Public Service Commission of Wisconsin

Summer Strand, Chairperson
Kristy Nieto, Commissioner
Marcus Hawkins, Commissioner

4822 Madison Yards Way
P.O. Box 7854
Madison, WI 53707-7854

November 14, 2024

To the Parties:

Re: Quadrennial Planning Process IV 5-FE-104

Comments Due:	Address Comments To:
Monday, December 9, 2024 - 1:30PM	**5-FE-104** Public Service Commission P.O. Box 7854 Madison, WI 53707-7854
This docket uses the Electronic Records Filing system (ERF).	

The Commission memorandum concerning the Focus on Energy Evaluation Work Group's recommendation to the Commission on a method for calculating avoided transmission and distribution costs for purposes of evaluating Focus on Energy is being provided to the parties for comment. Comments must be received by 1:30 PM on Monday, December 9, 2024.

Party comments must be filed using the Commission's ERF system. The ERF system can be accessed through the Public Service Commission's website at https://psc.wi.gov. Members of the public may file comments using the ERF system or may file an original in person or by mail at the Public Service Commission, 4822 Madison Yards Way, P.O. Box 7854, Madison, WI 53707-7854.

Please direct questions about this docket or requests for additional accommodations for persons with a disability to the Commission's docket coordinator, Jolene Sheil at (608) 266-7375 or Jolene.Sheil@wisconsin.gov.

Sincerely,

Joe Fontaine
Administrator
Division of Digital Access, Consumer and Environmental Affairs

MH:JF:bs DL:02037319

Attachment: Cadmus Memorandum
Attachment A – Cadmus Memorandum of 6/28/24

PUBLIC SERVICE COMMISSION OF WISCONSIN
Memorandum

November 14, 2024

FOR COMMISSION AGENDA

TO: The Commission

FROM: Joe Fontaine, Division Administrator
Tara Kiley, Deputy Division Administrator
Joe Pater, Director, Office of Energy Innovation
Mitch Horrie, Performance Manager, Focus on Energy
Jolene Sheil, Portfolio Manager, Focus on Energy
Division of Digital Access, Consumer & Environmental Affairs

RE: Quadrennial Planning Process IV 5-FE-104

Suggested Minute: The Commission directed the Division of Digital Access, Consumer and Environmental Affairs to draft an Order consistent with its discussion.

Introduction

In its November 2022 Final Decision for Quadrennial Planning Process IV (Quad IV), the Commission made several decisions related to the Focus on Energy (Focus) cost-effectiveness framework for Quad IV. (PSC REF#: 453081.) Order Point #23 from the Quad IV Final Decision directed the Focus Evaluation Work Group (EWG), either working alone or together with a third-party, to present to the Commission an alternative method for calculating avoided electric transmission and distribution (T&D) costs for the purpose of evaluating Focus cost-effectiveness. This memorandum presents for the Commission's consideration, a proposed methodology developed by the EWG in consultation with a third-party, the Regulatory Assistance Project (RAP).

Background

Wisconsin Admin. Code § PSC 137.05(12) requires the Focus Program Administrator to deliver energy efficiency and renewable resource programs that pass a portfolio level test of net cost-effectiveness, as determined by the Commission. Different cost-effectiveness tests include different combinations of benefits and costs and are designed to evaluate cost-effectiveness from a variety of perspectives. The Commission has used the Quadrennial Planning Process to review and assess whether to update its determination of Focus' primary cost-effectiveness test as well as secondary cost-effectiveness tests used for informational purposes.

Avoided costs are a benefit accounted for in cost-effectiveness tests used by energy efficiency and renewable energy programs. They represent the additional costs that would have been borne by the utility and passed along to ratepayers in the absence of program savings. Focus' primary cost-effectiveness test is a Modified Total Resource Cost (MTRC) test. As presently approved by the Commission, Focus' MTRC accounts for five types of avoided costs: 1) avoided electric energy costs, 2) avoided electric capacity costs, 3) avoided electric T&D costs, 4) avoided natural gas energy costs, and 5) avoided emissions costs.

The Commission established the Focus EWG during the first Quadrennial Planning Process to advise the Commission on measurement and evaluation issues. (PSC REF#: 137513.) At the Commission's direction, the EWG has advised the Commission on various cost-effectiveness issues over time, including recommending avoided cost methodologies for electric avoided energy costs (PSC REF#: 166595), natural gas avoided energy costs (PSC REF#: 230327), and electric avoided capacity costs (PSC REF#: 386919).

Avoided costs are updated at the beginning of each quadrennium and are reviewed annually by the EWG to ensure that benefits calculated as part of the evaluation of Focus remain aligned with market conditions, trends, and forecasts. In its Order from June 1, 2020, approving a methodology for calculating avoided electric capacity costs for the purpose of evaluating Focus, the Commission also directed the EWG to propose a method for calculating avoided T&D costs for the purpose of evaluating Focus. (PSC REF#: 390566.) The Commission approved the EWG's recommended methodology in its Final Decision of March 10, 2021, to be applied for purposes of evaluating Focus for the Quad III period. (PSC REF#: 406591.) The approved methodology uses an incremental cost approach based on a four-year running average of investor-owned utility (IOU) transmission infrastructure investments reported to the Commission in IOU Annual Reports.[1] The Commission found it reasonable for Focus to maintain this approach in Quad IV and directed the EWG or the EWG and a third-party together to present an alternative method (or multiple alternative methods) for its consideration in Quad IV. (PSC REF#: 453081.) Figure 1 on the following page outlines the steps used to derive avoided T&D costs using the incremental cost approach.

[1] IOU Annual Reports are filed by utilities each year as required under Wis. Stat. § 196.07. Transmission line statistics data used for the avoided T&D approach are reported under Schedule E-30 of the IOU Annual Reports.

Figure 1. Current Avoided T&D Calculation Approach

$$T\&D\ Project\ kW = Project\ kVA * Power\ Factor$$

Establish hourly kW. Project kVA is the operating voltage. Power Factor is the ratio of actual power to apparent power in an AC circuit.

$$T\&D\ Project\ kW\ per\ Year = T\&D\ Project\ kW * 8{,}760$$

Annualize kW.

$$Cost\ per\ Mile = T\&D\ Project\ Cost\ (\$) \div T\&D\ Project\ Miles$$

$$T\&D\ Project\ Cost\ per\ Mile\ per\ kW\ per\ Year = Cost\ per\ Mile \div T\&D\ Project\ kW\ per\ Year$$

$$Annulized\ Cost\ per\ Mile\ per\ kW\ per\ Year = \frac{r * T\&D\ Project\ Cost\ per\ Mile\ per\ kW\ per\ Year}{1-(1+r)^{T\&D\ Project\ EUL}}$$

r is the rate. EUL is the expected useful life.

The current methodology multiplies a four-year running average of the total miles of power lines constructed and the annualized cost per mile per kilowatt-year to derive an average cost per kilowatt-year. A four-year average of the input data is used to reduce the impacts of year-to-year cost variability in reported investments. The current methodology also assigns projects as either "transmission" or "distribution" based on the voltage level reported in the IOU Annual Reports to separate the benefits accruing from larger transmission projects from smaller, more localized projects whose function may more closely resemble distribution rather than transmission.[2] While this assignment of projects as "transmission" and "distribution" occurs with the current incremental cost methodology, the assignment only applies to those projects

[2] Projects designated as "transmission" based the voltage threshold are assigned an effective useful life of 50 years, while projects designated as "distribution" are assigned an effective useful life of 30 years in the avoided T&D calculation.

reported by utilities in the IOU Annual Reports as transmission line statistics data. Data concerning utility-owned and operated distribution system investments are not reported publicly and thus are not accounted for in the current methodology. The Commission's approval of an avoided T&D methodology for Focus in Quad III included conditions that Commission staff investigate opportunities to modify annual IOU reports to improve the transparency and consistency of the data used to calculate avoided T&D costs using the Commission's approved methodology and to revisit the topic of avoided T&D costs during the Quad IV Planning Process. The Commission also directed the Focus Evaluator to incorporate avoided T&D costs into a parallel analysis of benefits achieved by Focus programs as part of the evaluation of Quad III programs.

