Alberta Utilities Commission

Time Varying Rates

Assessment of Costs and Benefits

June 19, 2025

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Alberta Utilities Commission
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1 Executive summary

1. This report summarizes an assessment of the benefits and costs associated with enabling the framework for time varying rates for all customers in Alberta. The assessment incorporates analysis from external experts, including London Economics International LLC (LEI), Pricewaterhouse Coopers International Ltd. (PwC) and Guidehouse Inc.

2. The purpose of this assessment is to ensure that an informed analysis of costs and benefits is conducted prior to moving forward. Some factors in this analysis may have a high degree of variability or uncertainty. Where that is the case, the report documents the key assumptions and discusses the uncertainties associated with estimating costs and benefits. The report is not a detailed estimate of the exact costs or benefits of enabling time varying rates in Alberta, but rather provides a high-level assessment of whether the benefits are likely to exceed the costs of enablement.

3. In summary, the expected benefits outweigh the expected costs by orders of magnitude. The incremental capital costs anticipated to be incurred by distribution utilities to enable broad implementation of time varying rates in Alberta are estimated to be in the range of $18 to $75 million,[1] and a potential increase in ongoing operating expenditures of $2 to $4 million per year. These costs are expected to be materially outweighed by the benefits quantified, including avoided costs in Alberta's energy-only market and future avoided distribution infrastructure investments. The forecast benefits in 2035 alone are estimated at $118 to $124 million. This assessment supports the conclusion that a deliberate and coordinated approach to enabling time varying rates in Alberta is justified. Engagement with industry, customers and other interested stakeholders will be required to identify and effect the necessary changes to the regulatory framework to enable time varying rates.

4. Over the term of the current performance-based regulation (PBR) plans (2024-2028), each regulated distribution utility in the province is independently, and on different timelines, installing smart meters and deploying other, related advance metering infrastructure, which is required to enable time varying rates.[2] Therefore, the costs of installing smart meters are already expected to be included in current and future rates and were not included in the analysis as

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1 These estimated capital costs represent investments that will be recovered over the average expected life of the assets. The annual costs associated with this capital investment are estimated to be in the range of $1.2 million to $5.2 million.

2 Throughout this report, the AUC uses the term "smart meter" to refer to digital meters capable of measuring and relaying consumption data on a defined interval (e.g. hourly, 15-minute or 5-minute) or in real time. Where a different term, such as interval meter is used, this is intended to refer to a different category of meters that may have some, but not necessarily all, of the same functionality. For example, an interval meter may measure or track consumption on a defined interval but may not offer some of the other advanced capabilities, such as two-way communication capability. Where the AUC refers to advanced metering infrastructure, it is referring to the broader suite of infrastructure including meters and the meter data management infrastructure necessary to support time varying rates.

incremental costs associated with the future enabling of time varying rates to avoid double-counting.[3]

5. This report does not address how time varying rates could be deployed to end use customers, including that it does not consider the design of future time varying rates or the costs that non-regulated, competitive retailers might incur to take advantage of the enablement of the time varying rates framework. Ultimately, the structure of Alberta's electricity sector will require a well-coordinated effort between distribution facility owners, retailers, the Alberta Electric System Operator (AESO), the Alberta Utilities Commission (AUC) and other industry players to ensure seamless and cost-effective integration across all industry entities and the corresponding information and information systems necessary for end use deployment (e.g. metering, billing and settlement systems). It will also be important to work with customers and their representatives to ensure rates are designed to promote customer engagement and support.

6. Given the compelling benefit to cost ratio, the AUC will proceed to consult with utilities, retailers, the AESO and customer representatives regarding enabling time varying rates, including:

- Assessing the different options for meter data management (such as a centralized repository versus the continued decentralized approach).
- Identifying all policy and regulatory changes necessary to enable time varying rates in Alberta.
- Discussing opportunities for coordination with the AESO regarding its planned implementation of a shorter settlement interval.
- Developing a detailed enablement plan.

2 Why is it a good time to consider enabling time varying rates?

7. Time varying rates are a tool that can help electricity customers reduce costs by providing effective price signals to customers to shift electricity consumption to lower cost periods. This will become more important as the energy transition evolves in Alberta, including the broader penetration of electric vehicles (EVs), solar panels, energy storage and other decarbonization efforts. Numerous government and industry activities, recent and planned, support pursuing the enablement of time varying rates now or in the near future.

8. In 2023, the Government of Alberta directed the AUC to launch an inquiry into certain key issues associated with the growing level of renewable energy on the Alberta electricity

[3] Assumptions around what is, and what is not, included in current and future rates for the purposes of this analysis and report is not a commentary on any current or future applications from distribution utilities or others that may impact future rates. The Commission, acting in its adjudicative capacity, will consider any such applications on a case-by-case basis, based on the evidence and argument before it. For example, the AUC acknowledges that there is an ongoing proceeding in which FortisAlberta has applied for incremental capital associated with, amongst other things, advanced metering infrastructure, and that no Commission decision has been made on that request as of the writing of this report. Where the Commission grants incremental capital funding for advanced metering infrastructure, this may impact the costs in the cost-benefit analysis.

system. One of the issues the AUC was directed to examine was the impact the increasing growth of renewables has on both generation supply mix and electricity system reliability. In its report published in March 2024, the AUC concluded that higher levels of renewables will have significant impacts on reliability and affordability under the existing market design. In particular, the report concluded that by the late 2030s, under the existing market framework, customers would be paying significantly higher rates for electricity, while receiving a substantially lower level of reliability. As part of its final report, the AUC acknowledged many parties identified that demand response could play a role in mitigating both supply adequacy and affordability issues. Accordingly, the AUC committed to exploring demand response opportunities, including time varying rates, as a priority item in the near term.[4]

9. Also in March 2024, the Government of Alberta proclaimed the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*. The act establishes a framework to modernize Alberta's electricity system by allowing for the integration of new technologies and promoting a more proactive and coordinated approach to distribution system planning intended to, amongst other things, optimize existing and future investments required to support the integration of these new decarbonization technologies. Around the same time, the Government tasked the AESO with implementing changes to the wholesale electricity market design. As part of this restructured energy market initiative, the AESO is considering the move to a shorter settlement interval.[5] Relatedly, the Minister of Affordability and Utilities has indicated the government's interest in enabling demand response technologies and practices.

