MASTER OF PUBLIC POLICY
CAPSTONE PROJECT

Evaluating Methodologies of Quantifying Avoided Costs in Energy, Capacity, and Transmission and Distribution Resulting from Energy Efficiency Policies

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Submitted in fulfillment of the requirements of PPOL 623 and completion of the requirements for the Master of Public Policy degree

UNIVERSITY OF CALGARY | THE SCHOOL OF PUBLIC POLICY

Capstone Approval Page

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Acknowledgements

I would first like to thank my supervisor Dr. Blake Shaffer, for the feedback and guidance. None of this would have been possible without you. I would also like to thank Jesse Row, who introduced me to this research topic.

To my parents, Kai and Huichen, for the continued love and support through all my pursuits, especially my education.

Lastly, I would like to thank Richard and Rachel for the constant encouragement and support throughout my whole MPP experience.

Abstract

This study embarks on an in-depth exploration of methodologies for quantifying avoided costs in energy, capacity, and transmission and distribution as a result of energy efficiency policies. The research is anchored in a comparative lens, scrutinizing techniques adopted by jurisdictions such as California, New England, and Ontario. Motivated by the escalating electricity demand due to heightened electrification, the study seeks to understand how energy efficiency policies can be a counterforce by quantifying their utility system benefits. While the U.S. showcases a consistent adoption and documentation of energy efficiency policies, Canada's engagement appears fragmented. The prevailing measure for energy efficiency cost-effectiveness remains the total resource cost test, emphasizing avoided costs as energy efficiency's primary benefit. The investigation reveals a dependency on forward electricity price forecasts for avoided cost in energy, and construction costs of new power facilities for avoided cost in capacity. Methodologies for avoided transmission and distribution cost display variance, with some hinging on historical data blended with investment forecasts. Spotlighting Alberta reveals an imminent need for robust data infrastructure and agile adaptation mechanisms in the energy landscape, ensuring precise utility benefits quantification from energy efficiency policies.

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1. Introduction

This study investigates the methodologies for Alberta to quantify avoided energy, capacity and transmission and distribution (T&D) costs resulting from energy efficiency (EE) policy.

Alberta has an aspiration of achieving net-zero emission by 2050. Research shows clean electrification of the economy (substituting fossil fuels with increasingly clean, low-carbon electricity) is the cheapest and most efficient way to reach net-zero emission targets (Alberta Chambers of Commerce 2022). This increasing rate of electrification will inevitably drive up the demand for electricity which puts pressure on electricity operators to ensure the reliability of electricity supply. The need to expand the electricity system is associated with incurring additional cost to produce, transport and distribute electricity to consumers. EE policy is one of the well-recognized ways to manage electricity demand, which in turn avoids partial cost of system expansion.

Despite EE being a well-known cost-effective method to manage demand, quantifying the total avoided cost of an EE policy can be tricky, as there is no one-size-fit-all methodology to calculate the various avoided costs resulting from demand reduction.

A jurisdictional scan is conducted to examine how the U.S. and Canada quantify the avoided costs. EE policy has been widely adopted in the U.S. to manage the demand for electricity and its effectiveness has been proven. This report focuses on New England and California, which are leaders in EE policy and have the most comprehensive framework and documentation on it. Also, with Ontario being the only Canadian province which has been performing an achievable potential study on EE policy, this report summarizes Ontario’s approach to quantify avoided costs.

The result from the jurisdictional scan shows that the quantified avoided costs can differ significantly across jurisdictions and they aren’t directly comparable, largely due to the differences in the methodologies used and data availability. While there are avoided cost items which are commonly included as the benefits of the EE policy for many jurisdictions, the methodology to quantify avoided costs for each jurisdiction is uniquely rooted from each jurisdiction's market structure, forecast of the future, data availability and many other factors. The calculation also involves the usage of detailed energy data which are subject to availability and reliability. Some avoided cost may not be captured in the short-term benefit, as transmission and distribution constructions often incur in the long-run.

This report is structured as follows. Section 2 discusses the need for EE policy and how widely the policy has been adopted by the U.S. and Canada. Section 3 reviews the literature on electric utility system benefits and its components. The methodology and data are detailed in Section 4. A jurisdictional review on avoided costs quantification methodologies is conducted in Section 5. Section 6 contextualizes the methodology to Alberta. Section 7 provides concluding remarks.

2. Background

This section provides a brief review of the need for EE policy, the components of its primary benefits and the test to assess the cost effectiveness. This section also includes an overview of the current status of EE policy adoption in the U.S., Canada, and specifically Alberta.

