NARUC
National Association of Regulatory Utility Commissioners

Valuation of Distributed Energy Resources – Information and Application

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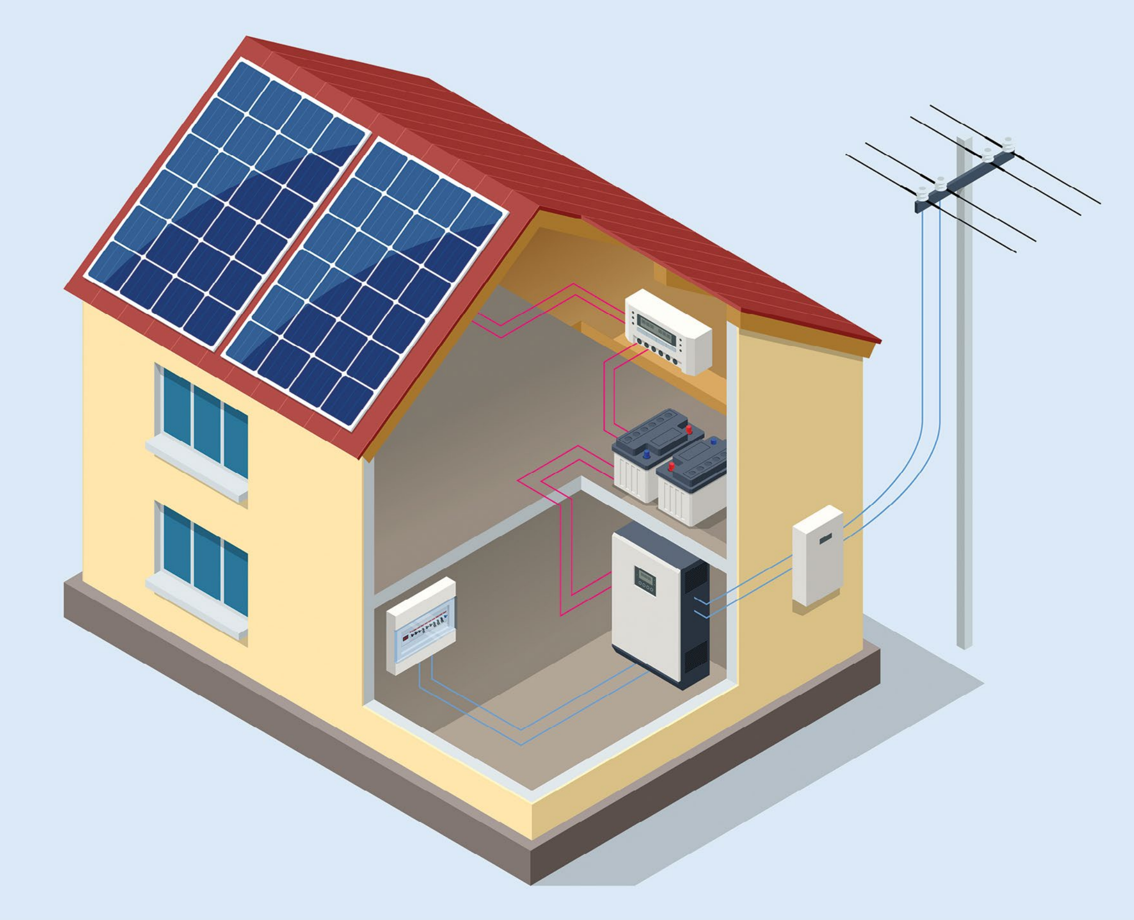

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I. Executive Summary

Valuation is the process used to inform price signals implicit in rate design through identification of applicable costs and benefits resulting from the operation of distributed energy resources (DERs). Creating incentives for DERs through rate design begins with how DERs are valued, and programs designed to support efficient grid operations can be strengthened by using thorough DER valuation methodologies. The valuation methodologies studied here from Minnesota, Kentucky, New York, California, and Hawaii have each generated unique DER tariffs designed to address the specific needs of their electrical grids, taking different approaches to create price signals that reflect the circumstances of their jurisdictions. Of these, all but Hawaii employs a Value of Resource framework that identifies the costs and benefits associated with operating DERs in their jurisdiction and then establishes compensation rates based on this accounting. Hawaii has implemented a Value of Service approach that assigns values to one or more specific functions that DER may perform for the grid and provides compensation based on the customer's decision to provide each of these services. The differences in valuation result in different incentives for customer DERs.