10. The AUC also recently commissioned a report from Guidehouse to study distribution costs associated with Alberta's path to net-zero.[6] The analysis concluded that incremental distribution costs associated with increasing levels of EVs, solar photovoltaics and energy storage in Alberta could reach $2.6 billion by 2050. A key driving factor for the incremental distribution costs was the forecasted timing and magnitude of EV adoption. Consistent with the AUC's prior observations,[7] Guidehouse's analysis identified that adoption of time varying rates can assist with optimization of distribution infrastructure, reducing the amount of incremental cost on the distribution system due to increased penetration of EVs, solar photovoltaics and energy storage. A key potential solution to avoid additional investment includes rate incentive programs for EV charging.

11. Moreover, distribution utilities in Alberta are at varying stages of installing the advanced metering infrastructure that would be required for time varying rates, with the expectation that smart meters will be in place for residential and other small customers[8] by 2028 or 2029.

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[4] AUC inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta, Module B Report, March 28, 2024, PDF page 19.

[5] In a letter dated December 10, 2025, the Minister of Affordability and Utilities directed the AESO to continue the Reformed Energy Market (REM) technical design, including collaborating with the AUC to implement 5-minute settlement for transmission-connected loads, generators and interties by 2032 and for all loads by 2040.

[6] Net-Zero Analysis of Alberta's Electricity Distribution System.pdf.

[7] For example, in its Distribution System Inquiry report, the AUC observed opportunities for improvements to rate and tariff design to support customers to make economically efficient decisions regarding their electricity consumption.

[8] Customers have been given the option to opt out of receiving a smart meter for a fee. Accordingly, while the AUC expects smart meters to be in place for almost all customers served by regulated distribution utilities, there

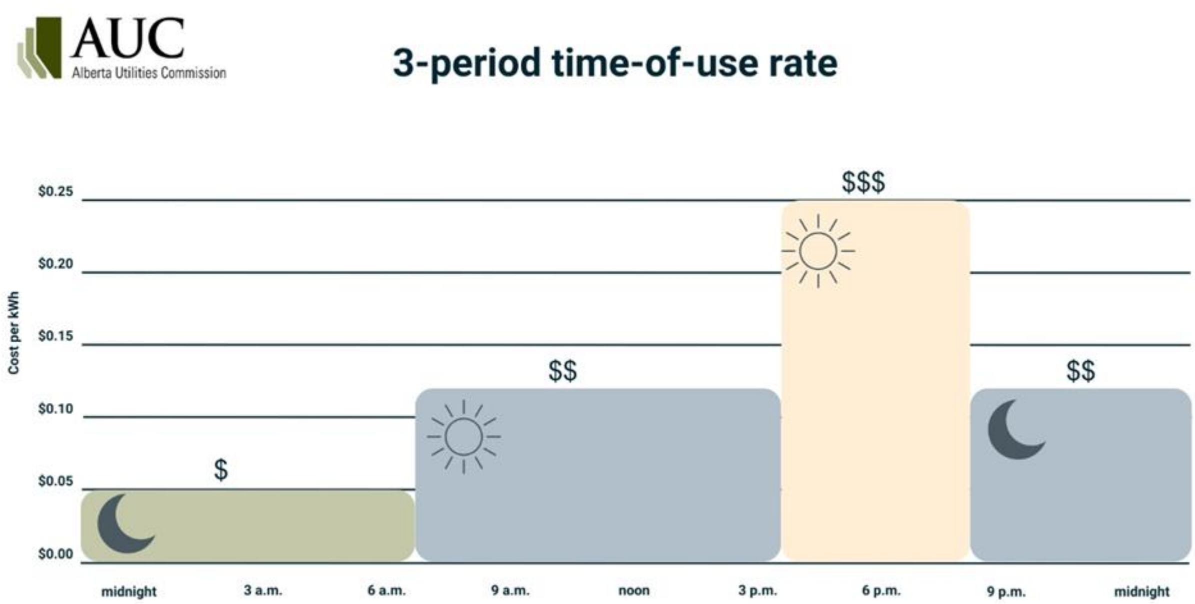
12. Doing the work now to ensure that the foregoing is managed in a coordinated fashion that best serves customers and the industry will provide a clear path forward for all stakeholders, minimize the risk of stranded investment and support an intentional and strategic approach to demand response, including time varying rates, to maximize benefits.

3 What are time varying rates and how do they work?

13. The term "time varying rates" captures a broad category of rates and pricing where the rate a customer pays for electricity depends on when (i.e., in which hours of the day and/or time of the year) and how much they consume. The intent is to incent customers to shift their consumption from times when overall demand (and prices) are high to times when demand (and prices) are lower. The result can be lower prices for customers and less strain on the systems that generate and deliver electricity.

14. Time-of-use (TOU) rates are a relatively straightforward category of time varying rates currently in place (either on an opt-in or default basis) for energy consumption in many other jurisdictions in North America and globally.[9] Under a time-of-use rate, both the periods of time and rates (prices) attendant to those periods are pre-determined. Figure 1 below presents an example of a 3-period time-of-use rate.

Figure 1. Example of TOU rates: three period TOU rate



will be a small minority of customers who will not have the technology in place to facilitate time varying rates. For example, in a 2024 application filed by ENMAX Power Corporation, ENMAX advised that as of April 30, 2024, it has installed nearly 330,000 AMI meters, and 135 customers had chosen to opt out of AMI meter service. Decision [29065-D01-2024](): ENMAX Power Corporation, Distribution Tariff Terms and Conditions Amendment Application, Proceeding 29065, August 26, 2024, paragraph 6.

9 For example, in Brattle's updated survey of pricing experiments, Dr. Sanem Sergici and Dr. Ahmad Faruqui documented 397 examples of time varying rates over 4 continents. Of the 397 examples, 205 involved a time-of-use structure. Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0.

15. As shown in the figure, there is a peak-period during the late afternoon and evening hours, off-peak periods during the daytime hours and the hours immediately following the peak, and a super off-peak period during the early hours of the morning. The price signal communicated to customers is quite clear in this rate design, it is more expensive to consume on peak (when demand is highest) than during other periods and least expensive to consume during super off-peak (when demand is lowest).

16. Provided customers can see, understand and respond, these prices incent customers to move as much consumption as possible away from the peak hours (from 3:30 p.m. to 8:30 p.m.) to the off-peak hours (from 6:30 a.m. to 3:30 p.m. and from 8:30 p.m. to midnight) or the super off-peak hours (from midnight to 6:30 a.m.) to save money on their electricity bill. In this example, the costs of off-peak consumption are approximately half the cost per kilowatt hour (kWh) of on-peak consumption. If customers can shift their consumption to super off-peak hours (midnight to 6:30 a.m.), they will pay a rate that is five times lower than the on-peak rate and less than half of the off-peak rate.