The governments of Canada and Alberta are on a path to decarbonize the economy. Alberta's Emission Reduction and Energy Development Plan includes an aspiration to achieve a carbon neutral economy by 2050, and to do so without compromising affordability, reliability and secure energy for Albertans (Alberta 2023). Electrification, the process of replacing technologies that are powered by fossil fuels with those that use electricity, will play a key role in transforming

Alberta’s energy system to meet the net-zero goal (Canada 2022). The shifting from fuel-emitting sources of energy to less-emitting electricity would potentially require a substantial increase in electricity supply resulting from demand hikes. Increasing the electricity supply is no easy task with resources and efforts going into building new generators, transmission and distribution lines, and delivering to end consumers. Also, it can be very costly and time-consuming for the new capacity to be built up. The province, as well as electricity generators and their regulators, play a key role in providing incentives and programming for EE to minimize overall demand which in turn avoid some of the costs associated with additional electricity supply and infrastructure construction (Canada 2022).

Demand side management is the modification of consumer demand for energy through various methods in order to avoid system overload during peak hours. The reliability of the electricity system can be compromised during high demand periods, such as around dinner time hours and on days with extreme weathers. EE is one of the demand side management tools to use less energy to perform the same task or produce the same result.

Avoided cost is often listed as the primary benefit of EE (Baatz 2015). Avoided cost is the incremental cost that is not incurred when the additional output is not produced; the various costs that would have been spent to meet peak demand; Costs avoided by supplying energy through other means, such as distributed energy resources, or decrease energy demand through EE improvements and flexible demand response. EE cost-effectiveness tests compare the benefits of an investment or program with the costs. Total Resource Cost test is the most common primary measurement of EE cost-effectiveness. It captures the total costs and benefits of DSM programming, including for the utility, program participants, and non-participants (Baatz 2015).

EE policy is widely adopted in the U.S. and every state has some form of EE policy in place. Among all the states, California ranked in the first place in the 2022 State Energy Efficiency Scorecard released by American Council for an Energy-Efficient Economy which compared states across six policy areas, including utility and public benefits programs and policies. The Golden State serves as a leader for other states by saving energy on multiple fronts with adoption of advanced clean energy building codes, stringent vehicle emissions standards, and industry-leading appliance standards. Rounding out the top 10 are Massachusetts (#2), New York (#3), Vermont (#4), Maine (#5), the District of Columbia (#6), Maryland and Rhode Island (tied at #7), Connecticut (#9), and Minnesota (#10). Nationwide, annual savings from ratepayer-funded electric efficiency programs is approximately 26 million megawatt-hours. These savings are equivalent to 0.68% of total retail electricity sales in the United States in 2021, enough to power almost 2.4 million homes for a year (Subramanian et al. 2022).

Similar to the U.S., not all Canadian provinces are on the same pace with the adoption of EE policy and documentation of avoided cost calculation. BC's CleanBC Better Homes and Better Buildings programs offer financial incentives, information and support to help households and businesses save energy and reduce greenhouse gas emissions by switching to high-efficiency heating equipment and making building-envelope improvements. Québec's Efficient Solutions Program provides financial assistance to businesses to implement eligible measures. The 2018 Efficiency Manitoba Act established the framework for moving responsibility for EE programs to increase EE savings while incurring lower program costs. Ontario offers various EE programs to homeowners and businesses to incentivize EE measure uptakes. Ontario's Independent Electricity System Operator also publishes a cost effectiveness guide for EE. The 2022 guide outlined the concepts, components and calculation of each cost effectiveness test and provided guidelines for cost effectiveness. The operator also engaged Guidehouse to conduct an integrated EE achievable potential study for electricity and natural gas across Ontario over a 20-year period.

Energy Efficiency Alberta was a provincial agency that promoted and supported EE and community energy systems (including micro-generation and small-scale generation) for homes, businesses and communities during 2017-2020. The agency had estimated its programs delivered $850 million in economic growth and returned $3.20 for every $1 invested (Bennett 2020). Currently, the Clean Energy Improvement Program helps people make energy efficient upgrades to their properties without having to put money down. The cost of the upgrade is recovered through the owner’s property taxes. To reduce emission in the electricity sector and ensure resiliency of the electricity grid during high demand periods, the Alberta’s Emission Reduction and Energy Development Plan has set out multiple actions and opportunities related to improving EE. First, the government will continue to work with stakeholders on approaches to support new technologies, including demand side management that will improve efficiency, reliability and fairness of Alberta’s electricity system; Second, the government will review Alberta’s distribution and transmission policies to ensure ongoing reliability, affordability and coordinated efforts to increase efficiency; Third, the government will consider energy management to supports to continue driving EE and emission reduction projects in industrial and commercial facilities. These policy commitments on adopting EE prompt the need to properly quantify the avoided costs and calculate the cost effectiveness of these programs (Alberta 2023).

