preliminary IRs, and potentially others, how does the current regulatory framework governing those connection schemes apply, or not apply, to the principles put forward in part (i)? What changes might be recommended?

27. EEA sees the above principles as important to the distribution system beyond the load and generation connection schemes summarized in the preliminary IRs. The AUC's preliminary IRs only raise supply-side connection schemes, whereas EEA argues that the principles be applied to also integrate demand-side options into distribution system planning. Specifically, these principles should also be applied to encourage NWAs, demand response, and energy efficiency programming. These all merit equal consideration as the originally-stated purpose of the Distribution Inquiry, "is to map out the key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system".[12]

28. EEA's submission presents information below to support the following:

    A. **Energy Efficiency Supports a Least-cost Approach** – Jurisdiction-wide and geotargeted (NWA) energy efficiency programs reduce costs in both the distribution system and for energy consumers. They are also a valuable tool in avoiding future costs that may be imposed by electric vehicles (EVs).

29. Therefore, Alberta's regulatory framework could better support the principle of "least-cost" through the following considerations:

    B. **Fund Energy Efficiency through the Utility System** – In contrast to other provinces in Canada, the utility system in Alberta does not integrate energy efficiency programming as a cost and risk management tool. In 2018, 94.5 per cent of energy efficiency total program funding in Canada and the U.S. (CDN$12.5 billion) was through utility systems.[13] Other jurisdictions fund energy efficiency through utility-based funding to ensure the benefits to the system are consistently and predictably supplied.

    C. **Address Potential Barriers to NWAs** - Given NWAs have not been prevalent in the distribution system, it merits consideration of what the potential barriers are for utilities engaging in NWAs.

[12] Alberta Utilities Commission (AUC). (2018). *Bulletin 2018-17, Electric Distribution Inquiry*. Exhibit # 24116-X0009, page 1. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0009_2018-17ElectricDistributionSystemInquiry_0010.pdf

[13] For North American energy efficiency program budgets see the data tables from the Consortium for Energy Efficiency (CEE)'s . *Efficiency Program Industry by State and Region Appendices, 2018* (Consortium for Energy Efficiency. 2019. *Efficiency Program Industry by State and Region Appendices, 2018.* https://library.cee1.org/content/efficiency-program-industry-state-and-region-appendices-2018/). For North American energy efficiency utility funding percentages, see Consortium for Energy Efficiency (CEE)'s *CEE Annual Industry Report, 2018 State of the Efficiency Program Industry, Budgets, Expenditures, and Impacts* (Consortium for Energy Efficiency (CEE). (2019). *CEE Annual Industry Report, 2018 State of the Efficiency Program Industry, Budgets, Expenditures, and Impacts*. https://library.cee1.org/system/files/library/13981/CEE_2018_AnnualIndustryReport.pdf).

Each of the above concepts is expanded upon in the following sections.

A. Energy Efficiency Supports a Least-cost Approach

30. Prior to outlining the limitations of the current regulatory framework, it is important to highlight why energy efficiency supports a least-cost approach in the distribution system as well as the broader utility system.

31. Experience in other jurisdictions shows that energy efficiency programming is an effective cost and risk management tool for the distribution system.

1) Passive Deferrals

32. Jurisdiction-wide programs save distribution system costs through passive deferrals. As outlined in EEA's Module One submission, passive deferrals refer to avoiding or temporarily deferring transmission and distribution infrastructure upgrades due to the peak demand reductions from jurisdiction-wide energy efficiency programs.[14]

33. Many utilities[15] conduct T&D cost studies to be able to include these avoided costs in their energy efficiency cost-effectiveness analysis. By having a better understanding of T&D passive deferrals, more programs and measures may become cost-effective and, subsequently, the overall cost-effectiveness of the overall program portfolio increases. *Ex-post* studies of actual avoided deferrals are not as commonly performed or publicly documented. However, there are some examples of documented benefits from passive deferrals, including:

   a) In 2012, ISO New England deferred over $400 million in planned transmission investments as a result of integrating energy efficiency savings into its planning processes.[16] This example highlights the value of having long-term, well-funded, jurisdiction-wide energy efficiency programs as well as the value of integrating energy efficiency planning and forecasting into the utility system.

   b) As outlined in EEA's Module One submission, Consolidated Edison saved $1 billion in projected T&D capital expenses by adjusting its forecasts to reflect jurisdiction-wide energy efficiency programs.[17]

[14] Energy Efficiency Alberta (EEA). (2019). *Submission of Energy Efficiency Alberta to the Alberta Utilities Commission, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0182, 12-19. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0182_EEA-AUCDistributionSubmission-Module1_fi_0191.pdf.

[15] The Mendota Group conducted a study that outlined the costs for 35 utilities that undertook avoided T&D cost calculations. The Mendota Group. (2014). *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments*. https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf

[16] Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*. https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

[17] Neme, C., & Sedano, R. (2012). *US Experience with Efficiency as a Transmission and Distribution System Resource.* https://www.raponline.org/wp-content/uploads/2016/05/rap-neme-efficiencyasatanddresource-2012-feb-14.pdf

2) Non-Wires Alternatives (or "Active Deferrals")

34. As outlined in EEA's Distribution Inquiry Module One submission, non-wires alternatives (NWAs) offer distribution system cost savings by actively delaying or deferring wires infrastructure investments by reducing peak demand through alternative solutions. Deferrals can occur through multiple project types, such as energy efficiency, demand response, solar PV, energy storage, etc., and often it is various project types that are collectively deployed to achieve timely peak demand reductions in a specified region.[18]

35. When energy efficiency programs are used as NWAs, energy efficient measures targeted at peak demand periods are incented in specified geographic areas where load reductions are required. These programs only differ from jurisdiction-wide programs through their enhanced marketing and/or increased incentives targeted at specific regions where a utility has assessed that infrastructure deferrals or delays are possible within a required period of time.[19] Most often, existing jurisdiction-wide programs are leveraged through geotargeted efforts to increase peak savings in a particular area.

36. In addition to the examples raised in EEA's Module One submission, The New York PSEG Long Island Utility 2.0's Super Savers Program is another successful energy efficiency NWA case study.[20] The Super Savers Program has several ongoing NWA projects, namely the South Fork Supply and Load Relief project.[21] This project is intended to contribute to the deferral of $294 million worth of transmission infrastructure (e.g. cables and substation upgrades). In June 2019, the project's portfolio consisted of over 150 MW of DER capacity including wind, storage, demand response, and energy efficiency.[22]

[18] Energy Efficiency Alberta (EEA). (2019). *Submission of Energy Efficiency Alberta to the Alberta Utilities Commission, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0182, 13-19. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0182_EEA-AUCDistributionSubmission-Module1_fi_0191.pdf.

[19] In this case, the term incentive is intended to encompass financing, direct install and rebates as different methods energy efficiency programs use to increase the uptake of high efficiency products.

[20] These are in addition to the examples listed in EEA's submission for Module One including the Tiverton NWA Pilot, Maine's Boothbay Project and ATCO Electric's program in Jasper. Energy Efficiency Alberta (EEA). (2019). Submission of Energy Efficiency Alberta to the Alberta Utilities Commission, Distribution System Inquiry, Module One, Proceeding 24116, Exhibit #24116-X0182, 15. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0182_EEA-AUCDistributionSubmission-Module1_fi_0191.pdf.

[21] Northeast Energy Efficiency Partnerships (NEEP). (2017). *EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies*. https://neep.org/sites/default/files/resources/NWA%20brief%20final%20draft%20-%20CT%20FORMAT.pdf

[22] PSEG Long Island. (2019) *Utility 2.0 Long Range Plan, 2019 Annual Update*. https://www.lipower.org/wp-content/uploads/2019/08/2019-06-28-PSEG-Long-Island-Utility-2.0-2019-Annual-Update.pdf

a) Energy efficiency NWAs have frequently been found to be the least-cost NWA resource. For example:

   i. The Maine Boothbay pilot project found that during two rounds of RFPs to procure NWA resources, energy efficiency was shown to be by far the lowest-cost resource.[23]

   ii. During the competitive procurement process of Consolidated Edison's load reduction projects, energy efficiency was shown to be the only project type that was cost-effective to enable T&D deferral.[24]

37. Geotargeting energy efficiency programming would be more expensive if it does not draw from existing jurisdiction-wide programs. The cost-effectiveness, speed, and size of energy efficiency NWAs can be enhanced by the existence of on-going, jurisdiction-wide programs. Existing jurisdiction-wide programs allow energy efficiency NWAs to quickly ramp up programs in geographically targeted areas through enhanced marketing and/or incentive offerings. It is more difficult to turn this resource on and off quickly without an existing suite of programs already in place.[25]

3) Electric Vehicles

38. Electric vehicles (EVs) could increase costs to Alberta's distribution system if left unmanaged. These potential distribution system impacts from EVs are being recognized in other jurisdictions.[26] A McKinsey Germany study found that "unmanaged, substation peak-load increases from EV-charging power demand will eventually push local transformers beyond their capacity, requiring upgrades… Without corrective action, we estimate that the cumulative grid-investment need could exceed several hundred euros per EV."[27] The Boston Consulting Group found that a non-optimized scenario would cost, per EV, $5,380 (US) to the distribution system and $420 (US) to the transmission system per EV through to 2030.[28]