17. Numerous studies demonstrate that time-of-use rates can successfully motivate customers to move consumption away from the specified peak hours. The overwhelming evidence from these rate offerings is that customers reduce their peak demand in response to higher prices during peak hours and that these demand reductions can be relied upon by utilities, regulators and other market participants to better plan and optimize existing and future investments in the system.[10] For example, in Ontario, time-of-use rates were introduced in 2009 and rolled out on a default basis in 2011 and 2012 for residential and small commercial customers. This meant that about 90 per cent of Ontario's four million customers were exposed to time-of-use rates. A Brattle Group analysis found that Ontario reduced usage during the summer peak by 3.3 per cent in the pre-2012 period, 2.3 per cent in 2012, and 2 per cent and 1.2 per cent in 2013 and 2014, respectively.[11] As discussed in this report, setting aside EV charging, LEI assumed a 3 per cent reduction in peak load from additional customers exposed to a time varying rates, based on this observed response.

18. By shifting some of their consumption to off-peak periods, customers can reduce demand on the system during the hours when the system is most likely strained. Considering that the electricity system is largely built to support peak demands locally and regionally, such reductions allow utilities to postpone or even avoid costly capital investments that would have otherwise been required. Customers with EVs are particularly responsive to these incentives, as they can shift charging times without significant inconvenience or lifestyle changes (for example, through automated charging). Given the substantial electricity demand associated with EV charging, time varying rates can incentivize EV drivers to shift charging times by rewarding them with significant electricity bill reductions if they charge at off-peak times. This creates a win-win scenario for customers, through lower bills, and utilities by helping to avoid or postpone making costly upgrades.

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[10] For more discussion on the trend in the available pilots, see Arcturus 2.0.

[11] "Time of Use Rates: An International Perspective" Ahmad Faruqui and Cecile Bourbonnais accessed at: https://energyregulationquarterly.ca/articles/time-of-use-rates-an-international-perspectives#sthash.iN55qZ9r.dpbs.

4 The current state of time varying rates and the supporting infrastructure in Alberta

19. Alberta is home to nearly five million people,[12] with residential power consumption accounting for approximately one-fifth of all electricity consumed in the province. Industrial consumption, by comparison, accounts for nearly half of all electricity consumed in Alberta.

Figure 2. Annual electricity sales by customer category

20. Most industrial and large commercial customers in the province have interval meters installed (meters that measure the energy consumed and the demand for a specified time interval such as an hour or 15-minutes) and already face rates / prices whereby the cost of demand or consumption can vary according to the time at which the consumption occurs. These large customers, representing approximately 75 per cent of the electricity consumed annually in Alberta, are therefore already exposed to some form of time varying rate.

21. This assessment focuses on the residential, small commercial and farm customers in Alberta that are not currently exposed to time varying rates.[13] The implementation of time varying rates for these customers has been limited to date, in part, because the distribution utilities did not have the required advanced metering infrastructure installed. Historically, these customers had (and, at present, may still have) cumulative electromechanical meters capable of measuring only total consumption (in kWh), which are typically read no more than once a month for billing purposes. Time varying rates are not possible with such metering equipment.

22. Recently, several distribution utilities in Alberta have replaced, or are in the process of replacing, these older cumulative meters with new smart meters and associated advanced

[12] population-estimates-ab-quarterly-1951-to-current.xlsx.

[13] While the majority of residential customers are not currently exposed to time varying rates, there is an optional time-of-use rate pilot available to ATCO Electric Ltd. residential customers in the Grande Prairie area. In approving this rate on a pilot basis in Decision 24747-D01-2020: ATCO Electric Ltd, 2019 Distribution Tariff Phase II Application, Proceeding 24747, April 30, 2020, the Commission directed ATCO Electric to provide a detailed account of the rate's adoption by customers and ATCO Electric's learnings from coordinating changes with ATCO Electric's retailers for eligible customers in its next Phase II application.

metering infrastructure.[14] [15] [16] It is expected that AUC-regulated distribution utilities will have completed the installation of smart meters in their respective service territories by 2028 or 2029. The timeline may be longer and is less certain for non-AUC regulated distributors, namely, small municipally-owned distributors and rural electrification associations.

23. Among other capabilities, smart meters can measure energy consumption and demand at specified time intervals (such as hourly, or every 15 or 5-minutes). However, the meters are just one part of the advanced metering infrastructure required, and it is important to recognize that meter functionality depends on how the advanced metering infrastructure is configured and the meter data management infrastructure that is available. For example, while EPCOR Distribution and Transmission Inc. installed smart meters throughout its service territory several years ago, the configuration of its AMI system does not currently support billing customers according to a time varying rate.[17]

24. There is great variability between distributors, and less visibility overall, into the timelines and capabilities of distributors' existing and planned meter data management infrastructure. Accordingly, in its assessment, the AUC sought to better understand the incremental costs that may be required to be incurred to support using smart meters to offer time varying rates to customers.[18]

5 The cost-benefit methodology and analysis of enabling time varying rates

25. The structure of Alberta's electricity industry, in which the generation and retail segments are primarily de-regulated, adds complexity to both the assessment and enabling of time varying rates. In Alberta, customers are billed an energy charge for the electricity they consume and wires charges for the delivery (transmission and distribution) of that electricity to them. While these charges are on a single bill, the AUC's role is focused on the economic regulation of the wires charges. The energy charge is, in most cases, established through an

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[14] Until recently, ENMAX Power Corporation was replacing existing meters with smart meters on an as needed basis. However, it did not have any back-end infrastructure to support the enhanced functionality of these meters. In 2023, ENMAX indicated it initiated a project to build a functional advanced metering infrastructure system and replace all non-advanced meters on its distribution system with smart meters. The program was originally scheduled to be completed in 2025. However, ENMAX has recently indicated that it has concerns about its ability to fund this project, which may result in delays in implementation.

[15] ATCO Electric is currently undertaking a smart meter rollout that is expected to be completed by 2028.

[16] FortisAlberta Inc. is also in the process of implementing its next-generation advanced metering infrastructure system, which is currently expected to be completed by the end of 2029. Fortis has stated that it will ensure that all new meters and the next-generation advanced metering infrastructure system have time varying rate capabilities.

[17] The AUC observed in the Distribution System Inquiry report that EPCOR replaced 99.9 per cent of its conventional meters with AMI meters in 2017, and that EPCOR estimated that to generate bills based on hourly data for all customers currently being billed on a cumulative basis would require additional capital investment of at least $10 million.