3. Literature review on Utility System Benefits

In assessing whether energy-saving projects make financial sense, it is crucial to have methods that measure if the benefits of these projects outweigh their costs. For more than two decades, there have been five main methods to evaluate these projects. While these methods have seen some small changes over the years, they remain the primary ways to judge the success of energy-saving programs. These five cost-effectiveness tests are the participant cost test, the utility/program administrator cost test, the ratepayer impact measure test, the total resource cost test, and the societal cost test (Baatz 2015).

When evaluating if energy-saving policies are financially worthy, the "total resource test" is often the first method used, followed by the "societal cost test." If the "total resource test" shows positive results, it indicates that the program will produce a net reduction in energy costs in the utility service territory over the lifetime of the program. The participant cost test, utility/program administrator cost test and ratepayer impact measure test are then used to indicate how different stakeholders might be affected (Baatz 2015). This report focuses on the total resource test, as it evaluates the net benefits of EE measures to the region as a whole and includes avoided costs as the utility as utility system benefits. Table 1 lists the benefits and costs included in the total resource cost test. The following of this section reviews the approaches involved in considering the utility system benefits.

Table 1. Benefits and Costs included in the Total Resource Cost Test

Benefits and Costs from the Perspective of All Utility Customers (Participants and Non-participants) in the Utility Service Territory	
Benefits	Costs
• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, distribution • Additional resource savings • Monetized environmental and non-energy benefits • Applicable tax credits	• Program overhead costs • Program installation costs • Incremental measure costs

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

3.1. Electric Utility System Benefits

The benefits of EE to an electric utility system encompass both direct energy savings and additional non-energy advantages. These advantages extend past the usual savings from reduced energy consumption and incorporate wider economic gains. This study aims to delineate the various benefits considered by administrators during the evaluation and selection of EE initiatives and to explore the methods employed to measure them. The process of assessing potential programs and planning for future resources hinges on the projection of these anticipated benefits. The significance of these projections cannot be understated, as they determine the extent and focus of EE strategies within a utility's area of operation (Baatz 2015).

Avoided costs in the energy sector can be broadly categorized into two types: energy-related and capacity-related. Energy-related avoided costs encompass aspects like market energy prices, the expense of fuel, pricing of natural gas commodities, among other fluctuating costs. On the other hand, capacity-related costs pertain to tangible infrastructure investments such as the establishment of power plants and the laying of transmission lines and pipelines (Baatz 2015). Notably, curbing energy consumption has environmental upsides, leading to diminished air pollutants, including those that contribute to the greenhouse effect. When delving into these categories, it is incumbent upon policy-makers to identify which benefits are both well-understood and measurable to be factored into the evaluation of cost-effectiveness (National Action Plan for Energy Efficiency 2008). It is observed that there is considerable variation in which benefits are considered in EE program assessments and the methodologies used for their computation. Table 2 is a list of commonly included utility system benefits and their description.

Table 2. Utility system benefits

Benefit	Description
Avoided cost of energy	Avoided marginal unit of energy produced
Avoided cost of capacity	Avoided cost of generating capacity
Avoided cost of T&D	Value of avoiding or deferring the construction of additional T&D assets
Avoided cost of ancillary services	Value of avoided ancillary services required to operate.
Avoided cost of environmental compliance	Avoided cost of compliance with existing and future environmental regulations
Demand reduction induced price effects	Value of energy or capacity market price mitigation or suppression resulting form reduced customer demand
Utility nonenergy benefits	Value of cost savings to a utility from EE programs. These benefits include reduced arrearage carry costs, reduced insurance premiums, or reduced cost of reconnections
Avoided cost of renewable portfolio standards	Value of a reduced cost of compliance with renewable portfolio standards as electricity sales decrease

Source: Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency, 2015

3.2. Components of Utility System Benefits

This section provides an overview of the three main components of utility system benefits (avoided cost of energy, avoided cost of capacity, and avoided cost of transmission and distribution) and various methodologies used to quantify them.

3.2.1 Avoided Cost of Energy

In the realm of estimating the avoided cost of energy, two predominant methodologies emerge. First, utilities that are unbundled and function within wholesale energy markets generally determine the avoided cost of energy through forward market predictions, anchoring their estimates on avoided market purchases. On the other hand, vertically integrated utilities, which usually are not participants in competitive wholesale markets and often have ownership and control over power generation facilities, predominantly utilize integrated resource planning models to project future savings in energy costs. The second approach harnesses a holistic system modeling technique, incorporating variables such as fuel cost predictions, anticipated environmental regulations, meteorological data, demand projections, and various other determinants to pinpoint future marginal prices (Baatz 2015).