39. While other jurisdictions are concerned about the potential distribution impacts of EVs, some are concluding that EV adoption can be managed through energy efficiency programs, demand response, smart charging and time of use rates. For example, the American Council for an Energy Efficient Economy (ACEEE) projects, in the US Southeast, an annual incremental energy efficiency increase of only 0.75 per cent above business-as-usual (BAU) is will be more than

[23] Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*. https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf
[24] *Ibid.*
[25] C. Neme, personal communication, December 16, 2019
[26] Nadel, S. (2017). *Electricity Consumption and Peak Demand Scenarios for the Southeastern United States*. https://www.aceee.org/sites/default/files/publications/researchreports/u1704.pdf
[27] Engel, H., Hensley, R., Knupfer, S., & Sahdev, S. (2018). *The Potential Impact of Electric Vehicles on Global Energy Systems*. https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/the-potential-impact-of-electric-vehicles-on-global-energy-systems
[28] Sahoo, A., Mistry, K., and Baker, T. (2019). *The Costs of Revving Up the Grid for Electric Vehicles*. https://www.bcg.com/publications/2019/costs-revving-up-the-grid-for-electric-vehicles.aspx

capable of offsetting the high energy demand scenario's added EV 2040 summer and winter peak load.[29] A similar study of New England found that an increase of only one per cent in incremental annual energy efficiency savings can easily offset additional winter and summer peak load from EVs.[30]

40. As discussed at the Module One Technical Conference and various submissions, EVs could impose significant demands on Alberta's distribution system. EPCOR completed a study with the University of Alberta on EV distribution impacts and found that 1-2 typical level 2 EV chargers (at 7.2 kW charging level[31]) per distribution transformer[32] could be enough to overload a transformer with typical residential loading.[33] [34] [35] This would likely require transformer replacement due to increased stress due to unacceptable low voltage on primary

[29] The report projects that EVs in the US Southeast, under a high energy demand scenario, will make up 32 per cent of 2040's passenger vehicle stock (i.e. 23.74 per cent more than the Business-as-usual (BAU) projections based on EIA data). The additional load would add over 3,500 MW to the region's 2040 summer peak (6PM). However, an annual incremental increase of energy efficiency of only 0.75 per cent above BAU (BAU annual incremental increase of energy efficiency is 0.25 per cent) is capable of reducing 2040 peak demand by over 30,000 MW, which more than offsets the High energy demand scenario's added EV load. In the 2040 Hybrid scenario, the total summer peak demand decreases by over 45000 MW due to incremental energy efficiency, photovoltaic generation uptake, and demand response (roughly 75, 15, and 20 per cent, respectively). Nadel, S. (2017). *Electricity Consumption and Peak Demand Scenarios for the Southeastern United States*. https://www.aceee.org/sites/default/files/publications/researchreports/u1704.pdf

[30] When the reference case is compared to a scenario of aggressive energy efficiency and EV adoption, energy efficiency reduces 2040 summer peak demand (6PM) by over 4000 MW and 2040 winter peak demand (6PM) by 2,000 MW. Relative to the reference case, electric vehicles only increase 2040 summer and winter peak by almost 600 MW. Nadel, S. (2016). *Electricity Consumption and Peak Demand Scenarios for New England.* https://www.aceee.org/sites/default/files/publications/researchreports/u1605.pdf

[31] The study found charging demand per EV is 3.2 to 19.2 kW. Chapelsky C., Gerasimov, K., & Musilek, P. (2019). *DER Impacts to Urban Utilities Study Summary*. https://www.epcor.com/products-services/power/Documents/micro-generation-research-solar-energy-electricity-grid-2019.pdf See footnote 39 for an increased understanding of Tesla's charging range.

[32] For a 37 kVA transformer (35.15 kW) serving 12 lots.

[33] EPCOR's presentation at the Module One Technical Conference outlined that the concurrent charging of only two Tesla EVs (at 19.2 kW) is greater than the average peak for a standard service transformer in Edmonton (24 to 36 kW). Chapelsky, C. (2019). *Electric vehicles –challenges and opportunities, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0416. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0416_EDTIEVChallengesandOpportunities_0450.pdf. See footnote 39 in EEA's submission for an increased understanding of Tesla's charging range.

[34] Chapelsky C., Gerasimov, K, and Musilek, P. 2019. *DER Impacts to Urban Utilities Study Summary*. From https://www.epcor.com/products-services/power/Documents/micro-generation-research-solar-energy-electricity-grid-2019.pdf

[35] Mr. Chapelsky noted another jurisdiction that used one transformer for every eight homes, potentially with a larger sized transformer. Chapelsky, C. (2019). *AUC Module One technical conference notes for September 11, 2019, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0437, paragraph 107. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0437_2019-10-31AUCModuleOnetechnicalconferenc_0475.pdf

cables feeding residential service transformers.[36] At the circuit level, 6 per cent of EV uptake (at 7.2 kW each) charging concurrently could reach circuit capacity.[37] [38]

41. EEA commissioned Navigant consulting to explore whether energy efficiency, demand response, and smart charging could cost-effectively mitigate some or all of EVs' potential distribution impacts in Alberta (see Appendix A of this report for the full study). The study uses one of EPCOR's transformers as a representative sample on whether demand-side management options could mitigate peak loading.

42. The report's main finding is that energy efficiency, residential demand response, and smart charging can cost-effectively avoid peak demand increases due to EV adoption for the study period (2020-2030) based on moderate and aggressive EV adoption scenarios for a typical residential charging scenario.[39] [40] Pursuing energy efficiency, demand response, and smart charging is also more cost-effective than upgrading the representative residential transformer.

43. The study demonstrates that the scalability of non-wires alternatives can allow for flexible, cost-effective mitigation of transformer loading. The relationship between overloading and cost-effectiveness is non-linear (i.e. costs escalate as the overloading on the transformer increases) and the scalability of non-wires alternatives allows for control of what is acquired.

44. Under the base scenario, a combination of several demand response and energy efficiency measures would be sufficient to cover study transformer peak requirements imposed by EVs without implementing smart charging. Energy efficiency and demand response can cost-effectively reduce the 2.7 kW of potential transformer overloading. (See Figure 1 for the full resource stack under the base scenario.)

[36] Chapelsky, C. (2019). *AUC Module One technical conference notes for September 11, 2019, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0437, paragraph 99. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0437_2019-10-31AUCModuleOnetechnicalconferenc_0475.pdf

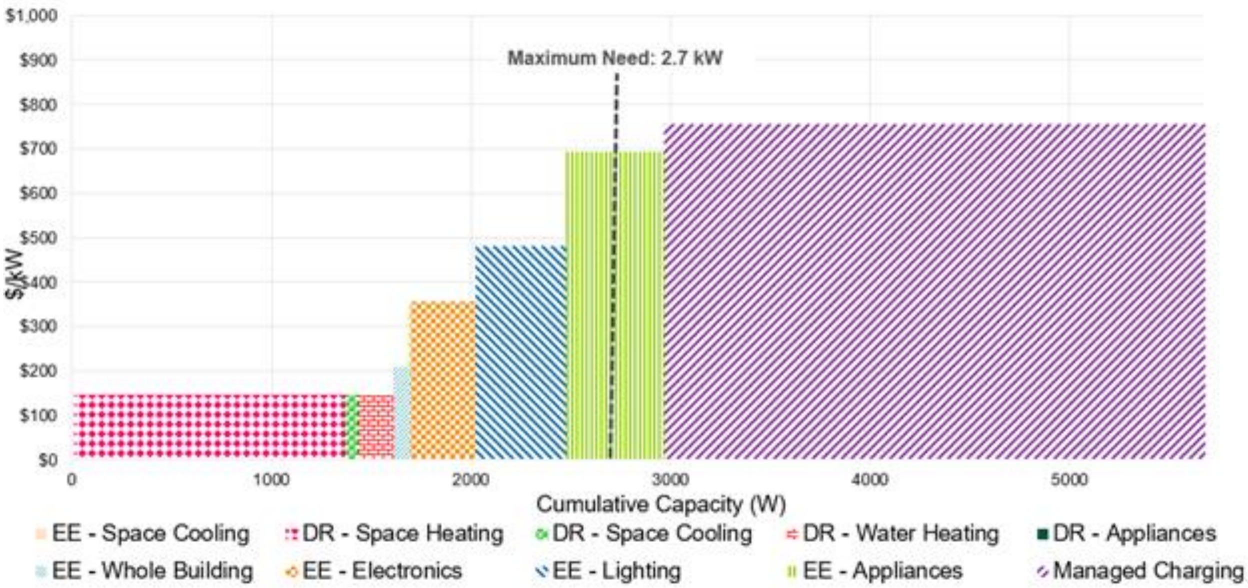
[37] Assuming 5,500 customers on EPCOR's residential circuits. EPCOR used the range of this example 2.4 per cent of customers would need to charge their EVs at 19.2 kW or 14.4 per cent of customers with EVs at 3.2 kW) at the same time to reach circuit capacity. Chapelsky, C. (2019). *Electric vehicles –challenges and opportunities, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0416. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0416_EDTIEVChallengesandOpportunities_0450.pdf

[38] 15kV residential circuit (circuit capacity of roughly 8 MW) – normal peak from base load at 5.6 MW which means there is 2.5 MW of remaining capacity.