[18] As noted earlier in this report, the AESO is considering introducing shorter settlement intervals in Alberta's wholesale electricity market and the government has provided direction to implement 5-minute settlement for transmission-connected loads, generators and interties by 2032 and for all loads by 2040. In its consultation, the AESO heard from a number of distributors regarding existing metering capabilities and that, in most cases, a move to 5-minute settlements will require increased investment in metering infrastructure. The AUC did not include these costs in its assessment.

unregulated, competitive contract between a customer and retailer,[19] meaning that the issue of offering time varying rates for the energy consumed is largely outside of the AUC's jurisdiction. The AUC can, however, assist in the creation and coordination of the regulatory framework that will enable competitive retailers to offer time varying energy rates to their customers. The AUC can also consider and approve time varying rate for the wires charges.[20]

26. In considering the enabling of time varying rates, the essential question is: will the benefits outweigh the costs? To answer this question, the AUC focused on quantifying the following, with the assistance of several external experts:

Benefits

(1) Energy market benefits.

(2) Wires (electric distribution) benefits.[21]

Costs

Incremental investment in the meter data management systems necessary to support time varying rates.

27. While this report speaks to time varying rates generally, some of the analysis focused on time-of-use rates specifically. For example, LEI forecast potential energy market benefits of implementing time-of-use rates and PwC provided order of magnitude costs for the meter data management systems required to enable time-of-use rates.

28. Based on the results of the work done by LEI and Guidehouse, enabling time varying rates is estimated to result in approximately $118 to 124 million in benefits (savings) in 2035. These annual benefits are primarily associated with avoiding incurring future costs in the energy market and distribution systems. They would be expected to increase over time, particularly as EV adoption increases. The benefits are largely driven by the expected rate of EV adoption (and the associated demand that EV charging creates), and any change to the assumptions made by LEI and Guidehouse regarding the rate of EV adoption would result in corresponding changes to the benefits. Based on the high-level cost analysis from PwC, enabling time varying rates is expected to require additional capital expenditures of $18 to $75 million for initial enablement, and a potential increase in ongoing operating expenditures of $2 to $4 million per year.

29. The analysis supports the conclusion that enabling time varying rates offers a way to make the transition to net-zero more affordable by reducing the expected increase to both wires and energy costs to be faced by customers. The high-level analysis shows that the benefits of enabling time varying rates exceed the increase in revenue requirement driven by the costs of

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19 With the exception of Rate of Last Resort (ROLR) customers, who do not have an energy contract with a competitive retailer and thus are on the default rate.

20 A jurisdictional scan completed by PwC found that in most other jurisdictions, time-of-use rates are applied exclusively to the energy consumed.

21 While the enabling of time varying rates may also have benefits for electric transmission, the AUC did not incorporate an assessment of transmission benefits at this stage in light of the important role the AESO plays in relation to much of the transmission infrastructure in Alberta and given various policy-related changes being considered at this point in time (such as changes to the *Transmission Regulation*, Alta Reg 86/2007). Future collaboration with the AESO could assist in developing an assessment of any potential benefits to transmission.

implementation by roughly $109 to $123 million a year starting in 2035, which is a compelling benefit-cost ratio. Additional potential benefits associated with lower system operating costs, improved system reliability and increased customer choice, were not quantified (and would be in addition to those benefits estimated). Time varying consumption data can also facilitate other creative retail rate and demand response opportunities for customers.

30. The inputs, assumptions and results of the analysis are discussed in further detail in the sections that follow.

Energy market benefits

31. The AUC used analysis from LEI to inform its assessment of the energy market benefits that could be achieved through enabling time varying rates.

Assumptions and analysis

32. LEI calculated the potential benefits associated with implementing time-of-use rates by comparing a scenario where time-of-use rates are implemented to a scenario where they have not been implemented. LEI modeled how power pool prices[22] and resource adequacy would change if time-of-use rates were adopted. As with any analysis that forecasts the future, the assumptions that are used can have a significant impact on the results.

33. Using the forecasts developed by the AESO for its 2024 Long Term Outlook, LEI modeled how energy consumption could be expected to change if customers who are not currently exposed to pool prices were exposed to time-of-use rates. While LEI assessed the impact of implementation of time-of-use rates on the AESO's "Decarbonization by 2035," "Decarbonization by 2050" and "High Electrification" cases from the 2024 Long Term Outlook, the AUC focused its assessment on the 2050 case as it is the more conservative scenario and aligns with provincial net-zero targets. If future load growth (particularly related to EV adoption) and other considerations (such as capacity additions and retirements), proceed more in line with a different 2024 Long Term Outlook case, such as the Decarbonization by 2035 case, the potential benefits associated with enabling time varying rates can be expected to increase.

34. The assumptions underlying LEI's analysis can be grouped into two categories: (i) the amount of system load exposed to time-of-use rates; and (ii) customers' response to time-of-use rates (i.e. how the load identified in (i) will respond).

35. First, when assessing the amount of system load that would be exposed to time varying rates, LEI had to consider the competitive retail structure in Alberta, and what it might mean for how energy prices are passed along to customers. One of the benefits of having competitive retailers in the Alberta marketplace is that customers are offered a variety of electricity rates, and they can shop for a rate that best fits their preferences. For example, time varying rates may be attractive to customers who are willing and able to change their consumption habits to lower their monthly bill. On the other hand, this variability may be undesirable for some customers

[22] From the AESO's "How-the-Pool-Price-is-Determined-2018.pdf:" "The wholesale electricity market in Alberta operates much like a stock exchange, matching offers from market participants who wish to sell electricity with bids from market participants who wish to buy it. The pool price is the dollar cost of a MW hour of electricity at the end of a given hour that is paid to electricity generators for supplying electricity by retailers (such as your local service provider). Typically, retailers purchase this electricity to supply residential and business customers, as well as large industrial customers."

who are less willing or able to shift consumption. Further, there is likely to be a subset of customers that would prefer to pay a premium to have the stability of paying a locked-in electricity rate that does not fluctuate over the course of the day.

36. To reflect that not all customers can be expected to choose a time varying rate, in its modelling, LEI assumed that time-of-use rates would affect 50 per cent of residential and other small consumers who have a contract with a retailer (i.e. who are not on the default, regulated rate). LEI also assumed that customers who are on the default, regulated rate would be subject to time-of-use pricing.[23] In aggregate, LEI anticipated that 22 per cent (approximately 2,600 megawatt (MW)) of the total system load would be impacted by time-of-use rates in 2030. Under normal weather conditions on a typical day in 2030, this would result in a 20 MW decrease to peak demand.[24] LEI also considered EV load separately from other types of consumption, and assumed that 100 percent of EV charging would be exposed to time-of-use rates, which they projected would result in a 29 MW decrease in EV charging load during peak hours in 2030. The 2024 Long Term Outlook cases from the AESO that underpinned LEI's analysis included significant growth in EV charging amounting to peak demands of 231 MW in 2030 and 1022 MW in 2035. The response of EV charging to time-of-use rates is expected to drive most of the savings associated with their adoption.