There is a notable divergence between the two primary methodologies. Integrated resource planning invariably leans on comprehensive system modeling to ascertain future pricing. However, the precise techniques employed can vary considerably among utilities or regions that adopt this methodology, as can the inclusion rate of T&D costs. This heterogeneity is similarly observed among companies and regions leveraging future market price predictions for their avoided energy cost calculations. Noticeably, some jurisdictions do not rely on either of the two primary methodologies. For instance, Pennsylvania and New Jersey employ forward-looking assessments of natural gas prices to gauge their anticipated energy savings (Baatz 2015).

Natural gas price projections play a pivotal role in determining anticipated avoided energy costs, being deemed the marginal fuel across various methodologies. Historically, forecasting natural gas prices has been a challenge due to their inherent volatility. Recent technological advancements in gas extraction have led to a decline in natural gas prices. Nonetheless, potential shifts in demand could propel prices upward in future. The historical unpredictability and discrepancies in natural gas price predictions make it intricate to utilize them for deducing avoided electricity costs. Hence, it is advisable for regulators to procure a spectrum of price forecasts, factoring in the associated risks, to guide planning decisions amidst the uncertainty of future natural gas prices (Baatz 2015).

Furthermore, it is essential to recognize that electricity costs fluctuate during different times of the day and across seasons. While many states and utilities have segmented avoided energy costs based on these temporal variations, several have opted not to.

3.2.2 Avoided Cost of Capacity

There are three ways to quantify avoided capacity: avoiding the construction of a new asset, the purchase of an existing asset, or market purchases for capacity. For utilities operating in regions that are not engaged in wholesale capacity markets, the primary methodology for approximating avoided capacity costs hinges on the expenditure tied to constructing a new power plant. Notably, data spanning from 2001 to 2011 indicates a tangible uptick in the real costs associated with building a new natural-gas-fired power plant. This escalation in construction expenditures for utility generation can be attributed to a number of factors, including the increasing demand for new capacity. The EE program will not only avoid securing excess capacity to meet peak demand, but it is also avoiding the reserve margin – typically equated to 15% of the peak demand forecast – associated with the avoided capacity (Baatz 2015).

3.2.3 Avoided Cost of Transmission and Distribution

Beyond the curtailment of generation expenses (both energy and capacity), reductions in load resulting from EE initiatives can facilitate the postponement or total evasion of incorporating load-related T&D facilities. This is largely attributed to the diminished load growth and alleviated strain on pre-existing equipment. Such load abatements potentially curtail utility expense on T&D infrastructure in the long run, since the necessity for upgrades, maintenance, and new constructions can either be deferred or wholly avoided (Baatz 2015).

Calculations in this domain exhibit significant disparities among utilities. Prior research suggests that there might not be a singular optimal methodology for calculating the avoided T&D

cost, as multiple methods might yield valid estimates. The determination of these avoided T&D costs hinges on factors like geographical positioning, overarching system impacts, and temporal distinctions (specific hours or seasons). Estimation of these costs requires complex system modeling which can be a highly complex process and is typically more challenging than estimating the avoided cost of capacity or energy (Baatz 2015).

The methodologies vary significantly across the U.S. Certain states lean on extensive historical records combined with prospective T&D investments to derive the marginal T&D capacity costs. Alternatively, the avoided cost of T&D can also be based on a levelized average of the actual cost of completed substation upgrade and line upgrade project costs over the past five years. Notably, there has been an observable surge in the construction costs tied to utility T&D for a variety of reasons (Baatz 2015).

4. Methodology

This study undertook a comprehensive jurisdictional review across two U.S. regions and one province in Canada to investigate the methodologies these jurisdictions employ to quantify utility system benefits.

The regions of California and New England were pinpointed for their exemplary leadership in EE policy, as recognized by the American Council for an Energy-Efficient Economy. For a grasp of Canadian methodologies, Ontario emerged as the choice given its unique position of having publicly accessible documentation on EE policy. I sourced the relevant documents detailing avoided costs from the respective utility regulators' online portals, carefully analyzing the methodological descriptions for the three categories of avoided costs. These insights have been collated and presented in section 5 of this report.

Drawing from the exemplary methodologies observed in these three jurisdictions, I integrated these insights into the context of Alberta, subsequently conducting a gap analysis to outline the steps Alberta should undertake to properly compute the avoided costs. These findings and recommendations are articulated in section 6 of this report.

5. Jurisdictional Review and Analysis

This section presents the findings on the methodologies employed for estimating avoided costs, stemming from a jurisdictional analysis of three distinct regions: California, New England, and Ontario (Canada).

