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POLICY BRIEF
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Efficiency Analysis in Electricity Rate Design:
A Case Study of Alberta's Bulk and Regional Transmission Tariff

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INTRODUCTION

This Policy Brief discusses the importance of efficiency analysis in the design of regulated electricity rates, through a case study of the Alberta Electric System Operator's (AESO) proposed Bulk and Regional Transmission Tariff. The AESO is the Independent System Operator (ISO) that operates in the province of Alberta.

Electricity transmission networks are a classic example of a natural monopoly. Natural monopolies are generally characterized by high fixed infrastructure costs and low marginal operating costs, creating significant economies of scale relative to the size of the market. In these industries, cost minimization is achieved by having a single service provider. However, by definition, a single provider would have monopoly pricing power. For this reason, governments generally prefer regulation to competition for the provision of transmission services, whereby public utilities regulators are charged with incentivizing transmission investment through benchmark or price regulation, and with setting rates for network access.[1]

A key function of any public utilities regulator is transmission rate design. It is well accepted that prices equal to short-run marginal cost promote the efficient use of a commodity, including transmission services. However, rates set at marginal cost do not allow the natural monopoly to recover all its sunk and fixed capital and operating cost. To ensure full recovery of these residual transmission network costs, an alternative regulated rate design is required. The fundamental challenge in electricity rate design is the recovery of these residual network costs.

The legislative frameworks and regulatory approaches applied by regulators in setting transmission rates vary across jurisdictions, but generally require the balancing of multiple objectives, including the sufficient recovery of prudently incurred costs, equity and fairness, cost causality, justness and reasonableness, rate stability and predictability, environmental outcomes, and economic efficiency, which we refer to herein as "rate design principles and objectives."

[1] There are two basic approaches to transmission investment within the economics literature (Hogan et al., 2010). The first approach uses a competitive or "merchant" transmission investment framework that relies on market-driven investment to increase transmission network capacity. The second approach relies on regulatory mechanisms to incentivize transmission investment to reduce congestion and promote reliability. This paper considers the second approach. A companion working paper to this Policy Brief (Olmstead et al., 2022), uses the first approach to derive the efficient competitive benchmark for transmission investment. Within this framework, it is demonstrated that a "no congestion" transmission policy results in the creation of residual network costs, and a regulatory mechanism is required to ensure recovery of prudently incurred costs. The working paper examines the efficiency attributes of regulated consumption-based cost recovery tariffs, including a demand charge, an energy charge and an embedded cost tariff design and demonstrates that no one tariff, including the embedded cost tariff design, is assured to be more efficient than another. That is, the relative efficiency of consumption-based tariff design is an empirical matter that depends on the relevant facts of the jurisdiction at the time.

Electricity rate design has a long history.[2] Historically, regulators have tended to use consumption-based charges to recover residual network costs, including energy charges levied on each kilowatt-hour of consumption and demand charges levied on consumption in coincident or non-coincident peak periods. Monthly fixed connection charges that are independent of consumption are also used but to a lesser extent. Each approach involves a trade-off between efficiency and equity. The recovery of residual network costs through a consumption-based charge induces inefficiencies since it distorts the signals sent to consumers of the social costs that are avoided by reducing consumption. Fixed charges may be deemed unfair or inequitable, if some consumers, particularly low-income, low-volume consumers, pay proportionately more for electricity than other consumers.

Many regulators focus primarily on the principle of cost causality when approving rates to recover residual network costs as it has become conventional wisdom that rates based on cost causation provide appropriate price signals that are aligned with enhancing economic efficiency, are fair, objective, equitable, and minimize inter-customer subsidies.[3] As a result, evidence included in regulated rate applications often rely mainly on cost causality studies as justification for proposed rates, rather than detailed economic efficiency analyses.

The AESO recently applied to the Alberta Utilities Commission (AUC) for the approval of its Bulk and Regional Transmission Tariff (AESO, 2021). The AUC proceeding to assess the AESO's application is ongoing, and is expected to be completed by early September 2022. A final decision on the Application is expected in late 2022. The AESO's proposed tariff is based on an application of the embedded cost methodology to tariff design. The embedded cost methodology is guided largely by the principle of cost causality; it seeks to signal to customers the long-run costs of providing transmission, in a way that identifies which costs have been incurred historically to accommodate (or have been caused by) patterns of usage (AESO, 2021).[4]

This Policy Brief makes the case for greater use of efficiency analyses in electricity rate design through a case study of the Alberta Bulk and Regional Transmission Tariff. Drawing on the findings of a companion working paper that considers residual network costs and the economic efficiency of regulated cost allocation in a general setting (Olmstead et al., 2022), this Policy Brief discusses the efficiency implication of the AESO's proposed tariff. The Brief argues that within Alberta's "no congestion policy" with "postage stamp rates" legislative framework, the embedded cost tariff design does not provide price signals that promote economically efficient short-run or long-run consumption or transmission investment decisions, nor does it establish rates the are truly reflective of cost causation (or economic efficiency).

The Policy Brief is organized as follows. Section 2 provides background on Alberta's electricity sector and the AESO's recent Bulk and Regional Transmission Tariff design proposal. Section 3 provides an assessment of the efficiency and equity properties of three types of consumption-based tariffs: a demand charge, an energy charge, and the AESO's proposed embedded tariff design. Section 4 argues that efficiency analysis in rate design will increase in importance with increased decarbonization, decentralization, and digitalization of the power grid. Section 5 concludes.