This report discusses how several Public Utility Commissions (PUCs) have assessed the value of DER for the purpose of tariff design. Valuation methodologies were analyzed using a standardized set of assumptions (i.e. resource size, type, and operation) to understand how price signals from each valuation methodology create incentives for DER owners. Completing an apples-to-apples comparison by standardizing conditions external to a DER runs counter to the rule that DER tariffs should be designed based on local conditions, but the goal of this analysis is to understand how differences in valuation methodologies create differing incentives via price signals rather than to gauge the efficacy of each methodology in addressing local system needs. The key findings of the analysis are:

Each of the methodologies and rate designs studied resulted in lower average compensation rates for grid exports than traditional net metering.

Each valuation methodology allows for some flexibility, but **methodologies that allow for greater pricing variation** (e.g. hourly pricing) **allow for more precise alignment of price signals with hours of need.**

Stronger price signals and incentives can be observed in methodologies that **require behavior change from participants to realize high compensation rates** for grid exports.

Transparency in valuation and **creation of easily digestible rates for DER users** will help align DER operation with system needs and encourage future investment in distributed resources.

Research and innovation will continue to be necessary to adapt to and guide DER adoption and grid conditions. **Finding what works and what does not from current valuation methodologies will be crucial** to future PUC proceedings.

Ultimately, DER valuation methodologies should be measured in the context of their local conditions to determine how they send price signals to align DER incentives with the needs of the grid. However, some methodologies send demonstrable price signals to enable DER to economically meet grid needs. Further adaptation and development of these valuation methodologies and rate designs will be pivotal in shaping the distribution system into the grid of the future over the coming years.

II. Terms

In this report, we use the following definitions:

Ancillary Services – Ancillary services are a category of capabilities that generation or storage resources may provide to ensure stable operation of the grid and adequate quality of electric power. Ancillary services include but are not limited to voltage control, frequency regulation, and provision of generation reserves.

Capacity – Capacity most broadly refers to the total amount of generation and transmission capabilities possible given the resources present on the grid. Individual resources each contribute to total system capacity. Measurement and compensation of generation and transmission capacity is vital to meeting electric loads.

Cost Shifting – Cost shifting in the context of net metering refers to the ability of participants in net metering programs to receive compensation and/or benefits in excess of the economic value of their contributions to the grid as a result of their exports to the grid if they are receiving credit for their exported generation at the full volumetric retail rate for the utility. This becomes a cost to the electric utility, which is then borne by other ratepayers whose rates may be increased to cover the lost utility revenue. Customers who can afford solar PV installation may receive a latent subsidy for this investment from non-participating customers, leading to cross-subsidization.[1] This cost shift has the potential to occur between customer classes.[2] and across residential customers of varying income levels.[3] However, the magnitude of the revenue lost to the utility has been a subject of debate and has not been empirically quantified for many utility service areas.

Distributed Energy Resource (DER) – A distributed energy resource is any device that connects to the grid at the distribution level to generate electricity or provide other services to utilities or individual customers, such as solar panels, electric vehicles (EVs), or residential battery storage.

Effective Load Carrying Capacity (ELCC) – Individual resources participating in restructured markets for electric power often receive ratings for the capacity that they can provide to the grid under specific operating circumstances, such as during the peak load hour of a season or year. ELCC is a means of estimating the ability of different resources to provide capacity to the grid in the times of greatest need and uses a percentage of a resource's theoretical maximum potential output to "derate" the capacity of that resource in alignment with its expected contribution to the grid.

Energy Markets – Energy markets, in states with restructured markets for electricity generation, are large scale auctions for procurement of electricity designed and administered by grid operators to economically value electricity generation and transmission at the wholesale level.

Export – Export for DERs is the release of electricity onto the grid through an interconnection to the distribution system. For valuation purposes, use of electricity through export is distinct from the use of electricity that is both generated and consumed "behind-the-meter," i.e. being used entirely onsite without being carried through the electrical grid.