37. Second, to model expected customer response, LEI had to assume the form of time varying rates that would be in place in Alberta. Most of the available studies were based on time-of-use rates that follow a prescribed schedule and were implemented in jurisdictions that do not have a competitive energy market or retail competition. Under a time-of-use rate structure, individual customers can reduce their costs by changing their behaviour such that more of their energy consumption occurs at off-peak, lower price periods. If customers shift a large volume of consumption to off-peak, it is expected to result in lower average power pool prices, which benefits all customers. These lower energy costs are the primary benefits quantified by LEI.

38. When assessing the impact of time-of-use rates on non-EV-related load, LEI found a wide range of customer responses which was affected by a number of variables including the enrolment methodology (i.e., the default rate offering versus voluntary opt-in), the difference between peak to off-peak prices and whether customers are given behavioural nudges such as peak time reminders and feedback / tips related to consumption. In its analysis, LEI assumed that time-of-use rates would have similar results in Alberta as has been observed in other jurisdictions. Specifically, LEI observed that various studies of time-of-use rates found a peak demand impact ranging from a 3 per cent reduction (in Ontario) to a 15 per cent reduction (multi-state in the United States) and selected 3 per cent given the relative recency and scale of the Ontario study.

39. To create a time-of-use rate-adjusted demand profile for Alberta, LEI decreased peak demand for customers that were assumed to be affected by time-of-use rates by 3 per cent, while

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[23] LEI assumed that 100 per cent of customers who were on Regulated Rate Option (the default electricity rate in place up until the end of 2024 before it was replaced with the ROLR would be subject to time-of-use rates, similar to some other jurisdictions, such as Ontario, where time-of-use rates are the default. LEI's analysis relied on data at a point in time when regulated retail customers made up approximately 9.5 per cent of system demand; the AUC expects this number has and will continue to decrease as more customers move from what is now the ROLR to a competitive retail rate.

[24] Only customers taking less than 1 MW of demand were considered as it was assumed that larger customers already use hourly metering and would not be affected by new time varying rates.

keeping total energy consumption constant (meaning that the reduction during peak hours would be offset by an increase in off-peak hours). In relation to EV charging demand, LEI assumed all EV charging would be subject to time-of-use rates and relied on results observed from Vermont that EV-related demand could fall by 25 per cent during peak system demand hours in response. This is consistent with observations that EV charging can generally be expected to be more elastic and therefore more price responsive.

40. LEI performed a static analysis that did not incorporate supply changes resulting from changing pool prices. As pool prices change, the behaviour of generators in the market would be expected to change in response, which could, over time, impact the pool price reductions forecast by LEI. As a result, LEI's assessment should be taken as a near-term assessment of the potential benefits of enabling time varying rates and does not reflect whether these benefits will persist in the long-term.

Results

41. The results of LEI's modelling demonstrated that while the change in forecast average system peak demand and absolute system peak demand was relatively small (an estimated 0.6 per cent reduction or 70 MW and 1.6 per cent or 220 MW, respectively, in 2035), it was sufficient to drive changes to power pool prices. The changes in pool price are then expected to translate into energy cost reductions for customers.

42. LEI projected that implementing time-of-use rates would result in a $0.86/MWh reduction in average pool price in 2035. LEI calculated that changes in pool price would result in a total annual benefit to customers (Table 1 below) of approximately $107 million in 2035. In addition to the customer benefits, any form of time varying rates would also support the market's ability to more reliably supply the growing system demand, as seen by the decrease in expected unserved energy in the table below.

Table 1. Energy market benefits of time-of-use rate adoption

Benefits (change)	Decarbonization by 2050 case	
	2030	2035
Average Energy Market Price impact (%)	-0.86	-1.2
Customer benefit ($ million)	55.91	107.42
Change in expected unserved energy (EUE)	-5.28%	-18.45%

43. In addition to the direct customer savings calculated by LEI, the reduction in expected unserved energy is a positive contribution to resource adequacy. This, in turn, will support system reliability, which was one of the concerns identified as part of the inquiry into renewable generation in Alberta. LEI's analysis also indicates that there are competitive benefits that result from the decrease in peak demand as there are reduced opportunities for market participants to economically withhold. Finally, LEI also identified the potential for time varying rates to result in decreases in carbon emissions, although in the scenario studied these reductions were minimal.

Distribution system benefits

44. The AUC used analysis from the Guidehouse Net-Zero Analysis of Alberta's Electricity Distribution System to inform its assessment of the distribution system benefits that could be achieved through enabling time varying rates.

Assumptions and analysis

45. The transition to net-zero by 2050 is expected to increase distribution system costs to serve increased demand, particularly in response to increased adoption of EVs. Time varying rates can reduce the magnitude of this cost increase, making the transition to net-zero more affordable for customers. Similar to the energy market benefits, the benefits of time varying rates on distribution wires costs will increase over time as EV adoption increases.

46. Guidehouse created three scenarios (a baseline, net-zero, and net-zero optimized scenario) in order to assess the incremental cost on the distribution system due to the transition towards net-zero by 2050. The baseline scenario was based on historical growth rates, with no material net-zero impact. The net-zero scenario was informed by the AESO's Net Zero Emissions Pathways report,[25] and forecast the incremental distribution system costs associated with higher growth in renewables and distributed energy resources (particularly EV adoption). The net-zero optimized scenario was also informed by the AESO's Net Zero Emissions Pathways Report, and then incorporated five mitigation solutions to determine the extent to which optimized solutions can reduce integration costs. Incentive rates, including time-of-use rates, were part of the mitigations incorporated into the net-zero optimized scenario.

47. The analysis considered the timing of future capacity or voltage constraints requiring mitigation on the distribution system for each of the three scenarios, and forecasted the Alberta integration costs to 2050 associated with implementing the necessary mitigations on the distribution system for each of the three scenarios.

48. This net-zero optimized scenario included the assumption that all EV customers would be enrolled in a time-of-use rate and would reduce their on-peak charging by 35 per cent. As shown in Figure 3, Guidehouse projected that EVs can be expected to add about 4.2 gigawatt (GW) in peak demand by 2050, but in its optimized scenario, it projected an increase in peak demand less than 3 GW.