The Quad IV Phase II staff memorandum provided the Commission with information on the avoided T&D benefits estimated in the first two years after the EWG's proposed methodology was approved by the Commission. (PSC REF#: 442095 at 81.) Two additional years of portfolio avoided T&D costs have been estimated since the Quad IV Phase II staff memorandum. Table 1 presents Focus' avoided T&D benefits calculated since being incorporated into Focus' annual portfolio evaluation cycle. On average, avoided T&D benefits have accounted for $52.6 million in program benefits each year since 2020, representing 8.3 percent of the overall portfolio benefits.

Table 1. Focus Avoided T&D Benefits, 2020- 2023

Metric	2020	2021	2022	2023
T&D Benefits	$54,665,398	$57,004,279	$52,382,582	$46,444,919
% of Overall Portfolio Benefits	7.9%	8.6%	8.9%	7.6%

Source: Annual Evaluation Reports

The Quad IV Phase II memorandum also noted that while modifications to IOU Annual Reports were investigated, direct outreach to American Transmission Company (ATC) to identify the primary purpose of transmission line investments reported proved to be a more practical and efficient process for improving these data for purposes of performing the calculation.[3] Even with this additional ATC data, EWG raised concerns that the overall avoided T&D approach did not meet the group's preferences for using publicly available data that is regularly and reliably updated (*Id.* at 83). Moreover, the EWG maintained its position that the method was not able to account for avoided distribution system costs and therefore was likely to be underestimating total benefits. Public comments received on the Phase II staff memorandum supported either maintaining the existing avoided T&D methodology[4] or investigating an alternative methodology that could ameliorate the EWG's concerns.[5] Comments on the Phase II staff memorandum filed by Clean Wisconsin recommended the Commission direct EWG to partner with RAP to propose an alternative method for calculating avoided T&D. (PSC REF#: 444184.) In its Final Decision setting the goals, priorities, and measurable targets for Quad IV of Focus, the Commission determined it was appropriate for the EWG, or EWG and a third-party, to propose an alternative avoided T&D method for its consideration in Quad IV. (PSC REF#: 453081.)

2023-2024 Avoided T&D Review

The Focus Evaluator, Cadmus, performed an updated review and analysis of avoided T&D methodologies beginning in late 2023 and concluding in the summer of 2024. Concurrent with this analysis, Commission staff engaged with RAP at the end of 2023 to request its assistance in developing an alternative avoided T&D methodology recommendation for the

[3] While both ATC and NSPW own and operate transmission infrastructure in Wisconsin, the Evaluation Team determined that ATC information on the primary purpose of transmission line investments were sufficiently broad based to inform assumptions applied for purposes of performing a statewide avoided T&D calculation.
[4] See: PSC REF#: 444133
[5] See: PSC REF#: 444217, PSC REF#: 444175, PSC REF#: 444179, PSC REF#: 444184

Commission's consideration. RAP began its engagement in early 2024 by holding discussions with Cadmus staff supporting the Quad IV and Quad III efforts investigating approaches for estimating avoided T&D costs. The EWG and RAP staff met in February 2024 for an initial discussion of the methodologies under consideration for review.

The EWG's initial effort recommending an avoided T&D methodology for the Commission's consideration in Quad III involved a review of methodologies used by utilities and other jurisdictions throughout the country. (PSC REF#: 403255.) This review primarily focused on two data sources summarizing methodologies in use: a 2014 report from the Mendota Group[6] and a 2015 report from the American Council for an Energy Efficient Economy (ACEEE)[7]. Cadmus expanded its search of potential methodologies for the EWG's 2023-2024 review to include an assessment of three alternative methods not previously considered by the EWG (Table 3 in Attachment A) and deeper assessments of three approaches that had previously been reviewed by the EWG (Table 2 in Attachment A). Cadmus, RAP, and Commission staff met in the spring of 2024 to discuss the merits of the alternative methodologies included in the updated analysis. Each method was assessed for its strengths and weaknesses and was screened against four criteria aligned with the EWG's priorities: 1) relies on publicly available data sources that are regularly and reliably updated; 2) uses straightforward calculations based on standard engineering and economic principles; 3) ensures regional specificity; and 4) can be developed and updated efficiently.

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[6] "Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments." Filed on behalf of Public Service Company of Colorado. October 23, 2014. Available online: https://mendotagroup.com/wp-content/uploads/2024/04/PSCo-Benchmarking-Avoided-TD-Costs.pdf.

[7] Baatz, B. *Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency*; American Council for an Energy-Efficient Economy: Washington, DC, USA, 2015. https://www.aceee.org/research-report/u1505.

Cadmus developed a draft memorandum in spring 2024 summarizing the avoided T&D methodologies it reviewed. Commission and RAP staff reviewed this draft memorandum and provided feedback and guidance. Through its analysis and discussion, Cadmus and RAP aligned on a recommended methodology to bring to the EWG for their consideration. The EWG reviewed Cadmus' draft memorandum in summer 2024 and provided feedback that was incorporated into a final draft (Attachment A). The EWG met on June 27, 2024, to discuss the range of methodologies analyzed including the recommended methodology proposed by Cadmus and RAP.

The EWG agrees with the findings from Cadmus and RAP that certain approaches introduced into the analysis for this investigation are not good candidates for Focus due to their reliance on highly localized data inputs (e.g., load forecasts, infrastructure upgrade costs and timing, and localized system characteristics) that are not publicly available and would be challenging for a statewide, third-party administered energy efficiency program to acquire and incorporate. The EWG also acknowledges that its review of alternative methodologies once again did not uncover an industry best practice methodology. Finally, the EWG concedes that a publicly available data source capable of supporting a Wisconsin-specific avoided distribution cost calculation could not be identified and that excluding these costs from its recommended approach is likely to undervalue the full benefits achieved by the program. The EWG recommends continued investigation to seek to identify publicly available data that would support a standalone methodology for distribution avoided costs aligned with its priority criteria.

Accounting for those limitations, the EWG supports the Cadmus/RAP recommended methodology and agrees with Cadmus and RAP that the recommended methodology more closely aligns with its preferred criteria than any of the other alternatives reviewed. The EWG finds that the recommended methodology is preferred to other methodologies analyzed as part of the 2023-2024 avoided T&D review due to its simplicity and reliance on publicly available data that EWG is confident will continue to be regularly and reliably updated. Although all members of the EWG participated in the review of the approaches analyzed, the utility representative requested to be recused from taking a position on the recommended approach to avoid any perceptions of conflict with their role outside of the EWG.

The EWG is appreciative of RAP's guidance in developing the proposed methodology and believes that RAP's expertise was valuable in formulating the EWG's recommendation to the Commission. The following section describes the EWG's recommended methodology in detail.

Recommended Methodology

The EWG's recommended methodology is an ATC rate-based avoided transmission cost approach. As mentioned above, no methodology reviewed by Cadmus and RAP was able to address a lack of publicly available, Wisconsin utility-specific distribution system cost data. Therefore, the EWG's recommendation includes a modification to apply a more appropriate term—avoided transmission costs—as opposed to avoided T&D costs. Henceforth, this memorandum will refer to the EWG's proposal as a recommended methodology for calculating avoided transmission costs.

The EWG's recommended methodology relies on ATC rates that are used in assessing actual transmission system costs paid by utilities when electric load is needed. Therefore, these rates also reflect transmission system costs that are not paid—are avoided—when electric load is not needed. The ATC transmission rate data used for the EWG's recommended methodology are updated annually and are publicly available on the Open Access Technology International, Inc. webSmart OASIS (Oasis) ATC website.[8] These ATC rates represent Wisconsin-specific transmission system charges applied to four of the five major Wisconsin IOUs: Madison Gas & Electric Company, Wisconsin Power & Light, Wisconsin Public Service, and We Energies. Though Northern States Power Company-Wisconsin transmission rates are not captured with this methodology, the EWG, in consultation with RAP, finds that the represented utilities are sufficiently broad based to derive a statewide avoided transmission cost for purposes of assessing Focus' cost-effectiveness.[9]

The data sources and steps for calculating avoided transmission costs using the EWG's recommended methodology are as follows:

1. Refer to the monthly Rate Calculation ATC rate in $/kilowatt-month provided on Schedule 9 of the most recent ATC Rate Projections provided by Oasis' website.[10]

2. Multiply the ATC rate for each year by 12 to derive the annualized transmission rate.

3. Calculate the average annualized transmission rate based on the most recently available four-year period.

4. Escalate the four-year average, annualized rate in $/kW-Year using the difference between the Wisconsin Department of Transportation Chained Fisher Construction Cost Index and the U.S. Bureau of Labor Statistic's Midwest Region Consumer Price Index.