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[2] The seminal work on ratemaking principles is Bonbright (1961). For a historical discussion of the evolution of electricity rate design, see Harris (2005).

[3] As described in AESO (2021) at paragraph 2, this is the position that the AUC has taken in recent decisions.

[4] The AESO's approach to tariff design was informed by their economic consultant NERA Economic Consulting (NERA). NERA (2021) considered two approaches to tariff design in Alberta: a marginal and embedded cost approach. It determined that the embedded cost approach better fits Alberta's legislative framework, namely the no congestion transmission policy, postage stamp transmission rates, and the characteristics of the Alberta transmission system.

BACKGROUND ON ALBERTA'S ELECTRICITY SECTOR

The following summarizes key aspects of Alberta's transmission policy framework, electricity market design, bulk and regional transmission system, and the current and proposed Bulk and Regional Transmission Tariff design.

i. Transmission policy

As a matter of public policy, Alberta's provincial government has decided that the province's transmission system will be planned so that all anticipated in-merit electricity can be dispatched without constraint. This policy is sometimes referred to as a "no congestion" transmission policy.[5] On the basis of this policy decision (and other policy decisions), the AESO undertakes and is responsible for planning the development of Alberta's transmission system.[6]

With respect to transmission pricing, generators are required to pay their local connection costs, pay location-specific line losses, and make contributions to system upgrade costs (a small fraction of total costs). All other costs, which constitute the bulk of the cost of the transmission system, are paid by electricity consumers.[7] These rates are not based on the location of the consumer in Alberta and are therefore referred to as "postage stamp rates."[8]

ii. The Alberta electricity market

Alberta's electricity industry was liberalized in the late 1990s. Transmission and distribution functions continued to be regulated as natural monopoly services. The introduction of a competitive, energy-only wholesale market — including the prices set by this market — was intended to provide economic incentives to efficiently operate the market on an ongoing basis and to induce adequate generation investment over time. Competition was also introduced into the retail market to provide consumers options to manage price variability over time.

Offers to supply power in the wholesale market are made by generators and importers for each hour. The AESO sorts these offers in ascending order of offer price[9] to form the energy market merit order.[10] At each point in time (including within the hour as necessary), the AESO dispatches up and down this merit order

[5] Specifically, the Transmission Regulation (Alberta) requires the AESO to, "tak[e] into consideration the characteristics and expected availability of generating units, plan a transmission system that: is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy…can occur when all transmission facilities are in service, and is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in-merit electric energy…can occur when operating under abnormal operating conditions" (Transmission Regulation, section 15(e)) and "make arrangements for the expansion or enhancement of the transmission system to that, under normal operating conditions, all anticipated in-merit electricity…can be dispatched without constraint" (Transmission Regulation, section 15(f)).

[6] This policy decision, including its rationale, is discussed in Government of Alberta (2003). A fundamental aspect of the intended "no congestion" aspect of this policy decision is the claim that this is necessary to facilitate Alberta's competitive wholesale market. The merits of this policy and the claims made in support of it are beyond the scope of this paper; for a more detailed overview and critique of it, see Church et al. (2009).

[7] Transmission Regulation, section (47)(a).

[8] Electric Utilities Act, section 30(3).

[9] Offer prices are not required to be based on marginal cost. The unilateral exercise of generator market power is disciplined by competition rather than by administrative rules. This has implications for the manner in which modelling occurs and what generation is considered to be "in-merit." These issues are not discussed in this paper.

[10] Of significant note to the determination of generation costs is that Alberta generators face meaningful costs associated with their carbon emissions. Carbon costs are meaningful in the sense that they are high enough that the marginal cost of electricity production from natural gas-fired generators is lower than from coal-fired generators, which would not be the case in the absence of carbon pricing. In addition, the carbon pricing regime provides compliance options that give significant value to the environmental attributes associated with renewable energy generators.

in order to balance supply and demand, setting the system marginal price equal to the highest dispatched offer price. The time-weighted average of system marginal prices within each hour is the pool price that is used for settlement.

The system marginal prices and pool prices are uniform across the whole market, i.e., there are no location specific prices such as nodal or zonal prices. Generator access to the transmission system is supplied on dispatch in real-time. There are no physical or financial transmission rights within Alberta, including within Alberta on the interconnections to British Columbia, Montana, and Saskatchewan.

This approach to setting wholesale prices is consistent with the "no congestion" transmission policy, at least in an expected sense. Specifically, the price-setting process essentially assumes that there is no transmission system congestion and produces a single province-wide price accordingly. Setting aside line losses, the absence of transmission congestion in a standard electricity market would result in nodal or zonal prices being equal. Therefore, a policy that requires transmission to be built to avoid congestion would have the effect of causing nodal or zonal prices to be equal. The absence of internal financial transmission rights is also consistent with this approach to setting wholesale prices.

Transmission congestion that has the effect of physically limiting supply from generators with offer prices below the market price (i.e., in-merit generation) does of course occur sometimes. In such circumstances, some generation in the constrained area is "constrained off" and other generation located in unconstrained areas with offer prices above the market price is "constrained on." The uniform market price is determined by ignoring the effect of the transmission constraint; the market price is set at the offer price of the last MW of generation that the AESO constrains off to manage transmission congestion. Generators that are constrained off do not receive compensation for revenues lost due to congestion. Generators that are constrained on are paid their offer price which is above the uniform market clearing price.[11]

iii. Alberta's bulk and regional electric transmission system

The AESO publishes a Long-Term Transmission Plan (LTP) every two years, which provides a 20-year forward-looking blueprint of how the transmission system in Alberta may need to be developed. The AESO assesses the expected dynamics in each of the planning regions as part of its transmission planning, which includes expected changes in load and generation in multiple planning regions. Planning regions are further subdivided into smaller planning areas.