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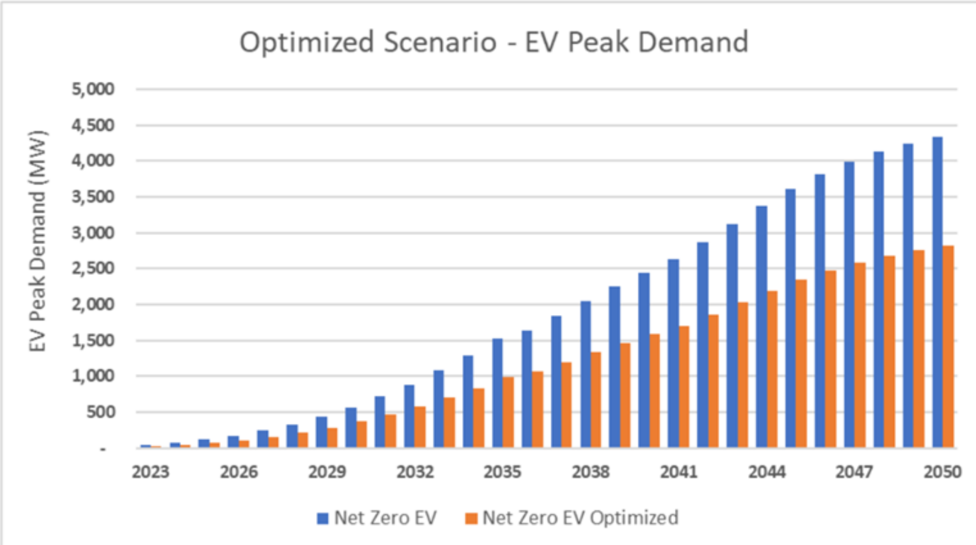
25 AESO-Net-Zero-Emissions-Pathways-Report.pdf.

Figure 3. EV peak demand 2023-2050



49. To align the Guidehouse analysis with the other assessments used to inform this analysis, and to ensure that its conclusions are conservative and do not overstate potential benefits, the AUC reduced the overall forecast benefits (reductions to incremental distribution costs) calculated by Guidehouse by a range of 25 to 50 per cent. This recognizes the variation in responses observed in relation to time-of-use rates generally, and LEI's assumed 25 per cent peak demand reduction (discussed above) of EV charging load in response to time-of-use rates. It also reflects that the optimized mitigation solutions incorporated by Guidehouse into its net-zero optimized scenario included other mitigations (for example, pairing photovoltaic systems with behind-the-meter battery storage).

50. A detailed summary of Guidehouse's approach to forecasting integration costs is provided in Section 1 of the Net-Zero Analysis of Alberta's Electricity Distribution System and is not duplicated in this report.[26]

Results

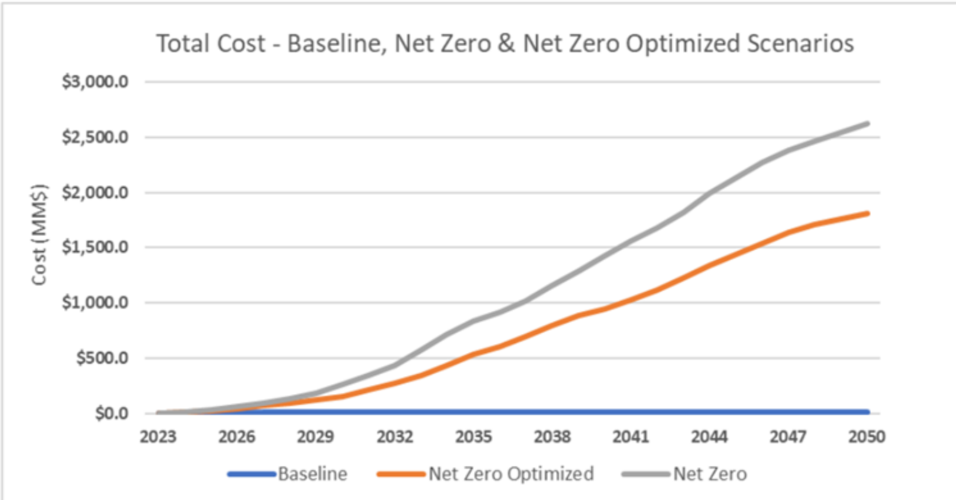
51. The same shifting of energy consumption from on-peak to off-peak periods that drives the energy market benefits will also reduce the future distribution wires costs by lowering the peak demand on distribution lines and transformers. Increasing EV adoption, in particular, is expected to lead to a sharp increase in peak demand on the distribution system and drive the need for upgrades to distribution lines and transformers supplying these customers. Shifting some of the EV charging load to off-peak times would reduce the peak demand on these lines and transformers and allow distribution utilities to defer upgrades and spread incurred costs passed along to customers over a longer time period.

52. Guidehouse concluded that optimizing the distribution system and reducing peak demand, including through the adoption of time varying rates, could reduce the incremental distribution infrastructure upgrades (and associated costs) by about $320 million by 2035 and $800 million by 2050.[27] The AUC estimates that enabling time varying rates can be expected to

[26] Net-Zero Analysis of Alberta's Electricity Distribution System.pdf.
[27] Net-Zero Analysis, PDF page 11.

account for at least 50 to 75 per cent of these reductions or between $160 million to $240 million by 2035 (between $400 million to $600 million by 2050).

Figure 4. Total annual integration costs[28]



53. The AUC estimates the impact of these reductions to incremental distribution costs to translate into annual savings (on a revenue requirement basis) of $11 million to $17 million in 2035, or $27 million to $42 million by 2050. Like the energy market benefits, EV adoption and the associated shift in EV charging to off-peak periods is the primary driver of these benefits. In the case of the distribution system benefits, Guidehouse found that EV integration drove over 90 per cent of the incremental integration costs and as a result, the estimation of benefits is sensitive to any changes in EV adoption rates.[29]

The costs of enabling time varying rates

54. As discussed earlier in this report, advanced metering infrastructure set up to collect interval data are needed to enable time varying rates. The smart meters that are integral to advanced metering infrastructure are being installed by the four regulated distribution utilities over the term of the current PBR plans (2024-2028). Therefore, the costs of installing smart meters are already expected to be included in current and future rates and were not included in the analysis as incremental costs associated with the future enabling of time varying rates. The incremental costs that were focused on in this analysis are the other incremental costs associated with enabling time varying rates in Alberta such as setting up the data management systems (for those utilities who have not yet done so or are not otherwise in the process of building out this capability).

55. Moving from monthly or daily meter reads to hourly, 15- minute or 5-minute reads requires managing and storing a much higher volume of data. Meter data requires validation before it can be used for billing, and higher volumes of data result in the need for more

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28 The difference between the gray (net zero) and orange (net-zero optimized) lines illustrates the reduced incremental costs that could be expected if mitigations solutions, including time varying rates, are employed. The difference attributed to time varying rates specifically would be captured by a trend line between the gray and orange lines (not illustrated here).

