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Comments on *Washington Utilities NEM Evaluation-Draft Results*

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on behalf of the Washington Solar Energy Industries Association

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M.Cubed, founded in 1993, provides economic and public policy consulting services to public and private sector clients. Practice areas include water energy utility resource planning, ratemaking, water and resource use efficiency, conservation measures, project impact analysis, natural resource allocation policies, and environmental plan preparation and review. Dr. McCann has testified over 50 times on electricity, air quality, water supply and other regulatory and planning matters.

PREFACE

These comments address the draft report prepared by E3 Consulting on behalf of a consortium of Washington electric utilities to evaluate the State's net energy metering (NEM) program for customer-generators. M.Cubed has prepared these remarks on behalf of the Washington State Energy Industries (WASEIA).

There are significant flaws in the report's methodology and technical execution. The study's findings are not sufficiently substantiated, and often draw conclusions beyond both the scope and analysis of the study. Much more work is required before being able to arrive at a satisfactory resolution of the required analysis.

INTRODUCTION

The electricity market is in flux, due to technology innovation, changing utility-customer relationships, and growing impacts of climate change on the grid. Meanwhile, the principles used in the industry to guide cost allocation for retail rate design have largely been static for fifty years.[1] Those now-quaint doctrines held that marginal costs reflecting market values could be captured entirely in the average incremental energy cost or market clearing price and the cost of new generation capacity to meet the single highest peak load hour of demand. The belief was that marginal generation costs could be reflected simply as a supply-side matter represented through two proxy measures. That simple world may have held for a period, but is no longer a reality.

The world, and electricity sector, have changed profoundly in the last 25 years. Hourly electricity markets have not delivered on their envisioned promises as they do not economically incent necessary new capacity addition without regulatory intervention, and have not incorporated environmental costs sufficiently to drive clean energy investments alone. Large-scale fossil fuel generation is being replaced by more dispersed renewables, storage, and distributed energy resources (DERs). These new technologies enable customers to produce their own energy and to substantially or fully escape reliance on the centralized utility grid. The era of the "prosumer" is upon us.

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[1] Alfred E. Kahn, 1988, The Economics of Regulation: Principles and Institutions, Cambridge, Massachusetts; London, England: MIT Press; National Economic Research Associates, 1977, "A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States," Prepared for EPRI Rate Design Study.

In the past several years, electricity systems have experienced several major multi-hour and multi-day outages, most notably in California and Texas, for reasons other than a failure to have sufficient installed capacity to meet the single highest peak load: (1) rolling blackouts in August 2020 in the area served by the California Independent System Operator (CAISO) due to a mix of market actions during a 1-in-35 year weather event while several thousand megawatts of capacity remained available;[2] (2) public safety power shutoffs (PSPS) to mitigate potential wildfire hazards in California utilities' service areas, sometimes lasting for days at a time;[3] and (3) widespread rolling outages in Texas caused by extreme freezing weather.[4]

These emerging and challenging cost-of-service consequences are not adequately captured in this study which crams the prosumer into the old paradigm previously discussed. We recommend the State avoid committing to a single specific approach that will have to be soon cast aside as technology evolves further.

Instead, policymakers should adopt the profound advice of James Bonbright, as often cited in regulatory proceedings.[5] This sage advises "gradualism" in any changes to Washington State policy, so that customers are able to invest with certainty, and technology is able to continue its advance.

METHODOLOGICAL ISSUES

Questions about the study framing

The study's first issue is its framing. It was initially put forward as a cost-shift analysis, but then the authors began to bolt onto their work elements of a value of distributed solar study. The mix of different perspectives used in the analysis reflects this confusion. The split focus of the authors between cost shift, and value of distributed solar, results in three possible frames—they should choose one:

1. A classic cost of service study that takes the current system and revenue requirements as static, assumes that it has been built out optimally, and applies standard cost allocation factors to determine customer revenue responsibility. This type of study ignores the past benefits created through displaced infrastructure investment and lower energy consumption so it overestimates the actual cost shift that has occurred.

2. An assessment of future costs and benefits, with changes in resources and investments, and projected customer usage and resource options. This framing is implied by the use of forecasted 2030 prices in the study. Unfortunately, the report's approach fails to acknowledge that the

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2 "California begins rolling blackouts after first Stage 3 emergency since 2001," Los Angeles Times, August 14, 2020, https://www.latimes.com/california/story/2020-08-14/la-me-statewide-power-outages-warning; and California ISO, CPUC and CEC, Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave, http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf, January 13, 2021 (included as Attachment A hereto).