The recommended approach has similarities to the current avoided transmission approach in that it averages both the input costs (ATC rates) and escalation factor (construction cost growth) over a four-year period to mitigate impacts of year-to-year variability. For projecting values in future years, the recommended methodology uses the same approach as the current avoided transmission methodology and Focus' avoided capacity calculation; it applies the rate of

[8] https://www.oasis.oati.com/woa/docs/ATC/ATCdocs/budget.html#2022budgetupdate1.

[9] Cadmus reported difficulty in identifying transmission rates that were specific to Wisconsin Xcel customers. An approach relying on publicly available ATC rates specific to Wisconsin IOUs was preferred to an approach that required developing an assumption of Wisconsin-specific rates from an IOU that owns and operates transmission infrastructure in multiple states which cannot be easily disentangled in raw data.

[10] Most recently available Schedule 9 ATC Rate Projections provided by Oasis as of the time of this memorandum can be accessed here: 2024_ATC_YE123124_RatePhaseIn-010924.pdf (oati.com).

inflation of the Wisconsin Department of Transportation Chained Fisher Construction Cost Index in excess of the U.S. Bureau of Labor Statistics Consumer Price Index (CPI).[11] This particular approach in forecasting future values is preferred because it specifically accounts for the inflation rate of materials such as steel and cement that are used in large infrastructure projects, and which tend to inflate at different, often higher, rates than the overall CPI. This approach is intended to avoid underestimating avoided transmission costs because of their unique inflation profile, while factoring out baseline CPI inflation rates to avoid overestimating costs associated with inflation accounted for in other forms of avoided cost.

Table 2 shows the annual avoided transmission costs resulting from the EWG's recommended methodology compared to the annual avoided T&D costs calculated in Quad III using the current methodology. Cadmus produced avoided transmission values using the proposed methodology back to the first year of Quad III (2018) for illustrative purposes. Values extending into the future are shown because measures in the Focus portfolio are expected to produce benefits over their lifetime. Certain measures can have long effective useful lives (EULs). Forecasted values are used to estimate the stream of benefits of these measures accounting for their full EULs.

First-year kW reductions are valued at the amount shown for the corresponding year in the table. Future years' benefits are discounted at the Commission approved two percent discount rate when calculating the total stream of benefits of a given year's kW reductions.[12] For example, under the EWG's recommended Quad IV methodology, kW reductions achieved by a measure in 2024 are assigned an avoided transmission value of $65.40/kW-Yr. That measure is

[11] Bureau of Labor Statistics Midwest CPI Summaries are available here: Midwest CPI Summaries: Midwest Information Office: U.S. Bureau of Labor Statistics (bls.gov).

[12] The Commission set a 2.0 percent discount rate for purposes of assessing Focus' cost-effectiveness in its Quad IV Planning Process Final Decision of November 14, 2022. (PSC REF#: 516583.)

expected to continue to save demand into the future throughout its EUL. The future value of the kW reductions of that measure is discounted by two percent per year beginning in 2025. This discounting continues through the end of the measure's EUL such that the present value of the stream of benefits decreases with time due to the compounding effect of the discount rate. This approach is consistent with the compound discounting applied to other forms of avoided costs used for purposes of evaluating Focus' cost-effectiveness.

It should be emphasized that the Quad IV values resulting from the EWG's recommended alternative methodology rely on a different data source compared to the Quad III values. The Quad III values are derived from IOU transmission line investments reported during a four-year period corresponding to Quad III. The EWG's proposed Quad IV values are based on average transmission rates over a more recent four-year period. Table 2 shows that the results using the two different methodologies are comparable despite relying on different underlying input data.

The primary driver of higher forecasted avoided costs in years after 2024 under the proposed methodology is a higher rate of inflation observed in the calculation period for Quad IV relative to the rate of inflation observed in the calculation period for Quad III. The inflation rates factored into the proposed Quad IV avoided transmission costs cover a four-year period that experienced the inflationary impacts of the COVID-19 pandemic and recent sociopolitical events while the inflation rates factored into the Quad III costs covered a four-year period occurring prior to a time when the inflationary impacts of the pandemic and other recent events had materialized. While the proposed methodology yields higher avoided cost values in years after 2024 compared to the values derived using the Quad III methodology and inflation rate, this result is anticipated to have limited impacts on portfolio level cost-effectiveness under the

MTRC test because of the aforementioned impacts of a compounding discount rate to the stream of benefits and because avoided T&D benefits represent only a fraction (between 7.6 and 8.9 percent observed since 2020) of total portfolio benefits (Table 1).

Table 2. Comparison: Quad III Avoided T&D Costs to Proposed Method Avoided T Costs

Year	Actual Quad III Avoided T&D Costs ($/kW-Yr)	Proposed Quad IV Avoided T Cost ($/kW-Yr)
2018	$66.22	$57.36
2019	$66.28	$57.81
2020	$66.34	$57.30
2021	$66.40	$58.53
2022	$66.47	$60.18
2023	$66.54	$62.25
2024	$66.61	$65.40
2025	$66.69	$66.75
2026	$66.76	$68.13
2027	$66.85	$69.54
2028	$66.93	$70.97
2029	$67.02	$72.44
2030	$67.11	$73.93
2031	$67.21	$75.46
2032	$67.31	$77.02
2033	$67.41	$78.61
2034	$67.51	$80.23
2035	$67.62	$81.89
2036	$67.73	$83.58
2037	$67.85	$85.30
2038	$67.97	$87.07
2039	$68.09	$88.86
2040	$68.21	$90.70
2041	$68.34	$92.57
2042	$68.47	$94.48
2043	$68.61	$96.43
2044	$68.74	$98.42
2045	$68.88	$100.46
2046	$69.03	$102.53
2047	$69.17	$104.65
2048	$69.32	$106.81
2049	$69.48	$109.01
2050	$69.63	$111.27
2051	$69.79	$113.56

Commission Alternatives – EWG Recommended Avoided Transmission Cost Method

In fulfillment of Order Point #23 of the Commission's Final Decision of November 14, 2022, the EWG presents to the Commission for its consideration a recommended alternative method for calculating avoided electric transmission costs for the purpose of evaluating Focus. Consistent with Order Point #23, the EWG's recommended method was developed in coordination with a third-party, the Regulatory Assistance Project (RAP). The EWG's recommended method is an avoided transmission cost methodology as opposed to an avoided T&D methodology. The efforts of Cadmus, RAP, and the EWG did not identify a viable methodology for estimating distribution avoided costs that satisfy the EWG's preference for a straightforward calculation methodology that uses public and accessible data specific to Wisconsin and can be regularly and efficiently updated over time.

Alternative One is an option to approve the EWG's recommendation for an ATC rate-based avoided transmission cost approach as described in this memorandum. Alternative Two is appropriate if the Commission wishes to modify the EWG's recommended approach based on its discussion. Alternative Three is appropriate if the Commission does not wish to approve the EWG's recommended approach at this time, and continue to use the incremental cost approach it has used since Quad III in Focus, as illustrated in Figure 1 of this memorandum, until such time that the Commission approves an alternative methodology. Under Sub-Alternative A to Alternative Three, the Commission may direct EWG to propose a different methodology informed by its discussion and return the proposal for Commission decision later in the quadrennial period. Under Sub-Alternative B to Alternative Three, the Commission may take no action and maintain the current methodology for the remainder of the quadrennial period.

Alternative One: Approve the EWG's recommended methodology.

Alternative Two: Approve the EWG's recommended methodology with modifications.