Hosting Capacity – Hosting capacity is the ability of the physical electrical system to accommodate the use of DERs without infrastructure upgrades, with a utility or state's "hosting capacity" measuring the total technical capability for a system to accommodate DERs in its current state. This includes considerations at all phases of the electricity system but is primarily concerned with the distribution level.

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[1] Picciariello et al. 2015; Clastres et al. 2019; Eid et al. 2014; and Sergici et al. 2019

[2] Johnson et al. 2017

[3] Verdant Associates 2021

Incentives – Incentives for the purposes of this report can be interpreted as the magnitude of price signals on the grid and should be seen as the strength with which DER owners/operators will receive compensation for grid services, i.e. the degree to which their behavior may be expected to change in response to price signals.

Net Energy Metering (NEM) – NEM is a rate design for DERs under which net flows into and out of the distribution system from a customer's point of interconnection are measured and trued-up at a pre-determined rate, where if a customer is a net exporter they may earn compensation from the utility and if they are a net importer they are able to reduce their electricity bills through bill credits for exports to the grid. Exports to the grid from the DER are compensated with a volumetric credit to the customer for energy (as measured in kWh) injected to the grid. This amount is credited at a regular period (often monthly) to a customer's electricity bill, with any amount in excess of a customer's energy consumption rolled over to the following month until being paid out at a given interval, (often annually) for the remainder of the generation credited. Traditional NEM rates value generation at the retail rate of electricity, a constant rate not considering any external factors such as grid congestion, avoided emissions, or time of day in which energy is injected onto the grid. However, NEM may also be used as a framework to incorporate a value for distributed generation distinct from the retail rate.

Price Signals – Price signals for the purposes of this report can be interpreted as the response of export rates to grid conditions, i.e. whether compensation increases or decreases in response to peak or off-peak load hours. The magnitude of price signals can be interpreted as incentives for DER to respond to rate changes.

Virtual Power Plant (VPP) – A VPP is an aggregation of DERs that can be composed of demand response, energy storage, generating resources, or any combination of these things. VPPs are distinct from individual DER in that they are dispatched by a centralized third party or utility to synchronize deployment, which allows them to respond to grid needs more effectively through methods such as reducing peak loads through coordinated operation of DERs.

III. Introduction

The landscape of DERs is evolving rapidly. As adoption continues to increase across the United States, states at all levels of DER penetration are now facing different challenges on their distribution systems than they were a decade ago. As a result, public utilities commissions (PUCs) are increasingly examining possible reforms to DER policies beyond traditional net energy metering (NEM) compensated at retail rates to proactively shape the proliferation of DERs in their jurisdictions.[4] Efforts to incentivize specific features and behaviors of DER, particularly through rate design, depend on underlying decisions to value DERs in ways that reflect the conditions of a jurisdiction's electricity system. These decisions on valuation can significantly alter the trajectory of DER adoption and present risks and opportunities for PUCs to address grid needs and decarbonize the power sector.

The two types of valuation methodologies that have become common in designing next-generation DER policy, as described in the 2016 NARUC Manual on DER Rate Design and Compensation, are Value of Resource (or "value stacking") and Value of Service tariff designs (summarized in **Figure 1**).[5] Both methods depend on holistic and comprehensive cost-benefit analysis based on the specific circumstances of a jurisdiction, guidance for which can be found in resources such as the National Standard Practice Manual for DER.[6] This report will examine cases of PUCs employing DER valuation methodologies to provide insights on how valuation can inform price signals and incentives provided through retail rates. The metrics and tariffs used to implement these valuations may vary significantly even within a single valuation methodology, and this report seeks to illustrate how these differences manifest in the resultant rates and outcomes for customers. Methodologies of DER valuation are examined in five states to understand how PUCs have chosen to reflect the conditions of differing electric systems. The methodologies are then compared using prospective compensation of a baseline generating resource modeled across the tariffs resulting from each valuation methodology.

Figure 1: Value of Resource vs. Value of Service Valuation Methodologies

Value of Resource	Value of Service
• Valuing the contributions of a specific resource type based on accounting of costs and benefits, internalizing externalities of DER adoption • Examples: value based on timing, location, & avoided generation	• Valuing services that DER can offer regardless of resource type, typically dependent on dispatch by a distribution utility • Examples: Dispatched Demand Response, Voltage Control, or Ramping services

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[4] Forrester and O'Shaughnessy 2025.