Figure 1 provides two useful illustrations of the bulk electric system that exists today in Alberta. The left panel illustrates the location of the major generation assets and the transmission system that connects them to consumers. The right panel illustrates the planning regions and areas that are used by the AESO to carry out its planning functions.

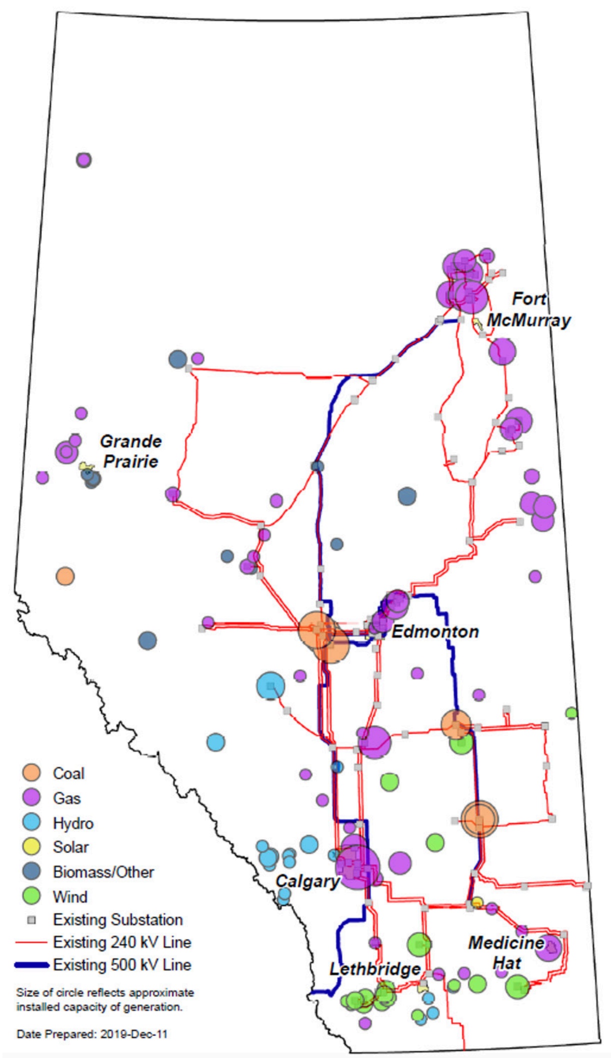
In recent years, a reduction of coal-based generation and an influx of renewable sources, among other changes, has altered the locational distribution of generation sources relative to demand in Alberta. This

[11] This approach to electricity pricing can lead to economic inefficiency if price responsive consumers in the constrained-on areas of the province consume more at the uniform market price than they would have consumed at a price equal to the marginal cost of the last MW of constrained on generation in their area. Furthermore, aside from assigning the cost of transmission losses to generators and requiring a relatively small contribution to system upgrade costs, the no congestion transmission policy and the lack of locational price differences means there is little incentive for generators to take transmission system limitations into account when deciding where to locate. This can encourage investment in areas where generation must already be constrained off due to transmission limits and thereby further increase the need for transmission expansion per the no congestion policy.

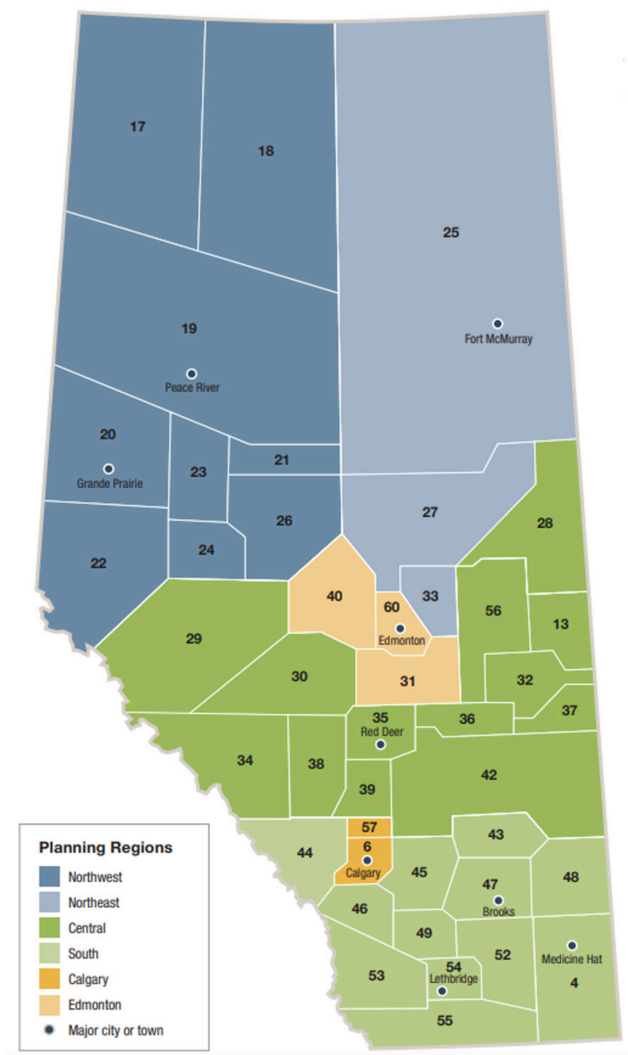
trend is expected to continue as coal generation in the Northwest, Edmonton, and Central planning regions retires or converts to gas while renewable generation capacity increases in the South and Central planning regions. Although the current bulk transmission system was developed in view of traditional generation location areas in Alberta, future generation investment is likely to continue locating in areas that differ from these traditional generation locations, such as where wind and solar potential is highest (AESO, 2021, paragraph 124).