3 "Nearly half a million PG&E customers to lose power amid planned fire-safety shut-offs Sunday," San Francisco Chronicle, https://www.sfchronicle.com/bayarea/article/Lafayette-Orinda-Moraga-brace-for-PG-E-outages-15670411.php, October 24, 2020; and Decision 19-05-042.

4 "Millions in Texas, Oklahoma without power as grid operators call for conservation," Utility Dive, https://www.utilitydive.com/news/millions-in-texas-oklahoma-without-power-as-grid-operators-call-for-conser/595122/, February 16, 2021.

5 James C. Bonbright, 1961, Principles of Public Utility Rates, New York City: Columbia University Press; Kahn (1988).

current investments by customers are sunk costs based on expectations about utility rates at the time the solar was installed.

3. An assessment of historic costs and benefits using contemporaneous market values and avoided investments as well as changes in customer usage and resources. This framing is implied in the report by the use of historic customer and DER installation data such as costs. To execute this framing completely the authors would have needed to use historic forecasts and costs. This latter element is missing from this study.

The study's methodology uses forecasted 2030 generation market prices, current rooftop solar costs with no accounting for projected cost reductions, which are then applied to increasing solar installations. There is no accounting for displaced infrastructure, resources (e.g., energy efficiency spending) and greenhouse gas (GHG) emissions in the past. Mix and matching as the authors have, leads the study to an overestimation of the cost-shift, and wide misses of the other elements of the value of distributed solar.

An important missing element includes changes in the electricity market environments, e.g., increased addition of batteries and rate designs that better address time and location costs/benefits. The value of distributed solar in the past when these installation decisions were made is not the same as the value going forward. We encourage the authors to make that distinction.

A cost-shift study is not a value of distributed solar study

A cost-shift study is a ratepayer-impact measure (RIM) or a "no loser" test. This perspective is clearly the motivation and emphasis of this study. Ironically RIM tests are no longer used for energy conservation or efficiency measures in Washington. Instead, Washington uses the total resource cost test (which is defined to match a societal cost test) as a primary assessment, and utility cost as a secondary test.[6] Importantly, distributed solar generation is defined as energy conservation in Washington State law for public buildings.[7] Given these legal specifications, this study does not conform with the standard for evidentiary analysis in this state. The report at a minimum should acknowledge upfront its failure to follow the specifications required.

The State's energy efficiency programs would fail the ratepayer impact test using this methodology

We might for example apply this cost-shift perspective to energy efficiency program spending by the three investor-owned utilities (IOUs) in the state. Because the benefiting customers are a small portion of the total customer base, there is a cost shift from those customers through the utility rebates to other non-participating customers. Avista, Pacific Power and Puget Sound Energy (PSE) collectively are spending $175 million to reduce energy loads by 379,000 megawatt-hours (MWH).[8] Using an expected

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[6] See ACEEE, "State and Local Policy Database: Evaluation, Measurement & Verification," https://database.aceee.org/state/evaluation-measurement-verification.

[7] RCW 43.19.670 - Energy conservation—Definitions.
(3) "Energy conservation measure" means an installation or modification of an installation in a facility which is primarily intended to reduce energy consumption or allow the use of an alternative energy source, including:
(e) Solar space heating or cooling systems, solar electric generating systems, or any combination thereof;
(f) Solar water heating systems;
(https://app.leg.wa.gov/rcw/default.aspx?cite=43.19.670)

[8] See https://www.utc.wa.gov/consumers/energy/company-conservation-programs.

average life of 10 years[9] and PSE's cost of capital,[10] the average utility contribution is $66.23 per MWH. The NEM Avoided Costs Model developed for the report[11] shows an avoided cost value for 2023 of $40.56 per MWH. That gives a net cost to ratepayers of $25.67 per MWH in direct payments, resulting in direct payment from non-participants to participants of these energy efficiency programs of $9.7 million per year.

Additionally, then there are the lost sales revenues that are foregone contributions to the "fixed" transmission and distribution costs. Again, other customers would have to pick up those cost obligations using the rationale in the study. Applying PSE's average rate and subtracting the avoided costs, the avoided bill payments amount to $31.5 million. All of that spending from energy efficiency programs are in fact a "cost shift" from all ratepayers to a small group of ratepayers who benefit through reduced bills.