[39] For the base scenario, there is 28 per cent EV new vehicle market share and the number of vehicles per transformer (or per 12 households) is 0 in 2020 and 2 in 2030. Under the aggressive scenario, there is 32 per cent EV new vehicle market share and the number of vehicles per transformer is 1 in 2020 and 3 in 2030. To ensure the scenarios were adequately aggressive, EV numbers were rounded up from Navigant's EV model output.

[40] Most of the EV models available in the market today accept a maximum power input of 7.2 kW from a Level 2 charger – however, some manufacturers, such as Tesla, can accept larger power inputs. Prior to 2017, Tesla vehicles (Model S, Model X) could come equipped with an onboard charger that could accept a maximum power input of 19.2 kW using a specialized dual-port charger. These dual-port chargers did not come standard with the vehicle. From 2018 onwards, all Tesla models, including the newly released Model 3, have two optional charging inputs – 7.7 kW is standard while 11.5 kW is considered "long range", or "performance". Still, many electric or plug-in electric vehicles are still charged with a Level 1 charger. Level 1 charging can account for up to nearly 70 per cent% of total charging sessions for plug-in hybrid vehicles. Therefore, study reviewers felt 7.2 kW is a sufficiently aggressive representation of a typical scenario.

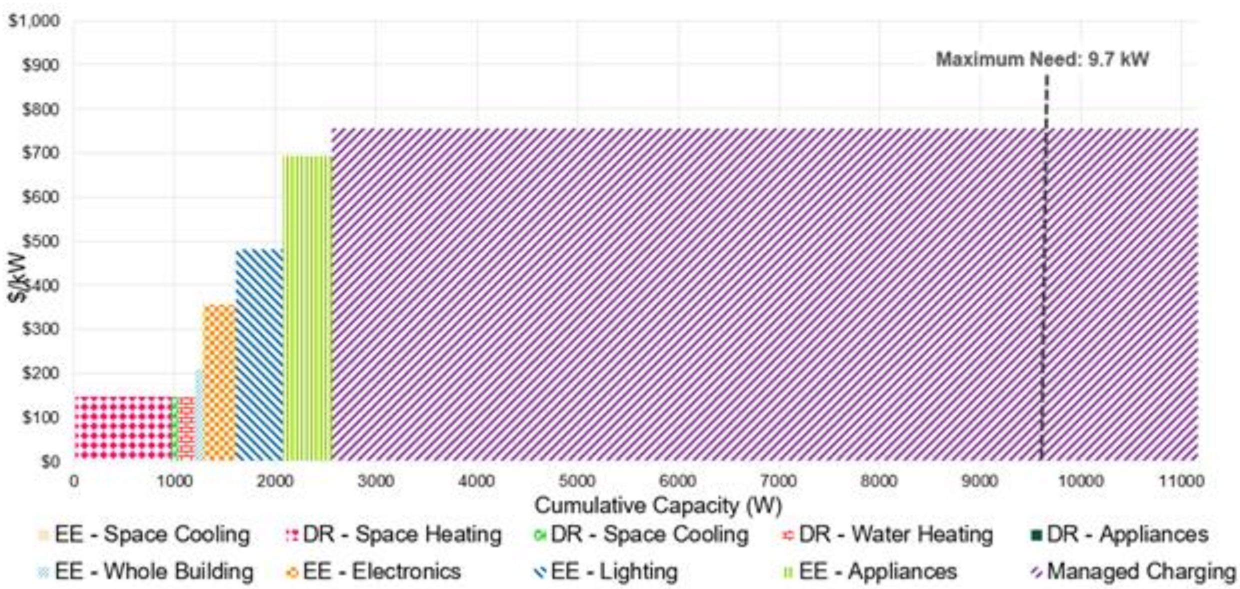
Figure 1: 2030 Resource Stack, Base EV Scenario



Source: Study Non-Wires Alternatives Study: How EE, DR and Managed Charging Can Cost-Effectively Offset EV Load Growth

45. Under the aggressive scenario, smart charging is required to mitigate a large portion of the transformer's need. However, energy efficiency and demand response act as less expensive alternatives. (See Figure 2 for the full resource stack under the aggressive scenario.)

Figure 2 : 2030 Resource Stack, Aggressive EV Scenario



Source: Study Non-Wires Alternatives Study: How EE, DR and Managed Charging Can Cost-Effectively Offset EV Load Growth

46. The study concludes, with limitations, that the non-wires alternative cost to meeting the transformer's need is at least 2.5 times more cost-effective than a traditional wires investment.

Under the base EV uptake scenario, the cost-effectiveness of non-wires investments in energy efficiency and demand response is as high as 23.8 times more cost-effective than the wires - based solution.

Table 1 Cost-Benefit Ratio of Non-Wires Alternatives vs. Traditional Wires Investment

Scenario	PV[41] of Traditional Wires Investment Cost ($)	PV[42] of Non-Wires Alternative Cost ($)	Cost-Benefit Ratio
Base EV Uptake	$10,524	$442	23.8
Aggressive EV Uptake	$12,792	$5,178	2.5

Source: Non-Wires Alternatives Study: How EE, DR and Managed Charging Can Cost-Effectively Offset EV Load Growth

4) Energy Efficiency's Utility System Benefits

47. Energy efficiency also acts as a cost and risk management tool through additional benefits to the transmission and distribution system, such as:

    a) Deferring or delaying maintenance on infrastructure,

    b) Decreasing T&D line losses for every unit of energy reduced,

    c) Providing better reliability and power quality by reducing stress to the system during hours of peak demand,

    d) Decreasing disruption to businesses and residents that often occurs when building T&D infrastructure, and

    e) Reducing land-use disputes that frequently arise when T&D infrastructure is built. These disputes arise due to health, aesthetic, and environmental concerns.

48. Energy efficiency offers other electric system benefits/cost savings.

    a) Program participants experience bill reductions through direct energy savings.

    b) All consumers save costs through rate reductions from energy efficiency NWAs and passive deferrals.

[41] Present Value
[42] *Ibid.*

c) Also, all consumers benefit from reduced supply-side costs and risks – such as reduced future fuel price volatility, decreased exposure to current and future environmental regulations (such as GHG reduction regulation), and potential deferred or avoided power plant peak capacity expansions.

d) There is also empirical evidence that demonstrates that energy efficiency reduces the market-clearing price for electricity.

i. Analysis of 2012 ComEd load and PJM long-term market prices shows a 1 per cent decrease in load causing 2 per cent price reduction.[43] Similarly, a 1 per cent Illinois load reduction caused 0.5 per cent–1 per cent price reduction in Midcontinent Independent System Operator (MISO).[44]

ii. Evidence from an Ohio price mitigation analysis, including capacity and energy price reductions, shows all customers, irrespective of their participation, save approximately $2 per month on their residential electricity bill due to energy efficiency programming.[45]

iii. Some jurisdictions consider Demand Reduction Induced Price Effects (DRIPE) in their cost-effectiveness screening including Massachusetts, Rhode Island, Vermont, Connecticut, Delaware, Maryland, and District of Columbia.[46]

iv. In July 2001, California achieved a peak demand reduction of 14 per cent as compared to 2000 – the year of prolonged electricity supply shortages – helping avoid a repeat event and prevent price spikes.[47]

e) Energy efficiency can enable demand response in multiple sectors as many efficiency measures also have demand response capabilities. For example, in the commercial and industrial sectors, many of the more important energy efficient measures are controls that not only provide ongoing annual energy savings but also enable demand response which can be utilized as an NWA and/or system capacity resource. This further reduces peak demand system-related costs if demand response is enacted.

f) Energy efficiency decreases the magnitude of required electric ancillary services - if energy efficiency and distributed energy resources are located close to where electricity is used.[48]

[43] Chernick, P., & Griffiths, B. (2014). *Analysis of Electric Energy DRIPE in Illinois*.
[44] Neme, C., & Chernick, P. (n.d.). *Value of Demand Reduction Induced Price Effects (DRIPE)*, 34.
[45] Chernick, P. (2019). *Energy-Efficiency Benefits to All Ratepayers: Price-Mitigating Effects for Ohio*.
[46] Baatz, B. (2016). *Utility System Benefits of Energy Efficiency: Current Experience in the U.S.*. https://energy-evaluation.org/wp-content/uploads/2019/06/2016-paper-baatz.pdf
[47] Taylor, C., Hedman, B., & Goldberg, A. (2015). *State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All*. https://doi.org/10.2172/1331049.
[48] U.S. Environmental Protection Agency (EPA). (2018). *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy – Part One*.

49. Energy efficiency also offers other consumer and societal benefits that go beyond cost savings such as:

a) Increased comfort and other consumer qualitative benefits,

b) Reduced greenhouse gas and other air emissions,

c) Enhanced environmental social governance,

d) Strengthened economic development and diversification of Alberta's economy, and

e) Alleviation of energy poverty.