Figure 1 | The Alberta Electricity System[12]

Left Panel:
Major generation and transmission assets[13]



Right Panel:
AESO transmission planning areas[14]



[12] For scale, Calgary and Edmonton are 300 km apart.

[13] As of December 11, 2019. See AESO (2020), Figure 4.2-1.

[14] AESO (undated), wherein the numbers that correspond to the specific planning areas illustrated in the figure are specified.

iv. Current and proposed bulk and regional transmission tariff design

The rates that consumers must pay for regulated transmission service are set out in the ISO tariff. Consumers are required to pay a connection charge (referred to as Rate Demand Transmission Service, or Rate DTS), an operating reserve charge, a transmission constraint rebalancing charge, a voltage control charge, and a charge for other system support services. The Rate DTS, which is essentially the bulk and regional transmission system tariff, is by far the largest charge levied under the AESO tariff. The specific rates for these charges under Rate DTS, as of January 1, 2022, are set out in Table 1.

Table 1 | Rate DTS connection charges, effective January 1, 2022[15]

Volume in **Settlement Period**	Charge
Bulk System Charge	
(a) Coincident **metered demand**	$10,501.00/MW/**month**
(b) **Metered energy**	$1.15/MWh
Regional System Change	
(c) **Billing capacity**	$2,775.00/MW/**month**
(d) **Metered energy**	$0.87/MWh
Point of Delivery Charge	
(e) **Substation fraction**	$14,332.00/**month**
(f) First (7.5 x **substation fraction**) MW of **billing capacity**	$4,717.00/MW/**month**
(g) Next (9.5 x **substation fraction**) MW of **billing capacity**	$2,797.00/MW/**month**
(h) Next (23 x **substation fraction**) MW of **billing capacity**	$1,873.00/MW/**month**
(i) All remaining MW of **billing capacity**	$1,153.00/MW/**month**

The current Rate DTS functionalizes transmission costs into three categories: bulk, regional, and point of delivery.[16] The cost for each category is allocated based on the following billing determinants.

Bulk System Charge: Charges for use of the bulk power system are comprised of a "coincident metered demand" charge and a "metered energy" charge. The "metered energy" variable is simply the quantity of electric energy, measured in MWh, that is consumed in each month. The "coincident metered demand" variable is defined as the metered demand at the point of delivery averaged over the 15-minute interval (limited to quarter hour clock intervals as opposed to any continuous 15-minute period) in which the sum of metered demand by market participants is greatest in the month. The coincident metered demand charge is often referred to as the 12-month coincident peak (12CP) charge.

Regional System Charge: Charges for use of the regional power system are comprised of a "billing capacity" charge and an additional "metered energy" charge. "Billing capacity" means, at a point of delivery, the highest of the following values: (i) the highest 15-minute metered demand in the settlement period, (ii) 90% of the highest metered demand in the 24-month period including and ending with

[15] The "settlement period" is the calendar month.

[16] Transmission assets are distinguished by voltage, where bulk assets are functionalized at 240 kV and above and regional assets at below 240 kV and above 25 kV (AESO, 2021, paragraph 106).

the settlement period, but excluding any months during which commissioning occurs, and (iii) 90% of the contract capacity or, when the settlement period contains a transaction under Rate DTS, 100% of the contract capacity.

Point of Delivery Charge: Charges for use of the point of delivery are related to a variable called the "substation fraction," which is essentially an individual consumer's share of consumption at a particular point of delivery substation.

On October 15, 2021, the AESO submitted its Bulk and Regional Transmission Tariff design application to the AUC seeking approval for a change in the methodology (tariff design) it uses to recover the bulk and regional portions of the AESO's revenue requirement through customer rates (AESO, 2021). In making the case for change from the current rate design to the proposed rate design, the AESO made several arguments. The following is a synopsis of these arguments (AESO, 2021, section 3.4.2):

- The current rate design was approved in 2005 on the basis that "the bulk system is largely constructed and sized, and costs incurred, to meet the peak load of the system" and that a 12CP methodology aligns with principles of cost causation and would therefore send appropriate price signals to customers. A subsequent decision in 2007 upheld the use of a 12CP for cost recovery, again relying on the finding that the transmission system is planned for peak load and hence peak load is the cause and primary driver for bulk system costs. The decision also concluded that transmission wires costs are largely fixed in nature and most appropriately recovered primarily through demand charges, and that "it is not possible for a customer to simply turn the power off and completely avoid the hour of system peak."

- The Alberta transmission system and electricity market have evolved since 2007, with the phase out or conversion of coal plants to natural gas generation, and the significant addition of variable renewable generation. These changes have altered the locational distribution of generation sources relative to demand in Alberta. Furthermore, customers' "ability to avoid transmission charges by responding to the 12CP price signal, thought to not be possible in 2005, has increased significantly."