In total the apparent cost shift is $41.2 million in 2023 for just the three IOUs' ratepayers. That would easily exceed the $43 million purportedly, as per the study, shifted from customer-generators to non-customer-generators. Why do the authors of this study not push for a significant revision of the state's energy efficiency programs due to the apparent inequity? Because *increasing* energy efficiency investment is one of the cornerstones of the State's climate action policies.

This study purports to assess cost shifts from net metered solar, but, as illustrated by using energy efficiency programs, it does not actually do that at all. The study conflates the concepts of *cost shift* and *revenue shift*. A *cost shift* is when one set of ratepayers pays more to benefit another set of ratepayers. Most utility conservation programs include both cost shift and revenue shift. The cost shift is in the form of fees assessed to all ratepayers to subsidize conservation measures for some ratepayers. This is considered acceptable in order to accomplish the social good of reducing energy consumption. The reduced energy consumption results in reduced energy sales and thus revenue for the utility, which is the revenue shift.

As a form of conservation, net metered solar reduces energy consumption from the grid and thus utility revenue. This should be considered a benefit as it is with other conservation measures, not a cost. Additionally, unlike other conservation methods, net metered solar provides this benefit with no fees assessed to other ratepayers. This study calculates the magnitude of the conservation benefit of net metered solar, but then asserts that it is not a benefit, but a cost shift. An honest assessment of any ratepayer costs from NEM systems would include actual utility costs, not reduced sales from unsubsidized conservation.

The underlying premise of this study revives the opposition raised by utilities in the 1970s opposing conservation efforts because of high fixed costs and the supposed immutability of the grid. As Washington has demonstrated by maintaining rates below the national average, while implementing one of the most aggressive energy-efficiency efforts, the utility system is actually quite malleable over the long run. Virtually all system costs can be displaced through reduced energy use, and this study must acknowledge this fundamental lesson from the last 40 years.

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[9] Rachel Gold and Seth Nowak, "Energy Efficiency over Time: Measuring and Valuing Lifetime Energy Savings in Policy and Planning," American Council for an Energy-Efficient Economy, Report U1902, https://www.aceee.org/sites/default/files/publications/researchreports/u1902.pdf, February 2019.

[10] PSE 2023 10Q, https://fintel.io/doc/sec-puget-energy-inc-wa-81100-10q-2023-may-11-19488-2216.

[11] See WA NEM Evaluation - Avoided Costs Model 2023-11-17.xlsb

A value of solar study requires a much more deliberative approach

Going beyond the question of whether a cost-shift/ratepayer impact study is a valid evaluation tool, this study is not structured as a value of distributed solar study, but it really wants to be. The initial study format did not include many acknowledged benefits of either distributed or grid-scale solar, even going so far as to assume that the entire state's utility grid would be entirely GHG-free by 2030 and that the hydropower system has no significant environmental impacts. This ignores the facts. The rest of the Western Interconnect, including California, is relying on Pacific Northwest (PNW) generation to reduce its GHG emissions after 2030, and that the Columbia River system is the focus of fisheries restoration efforts including the potential decommissioning of the Snake River dams.

This oversight arises from two factors. First the Technical Advisory Group (TAG) was given a few weeks to gather a list of possible benefits, without sufficient time or resources to document those benefits. Second, the E3 authors appear to give only cursory consideration to the TAG's list, often rejecting them simply because they would be too difficult to quantify in the short time given for the study. The TAG suggested many sources for the E3 team to research, but none of that information appears to have been used.

E3's failing to use benefits of distributed solar and storage highlights why this cannot be considered a full value of distributed solar study. This process was not provided the necessary time and resources. Other value of solar studies in Oregon and Minnesota have been multi-year efforts. The utility consortium, in their commissioning of this study, allowed only four months.

Conclusions about which resources are preferred cannot be drawn from an incomplete cost-shift study that does not meet the requirements of a value of distributed solar study. Washington State statute requires that the type of conclusions put forward in this report be supported by a full integrated resource plan (IRP), not a "back of envelope" study that focuses on a single resource.[12]

The study asserts that NEM customers have acted irrationally

Equally problematic is the study's finding that customer-generators (or prosumers) are not making rational decisions by choosing to install rooftop solar because it is a money loser for them under E3's analysis. Slide 22 on the Participant Cost Test (PCT) Results shows that for every example utility, customer generators would have been better off to avoid becoming a customer-generator. Clearly the authors are missing the broader motives of NEM customers which might be to reduce environmental impacts, or the comfort of future bill stability. E3 is missing these customers' expectations, and asserting that customers' choices are not a valid basis for assessing the benefits that accrue to participants. This is an analyst who puts themselves in the place of a consumer, and declares that the consumer is consistently making a bad choice. A more likely conclusion would be that the analyst does not have the full picture of the choices being made.