B. Integrating Energy Efficiency into the Utility System

50. Over 90 per cent of funding for energy efficiency programs in Canada and the U.S. is provided by utility systems (paragraph 29B above).

51. Integrating energy efficiency into the utility system is widely seen to offer greater stability and predictability in funding, and therefore implementation, of energy efficiency programs. It embeds those programs structurally into the larger utility system, thus leading to less drastic changes and variations in programming over time. Ultimately, this leads to maximizing cost reductions in the utility system.[49]

52. This funding approach also allows greater opportunities to integrate programming into utility system planning to ensure a least-cost approach with respect to smart grid, distribution and transmission infrastructure (active and passive) deferral. Integrating energy efficiency programs into Alberta's utility system is an important step towards institutionalizing energy efficiency in the province and better managing costs and risks for consumers, business and industry.

53. The funding source is not necessarily tied to a specific type of program administration and delivery model. Across North America, different jurisdictions have opted for utility, government agency or third-party delivery while using utility-based funding.

[49] Dunsky Energy Consulting. (2019). Integrating Energy Efficiency into the Utility System, A Review of Delivery and Funding Models. https://eea-assets.s3.amazonaws.com/documents/Dunsky_EEA-Utility-System-Integration-FINAL.pdf?utime=20190904113000; Winfield, M., Love, P., Gaede, J., & Harbinson, S. (2020). *Unpacking the Climate Potential of Energy Efficiency*. https://sei.info.yorku.ca/files/2020/02/UnpackingTheClimatePotential-Feb22.pdf?x10807

C. Address Potential Barriers to NWAs

54. At present, there have been few examples of NWA projects implemented in Alberta.[50] Through this Distribution System Inquiry, it merits asking why this is the case and explore whether there are any embedded barriers in the regulatory framework to having utilities pursue NWAs.

55. Questions to explore could include:

   a) Are Distribution Utilities currently enabled to pursue NWAs? Based on past rulings (ie Decision 2011-450), utilities or other parties may believe that energy efficiency NWAs are not eligible for cost recovery.

   b) Are there disincentives to pursuing NWAs? E.g., do wires solutions present a better return on investment for distribution utilities than non-wires solutions?

[50] Between 1991 and 1992, ATCO successfully and cost-effectively implemented an energy efficiency NWA project in Jasper, deferring a nearly $8.5-million transmission line. For more information, see EEA's Module One submission. Energy Efficiency Alberta (EEA). (2019). *Submission of Energy Efficiency Alberta to the Alberta Utilities Commission, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0182, 15. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0182_EEA-AUCDistributionSubmission-Module1_fi_0191.pdf.

1. (iii) Applying Technology Agnosticism to the Regulatory Framework

AUC Question: To what extent does the current regulatory treatment for micro-generation, distribution-connected generation (DCG), industrial systems designations (ISDs), energy storage resources, and any other customers or market participants apply the principle of technology agnosticism? Should this agnosticism be applied not only to the type of technologies used within those different regulatory constructs, but also to the fuel source, connection configuration, generator size, etc.? And how should this agnosticism extend between those regulatory constructs? In other words, should it matter what type of customer is connecting to the generating unit, what the size of the generating unit is, and what the generation will be used for, so long as the generator and customer adhere to certain technical limitations of the grid and pay the appropriate tariffs?

56. As already discussed in the principles section, technology agnosticism should include resource agnosticism to ensure equal consideration of both supply and demand technologies. As a result, planning processes and rate structures should be introduced that implement a level of demand-side solutions when more cost-effective than supply-side options. Resource agnosticism, or equal consideration of supply and demand technologies, is employed in multiple jurisdictions by ensuring cost-effective demand-side management programs are funded through the utility system. They are implemented to manage consumer energy costs and bring the multiple benefits listed above (see paragraph number 16).

57. Resource agnosticism is not currently being employed in the distribution system as demand-side technologies face barriers to adoption and Alberta's utility system currently does not address these barriers.

58. Applying the principle of technology agnosticism to the distribution system means both wires and non-wires alternatives should have associated planning processes and incentive/funding mechanisms to help meet the objective of safe, reliable, and economic delivery of electricity and natural gas.

1. (iv) Recommended changes to the Regulatory Framework

AUC Question: If, in response to the questions posed in parts (ii) and (iii) above, changes to the existing regulatory framework have been recommended, what would need to change and why? For example, the location and configuration of the metering? Access to certain information and data? Distribution and/or transmission network planning? Who pays for the cost of connecting the site's generating unit and how it is determined? The types of tariffs applied to the site for load and generation, and their potential design? The compensation for electricity supplied to the grid? Who has control over dispatch and settlement?

59. In aligning with the principle of pursuing the least-cost approach, EEA supports the employment of non-wires alternatives and jurisdiction-wide programs as a cost and risk management tool for the utility system. These approaches would also apply the principle of technology/resource agnosticism to the current regulatory framework.

60. At a high-level, these recommended changes should allow the distribution system to incorporate (or "equally consider") demand-side options. Some of these recommendations may require policy and legislative changes. While EEA understands, the Inquiry's objective is not to make policy recommendations to government, in "the spirit of fact-finding" these recommendations should be an important part of discussing the evolution of the distribution system given the expected impact of new technologies.

61. Therefore, EEA has the following recommendations (expanded upon below) in considering how Alberta's utility system should evolve:

    A. Take Steps to Encourage NWAs

    B. Enable and Integrate Jurisdiction-wide Programs into the Utility System

    C. Enable Smart Charging

A. Take Steps to Encourage NWAs

62. **Recommendation:** The Commission should assist in developing a regulatory framework conducive to having utilities assess and enable NWAs where practical, cost-effective and in a manner that reflects the Alberta context. Possible approaches to encourage NWAs are outlined below under headings 1 through 5. It is recognized that if policy and/or legislative changes do not take place, any Commission actions will have to fit within the current constraints of the existing regulatory framework. EEA's submission provides examples drawing on best practices in other jurisdictions but recognizes actions to support NWAs should be adapted to best serve the Alberta context.

1) Identify and Address Relevant Utility Disincentives for NWAs

63. A process to enable NWA should identify and address any utility disincentives for NWAs. The Commission may want to:

    a) Determine if PBR creates a disincentive for NWAs and consider adjustments to remove disincentives.

    b) Provide clarity to utilities, on whether NWAs (in particular, energy efficiency NWAs) fit within the legislative authority of the Utilities Acts given past rulings (i.e. Decision 2011-450) regarding DSM programming.

For utilities to actively pursue NWAs any barriers, legislative or financial, must be addressed.

2) Consider Utility Incentives for NWAs

64. One option to encourage utilities to pursue NWAs is to provide a revenue incentive. Providing an incentive can reduce or eliminate the due diligence required to ensure an "all cost-effective NWA" mandate (see section 1.iv.A.3). Precedence for utility NWA incentive approaches include:

    a) Allowing utilities to capitalize costs related to NWAs (even if they manage a competitive procurement for implementation or allocate funds to other organizations to implement). This option could reduce the disincentive for utilities to pursue NWAs, but not eliminate them as NWA project costs on which they would receive a return would be lower than the traditional "poles and wires" project cost and return.

        i. Illinois utilities can capitalize their energy efficiency expenditures and earn a rate of return on projects, including non-wires alternatives.[51]

    b) Utilities could be allowed to earn a rate of return for NWA related projects the same as or higher than other capital projects. Again, this would apply whether the utility implemented the NWA directly itself or administered a competitive procurement process to hire third parties to deliver DERs.

        i. Central Maine Power Company and Emera Maine both proposed such an incentive model to address the problem where lower-cost NWA projects, when capitalized or expensed, result in lower rates of return.[52]

        ii. The California Public Utilities Commission offers incentives for utilities as part of its Distribution Investment Deferral Framework for "identifying, evaluating, and selecting

[51] Brown, T., Lessem, N., & Zarakas, W. (2018). *Incentive Mechanisms in Regulation of Electricity Distribution: Innovation and Evolving Business Models*. https://comcom.govt.nz/__data/assets/pdf_file/0020/106076/Brattle-Group-on-behalf-of-ENA-Incentive-mechanisms-in-regulation-of-electricity-distribution-innovation-and-evolving-business-models-October-2018.PDF
[52] Whited, M. (2018). *Direct Testimony of Melissa Whited with Regards to Utility Incentives for Non-Wires Alternatives*. http://www.synapse-energy.com/sites/default/files/Testimony-Whited-NWA-Incentive-18-090.pdf

opportunities for DERs to defer or avoid traditional distribution investments and to produce net ratepayer benefits."[53] It proceeded with a 4 per cent adder in a competitive solicitation as a pilot in 2016.[54]

c) The cost savings between a traditional wires project and a less expensive NWA could be divided between utilities and ratepayers as a financial incentive to pursue NWAs.

i. For example, in 2017 New York's Public Service Commission approved a proposal by Consolidate Edison to split benefits from its NWA investments between shareholders and ratepayers. Whereas, the utility initially proposed a 50-50 split of benefits, the Commission approved 70 per cent to be paid to ratepayers and 30 per cent for the utilities.[55]

3) *Require all Cost-Effective NWAs*

65. Some states have required utilities to plan for NWAs where it would cost-effectively delay or defer distribution infrastructure. Some jurisdictions have made it a required element of utilities' distribution plans. This "all cost-effective" mandate is in place in all jurisdictions where NWAs are being routinely assessed, as it helps overcome financial and institutional barriers to NWA uptake.[56] These mandates should be technology agnostic to allow for flexibility on how NWAs are implemented.

