Comments on "Interim Report: Economic Valuation of Distributed Solar Power Generation and Storage in Washington State"

M.Cubed on behalf of the Washington Solar Energy Industry Association

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M.Cubed reviewed the "Interim Report: Economic Valuation of Distributed Solar Power Generation and Storage in Washington State" (Interim Report) prepared by the Washington State Academy of Sciences (WSAS), issued June 30, 2025.[1] The report provides useful background information, and values, benefits and costs to be considered.[2]

Table 4 lists the "Preliminary categorization of Potential Value Stack to be considered in research conducted in Phase 2."[3] These benefits are categorized as follows:[4]

- Deployment Benefits: realized in the deployment (i.e., installation) of the assets (e.g., jobs), but distinct from operational benefits
- Passive Benefits: realized from automatic operation of the asset, without active dispatch (e.g., value of energy generated based on retail rate design; GHG reduction from offsetting fossil generation; resilience benefit from automatic islanding)
- Active Benefits: realized from the active dispatch of the asset (e.g., participation in demand response programs) and from factors that change when it is used (e.g., time of use (TOU) rates)

The report also provides an example of applying this approach to impacts on distribution system costs in Table 3 "Illustrative example of Realized Benefits."[5]

We provide comments on three different aspects of this report, the first two of which appear not to be discussed in the report but were raised by WASEIA in its March 2025 stakeholder interviews. Unfortunately, the Interim Report appears to ignore many of the points raised in those interviews, which will reduce the credibility of the study substantially unless they are addressed directly.

1. Stakeholder perspectives to be considered.
2. Analytic premises about who owns and controls the output from customer-owned generation.
3. Inclusion and analysis of benefits and costs in the value stack.

[1] See https://washacad.org/wp-content/uploads/2025/07/2025_06_30-VOSS-Interim-Report-Final.pdf

[2] Starting at p. 27.

[3] See p. 29.

[4] See p. 28.

[5] See p. 26.

Stakeholder perspectives

The perspective that the WSAS is proposing to use is not discussed. Presumably it is some type of social welfare measure. However, what this entails should be explored in greater detail and either a consensus or at least a full understanding should be developed among the stakeholders. Further, certain parties may push perspectives that are not necessarily appropriate for this type of study.

Several perspectives are appropriate:

- First is a *full societal one* that accounts for not only direct financial costs but also the value of risk management associated with reliability and resiliency, affordability, equity, as well as non-energy impacts (NEIs) and benefits. NEIs include the full gamut of environmental impacts, wider economy wide effects such as jobs creation, reduced market price and bill volatility, improved wildfire mitigation and resilience, enhanced equity and greater customer autonomy and independence. Several of these may be difficult to quantify monetarily, but that does not make these any less important. Simply assuming a value of $0 because of this hurdle is inappropriate—the Academy should be exploring other ways to incorporating these into the decision-making framework. This perspective is also the one to be used for municipal utilities, which carry out the public charge of our government.

- Second is from the perspective of the *participating customer*. These are the decision makers on investing in DERs. Ignoring this perspective could lead to significant adverse consequences by not accounting for their decisions in planning for achieving the state's goals. The utilities should provide properly calibrated price signals and governments might offer rebates, subsidies or other incentives for investing, but the ultimate decisions lie with these households, businesses and other entities.

  Some of these customers may at some time find it financially attractive to exit the utility system as technology evolves—an economically-viable option today in California and Hawaii. The analysis should capture this perspective to assess the potential risk of customers leaving and determine what might be appropriate incentives to make remaining on utility service attractive. This is where societal benefits from DERs can be reflected in providing those incentives. Those incentives should not include shifting costs from other customers onto these customers as a tax to discourage installation of DERs.

Merging these two perspectives, the valuation process should consist of (1) the response to utility or government offers to adopt DER, which should be respected and accommodated in planning; (2) any desire to keep the customer on the grid for the benefit of other ratepayers, which should come with associated incentives; and (3) the ancillary benefits the DER customer provides the utility, other ratepayers, and society by making their investments.