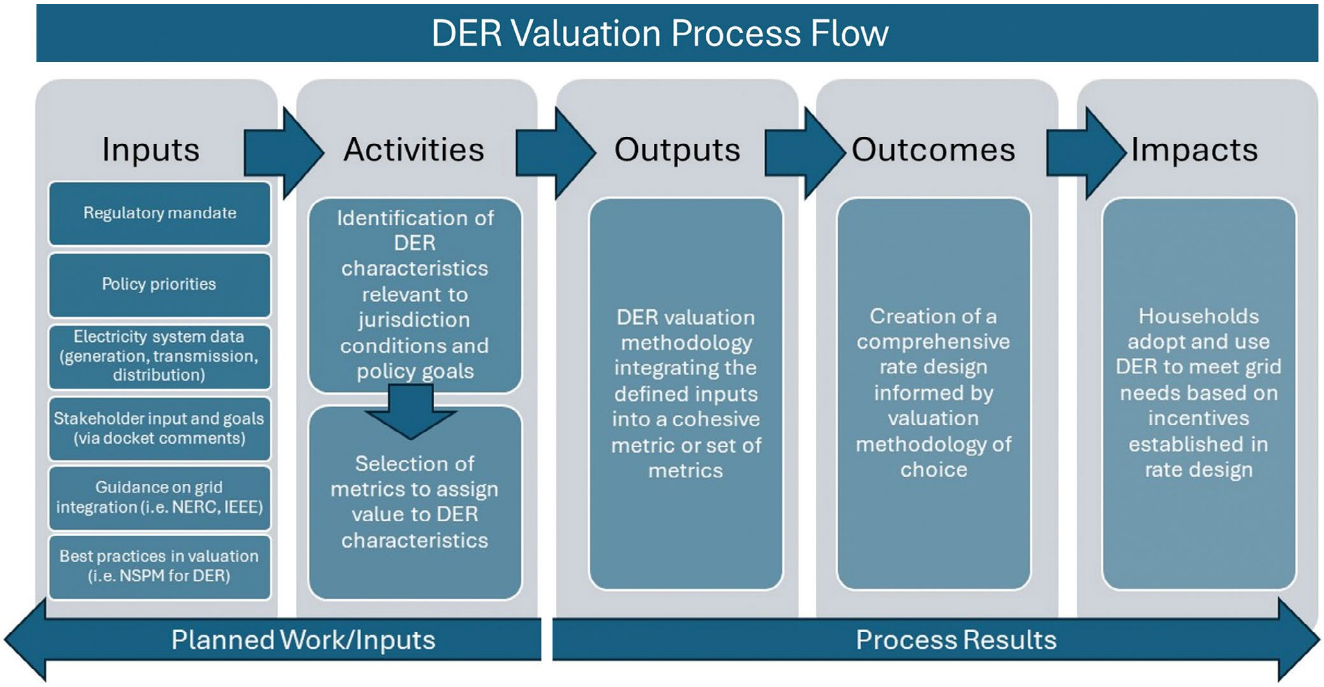
[5] NARUC Manual on Distributed Energy Resources Rate Design and Compensation, November 20216. https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

[6] National Energy Screening Project, National Standard Practice Manual, 2020 https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

IV. DER Valuation

Valuation is the process used to apply price signals in rate design through identification of applicable costs and benefits resulting from the use of DERs and the selection of metrics to represent these features. As illustrated in **Figure 2**, DER Valuation has the intention of translating policy goals and grid conditions into rate design to incentivize the desired consumer behaviors.

Figure 2: DER Valuation Logic Model



The value of DER influences consumer decisions that measurably affect utility investment, electricity rates, greenhouse gas (GHG) emissions from the power sector, and more. The process of valuation begins by understanding the influences and effects of DER adoption and operation in a state.