TECHNICAL ISSUES

Missing risk hedging values, and overlooked hydropower flexibility improvements

The study uses forecasted 2030 Mid-Columbia market hub prices to determine avoided costs. But those prices can be quite volatile, both within the year and across years. Distributed solar allows customer-

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[12] See RCW 19.280.030: Development of a resource plan—Requirements of a resource plan—Clean energy action plan. http://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030

generators *and* utilities to limit exposure to that volatility which hedges their risk. How to value this risk hedging is well understood in financial economics and is the basis for a large segment of the financial markets in options and futures. Despite being provided with references on the topic by the TAG, the study's authors have ignored this benefit.[13]

A study from Rocky Mountain Institute (2012) sets out one method for calculating the volatility cost of natural gas-powered electricity, which is the primary source for energy setting the market clearing price in the Mid-Columbia market. That study found the hidden cost of market volatility in market gas price appears to be $1.50 to $2.50 per MMBtu. Assuming a thermal efficiency or "heat rate" for the marginal use of gas in the electricity market of 7,500 British thermal units per kilowatt-hour (BTU per kWh), that translates to an additional 1.125 to 1.875 cents per kWh or $11.25 to $18.75 per megawatt-hour (MWH) provided by distributed solar.

Other customers on a customer-generator's respective utility benefit from this load reduction. That in turn reduces the prices in the Mid-Columbia market paid on all load served from that market, in turn reducing their exposure to market volatility. The E3 study is therefore failing to account for what is called a "pecuniary externality" where a reduction in overall market prices is created by the investments made by customer-generators. Quantifying that added value requires more complete system modeling than was conducted in this study.

Customers relying on full-requirement deliveries by the Bonneville Power Administration (BPA) could possibly assert that they are not exposed to this volatility because they have a fixed price contract. This unfortunately ignores the effects of climate change and drought in the Pacific Northwest. Volatility coming from the variability in hydro availability is substantial and needs to be accounted for in the same manner as gas price volatility. Northwest utilities' witnesses asserted in proceedings at the Federal Energy Regulatory Commission in 2002 that the Western energy crisis of 2000-2001 was triggered by the BPA declaring a shortfall of firm energy in May 2000.[14] The run on those markets illustrates the volatility that all customers face.

The prosumer's "assist" to this dilemma is ignored in the study. While a portion of the state's hydro plants are run of river, the largest plants such as Grand Coulee and BC Hydro's Revelstoke and Mica Dams[15] are managed to provide both summer exports to the rest of the Western Interconnect and irrigation to Columbia Basin farmers.[16] Increased solar generation from customer-generators reduces Pacific Northwest loads, improves flexibility, and also allows those plants to either export more power to

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[13] These references were provided but not included or expanded on in the study: https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_2012-07_WindNaturalGasVolatility.pdf; https://rmi.org/hot-air-cheap-natural-gas/; https://rmi.org/blog_managing_natural_gas_volatility_the_answer_is_blowin_in_the_wind/. In fact, E3 personnel published a study on the risk premium embedded in forward prices in the Mid-Columbia hub in 2011. (Andrew DeBenedictis et al, "How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest," The Electricity Journal, 24:3, pp. 72-6, https://www.sciencedirect.com/science/article/abs/pii/S1040619011000601, April 2011.) The TAG expected E3 to conduct further research on its own and expand this analysis since it should have all of the expertise and data required to calculate this hedging value.

[14] M.Cubed partner Richard McCann testified on behalf of the California Parties, including on the issue of hydropower availability.

[15] The BC Hydro complex is operated in coordination with the U.S. hydro fleet under the Columbia River Treaty and must be considered as a single system.

[16] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/community/columbia-river-operations-summary-fall-2020.pdf

California, thus reducing customer rates, or release more water at times that can enhance fisheries. As drafted, this study ignores the market reality that the state, and the region as a whole, is interacting with the Western Interconnect as a whole. Prosumers have a role to play in this future. Studying the prosumer's value will take significant time and resources, and the authors are encouraged to acknowledge this massive oversight in their work.