4) *Enable NWA Assessments*

66. Utilities require a process to be able to efficiently identify and assess NWA opportunities. Precedence in other jurisdictions indicate successful NWAs are enabled by certain "success factors":

a) sufficient lead time to have enough time to be able to successfully plan for and implement NWAs,

b) the project has a manageable amount of load reductions that are required for the specific timeframe, and

[53] Frost, J. (2019). *California Smart Grid Annual Report to the Governor and the Legislature*, 58.
[54] California Public Utilities Commission (CPUC). (2020). *Rulemaking 14-10-003: Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot.* http://docs.cpuc.ca.gov/publisheddocs/published/g000/m171/k555/171555623.pdf.
[55] Opalka, W. (2017, January 27). Con Ed rate order moves REV forward with shared savings,. *RTO Insider*. https://rtoinsider.com/new-york-psc-consolidated-edison-37259/
[56] Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*. https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

c) the deferral project's costs are sufficient to justify the effort and cost put into a detailed assessment.

67. On the latter point, there may be an opportunity to aggregate smaller projects to justify the costs of larger NWA programs (perhaps even province-wide) (e.g. multiple transformers to be deferred through energy efficiency program costs). To achieve these success factors, other jurisdictions have required/encouraged longer-term forecasts and established screening criteria to consider NWAs.

Forecasting

68. Utilities need to produce long-term forecasts of distribution infrastructure to allow for early consideration of NWAs. Experience in other jurisdictions has shown that utilities should provide ten-year plans with a requirement for updates, in order to effectively plan for NWAs. For example, in Rhode Island, as part of the state's "System Reliability Procurement" (SRP) policy, utilities must consider the potential for NWAs in their distribution planning for at least three years out.[57] National Grid, one of Rhode Island's largest utilities, typically releases an SRP report annually, in which it generally provides 10-year load forecasts.[58]

Screening Criteria

69. Other jurisdictions have established minimum screening criteria that would trigger a detailed assessment of NWAs to ensure a potential NWA project meets relevant "success factors". Precedence for screening criteria includes (Table 2 provides examples of jurisdictional specific criteria):

a) **Minimum Lead Time –** minimum lead time prior to the required capital infrastructure investment to ensure sufficient time to plan for and implement the NWA project.

b) **Maximum Load Size –** the load reduction need/requirement must be a manageable size to be addressed by DERs. Some jurisdictions use load relief as a percentage of total load to initially gauge whether load reductions are realistic.

c) **Minimum Project Cost Threshold –** ensures the potential benefits of T&D deferral are sufficient to justify a more detailed assessment of a potential NWA project.[59]

[57] *Ibid.*
[58] Title 39 Public Utilities and Carriers, Chapter 39-1 Public Utilities Commission, Section 29-1-27.7, System reliability and least-cost procurement. (2018). http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM. See National Grid's System Reliability Procurement reports such as the 2017 System Reliability Procurement Report for details on forecasting. National Grid. (2016). *2017 System Reliability Procurement Report.* http://www.ripuc.ri.gov/eventsactions/docket/4655-NGrid-SRP2017(10-17-16).pdf
[59] *Ibid.*

Table 2: Criteria for Requiring Detailed Assessment of Non-Wires Solutions

	Must Be Load Related	Minimum Years Before Need	Maximum Load Reduction Required	Minimum T&D Project Cost	Source
Transmission					
Vermont	Yes	1 to 3 4 to 5 6 to 10	15% 20% 25%	$2.5 Million	Regulatory policy
Maine	Yes			>69 kV or >$20 Million	Legislative standard
Rhode Island	Yes	3	20%	$1 Million	Regulatory policy
Pacific Northwest (BPA)	Yes	5		$3 Million	Internal planning criteria
Distribution					
PG&E (California)	Yes	3	2 MW		Internal planning criteria
Rhode Island	Yes	3	20%	$1 Million	Regulatory policy
Vermont	Yes		25%	$0.3 Million	Regulatory policy

Source: Neme, C., & Grevatt, J. (2015). Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments. *https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.*

5) Implement a Model to Assess and Procure NWAs

70. To initiate an NWA, an initial screen (with high-level criteria) could highlight where a more detailed NWA assessment should be triggered. Once a utility completes a detailed assessment with positive results a project would be initiated.

71. Subsequently, whether chosen by individual utilities or enacted as part of a standardized distribution planning process, an NWAs implementation model is the next consideration. At a high-level, there are two options for NWA implementation or delivery models including:

a) **Utilities plan for and deliver NWAs** - Utilities could build and own some DER capital assets if they were deemed to be cost-effective NWAs (e.g. Energy Storage) and deliver geo-targeted energy efficiency programs in-house or contract out to third-party delivery agents. With respect to energy efficiency, this model is most applicable to jurisdictions in which utilities are already running (and can therefore leverage) system-wide efficiency programs.[60]Jurisdictions that implement this model include Rhode Island[61] and Michigan[62].

72. An adaptation of this model could see the utilities working with the default energy efficiency agency to acquire energy efficiency program-specific NWAs.[63] In Vermont, if state regulators approve an NWA project, the utilities have the obligation to implement it. Although, utilities have the option of either contracting with Efficiency Vermont to procure such resources or competitively procuring them, Efficiency Vermont, the state's default energy efficiency agency, has always been engaged to deliver the efficiency resource component of NWAs pursued in the state. The state rules require Efficiency Vermont to be prepared to procure geo-targeted efficiency resources if requested by the utilities.[64] The cost of those efforts would typically be covered through the bills of the customers of the distribution utility whose system is affected. When the project affects multiple utilities or the state as a whole, regulators may alternatively direct Efficiency Vermont to shift part of its system-wide program funds to place greater emphasis on the targeted area. [65]

a) **Utilities plan for and competitively procure NWAs** – Utilities could identify opportunities for NWAs and competitively procure solutions - specifying required characteristics but not specific technologies (to adhere to the principle of technology agnosticism). Bids would indicate the amount of peak power that could be provisioned at specific times and at what cost per MW. This model shifts the risk to those who are engaged on contract and there would be significant penalties for non-performance. It would be third parties who would own

[60] C. Neme, personal communication, March 5, 2020

[61] National Grid runs jurisdiction-wide energy efficiency programs across Rhode Island. National Grid. (2020). *Energy Savings Programs*. https://www.nationalgridus.com/RI-Home/Energy-Saving-Programs/. However, National Grid is no longer a vertically integrated utility. Wood, E. (2017). Rhode Island Leapfrogs toward a Grid of the Future and Microgrids. *Microgrid Knowledge.* https://microgridknowledge.com/grid-of-the-future-and-microgrids/. In Rhode Island, utilities plan for and deliver NWAs. Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments.* https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

[62] Indiana and Michigan (I&M) (2019, November 19). *Annual Distribution System Plans considers NWAs and DERs.* [Slides]. https://www.michigan.gov/documents/mpsc_old/November_19_Presentations_671900_7.pdf. AEP, of which I&M is a subsidiary, is a vertically integrated utility. Brewer, R.G. (2018, April 17). How American Electric Power Company, Inc. makes most of its money. *The Motley Fool.* https://www.fool.com/investing/2018/04/17/how-american-electric-power-company-inc-makes-most.aspx

[63] The energy efficiency program administrator provides the cost curve for the potential energy efficiency programming peak demand reductions. This estimate would be based on a Potential Study completed by the energy efficiency program administrator and characteristics specific to the NWA region that will impact potential reductions (e.g. customer demographics, hourly load shapes, and current saturation the energy efficiency measures).