Two perspectives that are ***not*** important to include in a state-sponsored study are:

- *Investor-owned utility companies*. Private investors understand that they are taking on risk when investing and the company management can conduct its own analysis to determine what costs it will incur as a result of regulatory policies. Those companies can present evidence separately for each of their unique circumstances to determine what actions the Washington Utilities and Transportation Commission (WUTC) might take to balance allowable investor risk with societal objectives. That said, the Academy should be in a position to ensure that the premises and analytical methods used by the utilities in their rate case and planning submittals are consistent and commensurate with the analysis prepared by the Academy.

- A *ratepayer impact measure (RIM) test*. The underlying implicit premise of the RIM is that ratepayers are obligated to cover 100% of any risk of revenue shortfall, relieving utility investors of any such risk. This premise is too often unexamined. This is a gross overstatement and simplification of the "regulatory compact."[6] This perspective is really about responsibility for paying for stranded assets that are no longer economic in today's marketplace. The underlying assumption in the RIM test is that private losses by corporate shareholders are socialized to ratepayers while private gains in profits are solely the property of those shareholders. The RIM test perpetuates this imbalance.

  In a competitive market, which regulation is intended to mimic (see for example Alfred Kahn (1988)), investors (even bond holders) take on this responsibility and risk in exchange for returns on their investments and may be able to recover some portion of these revenue losses from other customers if the market allows it. If ratepayers bear this investment risk, utility managers lose their incentive provided by market discipline to make prudent decisions.[7] The U.S. Supreme Court in *Market Street Railway (1945)* ruled that regulated utilities are not protected from "economic forces."[8] Imposing the RIM test is inconsistent with this Court decision. Utility shareholders should be responsible for changes in revenues given that they receive an added risk premium in their authorized returns on equity to compensate for potential deviations from expected revenues and costs.

Analytic premises about who owns and controls the output from rooftop solar

Much of the asserted "cost shift" arises from the premise that utilities own and control 100% of the output from any customer-owned solar array and therefore has the right to charge the full retail rate for internal self generation, net of a credit based on "avoided costs." This premise is always implicit and couched in terms of "obligations", "fairness", and "fixed costs." Yet the utilities making these assertions cannot provide empirical evidence to back up these claims, instead making vague statements not consistent with actual decisions and operations. The Academy should closely examine this unstated premise and prepare its analysis consistent with the facts rather than uninformed opinion.

Based on legal precedents and regulatory decisions, customers have been entitled to consume on site the energy they generate with no obligation to pay the utility any portion of the retail rate beyond the

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[6] Further, there is no formal or legal definition of the regulatory compact. With the emergence of direct competition and customer-owned resources, this notion is increasingly archaic.

[7] This is a classic "principle-agent" market failure where those who bear the brunt of a decision is different from those making the decisions. Aligning these incentives is a primary focus of regulation to contain costs and rates.

[8] *Market Street R. Co. v. Railroad Commission*, 324 U.S. 548 (1945), https://supreme.justia.com/cases/federal/us/324/548/.

direct service connection to the grid dedicated to that individual customer.[9] Strong legal precedents and analogous market relationships that also support customers' right to consume self generation without interference from the utilities. Importantly, the utility is not delivering any energy when a customer is self-consuming and also is not delivering any other services such as reserves or using the grid lines. The utility sees only the reduction in load created by the portfolio of DERs serving the collocated demand when operating their generation fleets and transmission grids just as it occurs with energy efficiency, and the utility instead sees a highly reliable, predictable resource.

Unfortunately, the term "self generation" is nowhere to be found in the Interim Report. This appears to imply that this study has adopted this mistaken perspective about customers' rights to control the use of their own property without interference.

Inclusion and analysis of benefits and costs in the value stack

We presume that Table 4 is the complete list so far of benefits to be included and their classification into the three categories.