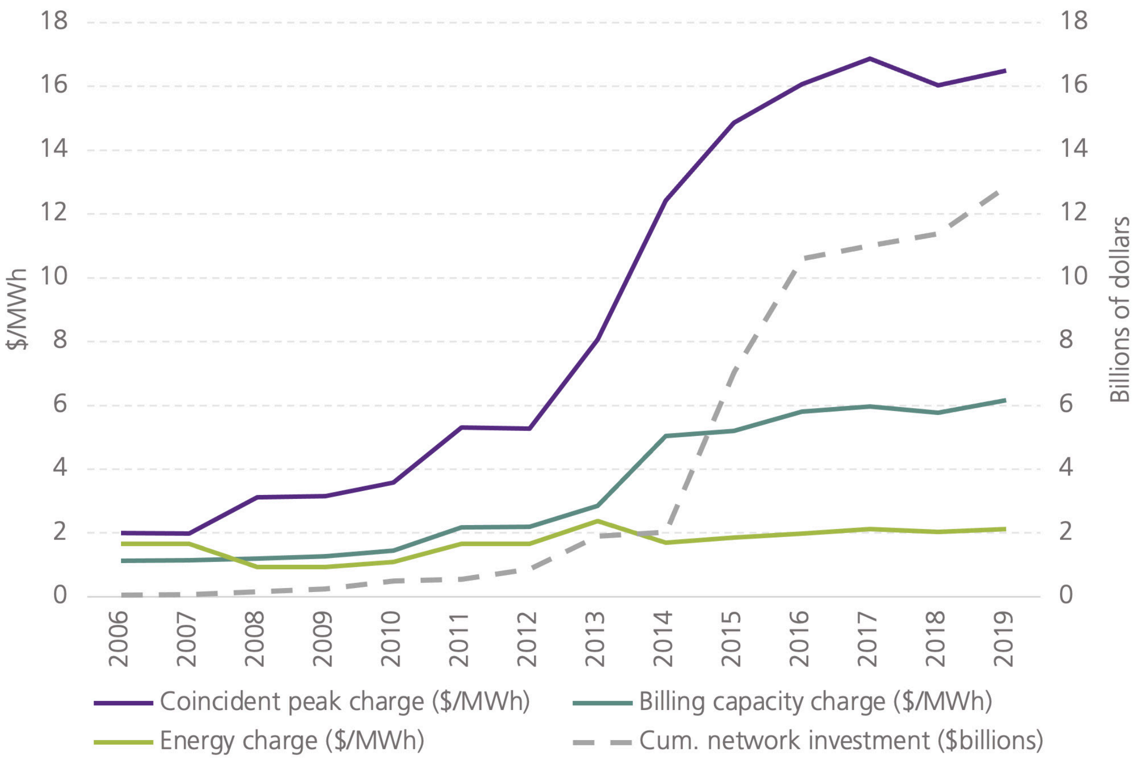
- Over the last 15 years, roughly $13 billion in transmission investments have been made to serve two purposes, to meet peak demand and to accommodate the flow of in-merit energy arising from the changing locational distribution of generation sources.

In its application, the AESO (supported by its consultant NERA) argues that in the context of the evolving transmission system, the current tariff design has "significant deficiencies" based on the following reasons:

- It fails to properly align the recent drivers of transmission investment because the 12CP charge overstates the cost associated with using the grid at peak times and does not account for investments made to facilitate the flow of in-merit energy.

- Customer response to the 12CP price signal has led to inefficient self-supply and consumption in peak periods. As these costs are all essentially fixed and sunk, this has had the compounding effect of increasing the 12CP charge and a shifting of costs from those that can avoid the coincident peaks to those that cannot avoid the peaks.

Figure 2 | Alberta Transmission Investment and Tariff Charges, 2006–2019



Since 2007, Alberta's total load has experienced steady growth while coincident metered demand growth has been relatively flat. Between 2014 and 2019, significant transmission costs were incurred related to additions to the bulk system. Because coincident metered demand has remained relatively flat while significant bulk transmission costs have been incurred, the coincident peak charge has increased significantly over this period. Figure 2 is a recreation of figures presented in the AESO application showing this significant increase in transmission network investment in the dashed grey line. It also shows the larger increases in the coincident peak charge relative to the billing capacity charge and the metered energy charge. NERA indicated that it augmented the data to present all tariff components in the same units of dollars per MWh; in doing so, NERA recognized that the coincident peak charge and billing capacity charges are actually levied on customers on a dollars per MW-month basis.[17]

Although increases in both the billing capacity charge and energy charge can be seen taking place from 2014 to present, the existing tariff design has resulted in disproportionately higher increases in the coincident peak charge. In the AESO's view, it has become evident that costs have become disproportionately allocated to the 12CP billing determinant under the current tariff design, and bulk and regional rates are no longer cost reflective of their underlying drivers. Overall, the AESO concludes that the current tariff design no longer meets the principles of cost causation and that an amendment to the current tariff design is required to realign the tariff with the principles of cost causation.

[17] This figure is adapted from Figure 3-1 A and B in AESO (2021) at page 37. The energy charge combines the "metered energy" charge for the bulk and regional systems. The 12CP and billing capacity charges converted to $/MWh terms by dividing total revenue from each charge by total annual DTS energy consumption. 12CP and billing capacity charges are actually levied on a $/MW-month basis.

The AESO requested NERA design a tariff that aligns with Alberta's legislative and regulatory framework (NERA, 2021, paragraphs 35 and 98) and adheres to well-known regulatory principles, including:

- Recovery of the total revenue requirement;
- Provision of appropriate price signals that reflect the costs of providing the service;
- Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies; and
- Stability and predictability of rates.