Alternative Three: Do not approve the EWG's recommended methodology.

Sub-Alternative A: Direct the EWG to propose a different methodology consistent with the Commission's discussion.

Sub-Alternative B: Take no further action.

Alternative Four: Other action consistent with the Commission's discussion.

MH:JF:TK:JP:JS:bs DL: 02023792

Attachment: Attachment A – Cadmus Memorandum of 6/28/24

Memorandum

To: Mitch Horrie; Public Service Commission of Wisconsin
From: Kyland Narcisse, Brian Hedman, Matthew Wisnefske, and Amalia Hicks; Cadmus
Subject: Recommendations for Estimating Avoided Transmission and Distribution Costs
Date: June 28, 2024

Purpose

This memorandum summarizes the current T&D avoided cost methodology, describes alternative methodologies that may be considered, and suggests a recommendation for a revised avoided transmission (T) cost methodology.

Introduction

There are three main categories of avoided costs for energy efficiency programs: energy-related avoided costs, capacity-related avoided costs and non-energy impacts. Energy-related avoided costs refer to market prices of electric energy, losses, natural gas commodity prices, and other benefits associated with energy production. Capacity-related avoided costs refer to infrastructure investments, such as power plants (generation capacity avoided costs), transmission and distribution (T&D) lines (T&D capacity avoided costs), and pipelines (gas T&D capacity avoided costs).[13] Non-energy impacts refer to improvements in the environment, health, safety, productivity, asset value and other impacts that result from investments in energy efficiency.

Transmission capacity refers to the availability of the electric transmission system to transport electricity in a safe and reliable manner. In areas with insufficient transmission capacity available to support the transmission of lowest-cost electricity, there will be transmission congestion costs due to the need to use higher-cost generation to avoid the transmission constraint.

As with generation capacity, an energy efficiency program's impact on transmission capacity depends on how it generates savings during the times coincident with the transmission peaks. If an energy efficiency program reduces load at the time of the transmission system peak, it will result in reduced costs.

Energy efficiency programs may reduce transmission capacity costs in two ways:

Energy efficiency programs may passively defer needed transmission capacity investments if their operation for other purposes (e.g., customer bill reductions) results in lower load at the same time the

[13] Energy.gov. Accessed December 2023. Adapted from the "National Action Plan for Energy Efficiency." https://www.energy.gov/scep/national-action-plan-energy-efficiency
National Energy Screening Project. Accessed December 2023. Adapted from the "National Standard Practice Manual." https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

transmission facilities are at their peak. In these instances, the energy efficiency program may be attributed with a system-wide average for the transmission capacity benefit provided.

Energy efficiency programs may actively defer transmission capacity needs as part of a geographically targeted non-wires solution. The value of active deferrals is typically based on the actual deferral value of the avoided transmission project (i.e., the costs avoided if the wires investment is deferred for a certain number of years). There is often a minimum cost threshold for transmission projects to be considered for a non-wires solution; therefore, the value of active deferrals is typically higher than that of passive deferrals.

Distribution capacity refers to substation and distribution line infrastructure necessary to meet customer electric demand, and as such, the net impact of an energy efficiency program will depend on the cost associated with the specific type of distribution infrastructure being affected. If customer demand exceeds distribution capacity, it will require investments to increase distribution capacity to a level that preserves safety and reliability. The net effect of energy efficiency programs on distribution capacity depends on how they operate during the distribution system peaks.

Energy efficiency programs can either actively or passively help defer or eliminate the cost of needed distribution system investments by reducing net load during peak hours. For passive benefits, an energy efficiency program may have the effect of reducing net load despite operating for some other purpose (e.g., customer bill reduction). For active deferrals, a utility may incentivize energy efficiency programs to provide specific locational distribution capacity benefits.

The typical approach for quantifying the benefits of energy efficiency is to forecast long-term “avoided costs,” defined as costs that would have been spent if the energy efficiency savings measure had not been put in place. For example, if an electric distribution utility expects to purchase energy for $70 per megawatt-hour (MWh) on behalf of customers, then $70/MWh is the energy-related avoided cost. In addition, the utility may not have to purchase as much system capacity (generation capacity avoided costs) or make as many upgrades to the transmission system (transmission capacity avoided costs) or distribution system (distribution capacity avoided costs).

In its Final Decision in Quadrennial Planning Process IV (docket 5-FE-104), the Public Service Commission of Wisconsin (Commission) ordered that the Evaluation Work Group (EWG) or EWG and a third party present to the Commission for its consideration an alternative method, or multiple alternative methods, for calculating avoided electric T&D costs.[14] As a result, the EWG engaged the Regulatory Assistance Project (RAP) as a third party to advise on the development and consideration of the alternative methods. In this capacity RAP has collaborated with the EWG, and this memo reflects its input, guidance and its support of the memo’s recommendations.

[14] Public Service Commission of Wisconsin. November 14, 2022. Docket 5-FE-104: *Final Decision Quadrennial Planning Process IV*. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=453081

Current Methodology

The Commission's Final Decision of March 10, 2021, establishing Focus on Energy's current approach to calculating avoided T&D costs (docket 5-FE-101) states: "Calculating the benefits of Focus for Wisconsin ratepayers requires an understanding of the costs that are avoided when energy consumption and demand are reduced." In response to this order, the Focus on Energy EWG reviewed multiple approaches and data sources to calculate avoided T&D costs. The EWG concluded that an incremental cost approach relying on data reported in the Investor-Owned Utility (IOU) Annual Reports to the Public Service Commission of Wisconsin is consistent with approaches used in other jurisdictions and the results are in line with expectations. Furthermore, the method aligns with the EWG's recommendations favoring an approach that maximizes reliance on publicly available data sources that are regularly and reliably updated, uses straightforward calculations based on standard engineering and economic principles, ensures regional specificity, and can be developed and updated efficiently."[15]

Figure 1 outlines the steps used to derive T&D avoided costs through the incremental cost approach.

Figure 1. Current T&D Calculation Approach

$$T\&D\ Project\ kW = Project\ kVA * Power\ Factor$$

Establish hourly kW. Project kVA is the operating voltage. Power Factor is the ratio of actual power to apparent power in an AC circuit.

$$T\&D\ Project\ kW\ per\ Year = T\&D\ Project\ kW * 8{,}760$$

Annualize kW.

$$Cost\ per\ Mile = T\&D\ Project\ Cost\ (\$) \div T\&D\ Project\ Miles$$

$$T\&D\ Project\ Cost\ per\ Mile\ per\ kW\ per\ Year = Cost\ per\ Mile \div T\&D\ Project\ kW\ per\ Year$$

$$Annulized\ Cost\ per\ Mile\ per\ kW\ per\ Year = \frac{r * T\&D\ Project\ Cost\ per\ Mile\ per\ kW\ per\ Year}{1-(1+r)^{T\&D\ Project\ EUL}}$$

r is the rate. EUL is the expected useful life.

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[15] Public Services Commission of Wisconsin. March 10, 2021. Docket 5-FE-101: *Final Decision Quadrennial Planning Process III.* https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=406591, page 4.

To reduce the year-to-year cost variability in reported T&D investments, a four-year running average of the total miles of power lines and the annualized cost per mile per kilowatt-year are multiplied to get the average cost per kilowatt-year. For projecting values in future years, this approach escalates the most recent average Midcontinent Independent System Operating Cost of New Entry (CONE) value by a growth factor that considers inflation and construction costs. The growth factor is calculated by taking the four-year average of construction cost growth, as determined by the Wisconsin Department of Transportation in the Chained Fisher Construction Cost Index and subtracting inflation (U.S. Bureau of Labor Statistics Consumer Price Index, Midwest Region 1) over the same period.