The forward-looking perspective overlooks the shifting of loads to summer peaks and the benefits of reducing those peaks afforded by distributed solar

The heat dome of 2021 highlighted an important trend—that the PNW utility system is becoming dual winter/summer peaking. Average summertime highs in Seattle and Portland have risen substantially over the last 40 years[17] with the number of days over 70 degrees increasing 50% and 90 degree days doubling during the 2010s compared to previous decades.[18] More households are installing air conditioning as a result.[19] Winter temperatures have risen commensurately which leads to reduced heating loads. Average highs have risen 1.8 degrees since the 1970s and the average lows have risen 1.7 degrees over the same period.[20] The number of days below 32 degrees has fallen by a third in the last decade.[21] It is getting hotter in the PNW. This trend is not reflected in the modeling conducted for this study. That leads to a substantial undervaluation of distributed solar generation by E3.

Slide 32 on Avoided Costs: Transmission and Distribution shows the solar generation profile (which is the same for rooftop and grid-scale solar) and compares it to grid peak load cost allocation factors. Those allocators may be valid for the distribution system based on historic data, but as discussed above, the region is now going beyond historic conditions and peak loads will rise in July and August.[22] Rooftop solar can defer when circuits become summer peaking through local supplies. That value is not reflected in the study.

Figure 5 in E3's companion report *Review of Tariff Design for Customer Generation* can be corrected to show how the power flow from rooftop solar is isolated to the local distribution circuit and avoids using transmission. The imports first come from remote generation, then through the transmission system, then the local distribution network which should be shown with multiple customers. Most of the solar output is used to meet household loads and never leaves the customer site. The remainder is exported, flowing from the customer-generator to neighboring local circuit. None of that power flows back up to the transmission network which is not used at being used at that time by the exporting customer-generator. NEM customers should be paying nothing for the transmission system as it relates to their

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[17] In the last 10 years, eight rank among the top 10 with number of days over 80 degrees. (https://www.extremeweatherwatch.com/cities/seattle/yearly-days-of-80-degrees). Number of days over 90 degrees exceeded eight before 2015 only once but has been eight or higher in five years since 2015. (https://www.extremeweatherwatch.com/cities/seattle/yearly-days-of-90-degrees).

[18] https://www.currentresults.com/Weather-Decades/USA/WA/Seattle/temperature-average-by-decade-seattle.php

[19] "The rise in Seattle's 90-degree days, charted all the way back to 1945," *Seattle Times*, https://www.seattletimes.com/seattle-news/data/the-rise-in-seattles-90-degree-days-charted-all-the-way-back-to-1945/, July 27, 2022.

[20] https://www.currentresults.com/Weather-Decades/USA/WA/Seattle/temperature-average-by-decade-seattle.php

[21] https://www.currentresults.com/Weather-Decades/USA/WA/Seattle/temperature-average-by-decade-seattle.php

[22] As an important note, San Diego Gas and Electric went from being a winter peaking utility as late as the early 1980s to a summer peaking utility within 20 years.

exported power. The combination of self-consumption and exports represents transmission capacity freed for generation to be sent to other customers. This value is completely ignored in the E3 study.