[64] It is possible that Efficiency Vermont has historically been the principle provider of efficiency resources because of its involvement in the development of baseline load forecasts, its assessment of geo-targeted efficiency potential and its ability to leverage existing statewide programs. C. Neme, personal communication, January 15, 2020

[65] C. Neme, personal communication, January 15, 2020

the NWA capital assets. For example, New York[66] and California[67] require competitive procurement of NWAs.[68]

73. Like the above model, a hybrid could see a default energy efficiency administrator provide peak reductions through energy efficiency if below the cost of the lowest winning bid. As with above, the amount of peak reductions would be determined by the administrator's Potential Study cost curve and regional characteristics.

a) **Hybrid model with a Neutral Entity** – In Maine, a neutral entity plays the role of identifying NWA opportunities. In 2019, Maine passed a law establishing an independent NWA Coordinator which works with Efficiency Maine Trust and utilities to assess the state's ability to cost-effectively implement NWAs in the place of conventional T&D system upgrades. The coordinator evaluates cost-effectiveness analyses and provides recommendations with respect to the types and the procurement of NWAs to utilities and utilities commission. If either the commission determines the NWA is appropriate or a utility voluntarily agrees to the NWA, the utility will procure the delivery of the NWA through Efficiency Maine Trust, a third-party, and/or will deliver the NWA themselves. The parties that are responsible for the delivery of NWAs are dependent on the type of proposed NWA. For example, utilities are required to contract with Efficiency Maine for the acquisition of any DERs that are "behind the meter".[69]

B. Enable and Integrate Jurisdiction-wide Programs into the Utility System

74. Integrating energy efficiency programs into Alberta's utility system is an important step towards institutionalizing energy efficiency in the province and better managing costs for consumers. Section 1. (ii) A. 4) describes the multiple distribution system and consumer related

[66] New York State Department of Public Service created a list of principles that utilities were expected to incorporate into their NWA projects one of which were to develop partnerships with third-party solutions providers and another was to seek solutions from market participants. Dyson, M., Prince, J., Shwisberg, L., & Waller, J. (2018). *The Non-Wires Solutions Implementation Playbook, A Practical Guide for Regulators, Utilities, and Developers*. https://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf

[67] The California Public Utilities Commission required utilities to include NWA demonstration projects in their distribution resource plans, and later established a procurement process and fixed incentive. Dyson, M., Prince, J., Shwisberg, L., & Waller, J. (2018). *The Non-Wires Solutions Implementation Playbook, A Practical Guide for Regulators, Utilities, and Developers*. https://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf

[68] Pacific Gas and Electric Company. (2019). *Smart Grid Annual Report – 2019*. https://www.pge.com/pge_global/common/pdfs/safety/how-the-system-works/electric-systems/smart-grid/AnnualReport2019.pdf .Shenot, J., Linvill, C., Dupuy, M., & Brutkoski, D. (2019). Capturing More Value From Combinations of PV and Other Distributed Energy Resources. https://www.raponline.org/wp-content/uploads/2019/08/rap_shenot_linvill_dupuy_combinations_pv_other_ders_2019_august.pdf

[69] Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments.* https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf; Maine Technology Institute (MTI). (2020). *The Electrical Grid of Tomorrow; The Role of the Non-Wires Alternatives Coordinator (E2Tech).* https://www.mainetechnology.org/events/the-electrical-grid-of-tomorrow-the-role-of-the-non-wires-alternatives-coordinator-e2tech/; An Act To Reduce Electricity Costs through Nonwires Alternatives, HP0855, LD 1181, Chapter 298, Public Law. (2019). https://legislature.maine.gov/legis/bills/bills_129th/chapters/PUBLIC298.asp

benefits. Section 1. (ii) B. makes the case for why jurisdiction-wide programs should be funded through the utility system.

75. **Recommendation:** The Commission should take steps towards funding jurisdiction-wide energy efficiency programs through the utility system. To fund energy efficiency through the utility system, the Commission would need to undertake various considerations including the following:

1) Identify Preferred Funding Source and Delivery Model

76. Based on precedence in other North American jurisdictions, utility system funding can be accessed in three different ways:

1) Distribution rates - Utilities could include energy efficiency programs in their rate applications.
2) New tariff or charge - A separate rate tariff or system benefits charge could be added to utility bills to fund energy efficiency programs.
3) An existing tariff – Energy efficiency programming costs could be funded by an existing tariff (e.g. the Independent System Operator tariff) or mechanism (e.g. the Balancing Pool provides funding for the Office of the Utilities Consumer Advocate).70

77. The Commission would determine if using one of the above funding sources is within their current mandate (even if it constitutes a broader interpretation of that mandate), and the legislative context for distribution utilities.

78. Energy efficiency administration encompasses the planning, design, implementation, and evaluation of all programs. An ideal program administration scenario would enable a portfolio of programs that were multi-fuel, jurisdiction-wide, multi-sectoral while being easy for consumers to access and understand.

79. Energy efficiency funding mechanisms are independent of program administration models. The primary energy efficiency administration models across North America include: 1) regulated electric and/or natural gas distribution utilities, 2) a third-party organization (or sometimes energy efficiency utility), and 3) through a government agency or department.[71]

[70] For further information on utility system funding options and their benefits and drawbacks see Dunsky Energy Consulting. (2019). *Integrating Energy Efficiency into the Utility System, A Review of Delivery and Funding* Models. https://eea-assets.s3.amazonaws.com/documents/Dunsky_EEA-Utility-System-Integration-FINAL.pdf?utime=20190904113000

[71] Dunsky Energy Consulting. (2019). *Integrating Energy Efficiency into the Utility System, A Review of Delivery and Funding* Models. https://eea-assets.s3.amazonaws.com/documents/Dunsky_EEA-Utility-System-Integration-FINAL.pdf?utime=20190904113000

2) Clarify Oversight Process

80. Utility system regulators oversee funding for energy efficiency programs, in part, by requiring program budgets to pass well-developed cost-effectiveness tests. Utility Commissions' oversight generally requires energy efficiency projected program costs to be determined by some cost-effectiveness threshold to ensure that energy efficiency programs/measures are only pursued if they are considered the least-cost option when compared to energy supply considering a specified range of costs and benefits. The Commission should undertake a review of what cost-effectiveness test(s) would meet utility system objectives. Multiple resources exist that compare different cost-effectiveness tests.[72]

81. When funding energy efficiency through the utility system, there can be upward pressure on rates due to: (1) efficiency program administration and implementation costs, and (2) potentially, depending on the policy implemented, the recovery of lost utility revenues, (if established in a given jurisdiction). Energy efficiency programs can also put downward pressure on rates through avoided T&D capacity costs, avoided system generation capacity costs, reductions in market-clearing prices for energy and some other factors. The net effect is the combined effect of the upward and downward pressure on rates.

82. A commonly referenced manual for assessing the cost-effectiveness of energy efficiency also guides how to address potential concerns about rate impacts.[73] Specifically, the Manual notes that bills typically go down for efficiency program participants even if rates have gone up a little. As a result, concerns about rate impacts are principally concerns about equity between impacts on participants and those customers who do not participate. Thus, the Manual suggests that three factors be assessed over a multi-year period: 1) average bill impacts, 2) average rate impacts and 3) participation rates. Regulators can then assess trade-offs between bill reductions for participants, rate and bill increases for non-participants and the portion of customers likely to participate over a multi-year period (and therefore be in the group that realizes bill reductions). For example, if 95 per cent of customers are expected to participate and see bill reductions over a ten-year program period, regulators may be more willing to accept modest rate impacts for non-participants than if only 10 per cent of customers are expected to participate and realize bill reductions.[74]

[72] National Action Plan for Energy Efficiency. (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, technical Methods, and Emerging Issues for Policy-Makers.* https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf; National Efficiency Screening Project (NESP). (2017). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*. https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf; American Council for an Energy-Efficient Economy (ACEEE). (2018). *Cost-Effectiveness Tests: Overview of State Approaches to Account for Health and Environmental Benefits of Energy Efficiency*. https://www.aceee.org/sites/default/files/he-ce-tests-121318.pdf; Woolf, T., Malone, E., Takahashi, K., & Steinhurst, W. (2012). *Best Practices in Energy Efficiency Program Screening: How to ensure that the Value of Energy Efficiency is Properly Accounted For.* http://www.synapse-energy.com/sites/default/files/SynapseReport.2012-07.NHPC_.EE-Program-Screening.12-040.pdf

[73] National Efficiency Screening Project (NESP). (2017). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*. https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf

[74] In the past, some jurisdictions used the Ratepayer Impact Test to assess whether there would be rate impacts. However, as the NSPM explains, the RIM test has significant limitations for assessing rate impacts.

83. A review of rate and bill impacts for future energy efficiency programs in Vermont provided the following results:

a) The average long-term rate impacts range from 0.5 per cent for business demand customers to 2.9 per cent for residential customers.[75]

b) Participants then experience bill reductions that outweigh the rate increases. Average bill savings for the study ranged from 1.9 per cent for business demand customers to 5.9 per cent for residential customers.

c) The per cent of customers participating in the programs was estimated to be high given the longevity of programming considered (over a 30-year period). [76]

84. Potential rate impacts from energy efficiency programming in Alberta are relatively small compared with other system costs.

a) A $50 million annual energy efficiency program budget[77], for example, is estimated to result in $0.38 being added to an average residential customer's monthly bill.[78]

b) A $150 million annual energy efficiency program budget[79] results in $1.42 being added to an average residential customer's monthly bill.[80]

c) These rate increases do not consider any downward pressure on the rates such as T&D cost savings etc. (see paragraphs 81-82 above) or bill decreases due to energy savings.

[75] These levels of energy efficiency program activity are relatively high when compared to the average level of activity across Canada and the U.S.