While the Commission adopted the incremental cost approach recommended by the EWG in 2021, the EWG identified certain data limitations with its recommended approach. Most notably, the EWG that the information in the IOU Annual Reports was insufficient to determine if the T&D investment costs were representative of the costs avoided by Focus programs. In consideration of the data challenges identified by the EWG, the Commission directed its staff to pursue modifications to the IOU Annual Reports to improve the quality and transparency of the reported data. Staff explored options to modify IOU Annual Reports and found that since only two entities, American Transmission Company (ATC) and Norther States Power – Wisconsin (NSPW), own and operate transmission infrastructure in Wisconsin, it would be more practical to request data directly rather than pursue report modifications. Commission staff and Cadmus coordinated with ATC to request data identifying the primary purpose of the transmission line investments reported to the Public Service Commission of Wisconsin. ATC staff provided these data, and Cadmus was able to incorporate them into their annual review of avoided T&D costs. While these data are an improvement over the information reported in IOU Annual Reports, certain data issues persist, namely a need for additional detail to explain the cost per mile ranges observed and the fact that information on the primary purpose of the investment is not publicly available. Consequently, in its Final Decision in Quadrennial Planning Process IV, the Commission directed the EWG, or the EWG and a third party, to review alternative methods once again for calculating avoided T&D for its consideration during Quad IV.[16]

[16] See Order Point #23 in PSC REF#: 453081. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=453081

T&D Estimation Alternatives

The EWG established preferences for avoided T&D cost-calculation approaches that consider four factors: (1) the use of public and accessible data, (2) a straightforward calculation methodology, (3) region specificity, and (4) ease of future avoided T&D updates. Cadmus' research into alternative methodologies found that many jurisdictions rely on utility and other entity-reported investments into T&D resources as a main source of data. In its initial review of avoided T&D methods in 2020, Cadmus performed a literature review and stakeholder outreach to assess viable approaches to calculating avoided T&D costs for purposes of evaluating Focus programs. The primary resource reviewed was a 2014 Mendota Group report summarizing avoided T&D approaches used throughout the country.[17] In its assessment, the Mendota Group's report revealed a wide variation among utility/program calculations and concluded that there is no best practice method. Cadmus presented the alternative methodologies identified in the literature and a summary of the stakeholder outreach performed to the EWG in fall 2020. Through stakeholder outreach and EWG deliberations, the consensus recommendation to the Commission was the incremental cost approach presented in figure 1 above. Table 1 lists the approaches used in the Mendota Group's report.

Table 1. Mendota Group Methodologies

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	Uses costs and load growth for specific T&D projects based on a system planning study	Vermont Electric Company (2003) – focused on specific transmission upgrade	• Potentially more accurate • Uses specific project data to develop estimates • Forces consideration of distributed energy resources effects on project-by project basis	• Costly and time-consuming • May not be appreciably more accurate than other approaches • Dependent upon individual projects included in analysis

17 The Mendota Group, LLC. October 2014. *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments.* https://mendotagroup.com/wp-content/uploads/2024/04/PSCo-Benchmarking-Avoided-TD-Costs.pdf

Method	Brief Description	Examples	Strengths	Weaknesses
A mix of Historical and Forecast Information	Uses data on historical and forecast T&D investments, determines what is related to load growth, and weights the historical and forecast contributions	ICF tool used in the Northeast, Vermont Public Service Department variation	• Uses publicly available Federal Energy Regulatory Commission (FERC) Form 1 data • Easily calculated and updated • Uses a form of marginal costs • Addresses "lumpiness" of T&D investments • Used by multiple other states • Relies upon historical as well as forecast information	• Assumes it is possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability, and customer growth • Does not incorporate variability associated with time/location differences • Cannot readily handle low forecast growth
Current Values	Develops average cost to serve existing load by dividing each system's net cost by each system's peak capability	MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL)	• Uses publicly available FERC Form 1 data • Easily calculated and updated	• May tend to undervalue • Does not incorporate variability associated with time/location difference
Rate case marginal cost data with allocators	Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings	California IOUs	• Uses publicly available data (rate case portion) • Uses approach consistent with rate-making • Uses time and location-differentiated data • Uses marginal cost information	• Potentially costly and time consuming • May not be appreciably more accurate than other approaches • Somewhat assumes use of hourly avoided costs for Generation • Requires estimation of investments deferred by EE
Rate case marginal cost data	Use T&D marginal cost of service data from a most recent rate case	Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY)	• Uses publicly available data • Is approach consistent with rate-making • Uses marginal cost information	• May not be appreciably more accurate than other approaches • Requires estimation of investments deferred by EE

Method	Brief Description	Examples	Strengths	Weaknesses
IRP Method	Uses without and without EE runs to determine avoided transmission costs	Tucson Electric Power	• Is consistent with integrated resource plan	• Is highly dependent on IRP's model ability to calculate transmission costs • Requires integrated resource plan • Only updated as frequently as resource plan • Typically can only provide transmission
Averaging method	Take simple average of a selection of similar jurisdictions	Wisconsin Focus on Energy Market Potential Study (used Iowa) Northwest Conservation and Electric Power Plan (used 8 utilities)	• Uses publicly available data • Very easily calculated	• Must pick appropriate proxy utilities for averaging • Not specific to one utility
Simple Method	Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize	No current users	• Very simple • Provides real information from specific example • Can be done for transmission, distribution and sub-transmission	• Project may not be system representative • Must still determine what portion of increased capacity relates to load growth

Understanding that the Commission was interested in revisiting the avoided T&D methodology in Quad IV Planning, Cadmus presented several additional alternatives to EWG in March 2022. The EWG determined that it was reasonable to maintain the current approach through the remainder of Quad III, but supported further investigation into an improved methodology in Quad IV. Table 2 summarizes the additionally assessed alternative approaches. The right-hand column of Table 2 characterizes the alternative approaches according to the EWG's priority criteria it considers in developing its recommendation to the Commission: (1) the use of public and accessible data, (2) a straightforward calculation methodology, (3) region specificity, and (4) ease of future avoided T&D updates.

Table 2. Previously Evaluated T&D Calculation Approaches

Alternative Approach	Positive Aspects	Negative Aspects	Meet EWG Recommendation?
Central Midcontinent Independent System Operator (MISO) MTEP Cost Estimates	Leverage consistent data (relies upon MISO data as do other avoided cost estimates).	Inaccurate land cost assumptions (significant delta vs. actual). Corrections rely upon same current weak dataset. Does not address distribution costs.	(1) Yes, data are accessible (2) Yes (3) Yes (4) No, lacks distribution costs
Growth in T&D Cost/Peak Load	Straightforward approach. Can address distribution.	Depends upon consistently growing load/demand forecasts. Load or peak decreases results in negative Avoided Cost. Needs IOU data that has no consistent publicly available source – for costs, and loads.	(1) No, data are not consistently accessible (2) Yes (3) Yes (4) No
ATC Transmission Rates	Simplest of all. Strong set of historical data. High confidence in continued access to free, publicly available data. Very transparent. Actual amount one would (not) pay if load is (not) needed.	Does not address distribution costs. Uses FERC Form 1 data without insight into expenditures related to load growth.	(1) Yes, data are accessible (2) Yes (3) Yes (4) No, lacks distribution costs

Further, two methods outlined by Demand Side Analytics for Central Hudson Gas and Electric Corporation (Central Hudson) in 2018 and by Synapse Energy Economics for Massachusetts Energy Efficiency Program Administrators in 2020 did not use publicly available data sources. Instead, they used localized avoided T&D costs based on either predictive or historical data. A third method, used in Vermont, relied on semi-publicly available data but had other methodological factors that were difficult to employ.

Central MISO MTEP Cost Estimates

The Central MISO MTEP Cost Estimates approach uses MISO Transmission Expansion Plan cost estimates available annually as part of the existing process.[18] According to MISO, cost estimates are "intended to be inclusive of all costs required to implement the project—the total project implementation cost for a potential project. The total project implementation cost estimate includes the project cost (as further

[18] MISO Energy. April 2022. *Transmission Cost Estimation Guide*. 20220208 PSC Item 05c Transmission Cost Estimation Guide for MTEP22_Draft622733.pdf (misoenergy.org)

described in the MISO's guide), contingency, and allowance for funds used during construction (AFUDC)."[19] Project total cost can be calculated per the equation below:

$$\begin{aligned} &Total\ Project\ Implementation\ Cost\ Estimate \\ &\quad = Project\ Cost\ Estimate + Contingency + AFUDC^{20} \end{aligned}$$

Where:

Contingency = a cost adder to account for uncertainty in the cost estimate

AFUDC = a cost adder to account for the cost of debt or equity needed to build the project.