5.1 California

In the state of California, the Public Utilities Commission employs the Avoided Cost Calculator for determine the benefits of Distributed Energy Resources, including EE, in the context of cost-benefit evaluations. This calculator provides projections of hourly, system-wide expenses associated with delivering electricity or gas services over a span of 30 years, presented in terms of \$/kWh or \$/therm. These hourly computations of avoided costs collaborate with specific program-centric data, like hourly energy conservation, to ascertain the benefits of a particular program. The Avoided Cost Calculator computes a variety of costs that can be avoided, including those related to energy, generation capacity, T&D capacity, as well as costs linked to natural gas infrastructure, ancillary services, and greenhouse gas emissions (Energy Environmental Economics 2022).

The foundation for these avoided costs is predominantly the data and insights derived from Integrated Resource Planning models. However, an exception lies in the quantification of avoided costs for T&D, which lean on information and directives originating from the distribution planning proceedings. A detailed exposition on the foundational inputs, underlying assumptions, and methodologies applied in the 2022 version of the Distributed Energy Resources Avoided Cost Calculator can be found in the documentation released for the same year.

5.1.1 Avoided Cost of Energy

The California Public Utilities Commission employs a production simulation model to project hourly wholesale electricity prices, grounded in the system load input and the dispatch from the simulated generation portfolio. This approach has been in operation since 2020, crafting values for the avoided cost components related to energy. Supplementary model runs have been undertaken for the years 2035, 2040, and 2045.

Once the model yields raw market prices – reflecting an idealized and streamlined vision of the day-ahead energy market – several refining steps are instated to these initial figures. This ensures they more closely mirror historical market behaviors and account for probabilistic real-world fluctuations. To begin with, even though the production simulation model delivers outcomes for the years spanning 2022 to 2032, as well as for 2035, 2040, and 2045, the energy prices for the intervening years are drawn through linear interpolation. Prices post-2045 are extrapolated, leaning on hourly implicit marginal heat rates. Subsequently, bounds are set for day-ahead energy prices, capping them at $1000/MWh and flooring them at $0/MWh. The third refinement involves the integration of a scarcity scaling function to the model's outputs, enhancing their fidelity to the non-standard market conditions, especially pronounced during peak periods when the system operates near its maximum capacity. This modification is pivotal, as prices in these scarcity intervals, marked by system stress, typically surpass those forecasted from basic fundamental analyses (Energy Environmental Economics 2022).

In the concluding stages, the impacts of an EE policy are calculated by multiplying the hourly avoided costs by the hourly impact shape of the EE measure. This process ensures accurate alignment of weekends and holidays in both the impact shape and the avoided cost datasets.

5.1.2 Avoided Cost of Capacity

Starting from 2020, a notable shift occurred when a battery storage mechanism supplanted the gas combustion turbine as the representative resource for marginal generation capacity. By 2022, there was the introduction of the Real Economic Carrying Charge method to discern the deferral value of a nascent battery storage asset. This technique computes the annual avoided investment cost by taking the difference between the expense of an investment made in a specific year and the same investment postponed by a year (Energy Environmental Economics 2022).

For deducing the avoided capacity cost, the structural and financial details of the battery storage entity are sourced from the Integrated Resource Planning. This plan also provides the vital cost and performance suppositions as well as a comprehensive financial pro-forma model. Utilizing these, the averaged fixed expenses of maintaining a battery across its projected operational lifespan of two decades are computed. The earnings accrued by these batteries within the energy and supplementary markets, determined through optimum dispatch, are then deducted from the previously calculated levelized costs to arrive at a net expense. Furthermore, the price values obtained from the production simulation model assist in determining the net market revenues attributable to a newly built battery storage resource (Energy Environmental Economics 2022).

Subsequently, generation capacity metrics, expressed in $/kW-yr and refined for thermal adjustments and losses, are delegated to the timeframes during the year that experience the peak requirement for system capacity, utilizing the production simulation model. The monthly/hourly projections of Expected Unserved Energy were consequently mapped to specific days of a year, referencing temperature records and harmonizing with the 2020 calendar to ensure synchronicity with energy pricing structures.

5.1.3 Avoided Cost of Transmission and Distribution

The value inherent in the *transmission avoided capacity costs* arises when reductions in peak loading are precisely achieved, both in terms of quantity and location, and with assured reliability. These costs are indicative of the potential financial implications on utility transmission investments as a consequence of peak load shifts. The underlying concept is that by leveraging customer demand reductions, distributed energy resources, or storage mechanisms, there could be a decrease in the demand for certain transmission initiatives, paving the way for their postponement or total omission. However, the practicality of deferring or avoiding these transmission projects is contingent on numerous variables. These include the feasibility of securing reliable, large-scale peak reductions in a timely manner to sensibly delay or bypass the project, and ensuring these reductions occur in strategic locations to adequately mitigate network flow demands (Energy Environmental Economics 2022).