[76] Woolf, T., Malone, E., & Kallay, J. (2014). *Rate and Bill Impacts of Vermont Energy Efficiency Programs.* http://www.synapse-energy.com/sites/default/files/SynapseReport.2014-04.VT-PSD.VT-EE-Bill-Impacts.13-088.pdf)

[77] $50 million is based on the per capita budget of the jurisdiction with the lowest spending in Canada. In 2018, Quebec had a per capita budget of $11.94. This per capita number, applied to the population of Alberta, results in an approximately $50 million budget. The per capita budget was calculated using 2018 population data from Statistics Canada (Statistics Canada. *Population estimates, quarterly*. Table 17-10-0009-01. https://doi.org/10.25318/1710000901-eng) and efficiency program budgets from the data tables in Consortium for Energy Efficiency (CEE) *CEE Annual Industry Report, 2018 State of the Efficiency Program Industry, Budgets, Expenditures, and Impacts* (Consortium for Energy Efficiency (CEE). (2019). CEE Annual Industry Report, 2018 State of the Efficiency Program Industry, Budgets, Expenditures, and Impacts. https://library.cee1.org/system/files/library/13983/2018_AIR_Data_Tables.pdf).

[78] As an illustration of potential rate increases for the whole system, the $50 million budget was divided by the total system MWh estimate in AESO's Transmission Rate Projection Workbook for 2020. The resulting $/MWh was then multiplied by the average residential monthly electricity consumption (600 kWh) obtained from the AUC website. Alberta Electric System Operator (AESO). (2018). *Transmission Rate Projection Workbook*. https://www.aeso.ca/rules-standards-and-tariff/tariff/current-applications/transmission-rate-projection-workbook/

[79] $150 million is based on the cost-effective results from EEA's Potential Study. Navigant (2018). *Energy Efficiency Alberta 2019-2038 Energy Efficiency and Small-Scale Renewables Potential Study*. https://eea-assets.s3.amazonaws.com/documents/Potential-Study-Report-2019-2038.pdf?utime=20190904113023

[80] As an illustration of potential rate increases for the whole system, the $50 million budget was divided by the total system MWh estimate in AESO's Transmission Rate Projection Workbook for 2020. The resulting $/MWh was then multiplied by the average residential monthly electricity consumption (600 kWh) obtained from the AUC website. Alberta Electric System Operator (AESO). (2018). *Transmission Rate Projection Workbook*. https://www.aeso.ca/rules-standards-and-tariff/tariff/current-applications/transmission-rate-projection-workbook/

3) Enable Data Sharing

85. If a non-utility were to administer jurisdiction-wide programs in Alberta, data sharing with utilities would be important to establish as it would enable greater assessment of savings opportunities and support program implementation - see section 2.9.B. for more details. Also, when energy efficiency potential studies include avoided T&D costs, program cost-effectiveness improves and the program portfolio can shift towards increased delivery of passive deferrals.

C. Enable Smart Charging

86. Recommendation: Assess whether smart charging, and small consumer demand response, programs merit AUC rate changes and/or a system-wide approach

87. EEA's submission has already highlighted the potential value of managed or smart charging and small consumer demand response to reducing distribution system costs (see section 1. (ii) A4). NWAs have been addressed earlier in this submission, smart charging merits additional consideration given its potential connection to time-of-use rates or an EV-specific rate. Small consumer demand response could be considered in addition to smart charging recognizing that their program structures could be quite similar. The discussion below is focused on smart charging as these programs are more widely established.

88. Smart charging programs can be designed in multiple ways. Each program must have pricing or a financial incentive to motivate consumers to participate in the program. Two basic options exist for smart charging program design:

a) Time-of-use (TOU) rates – TOU rates can provide financial motivation for consumers to engage in smart charging through pricing/rate structure. TOU rates, across the residential sector (and other sectors), or an EV-specific rate can be offered. In 2019, at minimum 20 utilities in the United States have offered special EV rates.[81] In comparison, nearly 600 utilities offer TOU rates.[82] TOU rates can be mandatory, opt-in or opt-out.[83] It has been demonstrated that opt-out programs have much higher participation rates (e.g. opt-in programs have had less than 20 per cent enrollment, whereas opt-out programs have experienced higher than 90 per cent participation).[84] TOU rates should be accompanied by an effective information program to help consumers realize the existence of the program and

[81] Trabish, H.K. (2019). EV charging promises a demand response bonanza for utilities, if they can handle it. *Utility Dive.* https://www.utilitydive.com/news/ev-charging-promises-a-demand-response-bonanza-for-utilities-if-they-can-h/563453/
[82] Energy Information Administration (EIA). (2018). *Annual Electric Power Industry Report, Form EIA-861 detailed data files, Form EIA-861. Dynamic Pricing*. http://www.eia.gov/electricity/data/eia861/
[83] Power Advisory, LLC. (2014). *Jurisdictional Review of Dynamic Pricing of Electricity*. *https://www.oeb.ca/oeb/_Documents/EB-2004-0205/Power_Advisory_Report_RPP_Jurisdictional_Review.pdf*
[84] Whited, M., Allison, A., & Wilson, R. (2018). *Driving Transportation Electrification Forward in New York*. http://www.synapse-energy.com/sites/default/files/NY-EV-Rate-%20Report-18-021.pdf

understand how to adapt behaviour.[85] An EV-specific rate requires a separate revenue-grade meter or some form of submetering technology to quantify electricity consumed through a residential EV charger. Although the installation of a separate meter for EV charging is a standard practice in jurisdictions with an EV rate, stand-alone and embedded, mobile, and onboard submetering technologies may offer a less expensive option for consumers.[86]

b) Controlled Charging – Controlled charging allows utilities to communicate with a consumer's EV charger to control when charging occurs and avoid contributing to peak demand. Again, financial motivation is required for consumers to sign-up either through: 1) a financial incentive (which may or may not be directed towards the purchase of a smart charger) (e.g. Efficiency Maine provided grants to install Level 2 chargers available to businesses, non-profits, and municipalities.)[87] , or 2) the utility owns the smart charger but the consumer allows the installation at their residence so they may benefit from owning a Level Two charger.[88] Controlled charging can mitigate the tendency for a new peak to form under TOU rates[89] which may have implications for distribution infrastructure that may be close to loaded at later points in the evening or if many EVs are clustered on one residential transformer (or circuit).

c) Hybrid Option – There is also a hybrid option where EV owners sign up for a smart charging program that allows for customer control of charging, but incentives for off-peak charging. This is similar to the TOU option but could be enabled through mechanisms other than rates and a revenue-grade meter.

89. The AUC could consider commissioning a report on if and how Alberta should incent smart charging (potentially including a cost-benefit analysis on options) as evidence in this submission points to benefits for entire distribution systems. Undertaking a province-wide study on the issue may benefit stakeholders by avoiding individual studies and result in a more integrated approach to understanding different approaches.

90. Another potential benefit of such a study could be to enable maximizing consumer choice. In their Module One submission, Greenlots advocated for ensuring that EV charging technology, hardware, software and network services are based open technical standards and protocols. If ratepayer funds are to be used to incent or purchase infrastructure to enable manage EV charging, it merits examining the best path forward to avoid stranded assets and higher

[85] Colgan, J.T., Delattre, A., Fanshaw, B., Gilliam, R., Hawiger, M.,Howat, J., Jester, D., LeBel, M., & Zuckerman, E. (2017). *Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates*. https://uspirg.org/sites/pirg/files/reports/TOU-Paper-7.17.17.pdf
[86] Whited, M., Allison, A., & Wilson, R. (2018). *Driving Transportation Electrification Forward in New York*. http://www.synapse-energy.com/sites/default/files/NY-EV-Rate-%20Report-18-021.pdf, 17-23.
[87] Natural Resources Council of Maine (NRCM). (2020). *Electric Vehicle Chargers*. https://www.nrcm.org/programs/climate/cleaner-transportation/electric-vehicle-chargers/
[88] Level two chargers are more costly and are an incremental advancement beyond the level one charger typically provided when a consumer purchases an EV.
[89] Hurlbut, D., McLaren, J., Koebrich, S., Williams, J., & Chen, E. (2019). *Electric Vehicle Charging Implications for Utility Ratemaking in Colorado*. https://www.nrel.gov/docs/fy19osti/73303.pdf

operating costs due to vendor lock-in.[90] The Commission may choose to establish requirements that maintain open technical standards and protocols.

[90] Greenlots. (2019). *Greenlots Module One Submission in the Commission's Distribution System Inquiry, Distribution System Inquiry, Module One, Proceeding 24116,* Exhibit #24116-X0169, 5-6. https://www2.auc.ab.ca/Proceeding24116/ProceedingDocuments/24116_X0169_GreenlotsAUCDistributionSystemInquiryMod_0178.pdf

1. (v) Effect on Other Entities

AUC Question: Given your responses to part (iv) above, what would be the effect on other entities that currently operate in, or benefit from, the AIES? What are the opportunities and challenges for distribution facility owners to evolve their business models and/or value propositions?

91. NWAs may present an opportunity for distribution facility operators (DFOs) to generate revenue without building poles and wires infrastructure. Providing utilities incentives to pursue NWAs could allow DFOs to benefit financially (even under a competitive procurement model). An NWA open procurement process could also increase access to revenue-generating opportunities in the distribution system increasing competition in an otherwise regulated monopoly.

92. Enabling NWAs and jurisdiction-wide programs would benefit consumers and ratepayers through better cost and risk management of the distribution system and energy bills.