29 Net-Zero Analysis, PDF page 11.

sophisticated validation systems. This increased volume of meter data gathered by utilities must also be shared with retailers and categorized based on the times of day identified in a chosen time varying rate. This can necessitate upgrading or investing in new infrastructure.

56. One challenge in estimating the costs of enabling time varying rates is that each distribution utility currently collects and manages its own meter reading data and there is limited available information regarding the current and planned capabilities of each distribution utility in this regard. Moreover, there is variability amongst distribution utilities in terms of current and planned capabilities (where this is known). Because the AUC has not yet engaged with distribution utilities on this point, it is unclear what meter validation and data management systems are already accounted for within each distribution utilities' plan to deploy advanced metering infrastructure. As a result, the cost assessment developed for this report considered a range of different systems and capabilities.

Assumptions and analysis

57. The capability to read meters on at least an hourly basis is generally accepted as a prerequisite for implementing time varying rates. PwC was retained to develop high level estimates of the potential cost of implementing hourly meter reading.

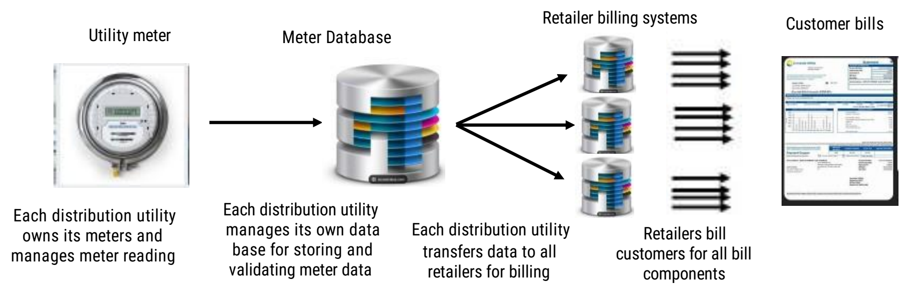
58. PwC considered two scenarios: (i) the costs of maintaining and building on the existing decentralized system for meter reading in Alberta; and (ii) the costs of developing a centralized metering system. In doing so, PwC made several assumptions of existing distribution utility capabilities. PwC's high-level (order of magnitude) estimates were based on a jurisdictional scan and PwC's experience working with utilities that have implemented advanced metering infrastructure systems and time-of-use rates.

59. Advanced metering infrastructure systems can be implemented using either a centralized or a decentralized model. These models differ in how meter data is collected, processed, and used. Alberta currently operates under a decentralized model for meter data management, as illustrated in Figure 5 below.

60. In Alberta, meter data is verified and stored by individual distribution utilities, where they collect, validate, store and then transfer the meter data necessary for billing customers to each retailer. The four major regulated distribution utilities, several non-AUC regulated municipally owned distributors and multiple REAs in Alberta must each share data with several dozen retailers.[30] Absent policy direction to encourage or require the development of a centralized model, it is expected that Alberta will continue to follow a decentralized model.

[30] On its website, the Office of the Utilities Consumer Advocate identifies more than 60 competitive retailers in Alberta: Utilities Consumer Advocate: Retailers and Distributors. The number of these competitive retailers operating within in a given distribution utility's service area may vary.

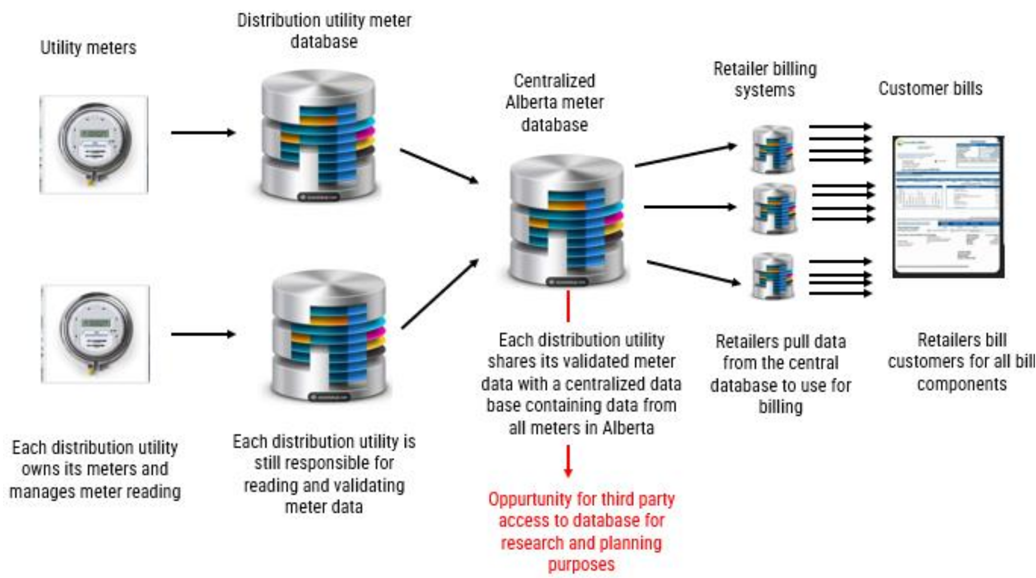
Figure 5. Decentralized approach for managing meter data



61. Alternatively, under a centralized system, meter data is sent and stored in a centralized database, which can then be accessed for billing by retailers (and potentially others third parties, such as government agencies and academic researchers). This centralized approach allows for uniform access to, and management of, time varying meter data across all distribution utilities and their customers.

62. A centralized approach to meter data management has been adopted by other jurisdictions such as Ontario and Texas, although there is variation between centralized data management systems. For example, in Texas, the centralized entity (referred to as Smart Meter Texas) receives data that has already been verified whereas in Ontario, the centralized entity (referred to as the Smart Metering Entity) verifies meter data itself. Smart Meter Texas is a collaborative effort among a group of utilities. In Ontario, the Smart Metering Entity was established, and it operates within Ontario's Independent Electric System Operator. PwC advised that in other jurisdictions where a centralized model was adopted, this decision appeared to be driven by government for policy reasons unrelated to a cost-benefit analysis.

Figure 6. Centralized approach for managing meter data



63. The AUC worked with PwC to develop estimates for both a centralized model as well as continuing with the decentralized approach currently in place. In developing its estimates, PwC assumed that meter data would be gathered hourly for residential and small commercial customers.