NERA recommended the use of the embedded cost approach to residual network cost recovery and rate design. As described in NERA (2021), "the embedded cost methodology seeks to signal to customers the long-run costs of providing transmission, in a way that identifies which costs have been incurred historically to accommodate (or have been caused by) particular patterns of usage, particular customers, and/or particular services."[18] NERA (2021) outlines the steps required to calculate its recommended tariff design under the embedded approach to include:[19]

(i) classification of transmission costs between demand and those associated with accommodating flows of in-merit energy;

(ii) functionalization of the demand related costs in to two categories, bulk system demand costs and regional system demand costs; and

(iii) allocation of bulk system costs through a 12CP demand charge, regional system costs through a charge on billing capacity, and the costs associated with accommodating flows of in-merit energy through an energy charge.[20]

The key step in the process is the classification of costs between demand and in-merit energy. NERA (2021) uses what they refer to as a "minimum system approach" to classify costs between demand and in-merit energy. In NERA's words, the minimum system is defined to reflect the size of the transmission system required to meet peak load. The size of the minimum system defines the proportion of costs classified as demand-related, while the difference between the actual and minimum systems defines the proportion of costs classified to accommodating the interregional flow of in-merit energy.[21]

As a proxy for the minimum system, NERA (2021) uses the maximum hourly metered net load in a regional planning area measured in MW for a given reference period. To estimate the actual system in the regional planning area (the numbered areas in Figure 1), NERA (2021) determines if the transmission system required to accommodate flows of in-merit energy in each planning area exceeds the size of the minimum system. The proxy for the transmission system required to accommodate flows of in-merit energy in a regional planning area is the maximum hourly generation measured in MW for the reference period. Notably, the

[18] NERA (2021) considered two approaches to tariff design: a marginal and embedded cost approach. It determined that the embedded cost approach better fits the legislative framework, namely the no congestion transmission policy, postage stamp transmission rates, and the characteristics of the Alberta transmission system. It describes the marginal cost approach (at paragraph 106) as setting a tariff based on an estimate of how a change in demand from a customer will affect the future costs of a utility.

[19] The current tariff was also established using the embedded cost methodology. However, for the current tariff, the first step was the functionalization of costs between bulk and regional system costs. This was followed by the classification of costs between demand and energy (AESO, 2021).

[20] NERA (2021), paragraph 260 at page 88.

[21] NERA (2021), paragraph 262 at page 89.

peak demand and peak generation hours in a region may not be the same. If the peak generation exceeds the peak demand in a region, the actual transmission needed to accommodate in-merit energy is said to be greater than the minimum system. Conversely, if peak demand exceeds peak generation the minimum system to meet demand is sufficient to accommodate in-merit energy flow.

Once the minimum and actual system for each region is determined, the individual regional results are aggregated to define the overall minimum system and the actual system for Alberta. The overall systems are used to allocate costs between demand charges and energy charges. The portion of transmission costs allocated to a demand charge are calculated as the ratio of the overall minimum system and the actual system measured as a percentage. The portion of transmission costs allocated to accommodate flows of in-merit energy are then equal to 100% minus the portion of costs allocated to a demand charge.

Based on NERA's recommendation to use the embedded cost allocation approach and its application of this approach to the Alberta system, the AESO is proposing changes to the current tariff as set out in Table 2. The proposed tariff allocates less of the residual network costs to the 12CP and Billing Capacity charges and more to the energy charge than the current tariff. The AESO argues that their proposed tariff meets the primary rate design objectives, mainly it reflects cost responsibility and sends efficient price signals (AESO, 2021, section 3.7).

Table 2 | Summary of AESO proposed allocations to billing determinants and charges under current and proposed rate design[22]

Billing determinant	Cost allocation		Charges	
	Current**	Proposed	Current**	Proposed
Coincident peak (12CP) ($/MW-month)	49.30%	29.10%	$10,508	$6,206
Billing capacity ($/MW-month)	21.80%	16.80%	$2,914	$2,273
Energy* ($/MW-month)	6.20%	31.30%	$2.01	$10.45
Point of service ($/MW-month)	22.70%	22.70%	No change	
Total	**100%**	**100%**	Not applicable	

Notes:
* The energy charge is the sum of the bulk and regional energy charge.
** Current rate uses 2019 Test Year rates.

[22] Adapted from Tables 3-3 and 3-4 in AESO (2021).

EFFICIENT TRANSMISSION INVESTMENT, RESIDUAL NETWORK COST RECOVERY, AND THE ECONOMIC EFFICIENCY OF REGULATED RATES

A companion paper to this Policy Brief, titled "Residual network costs and the economic efficiency of regulated cost allocation," develops a theoretical model and a numeric example to consider the sources of residual transmission network costs, and to set out a framework through which the economic efficiency of the regulated rates set to recover these costs can be analyzed (Olmstead, et al., 2022). This section provides a summary of the key findings of this working paper and discusses the implications of these findings for Alberta's Bulk and Regional Transmission Tariff design.

i. Key findings of the companion working paper

Olmstead et al. (2022) develop a theoretical model to illustrate how a "no-congestion" transmission policy, such as the one in place in Alberta, leads to over investment in transmission capacity relative to the first-best efficient amount.[23] By design, the over investment eliminates congestion, locational price differences, and the "congestion rents"[24] that the system operator collects when there are locational price differences. Congestion rents provide a source of revenue for transmission owners that covers all or some of the transmission owner's fixed capital and operating costs. In this sense, the "no congestion" policy causes residual network costs and the need for a regulatory mechanism to ensure transmission cost recovery.