First, it is not clear to us as to why the benefits need to be classified into deployment, passive and active. Further, the definitions of and boundaries between these categories are vague and confusing. For example, why is resource diversity a "deployment" benefit when that diversity is operationalized by displacing other resources on the grid? This is equally consistent with the definition for "passive" benefits. The categories appear to be more about whether the utility or a third-party vendor has direct control over operation of the DER. Whether such direct control provides a real benefit should be addressed separately in the study rather than simply be assumed as being present. The success in California to meet 20% of the customer aggregate peak load without any direct control calls into question whether an "active" benefit can be distinguished in a significant way from other benefits. We have never seen this type of categorization in any other setting and believe it is unnecessary. It is more of a distraction than useful.

Second, the analysis should be conducted on the fleet of DERs, not on individual customers or generation units. Doing otherwise assumes away one of the most important benefits of DERs. The fleet itself provides portfolio diversity that minimizes unanticipated outages in aggregate. Those outages are uncorrelated across solar arrays. Distributed solar systems should be treated as a singular portfolio with uncorrelated risks or very low "betas" in investment parlance.[10] One thousand 10 kW solar systems pose a substantially smaller outage risk than a 10 MW grid scale generator. The outage rate for the portfolio should be measured as a single group, not individual generators. For example, the fleet of solar DERs is so predictable and reliable that the California Independent System Operator (CAISO) has treated it as a load reduction for more than two decades in the same manner as energy efficiency, this despite rooftop solar now producing 20% of the CAISO-area customer peak load.[11] (The CAISO metered peak is about

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[9] Jon Wellinghoff and Steven Weissman, "The Right to Self-Generate as a Grid-Connected Customer," Energy Bar Association, https://www.eba-net.org/wp-content/uploads/2023/02/11-23-305-326-Wellinghoff_FINAL-11.10.pdf, 2015.

[10] "The capital asset pricing model – part 1.", ACCA, https://www.accaglobal.com/us/en/student/exam-support-resources/fundamentals-exams-study-resources/f9/technical-articles/capm-part1.html

[11] For further discussion, see https://mcubedecon.com/2025/02/27/white-paper-on-how-rooftop-solar-is-really-a-benefit-to-all-ratepayers/.

20% lower than the actual customer peak, and three hours later in the day.) The CAISO has not added any additional reserves or transmission capacity to back up or serve the loads that are served by these DERs.

Looking at the list of benefits in Table 4, we start with the those listed, and then add several that have been excluded but are critical to determining the full value stack.

1. Avoided cost of renewable resource purchases – Storage also reduces this need by avoiding a certain amount of curtailment, particularly in wet hydro years. In addition, many of the newer grid-scale renewables have storage as well that can be displaced by distributed storage.
2. Avoided cost of carbon –The repost is not clear on the distinction between “directly imposed” and “social cost.” On the social cost, The US EPA has adopted a value for regulatory purposes and several published articles propose higher values.
3. Resource diversity – This can be measured in the same way that investment portfolio diversity is calculated. The WSAS should use appropriate financial tools to estimate this benefit.
4. Fuel price risk hedging - A paper estimates the risk cost of natural gas price volatility that can be used to estimate this value.[12] This hedging value can be estimated by using option pricing models.
5. Market price response – Reduced load diminishes exposure to market price volatility created by combinations of scarcity pricing and natural gas price fluctuations. That market price volatility is created more by scarcity than by fuel price fluctuations.[13]
6. Ancillary services – Solar also provides ancillary services benefits by reducing metered loads which are the basis for determining the need for ancillary services. As discussed above, the output is steady and reliable. Utilities do not add any reserve margin, which is the largest component of ancillary services, to account for DER generation beyond the meter. The cost of these services can be significant; for example, the CAISO reports prices ranging from $2 to $6 per megawatt-hour.[14]
7. Avoided transmission capacity - Distributed solar and storage avoids transmission costs because it both serves internal loads and the local neighborhood and circuit. The power from these distributed resources never reaches the transmission network, so that set of assets are not used by solar exports.
   The transmission rate billed to load serving entities (LSEs) turns the incremental cost of adding generation into a “postage stamp” by spreading the total revenue requirement over a measure of customer demand (often peak kW demand in specified months.) This is not representative of the true marginal cost of transmission.
   A key fact that is often overlooked is that transmission costs are driven by the addition of new generation, not directly by demand or load increases. Further, transmission additions to support new generation extend beyond just the single path from the generator; reinforcements are