The documents further highlight that as utility systems evolve, the specific regions requiring demand cutbacks or decentralized energy solutions will shift. This is because loading on utility systems develops distinctively across different areas within utility jurisdictions. As a result, the year-on-year capacity expenses are subject to fluctuations based on climatic regions and the specific utility in question (Energy Environmental Economics 2022).

Subsequently, these yearly capacity costs are distributed across the hours of a year to mirror the fluctuating demand for transmission capacity. The method employed to decide upon this allocation is the peak capacity allocation technique, which is instrumental in determining the hourly distribution allocation factors.

Moreover, in order to realign transmission peak capacity allocations, similar day-to-day and meteorological adjustments are undertaken. Climate-specific temperature data is amalgamated to formulate temperature blueprints for every utility. This is accomplished by computing the weighted average of temperatures, grounded in the loading of each climate zone within a particular utility's region.

Distribution avoided costs is the monetary benefits of postponing or entirely foregoing investments in distribution infrastructure by curtailing the demand for distribution peak capacity. The annual distribution marginal cost is comprised of both near-term and long-term costs.

In the near-term, these avoided costs pertain to a select few utility capacity ventures that may potentially be delayed due to the integration of EE measures within the designated project territories. Such costs quantify the benefit of postponing these distribution investment initiatives through the incorporation of EE or similar demand-reducing strategies, which exceed the anticipated EE augmentation the utility foresees for the specified area given the prevailing EE guidelines, incentives, and schemes. The calculation for near-term distribution marginal costs (spanning the initial five years of the projection) adheres to the guidelines posited in the T&D White Paper. It harnesses insights derived from the utility's Distribution Deferral Opportunity Report and Grid Needs Assessment submissions. The methodological approach utilizes the utilities' Grid Needs Assessment projected scenario to pinpoint the unit expenditure of enhancing distribution capacity. A hypothetical projection that reincorporates the EE-induced load reductions embedded within the utility's strategic plan is crafted to draft an alternate distribution capital scheme. This hypothetical strategy is subsequently transformed into a system-wide average marginal cost, employing conventional General Rate Case techniques, which encompasses the application of an annualization coefficient complemented by incremental loaders or adders (Energy Environmental Economics 2022).

The investor-owned utilities in California have employed a diverse array of techniques to ascertain long-term distribution marginal costs. The General Rate Case values have been endorsed by the California Public Utilities Commission as the benchmark for estimating extended marginal costs. The most favored data repository consists of values ratified for revenue distribution from the most recent proceedings.

The annual distribution capacity costs are distributed throughout the calendar year to mirror the fluctuating demand for distribution capacity. The hourly distribution allocation coefficients are devised to match the specific timeframes from which historical data is procured. This is achieved using regression analyses of distribution hourly loads, archival utility records, and General Rate Case evaluations. In order to synchronize distribution and generation expenses, the distribution allocation coefficients are reordered to correspond with meteorological records, weekends, and national holidays.

5.2 New England

ISO New England Inc., an independent, not-for-profit Regional Transmission Organization located in Holyoke, Massachusetts, serves six states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The *2021 Avoided Energy Supply Component Study* details the cost trajectories of potential energy supply components that could be avoided in future years. This potential avoidance stems from decreased consumption of electricity, natural gas, and other energy sources, primarily driven by EE programs and various demand-side interventions across the New England region. In order to quantify the impact of EE and other demand-side initiatives, hourly avoided costs are computed for each of the six New England states. These computations simulate a prospective scenario where, post-2020, the program administrators in New England abstain from introducing any new demand-side interventions (Synapse Energy Economics 2021).

5.2.1 Avoided Cost of Energy

The EnCompass model forecasts the expected level of electric system energy in New England from 2021 to 2035, taking into account a range of factors including capacities, fuel prices, heat rates, availability factors, and other unit-specific characteristics. This model also offers predictions for wholesale energy prices. The fluctuations in these predicted prices – noticeable on both peak and off-peak bases – is driven by various elements, notably system demand, accessible units, transmission constrains, fuel price fluctuations, and other unique attributes. There are two primary factors underpin this evolving price trend: (1) the rise in renewable energy and imported generation, which progressively ousts costlier fossil-fuel-based units, and (2) a downward trajectory in the future real-dollar value of the Algonquin basis during certain months (Synapse Energy Economics 2021).

To ensure accuracy and relevance, the dispatch model undergoes calibration, integrating both actual and historic datasets. This process involves aligning the model with real-world considerations related to available generation units, fuel cost dynamics, and system demand projections.