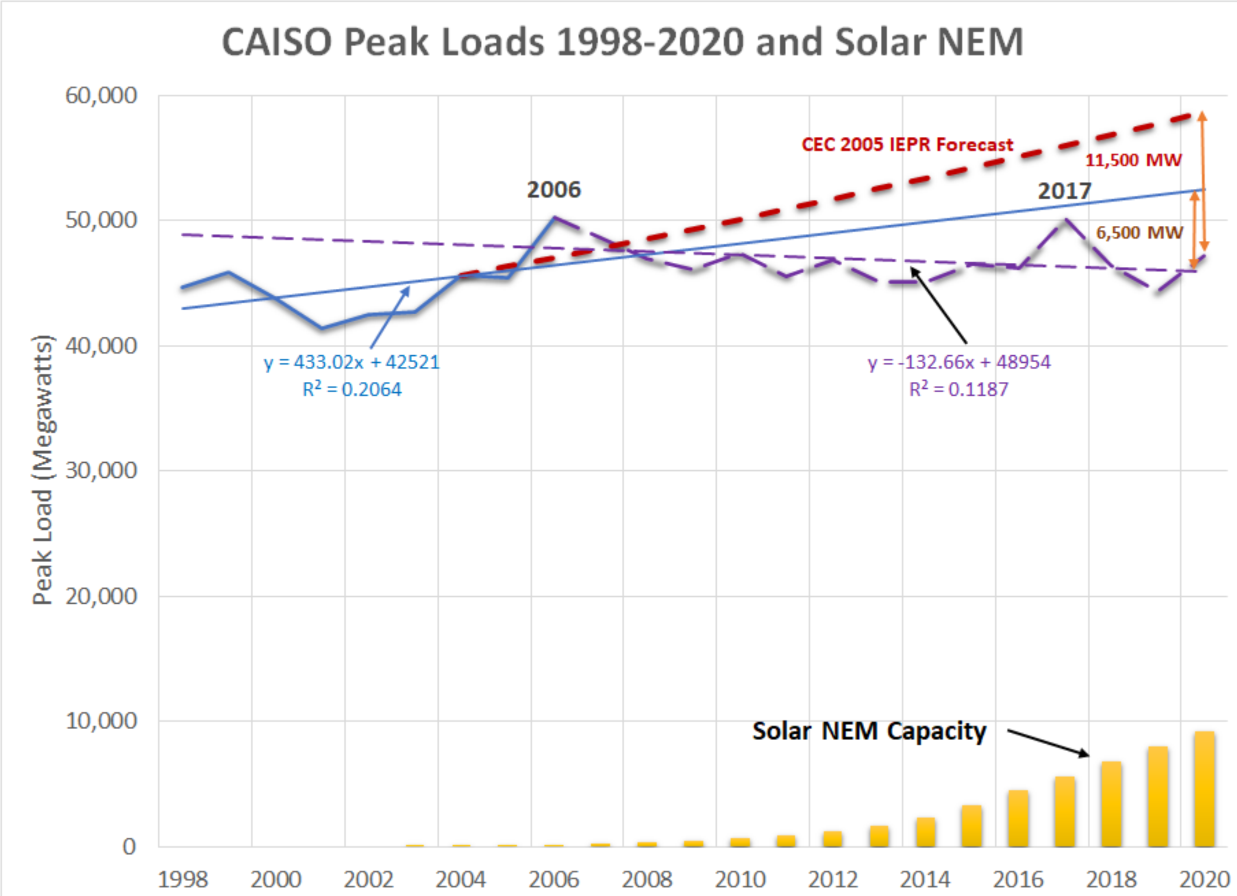
California's experience shows the value of distributed solar

Distributed solar generation installed under California's net energy metering (NEM/NEMA) programs has mitigated and even eliminated load and demand growth in areas with established customers. This benefit supports protecting the investments that have been made by existing customer-generators. Similarly, prosumers can displace investment in distribution assets. That distribution planners are not considering this impact appropriately is not an excuse for failing to value this benefit for the purposes of this study. For example, Pacific Gas and Electric's sales fell by 5% from 2010 to 2018 and other utilities had similar declines. Peak loads in the CAISO balancing authority reach their highest point in 2006, and the peak in August 2020 under exceptional conditions was 6% below that level.[23]

A closer look at California illustrates that much of that decrease appears to have been driven by the installation of rooftop solar. Figure 1 below illustrates the trends in CAISO peak loads in the set of top lines and the relationship to added NEM/NEMA installations in the lower corner. It also shows the CEC's forecast from its 2005 Integrated Energy Policy Report as the top line. Prior to 2006, the CAISO peak was growing at annual rate of 0.97%; after 2006, peak loads have declined at a 0.28% trend. Over the same period, solar NEM capacity grew by over 9,200 megawatts. The correlation factor or "R-squared" between the decline in peak load after 2006 and the incremental NEM additions is 0.93, with 1.0 being perfect correlation. Based on these calculations, NEM capacity has deferred 6,500 megawatts of capacity additions over this period. Comparing the "extreme" 2020 peak to the average conditions load forecast from 2005, the load reduction is over 11,500 megawatts. The obvious conclusion is that these investments by Californian NEM customers have saved all ratepayers both reliability and energy costs while delivering zero-carbon energy. Washington can expect similar benefits if rooftop solar is allowed to flourish.

[23] The peak in September 2022 that falls outside of the analysis period was created by exceptional one-in-35 year weather conditions and still less than 4% above the previous record.