[12] See https://rmi.org/blog_managing_natural_gas_volatility_the_answer_is_blowin_in_the_wind/

[13] For further discussion, see https://mcubedecon.com/2022/03/08/why-utility-prices-cannot-be-set-using-short-run-marginal-costs/

[14] CAISO, “2024 Annual Report on Market Issues & Performance,” Department of Market Monitoring, https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf, August 7, 2025.

made in other locations in the network to maintain reliability and support. As a result, the marginal cost of transmission must be calculated using the total increase in revenue requirements for the transmission system measured against the incremental generation additions. *In California, this marginal cost is 12.5 cents per kilowatt-hour which is about three times higher than the retail rate component*.[15]

8. Transmission resilience – solar also provides this benefit by reducing the overall load. This decreases the amount of transmission capacity or local generation needed to restart an area after an outage. In addition, storage is of limited use for resilience unless it is paired with solar to extend the availability of storage. During the sunnier seasons, a solar + storage combination can run indefinitely, whereas a stand alone storage battery can only run a few hours.
9. Avoided distribution costs –DERs can lower the amount of required distribution built to serve a community as the noncoincident peak load is reduced. These savings should be reflected in reduced distribution charges as capacity is freed up to be used by other nearby customers instead.
   Contrary to utilities' assertions, distribution costs are only fixed in the very short run. Utility analysts confuse the accounting basis for recovering sunk costs with the economic basis using forward looking costs. In a competitive market, businesses recover most or all "fixed" costs through variable pricing that reflects that customers have choices. If a customer is charged a fixed fee for a given amount of distribution capacity, in a functioning market they would gain full ownership of that capacity and be able to sell it to other customers who demand it. That market would likely be spliced into hourly segments, which is kilowatt-hours for electricity. However, the transaction costs of customers trying to sell to each other would be large compared to the actual value. This is why we have "dealer" markets that purchase inventory from sellers or producers and sells it to buyers. This is how retail stores work when they buy stock from a supplier and then sell to consumers. The utility also serves this function, which is why distribution should be priced on a $ per kWh basis.
   Further, DERs reduce or avoid these incremental replacement costs in generation, transmission and distribution, but have only been credited with generation to date; it should be credited for transmission and distribution savings as well. For generation when a new generator is added to replace a retired unit, this is treated as a marginal cost to the system by utilities in resource planning. This situation is now readily apparent as load growth has stagnated but the utilities are adding new generators, often renewables, to replace retired fossil fuel plants. To be consistent with the approach to generation, any additions to the transmission and distribution grid, including for the purpose of replacing retired equipment, should also be treated as a marginal cost. This is not the case for utility planning now. In other words, a significant inconsistency exists in utility resource planning between generation versus transmission and distribution.
10. Distribution Reliability/Resilience – The listings in Table 4 for technologies are reversed versus transmission which makes little sense. As discussed above, these benefits are applicable to both.
11. Reducing fire risk by deenergizing power lines – This option is only available if storage is paired with solar to extend islanding for several days or longer, so it is a benefit that also accrues to solar albeit in an interdependent mode. The benefit can be measured through the avoided costs

[15] See https://mcubedecon.com/2025/04/21/caiso-transmission-costly-for-new-generation/.

of utility mitigation measures such as undergrounding, covered conductors and fast trip closers. All of these costs are readily available from sources in California.