Through a numeric example (a parable) that reflects key attributes of the Alberta competitive wholesale electricity market and transmission network, Olmstead et al. (2022) then examine the efficiency considerations of consumption-based transmission tariffs, including demand charges, energy charges and the embedded tariff design as described by AESO (2021) and NERA (2021). The parable provides two insights.

First, there is no theoretical foundation to suggest that the embedded rate design approach to residual cost recovery best provides efficient price signals and promotes the most efficient outcomes relative to other consumption-based, postage stamp tariffs, including a pure demand charge or pure energy charge. Furthermore, "true cost causality" is not possible with postage stamp rates and the embedded rate design because the postage stamp policy treats all consumers as a homogenous group; it does not allow different treatment between consumers that benefit from (cause) the transmission costs, and consumers that do not. This represents a challenge to the view that cost causation studies are inherently related to efficiency considerations in transmission rate design when there are postage stamp rates. Detailed efficiency analyses would provide better information about the implications of different proposed tariff designs.

Second, the economic efficiency attributes of a given set of consumption-based tariffs is an empirical question. That is, no one consumption-based design can be deemed more efficient, a priori. Instead, the efficiency properties of any consumption-based tariff will depend on the general features of the electricity

[23] The theoretical model is based the two-node model developed in Joskow and Tirole (2005).

[24] Under a standard market design with locational prices, when a transmission line connecting two regions (regions A and B) is congested, the prices in the two regions are different, with the price in the region with constrained off generation (region B) being lower than the price in the region with constrained on generation (region A). In this situation, the system operator collects congestion rents. Congestion rents are the difference between what consumers in region A pay to the system operator for the electricity imported from region B, and what the system operator pays the generators in region B the electricity exported to region A multiplied by the amount of trade flow over the congested transmission line.

markets under review, including the elasticity of demand, the elasticity of supply (including substitution options that may vary in long-run from the short-run), and the cost recovery timeframe; an informative efficiency analysis must consider various market factors.

ii. Implications for Alberta's Bulk and Regional Transmission Tariff design

The AESO argues that its proposed tariff design meets the primary rate objectives: reflect cost responsibility and send efficient price signals (AESO, 2021, section 3.7).[25] Olmstead et al. (2022) demonstrate that there is no theoretical basis to justify these conclusions. Instead, the cost causation and efficiency merits of the embedded cost tariff design relative to other tariff designs is an empirical matter.

Furthermore, the AESO's tariff application does not endeavour to establish that efficiency would be improved with the implementation of the proposed tariff through the inclusion of any substantive empirical evidence. Olmstead et al. (2022) demonstrate that the relative efficiency of different consumption-based tariffs depends on several specific market factors, including customers' elasticity of demand, the elasticity of supply, and the timeframe for which costs are to be recovered. A more comprehensive assessment of the relative efficiency of the current and proposed tariff would require consideration of these and other market factors to draw conclusions about efficiency implications.

THE GROWING IMPORTANCE OF EFFICIENCY ANALYSIS IN RATE DESIGN

Electricity industries have changed dramatically over recent decades. Historically, electricity industries were structured such that a relatively small number of large generators (thermal, nuclear, and hydro, depending on the jurisdiction), located at a relatively small number of places, were connected through transmission and distribution networks to a large number of consumers of various types, spread over large areas. These industries tended to be operated by vertically integrated corporations, either publicly or privately owned, whose rates and investment decisions were regulated by public utilities commissions. The preference for vertical integration (generation, transmission, distribution, and retail services) and regulation was due to several factors, including the minimum efficient scale of generation capacity being relatively large, and the transaction costs of short-term coordination between generation and transmission scheduling being relatively high (i.e., natural monopoly characteristics).

Furthermore, consumer demand was generally not responsive to price (i.e., highly inelastic). This was due in part to technology limitations (i.e., the lack of real-time metering technologies and the ability of the vertical utilities to pass on time varying prices). From an efficiency perspective, the highly inelastic nature of demand meant that recovering fixed capital and operating costs by setting marginal network access rates above marginal cost (above zero) resulted in relatively small (but not zero) inefficiencies.

By the 1990's, scale economies in new natural gas generation technologies and advances in computing power and market algorithms that reduced transactions cost in the coordinated scheduling of generation and transmission meant that the generation and retail functions were no longer considered natural

[25] NERA (2021) states its evaluation criteria in Section 4 of its report as including: A – Recovery of the total revenue requirement; B – Provision of appropriate price signals that reflect the costs of providing service; C – Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies; and D – Stability and predictability of rates and revenue.

monopolies.[26] This led to the introduction of competition in generation and electricity retail markets in several jurisdictions, including Alberta; transmission and distribution systems remain natural monopolies subject to rate regulation.

Restructured generation markets produce a market price that incentivizes consumers to reduce consumption at times when the market price exceeds their value of electricity (which tended not to happen in regulated markets where the access price was set close to average cost). In addition, competitive market prices incentivize traders to schedule electricity trades from low price / low value areas to high price / high value areas. Taken together this means that demand has become more price responsive (less inelastic) over time.

Change in electricity markets is likely to accelerate due to the increased decarbonization, decentralization, and digitalization of the power grid.