Figure 1



Avoidable transmission costs are underestimated

The "heat map" on the study's Slide 32 misrepresents the loads on Washington's transmission system. Distribution is installed to meet increases in customer connections and loads, and those circuits are connected via feeders to substations. Those increased loads are often offset by decreased loads on other circuits so that system loads do not increase. In the PNW, peak and energy loads have been flat since 2000, reflecting this geographic shifting.[24]

On the utility's end, if needed, generation is added to meet increased loads, and then transmission is added to convey that generation to substations. Added transmission is rarely motivated by increased loads without associated incremental generation capacity. The incremental cost of new transmission is determined by the installation of new generation capacity as transmission delivers power to substations before it is then distributed to customers. For this reason, marginal transmission costs must be attributed to generation.

The report's heat map chart on Slide 32 also does not include perhaps the largest single load on the transmission system-the export of hydropower during the summer peak down the Pacific Intertie. That

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[24] See NPPC: https://www.nwcouncil.org/2021powerplan_historic-trends-energy-use/

is because the chart relies entirely on local loads and ignores the larger wholesale market. Focusing on generation instead would show a different focus for transmission versus distribution.

The cost of transmission for new generation has become a more salient issue.[25] The appropriate metric for distributed solar is therefore the long-term value of displaced transmission. Using similar methodologies for calculating this cost in the CAISO and PJM balancing authorities, the incremental cost in both independent system operators is $37 per megawatt-hour or 3.7 cents per kilowatt-hour. [26] This added cost about doubles the cost of utility-scale renewables compared to distributed resources. The rapid rise in transmission rates over the last decade are consistent with these findings. If economies of scale did hold for the transmission network, those rates should be stable or falling. This amount should be used to calculate the net benefits for the prosumer avoiding the need for additional transmission investment by providing local resources rather than remote bulk generation.

E3 asserts without evidence that it had not seen large transmission costs associated with renewables in Washington. The reason is understandable—the state has added only about 700 MW of grid scale wind and solar power since 2014. In comparison, California has added more than 20,000 MW of solar alone over the same period.[27] To meets its ambitious GHG reduction targets, Washington will have to install a commensurate amount of renewables, distributed and/or grid scale.

Greenhouse gas reductions are likely underestimated

Long term emission reductions, not hourly market emission rates, must be used to calculate GHG savings from DERs. A recent study mistakenly used hourly power GHG emissions as "marginal" which were higher than the average emissions, yet average rates were falling.[28] This is not mathematically possible—when average rates are falling, incremental emission reductions must be above average reductions. Relying on emissions at the Mid-Columbia market hub therefore underestimates the reductions created by reducing metered loads by the prosumer.

Installing customer-owned distributed energy resources is more likely to increase, not stymie, conservation investment

The study makes the assertion that energy conservation is likely to decrease for customers who install rooftop solar. The conservation incentive for customers is upfront when installing customer-owned generation. A customer immediately avoids, with little uncertainty, expensive solar investment by reducing on-site load. The incentive to reduce energy use cost effectively may be even more obvious when installing solar panels than for customers who remain on utility service and see their savings trickle in small amounts over a period of years instead of immediately.

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[25] Doug Karpa, "Exploding transmission costs are the missing story in California's regionalization debate," *Utility Dive*, https://www.utilitydive.com/news/exploding-transmission-costs-are-the-missing-story-in-californias-regional/526894/, July 5, 2018.

[26] "Testimony of Richard McCann, Ph.D. on Behalf of the Agricultural Energy Consumers Association and the California Farm Bureau Federation," CPUC Rulemaking 20-08-020, June 18, 2021, pp. 15-16; and "Prepared Supplemental Testimony Of Richard McCann, Ph.D on Behalf of the Kentucky Solar Energy Industry Association," before the Public Service Commission of the Commonwealth of Kentucky, Kentucky Power Company Case No. 2020-00174, February 25, 2021, pp. 9-10.

[27] https://www.seia.org/state-solar-policy/california-solar

[28] Holland et al (2022), " Why marginal CO2 emissions are not decreasing for US electricity: Estimates and implications for climate policy," https://resources.environment.yale.edu/kotchen/pubs/margemit.pdf

CONCLUSION

The study, as presented, has a number of serious methodological inconsistencies and flaws. It also struggles with its technical analysis. This is simply a reflection of the rushed nature of the timeline provided to E3, and limited actual input drawn from the TAG and other stakeholders.

These results should be fully discounted until a more complete study can be prepared that better reflects the perspectives specified by Washington State law, and that reflects the realities of the evolving climate, and energy environment.