5.2.2 Avoided Cost of Capacity

The foundation for determining avoided capacity costs lies in both current and anticipated clearing prices within the ISO New England's forward capacity market. These forecasted prices draw insights from recent auction activities and prospective shifts in demand, supply, and overarching market regulations. The subsequent paragraphs delve into the mechanisms used to develop avoided capacity prices from forward capacity market auctions and highlights pivotal assumptions driving this analysis.

Derived from the forward capacity market auction rates for power years commencing June 2020, the avoided capacity prices capitalize on concrete auction outcomes for the delivery years spanning 2021/22 to 2024/25. For the extended analysis timeframe, historical auction results serve as extrapolation benchmarks. Notably, the four of the most recent forward capacity auctions, which uniquely cleared at actual bid prices in contrast to a preset administrative threshold, is instrumental in shaping the future capacity price narrative. In each of these auctions, historical supply curves and administrative demand curves are estimated. The intersection of the two curves depicts the historical capacity price (Synapse Energy Economics 2021).

Future capacity prices are projected using the same steps described above. As the predicted peak surges, the demand curve shifts rightward. Conversely, the supply curve's movement, either to the left or right, hinges on the balance between resource additions and retirements. The intersection of these two curves indicates the capacity price. These projected capacity prices for the post-2024 horizon then seamlessly appended to the actual capacity prices from 2021-2024 and the corresponding projections, accounting for the influence of EE measures introduced post-2020 (Synapse Energy Economics 2021).

5.2.3 Avoided Cost of Transmission and Distribution

In the 2021 Avoided Energy Supply Component Study. Section 10 outlines a methodological approach for program administrators to estimate avoidable T&D costs for planning and reporting of EE program benefits.

First, a standardized approach is presented to estimate generic system-level avoidable transmission or distribution costs. The six steps are: select a time period for the analysis; determine the actual or expected relevant load growth; estimate the load-related investment in dollars incurred to meet that load growth; determine the cost of load growth in $ per MW or $ per kW; derive an estimate of the avoidable capital cost in $ per kW-year; add an allowance for operation and maintenance (Synapse Energy Economics 2021).

The goal of these generic avoided-cost computations is to estimate the overall, long-term ratio of T&D savings per kW of avoided load growth. This evaluation operates under the presumption that every kW reduction, irrespective of its location, offers the same savings. This standardized approach offers simplification for widespread EE programs.

Second, to estimate the value of an EE program in a location-specific context, a methodology is introduced to calculate the localized value of avoided T&D. The three steps are: identify target areas and required load reduction; determine benefits of targeted load reductions by identified target area; calculate avoided cost ($/kW) based on the present value of deferred expenditures and the required load reduction (Synapse Energy Economics 2021).

5.3 Ontario

Ontario’s Distributed Energy Resources Potential Study Volume II: Methodology & Assumptions outlines the approach used to quantify each of the benefits considered in the total resource test. This report is prepared by Dunsky Energy and Climate Advisors for Ontario’s Independent Electricity System Operator.

For avoided cost of energy, the study employs real-time energy prices as an indicative measure for the potential savings EE can offer. The research group employed a unique hourly dispatch model which simulates the market behavior of energy bids, in addition to the variables of demand and weather conditions, which influence Ontario's wholesale market pricing. This model, along with the resulting avoided costs, reflects the distinct market characteristics of Ontario’s hybrid system, ensuring that seasonal and weather-related factors are considered.

System demand was based on the Independent Electricity System Operator’s Annual Planning Outlook 2021 net demand outlook, with necessary adjustments to account for the enhanced electrification captured in those models.

The avoided generation capacity cost was estimated as the net cost-of-new-entry for a simple-cycle gas-fired turbine generation facility, with escalations occurring throughout the forecast period.

To assess the avoided transmission costs, a thorough review of regional planning materials was undertaken to pinpoint specific areas or subregions in Ontario's grid that are likely to be governed primarily by thermal capacity overloads. A model of demand growth expectations and estimates of existing system capacity for each identified subregion was constructed to determine specific investment need dates. The financial benefits of postponing conventional transmission investments are derived from the avoidance of yearly amortization expenditures, computed utilizing standard utility capital costs and investment rates (Dunsky 2022).

Lastly, the concept of system service was identified as a credible gauge for future infrastructure expansion costs to cater to upcoming consumer demands. Therefore, it was chosen as the representative factor for avoided distribution expenses. A forecast detailing future distribution infrastructure investment under the system service framework was formulated, grounded in historical expenditure patterns and provincial load growth trajectories (Dunsky 2022).

6. Gap Analysis for Alberta

Following an exhaustive review of quantification methodologies for avoided costs in California, New England, and Ontario, this study pinpoints specific policy discrepancies that Alberta must address to adequately measure the utility-based advantages of EE initiatives.