- Decarbonization, the decreased reliance on carbon-based fuels for electricity production, has already led to expanded investment in renewable energy generation and supporting transmission and distribution networks. Throughout the world, active pursuit of decarbonized production of electricity has resulted in significant changes in electricity industries. Public policy has been a key driver, but so too has the nature and pace of technological change. The electricity sector is of major importance to global decarbonization objectives and electrification of energy end-use as a critical component of climate action (Canada Energy Regulator, 2021). These types of objectives often include an element of economy-wide electrification, whereby the energy sources used in other sectors of the economy transition to use electricity as their energy source. In Canada, many programs and policies have been implemented by the federal, provincial, and territorial governments to reduce carbon emissions from the electricity sector and promote electrification of end-use energy. Noteworthy among the major technological developments impacting traditional electricity sectors is the scale of emergence of electric vehicles (Webb and Clevo, 2017). The Canada Energy Regulator (2021) sees the electricity sector playing a critical role in achieving net-zero emissions objectives in Canada.[27]

- Decentralization, the disbursement of electricity production of a few large, transmission connected power plants across many small-scale, consumer owned distributed energy resources, is becoming more prevalent with the increased scalability and declining cost of non-emitting power generation and storage technologies. Technological advancements and falling costs, as well as support schemes for renewables, distributed generation, energy efficiency, and demand response have resulted in rapid deployment of distributed energy resources (Koirala and Hakvoort, 2017). With greater prevalence of distributed energy resources and electric vehicles, the role of households and local communities is changing from passive consumers to active producers and consumers, or "prosumers" (Sioshansi, 2019).

- Digitalization, including the digital transformation of data, the use of data to produce useful information and insights, and the exchange of data between people, devices, and machines, is improving the ability of network owners, retailers, and aggregators to monitor and control assets reliably and efficiently, and accelerating consumers' deployment of smart controls and connected devices to adjust their electricity use in response to dynamic signals from the power grid.

[26] For a discussion on the factors that contributed to electricity market restructuring see Hunt (2002) and Stoft (2002).

[27] For a discussion of the carbon emissions policy and the downward trajectory of carbon emissions from Alberta's electricity industry, see Olmstead and Yatchew (2022).

These changes are likely going to cause demand for electricity from the bulk transmission system to become even more elastic. As a result, setting marginal network access rates above marginal cost will result in increasingly larger inefficiencies. The degree of inefficiency that will result from setting marginal rates above marginal cost is an empirical matter.

Economic efficiency and welfare maximization are central concepts in economic theory. As the electricity sector is looked to as a solution in economy-wide decarbonization initiatives, inefficient rate designs have the potential to produce greater inefficiency in the future. Robinson (2019) argues for the importance of efficient economic signals throughout the electricity system, suggesting that the existing economic signals that consumers receive in many countries are likely to discourage efficient decisions and could slow decarbonization or unnecessarily raise its costs. Inefficient electricity tariffs could impede the electrification of transportation, home heating, water heating, and other services, as well as the development of innovative retail business models and products for consumers.[28]

Alternative tariff designs that rely more heavily on the recovery of residual network costs through connection charges that do not vary with consumption – effectively fixed charges – do not reduce economic efficiency as energy and demand charges do. It is well established that fixed charges do not distort short-term consumption decisions and hence promote more efficient outcomes. The challenge with fixed charges, however, is identifying a billing determinant that would allocate costs in a manner that is deemed fair and equitable. Several economists have recently advocated for a greater use of fixed connection charges for the recovery of residual network costs, including Batlle et al. (2020) who consider a fixed charge based on a one-time measure of historic consumption and Borenstein et al. (2021) who consider the use of income-based fixed charges. Borenstein et al. (2021) further argue that the growing trend towards the decarbonization, decentralization, and digitalization of power grids is making the need to design rates that promote efficiency even more important.

Economically efficient decision making is especially important for new dynamics such as electric vehicle charging (Levin, 2018). Different rate designs will impact the degree of consistency between the choices the consumer makes to minimize their own bill with the choices they would make if seeking to minimize system costs (Linvill, 2018). Certain regulatory bodies explicitly incorporate the principle of economic efficiency in rate making and approval. For example, the California Public Utilities Commission has set forth certain rate making principles which include the principle that rates should encourage economically efficient decision making (Levin, 2018). It will be increasingly important for regulators to ensure that a robust examination of efficiency is incorporated into the regulatory rate design, review, and approval processes.

[28] Due to bounded rationality-based constraints on regulatory decision-making, competitive markets are more effective institutions for the introduction and integration of new technologies than regulated constructs and are essential for decentralization to occur efficiently. The decentralization inherent in competitive markets also operationalizes the principle of subsidiarity.

CONCLUSION

This Policy Brief discusses the use of efficiency analysis in the design of regulated electricity rates and considers a case study of the AESO's proposed Bulk and Regional Transmission Tariff design.

The key finding of the Brief is that there is no theoretical foundation to support the conclusion that the embedded cost methodology for residual network cost recovery and tariff design as reported by the AESO and NERA will best achieve the principles of cost causation and provide appropriate price signals that are aligned with enhancing economic efficiency. The issue of the relative efficiency of a proposed consumption-based tariff design, be it a demand charge, energy charge, or an embedded cost tariff design, is an empirical matter that requires consideration of the specific of the specific market factors of a given jurisdiction.

Many related issues were beyond the scope of this paper but merit research attention. Among these are the equity implications of fixed charges and potential mitigation options and the quantification of inefficiencies associated with specific tariff designs.

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