12. T&D O&M costs – Both technologies create this benefit by reducing loads and usage. Thermal stress that increases nonlinearly with higher loads shortens the life of T&D equipment. Solar alone because it generates the most during the hottest part of the day, reduces this thermal stress disproportionately.
13. Other avoided environmental costs: DERs are built on existing infrastructure that has already disrupted an ecosystem. Grid scale generation most often is built on "greenfields" that disrupt ecosystems and/or takes land away from other productive uses. It also requires large-scale transmission that creates its own environmental problems and can block important species corridors and networks. These environmental consequences should either be valued or included as constraints on grid scale development. The shadow values of those constraints should be included in the analysis.
14. Land use including Tribal lands: Similar to environmental consequences, the shadow value from constrained grid development can be used as a proxy for this value. For other land uses, the value is likely to arise in developing integrated building energy systems.
15. Hydroelectric ramping – Solar generation can be stored by hydropower for use later in a day, a season or a year. The Columbia River System is the largest in the U.S. and easily accommodates the output from relatively small amount of solar capacity. This ability converts solar indirectly into a much more reliable resource. The hydro output in California has shifted later in the day in response to the solar installed there.
16. Tax revenues / workforce development / jobs - Adding DERs creates more local economic activity and jobs than grid scale generation, which is often built by "here today, gone tomorrow" construction firms. Rooftop solar creates 4.4 to 8.4 times more jobs per installed MW than utility-scale solar based on two data sources. As a result, rooftop solar will sustain as many as 1,792 jobs in 2024 compared to a high estimate of 290 jobs associated with utility-scale solar and 239 for wind for the same installed capacity.[16] Rooftop solar also supports more locally-retained business and personal income because it relies on neighborhood businesses to install the panels This local and regional value is usually ignored in valuation studies that focus on "least cost" solutions, and should be properly considered.

Benefit factors missing from Table 4

1. *Time value of resource deployment:* The analysis should evaluate the impact on rates from adding unneeded assets if expected increased demand does not materialize. The potential costs of large, bulky, investments that require long-lead times and lock in capacity should be weighed against more flexible resource additions that come in smaller increments.[17] On average it takes just 60 days to fully install a rooftop PV system. In contrast, utility-scale solar needs an average of 1,330 days.[18] Based on this data, 2,200 MW of rooftop solar could be installed in the time it

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[16] See https://waseia.org/wp-content/uploads/M3-The-Economic-Benefits-of-Rooftop-Solar-to-Washington.pdf

[17] John Farrell, "Small Solar's Speed Advantage," Institute for Local Self-Reliance, https://ilsr.org/articles/small-solars-speed-advantage/, August 22, 2025.

[18] See https://waseia.org/wp-content/uploads/M3-The-Economic-Benefits-of-Rooftop-Solar-to-Washington.pdf

would take to build a 100 MW utility-scale project. The value of flexible and accelerated resource addition should be included in the analysis.

2. *Economic and physical volatility and vulnerability:* DERs reduce the variability and vulnerability of the utility system to both economic and physical risks. Adding new generation from wholesale power markets and cost overruns in transmission and distribution grid expenditures can create rate spikes that stress customers' finances. Failures of transmission links can lead to extended outages and elevate fire risks. The current planning approach that ignores vulnerabilities created by volatility hides the costs of insurance against that volatility, embedded either in future rates or government spending that compensates for not accounting for risk today.
   Further, this assessment must include the financial risks to communities from rising rates. Bill stability has inherent value—that is a key reason why more people own homes rather than rent. Bill stability is distinct from affordability. The analysis should calculate the value of an economic risk that causes bills to be unaffordable beyond a simple point forecast of resource costs.
3. *Transportation electrification*: Transportation electrification differs from building electrification in two important ways. First, an EV can be charged in multiple locations. Installing solar away from residential sites at commercial locations and parking lots can be an important means of expanding the EV fleet through extending charging stations while avoiding costly grid additions that serve low load factor uses. The second is that EVs can become important storage resources that improve reliability and resiliency. Cars are parked 95% of the time so they can charge from available local solar and then either discharge back to a residence or drive from one location to another to discharge the energy.
4. *Consumer autonomy and independence*: The purpose of utility regulation, as state previously, is to mimic the performance of competitive markets which benefits consumers. Perhaps the most important aspect of competitive markets is the ability of producers to enter when prices rise and for consumers to choose among those producers. That creates market discipline that regulators are hard pressed to duplicate. DERs are the most significant entrant in more than a century to provide customers with the autonomy and independence afforded by competitive markets. The Academy should be including that benefit in its value stack.
   A further benefit is that such autonomy reduces concentration of political power within large corporations, which in turn improves the performance of democracy. This benefit is harder to quantify but that does not make this gain any less real.
5. *Economic equity*: The report does not attempt to measure how economic equity can change with increased deployment of DERs. This changes in two dimensions. The first is the ability of lower income households to lower their energy bills and gain more stability, much the same as home ownership creates these benefits over renting. The Academy may look at how the benefits of home ownership over renting are measured and apply these methodologies in this case. The second is that solar installation firms are owned locally much more often and generally higher workers who live locally, keeping more spending within the local circular economy. This effect is measured in the referenced study above on economic impacts and can be further expanded to explore these equity effects.