93. With respect to jurisdiction-wide programs, integrating energy efficiency into the utility system will help ensure any impacts from energy efficiency are predictable and consistent over time. This will benefit all entities that operate on the Alberta Interconnected Electric System, as well as distribution and retail utilities and consumers. Stable funding would enable long-term planning for energy efficiency programming which in turn would allow AESO, generators and retailers to take their impacts into account when planning and forecasting.

2. Other load and generation configurations (including Non-Wires Alternatives or demand response schemes)

Non-Wires Alternatives

B. Would you recommend changes to what, and with whom, information and data is shared? Why and based on what principles? How would this affect certain connection schemes?

94. Data such as hourly load shape (at the appropriate level for the NWA e.g. transformer, feeder etc.) and customer demographics (for the NWA area in question) would need to be made available to the energy efficiency program administrators (or other NWA bidders) under any NWA procurement model where utilities engage third parties. This allows for a more accurate assessment of NWA project benefits and costs.

95. Types of utility data that can significantly increase the cost-effectiveness of third-party NWA bids or project implementation are:

    a) System data including real-time pricing, capital investment plans, load forecasts, reliability statistics, and planned reliability and resiliency projects,

    b) Customer specific data – may be enabled through customer opt-in tools such as the Green Button standard[91], and

    c) Aggregate customer data.[92]

96. Accuracy and transparency in methods and types of utility data being shared are important for successful implementation. Beyond sharing data, the utility may further increase the transparency of the project solicitation process by releasing project evaluation models that proponents can use to optimize their bid. For example, PG&E worked closely with the Oakland community in the development of its non-wires alternative proposal which helped identify key stakeholders, assets, and local needs.[93]

97. Some examples of utilities sharing their data and public commissions with supporting rules established include:

    a) IESO recognizes the value of developing accessible datasets and tools for incorporating NWAs. It also identifies the need for improved understanding of regulatory rules and processes governing NWA projects.[94]

[91] The Green Button standard helps customer data to be shared through a standardized format and process that reduces the complexity of collecting and aggregating customer data.
[92] Dyson, M., Prince, J., Shwisberg, L., & Waller, J. (2018). *The Non-Wires Solutions Implementation Playbook, A Practical Guide for Regulators, Utilities, and Developers*. https://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf
[93] Steinbacher, K., & Stanton, T. (2019, October 8). Non-Wires Alternatives for Grid Expansion: What the U.S. Can Teach Europe, *Energy Post*. https://energypost.eu/non-wires-alternatives-for-grid-expansion-what-the-u-s-can-teach-europe/
[94] Independent Electricity System Operator (IESO). (2019). *IESO Regional Planning Review Advisory Group (RPRAG) Meeting #5*. http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rpr/rprag-20190624-presentation.pdf?la=en

b) New York Public Services Commission rules allow building owners to provide access to third parties (who may be pursuing NWAs) to access their detailed utility data.[95] [96]

i. "Joint Utilities" (e.g. Con Edison, Central Hudson Gas & Electric, etc.) regulated by the New York Public Services Commission are sharing distribution-level data, which significantly increases transparency and the ability for third parties to offer market-based NWA and DER solutions.[97] Specifically, Central Hudson's current distribution system's implementation plan highlights current system data that is available to third-party stakeholders. It includes up to five years of historic hourly load data for its circuit feeders, load-serving substations along with forecasts where available. Other data available includes maps highlighting areas where are more/less applicable for NWAs and DER projects. As of 2016, 77 per cent of substations and 61 per cent of feeders have reliable hourly data.[98]

C. Would you recommend changes to distribution network planning? Why and based on what principles?

98. See response to question 1.(iv) A. B. Take Steps to Enable and Integrate

99. These recommendations are based on the principles of customer choice, technology agnosticism and least-cost approach.

J. Do you have any other recommended changes?

100. See response to question 1.(iv) C. Enable Smart Charging

Advanced Metering Infrastructure/Data Access

B. Would you recommend changes to what, and with whom, information and data is shared? Why and based on what principles? How would this affect certain connection schemes?

101. It is recommended that an energy efficiency program administrator should be provided access to consumer energy consumption through amendments to Rule 010 in order to reduce

[95] Kirschbaum, K. (2019). *Case 14-M-010 1In the Matter of Reforming the Energy Vision and Case 16-M-0411 In the Matter of Distributed System Implementation PlansJoint Utility Aggregated Whole Building Data Terms and Conditions*, 14. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={48E9F37A-55DE-4382-BF3E-3DCDD3055CBF}
[96] Central Hudson. (2016). *Central Hudson Initial Distributed System Implementation Plan*. http://nyssmartgrid.com/wp-content/uploads/Central-Hudson-DSIP-Report.pdf
[97] Trabish, H. (2017). How utility data sharing is helping the New York REV build the grid of the future, *Utility Dive*. https://www.utilitydive.com/news/how-utility-data-sharing-is-helping-the-new-york-rev-build-the-grid-of-the/434972/
[98] Central Hudson. (2016). *Central Hudson Initial Distributed System Implementation Plan*, 117. http://nyssmartgrid.com/wp-content/uploads/Central-Hudson-DSIP-Report.pdf

participant and program costs and meet energy efficiency program participant needs. This submission has outlined the multiple benefits energy efficiency programs provide to consumers, justifying the enabling of these programs. Access to historic and current energy consumption data would reduce unnecessary costs and increase the timely implementation of programs. Increasing the speed and efficiency of obtaining data would also increase the overall cost-effectiveness of energy efficiency programs.

102. For example, experience from EEA's Customer Energy Solutions (CES) program demonstrated that data access restrictions in Rule 010 meant that program applicants and EEA staff had to find alternative means to access data. Additional EEA and program implementer staff time was required to obtain alternative data (e.g. sub-meter data). Fortunately, all program participants had large enough operations to have sub-metering data, but with smaller consumers (for other programs) this alternative data may not exist. Using alternative data can also impact the accuracy of results.

103. Access to program participant data is driven by the least-cost approach principle.

C. Would you recommend changes to distribution network planning? Why and based on what principles?

104. In Module One, multiple participants highlighted the limitations of approaching the AUC on an individual basis with a business case to obtain cost approval to install Advanced Metering Infrastructure (AMI).

105. It would be beneficial for the AUC to consider other recommendations coming out of the Distribution System Inquiry alongside how to address AMI. It may merit assessment through a cost-benefit analysis that incorporates multiple factors discussed below.

106. AMI can provide multiple benefits to utilities and AESO in managing the grid in a world with higher levels of DER penetration. AMI data can be used in combination with Distributed Energy Resource Management Systems (DERMS) to enable real-time monitoring and dispatch of DERs to optimize the balance of distribution assets. These AMI benefits should be fully valued and considered in an AMI cost-benefit analysis.

107. From an energy efficiency perspective, AMI can benefit energy efficiency and demand response programs. AMI data can be used to enhance program uptake and effectiveness and increase savings for consumers. For example, AMI data can be used to better identify, assess and target energy efficiency programs based on a consumer's unique load profile and needs. AMI data has also been used to identify potential upgrade opportunities for a much lower cost than an on-site energy assessment. AMI data can also be used to track and evaluate both project and program impacts in a faster and more detailed way than traditional evaluation approaches. This enables more rapid adjustments to be made to programs to improve performance.

108. In order to unlock the benefits of AMI, it must be undertaken within an environment that enables its benefits (including a supportive regulatory environment). Without a supportive

environment in place, and the communication network needed to communicate with AMI devices for a given application, there is risk in investing in AMI infrastructure as the technology may be underutilized or become outdated by the time the supporting systems are in place.

109. Contrarily, there is also risk in not enabling the introduction of AMI technology at the right time, as it takes years to fully deploy. Careful cost-benefit assessment is required to determine the optimal time for AMI deployment. This assessment should include a comparison to other approaches to achieving similar grid management goals including other approaches to demand side management and initial AMI deployment for DER sites only.

110. For energy efficiency and small consumer demand response programs, there may be more immediate and less expensive opportunities before full or partial-AMI implementation occurs. This includes using internet-connected devices such as smart thermostats and other internet enabled technologies. These connected devices may be able to both reduce energy use and shift load timing to achieve desired demand response goals. Like AMI, in order to achieve peak demand reduction (through energy efficiency) or shifting (through demand response), these internet-connected devices need to be associated with mechanisms that value this activity and provide financial motivation for participation. Information programs as well as: 1) time of use (TOU) or real-time pricing rates, or 2) financial incentives will be required to ensure continued use of these devices, (e.g. options include an upfront financial incentive with a contract or discounted $/kWh for demand response [including reduced operation]).

111. It is also important to remember that easier and more cost-effective opportunities are available through traditional passive energy efficiency programs that deliver these benefits (such as peak load reduction) with low costs, and do not require active metering, control or pricing infrastructure. Much of this submission has already highlighted how traditional energy efficiency programs can be enabled to deliver multiple benefits.

Appendix A – Non-Wires Alternatives Study How EE, DR and Managed Charging Can Cost-Effectively Offset EV Load Growth

[next page]