64. The estimates developed should be considered as rough order of magnitude estimates, based on PwC's experience and public information gathered from other jurisdictions. PwC made assumptions of existing distribution utility capabilities without consultation with distribution utilities or retailers.

65. For ease of reference, the cost estimates for both centralized and decentralized models were broken out into (i) top-down; and (ii) bottom-up estimates of the additional costs to enable hourly readings, as shown in Table 2 below. As can be seen, there may be little or no material cost difference to enable the centralization of meter data management versus remaining on the current decentralized model approach. However, there is a broader range of costs for centralized systems, as most centralized systems are larger and include more capabilities than time-of-use rates, which increases the cost of implementation.

66. Because these costs are based on very high-level assumptions, a 50 per cent contingency was added to the estimates developed by PwC.

Results

67. As detailed in Table 2 below, PwC estimated that the costs for developing a centralized model are between $15 million to $50 million, whereas the costs for developing a decentralized model are between $12 million to $38 million. Applying the 50 per cent contingency discussed above, the AUC concludes that the reasonable costs that could be expected to be incurred for developing a centralized model are between $22 million to $75 million, and $18 million to $57 million for a continued, decentralized model. This would result in an annual revenue requirement impact of between $1.2 million and $5.2 million.

68. PwC also estimated that there would be on-going annual operating costs for the centralized system in the amount of $2 to $4 million.

Table 2. Cost estimates for centralized and decentralized meter data management

	Decentralized model		Centralized model
Top-down - benchmarking	**$12 – $38 million** Utilities with relevant time-of-use models deployed – cost case based on People, Systems, and Process transformation	**Bottom-up approach - benchmarking**	**$30 – $50 million** Jurisdictions where applicable and related to Alberta's scope and retail landscape
Bottoms-up - effort assessment	**$16 – $31 million** Scenario based effort model (representing Alberta-based distribution utilities) based on: • systems landscape, capabilities, maturity of advanced metering infrastructure capabilities, infrastructure and operational readiness Assumptions will be made regarding distribution utilities' capabilities developed during advanced metering infrastructure implementation, customer systems and process maturity, meter data management system capabilities, meter configurations, retail data exchange capabilities, and exchange/settlement changes, et.	**Top-down approach - cost assessment**	**$15 – $26 million** Consists of: • Data Hub Implementation costs • Estimated operations/sustainment costs • Volume of data (Ingress and egress charges for the volume of data transfers – in scope rate classes) • Cloud and computing costs utilizing hyper-scalers in consumption-based models Assumptions will be made regarding operations/sustainment costs, volume of data and retention policy, expected required functionality, and implementation costs.

69. The cost estimates do not include the costs of any changes retailers would be required to make to their billing systems to take advantage of smart meter data. Nor does the analysis in this report consider the costs of implementing any specific rate offering(s), such as customer education and advertising costs. Additional costs may be incurred, for example, by competitive retailers to change their systems to offer various time varying rate offerings, but these costs are largely outside the purview of the AUC and may vary considerably depending on how time varying rates are enabled. In any event, given both the evolution happening organically in the sector (for example, with smart meters being installed whether or not time varying rate capabilities are enabled) and the magnitude of potential benefits, the AUC is satisfied that the additional incremental costs associated with implementation will not change the conclusion that the enablement of time varying rates is reasonable and justified for residential and other small consumers in Alberta.

6 Recommendations and next steps

70. With an estimated benefit to cost ratio greater than 12:1, there is a compelling case for pursuing the enablement of time varying rates for residential, small commercial and farm customers in Alberta over the next three to four years. The enablement of time varying rates over this time period will coincide with the distribution utilities' plans to finish installing smart meters and provides an opportunity to coordinate with the AESO on its plans to implement shorter settlement periods for load and generation in Alberta.

71. As discussed in previous parts of this report, a unique consideration for Alberta is that while distribution and transmission utilities (wire owners) are regulated by the AUC, the

generation and retail segments of the electricity industry are largely not regulated and are instead subject to competitive market forces. While customers may respond to the price signals embedded in the individual components of their bills, ultimately, it is the total electricity bill that influences their decisions. This means that customers decisions will be driven by a price signal that is a combination of all the prices in their bill which includes energy consumption charges, delivery (distribution and transmission or "wires") charges and retailer fees. The AUC recommends a consumer-centric approach to implementation to ensure that time varying rates, and the components on a customers' bill, are designed with customers and their potential responses to time varying prices at the forefront.

72. Consideration should be given to assessing whether distribution utilities should implement time varying rates to recover some or all of the delivery / wires charges (i.e., to recover the costs of distribution and transmission systems) for residential, small commercial and certain farm customers. Typical time-of-use rates for these customers observed in other jurisdictions are applied to the energy consumption portion of a customer's bill. Accordingly, it would be beneficial to explore time varying rates for both wires charges and energy charges. Time varying rates for energy charges could be implemented through encouraging or requiring competitive retailers to offer time varying rate options and / or by transitioning the regulated rate (currently the ROLR) to a time varying rate following its expiry at the end of 2028.[31] In tandem with time varying rates on the delivery component of the bill, this would result in strong incentives for customers to reduce their consumption during hours where the cost of electricity is greatest and the existing delivery system faces the greatest strain.

73. These recommendations are based on the high-level cost benefit assessment described in this report as well as other academic references and experiences with time varying rates in other jurisdictions. The cost-benefit assessment was a high-level assessment only, completed for the purpose of determining if enablement of time varying rates should be pursued.

74. Consultation with industry participants and customers, as well as further, more detailed, assessments of the costs and benefits of implementing different forms of time varying rates, should be undertaken to determine the specific rate designs most suitable for Alberta. Doing so may also allow for incorporation of the results of the Reformed Energy Market (REM) work that the AESO is completing.

31 As the distribution utilities complete their AMI systems implementation and actual hourly (or more frequent) load profile data for all customers becomes available, retailers will have the ability to design rate offerings that accommodate the wide variety of customer preferences. To leverage the competitive nature of Alberta retail energy offerings, it is more important to provide competitive retailers with granular data on customer actual consumption and let them come up with various competitive rate offerings that may include certain time varying rate options, rather than mandate a particular form of time varying rate for competitive retailers.

75. The AUC recommends and plans to proceed with the following next steps:

- Engage with the distribution utilities, retailers and the AESO regarding implementation of time varying rates for wires charges and any opportunities for coordination with the work to move to 5-minute settlement intervals with the AESO.

- Consult with industry on the opportunities to implement time varying rates in energy retail offerings.

- Work with stakeholders to identify the necessary policy and regulatory changes necessary to support the implementation of time varying rates in Alberta.

- Develop a detailed enablement plan that incorporates the results of the consultations and additional study set out above.