Illustrative example of Realized Benefits for distribution grid capacity

Table 3 on page 26 shows an " Illustrative example of Realized Benefits." While this example is useful, that is so because it illustrates important flaws in the approach and list of benefit factors:

- Optimistic – No Control – As pointed out previously, the output of the fleet of DERs is highly predictable and reliable. The timing of solar production is well understood. Most importantly this ignores the benefits from reduced line losses and the absence of reserve margins. These add up to 40% to the value of the DER capacity, so a 10 kW array can deliver up to 14 kW of displaced utility resource additions. In addition, the solar output can be stored in existing hydropower reservoirs by displacing hydro output (which is happening in California) and released later. The value should be at 9 kW or higher for summer time peaks. *The relationship between solar additions and peak load growth deferrals in California over the last 20 years is in excess of 90%.*[19] Perhaps less well understood is its relationship to customer loads—when solar output falls on a summer day, the air conditioning load also decreases, but that relationship is ignored in these assessments. This also ignores how localizing generation within a neighborhood avoids using higher voltage networks. Further, this example ignores other non-energy benefits such as increased local economic activity from solar installation compared to distribution system investment, maintenance and operation.
- Worst case - No Control – Again, this ignores important aspects of solar DERs. The system and local peaks may not align, which means that the benefit is somewhat smaller. However, T&D is built for more than just the peak period because it is necessary to transmit energy during all hours of the day. And even with winter peaking, meeting the summer peak has value as the Western Interconnection is summer peaking and the Pacific Northwest is a net exporter that receives sales revenues from other states. To assert that solar arrays have provide absolutely no benefit to date is belied by the experiences in other states with higher solar penetrations.
- Battery Addition [3 cases] – The value is the incremental increase from the No Control baseline created by better alignment between solar output and system and local peaks. However this increment is much smaller than presented in this example because the baseline of the No Control option is much higher.
- Utility-owned system – This somehow converts a system into a "perfect" set up with no real explanation. VPP and DR programs will deliver exactly the same benefits as utility ownership if the price signals are correctly constructed and conveyed. Even then, utilities dispatch based on the same price signals that are sent to VPP and DR participants. There is no empirical justification for an incremental benefit for utility ownership over other ownership modes.

The Academy should focus on clearly documented distinctions that can be empirically demonstrated. Opinions from stakeholders that cannot be supported with some form of evidence should not be included, much the same as with any peer-reviewed study. Where two viewpoints are at odds, the Academy should clearly highlight the distinctions and discuss fully the implications of each position. If no obvious resolution exists, the Academy should include the results from both perspectives in its analysis. The Academy does not have a mandate to arrive a single solution that discards viable and realistic alternatives.

[19] For supporting analysis, see https://mcubedecon.com/2025/02/27/white-paper-on-how-rooftop-solar-is-really-a-benefit-to-all-ratepayers/.