Cadmus has not conducted more detailed research into this methodology due to significant observed inaccuracies in cost assumptions. This methodology uses regional average length costs, which are not reflective of land costs in Wisconsin. For this to be a viable option for Wisconsin, more local data would be needed. Further, while this approach would be Wisconsin-specific, accessible, and straightforward, it does not address distribution costs.

Synopsis: This alternative meets three out of the EWG's four criterion and should be considered a workable methodology.

Growth in T&D Cost/Peak Load

The Duke Energy Indiana, LLC approach described in the March 2020 testimony before the Indiana Utility Regulatory Commission, like many methodologies discussed in this memo, does not provide a detailed breakout of specific data inputs used to calculate avoided T&D.[21] This approach relies on a system average calculation using IOU data for average load growth capital additions for both transmission and distribution. The general steps are as follows:

1. Calculate average load growth capital additions
2. Calculate an annual fixed charge rate
3. Multiply Step 1 by Step 2 to calculate a $/kW avoided transmission and distribution[22]

Results are escalated using the Handy Whitman North Central Construction Cost Index for Transmission and Distribution. This approach shares some similarities with the current method utilized in Wisconsin,

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19 MISO Energy, *op. cit.*, p. 4.

20 MISO Energy, *op. cit.*, p. 5.

21 Indiana Utility Regulatory Commission. March 19, 2020. IURC Cause NO. 43955 DSM-8: *REBUTTAL TESTIMONY OF JAYME T. STEMLE SENIOR RATES & REGULATORY STRATEGY ANALYST DUKE ENERGY BUSINESS SERVICES LLC ON BEHALF OF DUKE ENERGY INDIANA, LLC.* https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/07ebe376-a86a-ea11-a811-001dd801892c/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=43955%20DSM%208%20Rebuttal%20Testimony%20of%20Jayme%20T%20Stemle%2003192020.pdf, page 3.

22 *Ibid.*

but without access to publicly available data it cannot be easily replicated and would, in theory, be subject to the same limitations as the current method in terms of backward-looking data and dependence on variation in infrastructure construction totals.

Without access to the corresponding data, a more detailed data input and calculation break out are not possible at this time. This approach would theoretically be Wisconsin-specific and straightforward, but it is not easily updated nor is the data publicly accessible.

Synopsis: This alternative meets two out of the EWG's four criteria and is a less workable methodology than other alternatives.

ATC Transmission Rates

The ATC Transmission Rates methodology stems from the 2015 New York State Electric and Gas (NYSEG) Marginal Cost of Electric Delivery Service document prepared by NERA Economic Consulting.[23] This is a rate-based avoided transmission approach using NYSEG's Transmission Service Charge (TSC), flat values in MWh sold or transported, as marginal transmission cost.[24] The data used includes the average of recent historical TSC charges in $/MWh and factors to account for losses using estimates of average marginal energy losses by period. These marginal transmission costs are calculated for different periods and voltage rates.

Like other methodologies, specific calculation information is not available. With Wisconsin-specific data sources, rates can be annualized to calculate an annual avoided transmission cost. The Oasis ATC Schedule 9 rate data is an appropriate Wisconsin-specific rate data source.[25] It is worth noting that this method uses American Transmission Company FERC Form 1 data that are adjusted using 13-month averages and does not match filed FERC Form 1 data by year exactly, but are substantially similar. Rates are represented for the following utilities: Madison Gas & Electric Company, Wisconsin Power & Light, Wisconsin Public Service, Wisconsin Energy Corp, and the Upper Peninsula Power Company. Though Northern States Power Company-Wisconsin transmission rates aren't captured in this methodology, these five utilities are sufficiently broad based to derive a state-wide avoided transmission cost for the assessment of cost-effectiveness for Focus on Energy.

The general steps for calculating avoided transmission for Wisconsin are as follows:

1. Refer to the monthly Rate Calculation ATC rate in $/kW/month provided on Schedule 9 from the most recent ATC Rate Projections provided by Oasis' website (see example link[26])

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23 NYSEG and NERA Economic Consulting. May 2015. *Marginal Cost of Electric Delivery Service*. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B7CD6B412-8916-4045-A785-D317597D6BC8%7D

24 NYSEG and NERA Economic Consulting, *op. cit.*, p. 3.

25 American Transmission Company. October 11, 2023. *American Transmission Company Budget and Rates Page.* http://www.oasis.oati.com/woa/docs/ATC/ATCdocs/budget.html#2022budgetupdate1.

26 2024_ATC_YE123124_RatePhaseIn-010924.pdf (oati.com)

2. Annualize this by multiplying by 12 months
3. Escalate using the difference between the Wisconsin Department of Transportation Chained Fisher Construction Cost Index and the Bureau of Labor Statistic's Midwest region Consumer Price Index

The ATC Transmission Rates methodology is the simplest of the researched approaches. Wisconsin-specific rate data are available, calculation is straight-forward and easily updated, and data are publicly obtainable. However, this source does not provide information for avoided distribution and there is not a clear indication of how much capital expenditure is load growth related in the FERC Form 1 data. Oasis ATC rates are updated mid-October every year**.** These rate changes do not highly vary year-to-year. Similar to the other Focus on Energy avoided costs, avoided transmission would be calculated in the first year of each Quadrennium to set values for the evaluation period and would be reviewed annually to determine the appropriateness of the values should substantial changes occur. Like the previously approved avoided T&D methodology, the avoided transmission cost is calculated using the 4-year rolling average of annualized rates.

Synopsis: This alternative meets three out of the EWG's four criterion and should be considered a workable methodology.

Central Hudson Probabilistic Forecasting

The 2018 probabilistic forecasting methodology used by Central Hudson Gas and Electric Corporation (Central Hudson) in New York is based on assigning values to load forecast possibilities with the intent to reflect uncertainty more accurately.[27] This methodology includes the following data, all of which was provided by Central Hudson to their DSM evaluator except for weather data:[28]

- 2010-2017 substation and transmission area hourly interval data
- 2010-2017 Dutchess County Airport weather data
- 1-in-2 weather year peak conditions data
- 1-in-2 forecasted Central Hudson System loads
- Design rating information for each substation and transmission area

[27] Demand Side Analytics. July 2018. *2018 Central Hudson Location Specific Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods*. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={56F63629-609A-4A28-A29F-508284C7136A}

[28] Demand Side Analytics. July 2018. *2018 Central Hudson Location Specific Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods*. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={56F63629-609A-4A28-A29F-508284C7136A}, page 9.

- Costs for infrastructure upgrades

Probabilistic forecasting is broken down into six main steps:

1. Estimate historical load growth controlling for differences in weather, day of week, and season
2. Simulate potential load growth trajectories
3. Identify the timing of infrastructure investments for each simulation run, location, and year
4. Identify the magnitude of demand management needed to maintain loads below design rating
5. Model T&D infrastructure costs with and without demand management for each simulation run, location, and year
6. Calculate avoided costs per kilowatt for each simulation run and location

Step 1 uses econometric models to estimate historical load growth as percentages for weather-normalized loads. Year-to-year growth patterns determine the trend and variability of load growth patterns. Step 2 develops load growth forecasts based on the historical growth pattern from Step 1 using 5,000 Monte Carlo simulations per substation and transmission area by year. These simulations assign confidence bands for identifying likelihood. Steps 3, through 6 are completed for each of the 5,000 simulations per location. Step 3 assigns the timing of infrastructure investment by assuming upgrades occur the year after forecast loads exceed the design rating for two consecutive years. Step 4 assumes demand resources remained in use for up to 10 years or until the demand reduction needed exceeded 20%, whichever occurred first. Step 5 assigns annualized revenue requirements of the infrastructure upgrade (costs divided by estimated life) in the third year following the design rating being exceeded for two consecutive years. Finally, in Step 6, avoided costs per kilowatt are calculated based on the likelihood that reducing loads below the design rating would defer or avoid growth-related infrastructure upgrades using the following equation:

$$Total\ Deferral\ Value\left(\frac{\$}{kW}\right)$$
$$= \frac{Capital\ Cost\ (\$) * Revenue\ Requirement\ Adjustment * \left(1 - \left(\frac{1+i}{1+r}\right)^{\Delta t}\right)}{Load\ Reduction\ Need\ for\ Deferral\ (kW)}$$