Alberta's competitive wholesale marketplace suggests an imperative to compute the avoided energy cost through forward market predictions, aligning the avoided energy cost with avoided market purchases. To execute this approach, Alberta requires the establishment of robust data and modeling capabilities to project upcoming market rates. The constructed model must be carefully calibrated with tailored assumptions to reflect the nuances of Alberta's energy sector and project natural gas prices with high precision – a task fraught with complexities. As Alberta gravitates towards greener energy production, various elements like the proliferation of renewable energy, surges in electricity demand, innovations in hydrogen, and stringent emission regulations can influence natural gas pricing. Subsequent to modeling, multiple refining stages, including the incorporation of a scarcity scaling function, are vital to incorporate real-world parameters into the theoretical model.

In 2019, about 89% of electricity in Alberta is produced from fossil fuels (Canada 2022). Therefore, in the near term, the construction cost for a new simple-cycle gas turbine generation facility should serve as the proxy for the avoided capacity cost. As the future unfolds and renewable energy plays a more significant role in electricity generation, a shift towards battery storage resources as a benchmark may be necessary for Alberta.

Drawing parallels with the three regions previously scrutinized, Alberta's computation for avoided T&D costs should be steered by regional T&D planning. This is imperative as electricity consumption and load reduction vary across regions, each with its distinct system capacity and capital expenditure. Pivoting on the geographical focal points of Alberta's proposed EE initiatives and projected load expansion, the province can either develop a holistic methodology to estimate the overall, long-term savings ratio for T&D per kW of reduced load; or lean towards pinpointing localized T&D savings. For guidance on both avenues, the New England report serves as a comprehensive reference. It is crucial to consider the timeline of avoided T&D costs as some utility capacity projects can be avoided in the near-term. A holistic grid planning document can be instrumental in considering long-term distribution marginal costs.

It is paramount that annual saved costs are distributed across the year's hours, mirroring the fluctuating requirements for energy purchases, generative capacity, and T&D capacity. Furthermore, meteorological conditions and weekly dynamics, such as weekends, ought to influence the hourly avoided cost allocation.

In the rapidly evolving landscape of energy market, policy, and technological advancements, Alberta, alongside its electric system operators, should remain forward-looking, demonstrating resilience to price volatility and shifts in energy production, and maintaining political acuity.

7. Conclusion

In this study, I have delved into the overarching techniques for estimating avoided costs pertaining to energy, capacity, and T&D. Additionally, I explored the distinct methods adopted by the jurisdictions of California, New England, and Ontario via comprehensive jurisdictional comparisons. This inquiry stems from the prevailing challenge posed by the surge in electrification, which escalates electricity demand and correspondingly amplifies the costs linked to its production, transmission, and distribution. Through this lens, I investigated the distinctive manner in which EE policies mediate demand and quantified their benefits to utility systems.

My research, drawing insights from prominent EE organizations, highlights that while EE policies are extensively adopted and well documented in the U.S., their adoption in Canada appears uneven and less extensively reported. I observe that the predominant metric to gauge the cost-effectiveness of EE is the total resource cost test, with avoided costs being recognized as the primary benefit of EE initiatives.

I analyze the generic methodology for quantifying the three types of avoided costs: energy, capacity and T&D. I find that energy avoided costs frequently hinge on forward market projections for natural gas prices. Predominantly, the construction cost involved in building a new power facility serves as the benchmark for determining avoided capacity costs. The strategies to compute avoided T&D costs exhibit diversity; some jurisdictions lean on a blend of past data and future T&D investment projections to discern the marginal T&D capacity cost.

Upon evaluating the methodologies employed across California, New England, and Ontario, a pattern emerged. Each of these regions leverages anticipated electricity pricing to determine the avoided energy costs. Both California and Ontario's metrics rest on the expenditure associated with replacing a gas combustion turbine to estimate the avoided capacity cost, whereas New England's approach is anchored in the clearing price in its forward capacity market. When it comes to the avoided cost of T&D, the employed methodology relies on avoiding infrastructural investments, with the approach being varied based on temporal (near-term and long-term) and spatial (standardized and localized) considerations.

Lastly, through the lens of Alberta's context, I have spotlighted the policy gap that warrant attention for a precise estimation of the utility system benefits stemming from EE policies. Alberta's methodological landscape seems to resonate most closely with the frameworks of Ontario and California. Yet, Alberta stands at the threshold of a transformative journey, necessitating a robust data infrastructure to carve out a model tailored to its unique needs. The strategies for capacity and T&D will be influenced by Alberta's envisioned forecast for future energy sources, choosing between generic and more locale-specific approach. Vital to this entire endeavor is the capacity to swiftly adapt to the dynamic shifts in energy pricing and production portfolio, all the while maintaining a keen political acumen.

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