Where:

i = the inflation rate
r = the discount rate
Δt = the deferral period[29]

[29] Demand Side Analytics. July 2018. *2018 Central Hudson Location Specific Transmission and Distribution*

$$Annualized\ Deferral\ Value = Total\ Deferral\ Value\left(\frac{\$}{kW}\right) * \frac{(r-i)}{(1+r)} * \frac{(1+r)^{n}}{(1+r)^{n}-(1+i)^{n}}$$

Where:

The deferral value = annualized for each simulation run and location
i = the inflation rate
r = the discount rate
n = the number of deferral years[30]

$$Expected\ Avoided\ Cost_{l,t} = \frac{\sum_{r=1}^{5000} \$ \frac{kW}{year_{l,r,t}}}{5000}$$

Where:

Expected avoided costs for all simulation runs (*r*) for each year (*t*) at an individual location (*l*)[31]

Probabilistic forecasting allows for increased flexibility in the quantification of managing demand. With detailed location data, the avoided costs derived are highly specific. However, the resources, modeling, and methodology described are comparatively intensive. Replicating yearly avoided T&D costs requires significant coordination among data sources, modeling expertise, and scenario runs. An additional characteristic of this approach is that avoided T&D can potentially be zero, depending on the probability of infrastructure upgrades being required in a particular year.

Synopsis: This alternative meets two out of the EWG's four criteria, and is a less workable methodology than other alternatives.

Synapse Energy Economics Localized T&D

The 2020 localized T&D methodology detailed by Synapse Energy Economics for Massachusetts Energy Efficiency Program Administrators is based on load forecasts provided by utility data requests such as load forecasts and investment expenditures.[32]

This localized T&D methodology is broken down into five steps:

1. Identify target location and required load reduction
2. Establish type and required duration of load reduction

Avoided Costs Using Probabilistic Forecasting and Planning Methods. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={56F63629-609A-4A28-A29F-508284C7136A}, page 16.

30 *Ibid.*

31 *Ibid.*

32 Synapse Energy Economics, Inc. May 1, 2020. *AESC Supplemental Study Part II: Localized Transmission and Distribution Benefits Methodology.* https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_II_Localized_TD.pdf

3. Calculate costs avoidable by load reductions
4. Calculate benefits of targeted load reduction by target area
5. Calculate avoided cost (cost per kilowatt)

Step 1 collects utility peak load forecasts of five to 10 years for distribution and 10 years for transmission planning. It also establishes system planning criteria, such as voltage ranges, loading criteria, and phase balancing, at local levels to determine the infrastructure required to maintain standards under normal and contingency situations. Step 2 determines the magnitude, duration, and coincidence of the load reduction through system power flow analysis as compared to the location and timing of baseline solutions. Step 3 determines the costs of traditional engineering solutions avoidable by load reductions, such as load growth and reliability. Step 4 calculates the reduced present value of deferred expenditures using the formula below to calculate the real carrying cost, which is then multiplied by the cost of the investment to reach the annualized expenditure.

$$RCC = WACC + income\ tax + property\ tax + insurance + O\&M$$

Where:

RCC	=	the real carrying cost (%)
WACC	=	the weighted average cost of capital
income tax	=	the income tax rate
property tax	=	the property tax rate
O&M	=	the operations and maintenance rate[33]

Finally, localized avoided T&D (cost per kilowatt per target area) is calculated in Step 5 by dividing the present value of deferral or avoidance benefit by the required load reduction to achieve the deferral or avoidance.

This methodology addresses both avoided T&D and provides very detailed localized avoided costs. Like the Central Hudson probabilistic forecasting methodology, this localized T&D method uses specific locational utility data to estimate likely load reduction needed to defer investment. Location-based analysis requires significant data collection efforts from utilities, which is not in line with preferences established by the EWG at this time. Further, it would be difficult to update this avoided cost yearly, as the method does not use publicly available data, and requires comparatively extensive modeling efforts.

Synopsis: This alternative meets two out of the EWG's four criteria, and is a less workable methodology than other alternatives.

[33] Synapse Energy Economics, Inc. May 1, 2020. *AESC Supplemental Study Part II: Localized Transmission and Distribution Benefits Methodology.* https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_II_Localized_TD.pdf, *page 9.*

2021 AESC Report

The 2021 Avoided Energy Supply Components (AESC) in New England Report adopted in Vermont describes an alternative approach to calculating avoided T&D using neither the probabilistic nor localized T&D methodologies described above.[34] The AESC report uses historical data from ISO New England's transmission cost allocation (TCA) for load-related investments using pool transmission facilities (PTF) data.

The general steps for calculating avoided T&D using the AESC method are as follows:

1. Determine actual or expected relevant load growth in analysis period (MW)
2. Estimate load-related investments in dollars incurred to meet the load growth
3. Divide results of Step 2 by the result of Step 1 to determine the cost of load growth in cost per megawatt or cost per kilowatt
4. Multiply Step 3 by a real-levelized carrying charge to derive an estimate of the avoidable capital cost (cost per kilowatt-year)
5. Add an allowance for the operation and maintenance of the equipment to derive the total avoidable cost (cost per kilowatt-year)

The report does not enter specifics on what data are required to calculate each step, but the approach uses ISO TCA PTF data for both T&D avoided costs in Vermont. Without further visibility into the methodology, it is not possible to search for an alternative public data source applicable to Wisconsin territory. Note that AESC avoided costs assume no energy efficiency programs are implemented in the future. A benefit to this methodology is that as a non-localized approach, it is simpler to apply a statewide avoided cost. While simpler, in theory, than the Central Hudson probabilistic forecasting and Synapse Energy Economics localized T&D approaches, this approach also does not comport with current EWG guidelines requiring publicly available data which can be updated regularly with relative ease.

In a recent rate case for Wisconsin Power and Light (WPL), Renew Wisconsin's Dr Divita Bhandari described a very similar methodology which theoretically could be used to determine T&D avoided costs.[35] That revised approach, however, does not meet current EWG criteria, in that it requires the arbitrary definition of load adding projects based on an estimate of projects not explicitly defined as "load growth" by ATC. Further, this approach returns very similar per-kW avoided costs as the simpler and more straightforward approach discussed above utilizing ATC transmission rates.

Synopsis: This alternative meets two out of the EWG's four criteria, and is a less workable methodology than other alternatives.

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[34] Synapse Energy Economics, Inc. May 14, 2021. *Avoided Energy Supply Components in New England: 2021 Report*. https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

[35] See PSC REF#: 432709 at 14.

The literature review did not identify any other applicable public data sources outside the ATC data used in Focus on Energy's current avoided T&D methodology. Table 3 summarizes the pros and cons of Cadmus' literature review of these three alternate methodologies.

Table 3. Literature Review Alternate Methodology Pros and Cons

Alternative	Positive Aspects	Negative Aspects	Meet EWG Recommendation?
Central Hudson Probabilistic Forecasting (New York)	• Increased flexibility in managing demand • Detailed, localized avoided T&D results	• Requires utility data • heavy modeling, does not produce statewide values	(1) No (2) No (3) Yes (4) No
Synapse Energy Economics Localized T&D (Massachusetts)	• Detailed, localized avoided T&D results	• Requires utility data • heavy modeling, does not produce statewide values	(1) No (2) No (3) Yes (4) No
2021 AESC Report (Vermont)	• Uses regionally available data • Produces statewide value	• No equivalent Wisconsin data source	(1) Yes (2) No, lacking methodology visibility (3) No (4) No

Summary and Recommendation

Cadmus' literature review of T&D methodologies adopted in other jurisdictions found that most approaches based on localized T&D methodologies do not align with the EWG's current preferences. Public data availability remains a primary concern for the EWG, as does methodological simplicity, and statewide applicability. The current Focus on Energy methodology using the incremental cost approach, which leverages recent ATC public annual transmission investments, remains the only currently publicly accessible data for avoided T&D cost calculation that meets EWG selection criteria.

However, the current T&D methodology used in Wisconsin assigns projects to "transmission" or "distribution" based solely on the voltage level reported on the PSC IOU Annual Report Data Website; voltage thresholds above 40kV are assigned as transmission and below that threshold are classified as distribution.[36] This distinction is made under the current avoided T&D methodology to separate benefits accruing from larger transmission projects from smaller local distribution projects, but the threshold is somewhat arbitrary. The absence of distinct utility-owned and operated distribution data would more appropriately characterize the output of the current methodology as avoided transmission costs as opposed to avoided T&D costs. Exclusion of these data under the current methodology potentially reduces the accuracy of current avoided T&D calculations. Unfortunately, the literature review did not identify a public distribution data source that is appropriate for Wisconsin-specific avoided distribution calculations.

Among all of the alternatives studied, only two meet three out of the four EWG criteria. Neither of these alternatives address distribution costs, but the remaining three criterion are comparable. Table 4 summarizes these two alternatives.

[36] The transmission line statistics report spreadsheet does not include any projects with operating voltages between 35.1 and 45.9 kV. The analysis uses 40 kV as the threshold for determining whether a project is transmission or distribution to avoid any potential for confusion on whether 35 kV projects are being included or excluded as distribution projects.

Table 4. Summary of the Leading Alternatives

Alternative	Positive Aspects	Negative Aspects	Meet EWG Recommendation?
Central Midcontinent Independent System Operator (MISO) MTEP Cost Estimates	• Leverage consistent data (relies upon MISO data as do other avoided cost estimates).	• Inaccurate land cost assumptions (significant delta vs. actual). Corrections rely upon same current weak dataset. Does not address distribution costs.	(1) Yes, data are accessible (2) Yes (3) Yes (4) No, lacks distribution costs
ATC Transmission Rates (Recommended)	• Simplest of all. Strong set of historical data. High confidence in continued access to free, publicly available data. Very transparent. Actual amount one would (not) pay if load is (not) needed.	• Does not address distribution costs. Uses FERC Form 1 data without insight into expenditures related to load growth.	(1) Yes, data are accessible (2) Yes (3) Yes (4) No, lacks distribution costs

Based on a review of the current literature, EWG guidance, and public data availability, Cadmus recommends that Focus on Energy revise the approach to calculate avoided transmission costs using ATC annual transmission statistics available on the Oasis ATC website using the ATC Transmission Rate methodology.[37] This recommendation is based on the fact that the ATC alternative is both simpler and more accurate. The most substantial modification in the methodology is the exclusion of distribution as a separately included category of avoided costs, focusing strictly on the development of the more clearly definable transmission benefits. Consequently, Cadmus recommends that, should the EWG agree with its recommended approach, the EWG's proposal to the Commission should convey this distinction and use terminology that appropriately describes the benefits that are estimated. Cadmus will continue to monitor the literature and industry guidance for an appropriate distribution benefit data source throughout the coming quadrennium.

Table 5 lists the currently used avoided T&D values and the new recommended method avoided transmission (T) values from 2018 through 2051 using the revised approach. In CY 2022, avoided T&D benefits were $52,382,582 dollars, representing about 9% of mTRC benefits in the Focus on Energy portfolio. While the new methodology yields a higher avoided cost forecast over time, the impact on the overall portfolio is not substantial and is not expected to meaningfully alter the portfolio level mTRC results. The primary driver of increasing avoided costs under the revised methodology is the increased rate of inflation occurring during the calculation period, which was higher than inflation in the prior quad.

[37] American Transmission Company. October 11, 2023. *American Transmission Company Budget and Rates Page.* http://www.oasis.oati.com/woa/docs/ATC/ATCdocs/budget.html#2022budgetupdate1.

Table 5. Quad III Avoided T&D Costs Compared to Recommended Method Avoided T Costs

Year	Actual Quad III Avoided T&D Cost ($/kW-Yr)	Proposed Quad IV Avoided T Cost ($/kW-Yr)
2018	$66.22	$57.36
2019	$66.28	$57.81
2020	$66.34	$57.30
2021	$66.40	$58.53
2022	$66.47	$60.18
2023	$66.54	$62.25
2024	$66.61	$65.40
2025	$66.69	$66.75
2026	$66.76	$68.13
2027	$66.85	$69.54
2028	$66.93	$70.97
2029	$67.02	$72.44
2030	$67.11	$73.93
2031	$67.21	$75.46
2032	$67.31	$77.02
2033	$67.41	$78.61
2034	$67.51	$80.23
2035	$67.62	$81.89
2036	$67.73	$83.58
2037	$67.85	$85.30
2038	$67.97	$87.07
2039	$68.09	$88.86
2040	$68.21	$90.70
2041	$68.34	$92.57
2042	$68.47	$94.48
2043	$68.61	$96.43
2044	$68.74	$98.42
2045	$68.88	$100.46
2046	$69.03	$102.53
2047	$69.17	$104.65
2048	$69.32	$106.81
2049	$69.48	$109.01
2050	$69.63	$111.27
2051	$69.79	$113.56

Future Research

Distribution Avoided Costs

Further discussion among stakeholders and researchers is needed to determine an appropriate standalone methodology for distribution avoided costs. At present, no identified process appears capable of meeting the criteria set by EWG to use public and accessible data, has a straightforward calculation methodology, is specific to Wisconsin, and provides easy calculation of future avoided T&D updates. The EWG recommends continued investigation and research to develop a methodology that meets these four criteria specific to avoided distribution and return to the topic at regular intervals.

Distributed Energy Resources and Distributed Generation

Focus on Energy's portfolio measure mix, along with the broader electrification and fuel switching landscape, is rapidly changing. This will require further dedicated research to accurately determine how these changes will impact distribution avoided costs.

Emerging measures and program designs, such as residential or small commercial rooftop solar, electric vehicles, battery storage, and microgrids, might potentially require a different set of avoided cost considerations than more traditional energy efficiency programs. The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (DERs) gives an overview of benefits and costs associated with transmission and distribution related to energy efficiency and distributed generation.[38] Energy efficiency impacts to transmission typically show as benefits while it is more mixed for distributed generation due to potential negative effects on peak demand.[39, 40] For the consideration of any avoided T&D values, it is worth considering the system impacts of both energy efficiency and distributed energy generation and storage resources.

Currently, there are no short- or medium-term plans to expand the Focus on Energy portfolio of programs to include large or grid scale solar, battery, or other DER program measures. The current portfolio incents only those measures that do not require a "step-up" in connection from a participating residential or small commercial site. If the program were to offer such measures, it is likely that there would have to be substantial incentive costs associated with covering the costs of upgraded energy infrastructure. Further, there is currently no evidence that utilities or program administrators will bear the full or even majority of upgrade costs, as many projects requiring capacity upgrades are often paid for by participating customers.

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38 National Energy Screening Project. Accessed March 2024. Adapted from the "National Standard Practice Manual." [NSPM-DERs_08-24-2020.pdf (nationalenergyscreeningproject.org)]

39 National Energy Screening Project, *op. cit.*, p. 6-3.

40 National Energy Screening Project, *op. cit.*, p. 8-3.

Cadmus recommends continuing the practice of including transmission benefits for eligible renewable projects when calculating cost effectiveness for Focus on Energy until Wisconsin utilities start finding substantial evidence of reverse flow on their distribution or transmission resources and an increase in system costs. There is currently no evidence that transmission avoided costs are negatively impacted by any of the measures incented by the renewable or DER offerings in the Focus on Energy portfolio. Cadmus also recommends revisiting this topic regularly as more renewable energy measures and other DERs grow as a portion of the portfolio. Areas of potential research may include: (1) the number of feeders and substations where DER and Distributed Generation penetration is high, (2) the number of hours in the day when reverse flow is occurring, and importantly (3) the number of feeders and substations that have reached their thermal limits for reverse flow and would require upgrades, and (4) the EWG and its partners approve a methodology determining specific distribution avoided cost benefits.