A. Upstream Considerations: Grid Conditions and Prospective Policy

Each state contains a unique electrical infrastructure and set of policies governing the use and expansion of its system. Adoption and deployment of DERs will increasingly become determinants of grid development, helping to defer utility investments in generation, transmission, and distribution infrastructure. Increasing generation from distributed solar photovoltaic (PV) panels and shaving peak loads using combined PV and battery energy storage (BES) systems can also contribute to decreasing GHG emissions from the power sector, leading to air quality improvements and contributing to meeting state emissions targets. Some states may also set explicit targets for their desired levels of DER adoption for solar PV or BES systems.

DERs can also cause operational and economic costs for the grid without adequate policy and management. Infamously in California, the "duck curve" created by the drop-off of distributed solar PV production and resulting wholesale market price spikes in the evening peak load hours required significant regulatory and market reforms to rectify.[7] More recent California PUC proceedings have shown evidence of cross-subsidization to DER owners through net billing tariffs, creating cost-shifting effects that can cause cost burdens to low- and middle-income ratepayers, although the effects of cost-shifting in California have been debated by industry

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[7] Jones-Albertus 2017.

observers.[8] Research from the Lawrence Berkeley National Lab suggests that the risk of cost-shifting from NEM policies is likely to be minimal at observed levels of distributed solar installation for most states, but the cost-shifting that California has encountered could affect other states in the future as DERs continue to proliferate and reach higher proportions of the generation mix.[9] Many states, particularly those with low electricity rates and low rates of DER adoption, may still find that NEM appropriately addresses the needs of their electricity grid and policy goals. However, as DER adoption grows, it is important to examine how policies such as NEM implicitly value DERs through either the value of the retail rate or avoided cost of electricity consumption from a utility, and whether changes in local conditions necessitate changes in how that value is calculated.[10]

Table 1: Characteristics of DER Used in Valuation

Value Proposition	Applicable Phase	Implementation Status (CA, HI, KY, MN, NY)
Avoided Fuel Cost	Generation	Currently In Use (MN, KY)
Avoided Power Plant O&M (Fixed & Variable)	Generation	Currently In Use (MN, KY)
Avoided Electricity Generation	Generation	Currently In Use (KY, NY, CA)
Avoided Ancillary Services	Generation	Currently In Use (MN, CA, HI, KY)
Avoided Greenhouse Gas Emissions	Generation, Societal	Currently In Use (MN, KY*, NY, CA) *considered for environmental compliance
Avoided Capacity Cost	Generation, Transmission, and Distribution	Currently In Use (MN, KY, NY, CA)
Avoided System Losses	Transmission, Distribution	Currently In Use (CA, MN)
Avoided Environmental Compliance Cost	Societal	Currently In Use (MN, KY, CA)
Economic Benefits/Job Creation	Societal	Currently In Use* (KY) *used in 2020 Kentucky Power rate case but evaluated only on ad hoc basis.
System Resilience	Societal	Not In Use
Efficient Land Use	Societal	Not In Use
Improved Air Quality	Societal	Not In Use

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[8] See Lyser 2024, McCann et al. 2025, Sergici et al. 2019. Cost shifting can occur from higher income customers (who historically realize higher rates of rooftop solar PV adoption in California) participating in traditional NEM being compensated for grid exports at the normal retail rate including costs for transmission and distribution of electricity, resulting in a higher implicit value for distributed generation that may lead to rate increases for non-participating customers. The measurement of this cross-subsidy is a subject of debate in the literature.

[9] Barbose 2018.

[10] Lawson 2019.

Properly identifying and measuring the costs and benefits associated with DER in a state is crucial to the appropriate valuation of DER (See Table 1 for examples of components used in valuation). This report does not examine the steps of conducting a thorough benefit-cost analysis (BCA) for DER, only to discuss how BCA influences DER Valuation.[11]

B. Downstream Effects: Standards to Inform Rate Design

Methodologies to weigh the costs and benefits of DERs are employed to guide the design of DER programs and ultimately to set prices and incentives for adoption and operation of DER. Providing predictable and substantial compensation to DER owners can facilitate adoption of DERs, and compensation less than the value provided by DERs or lack of certainty in compensation can discourage investment in distributed generation. Additionally, a growing body of literature supports the idea that DERs have the potential to measurably reduce costs and emissions associated with the generation of electric power when participating in an aggregation or Virtual Power Plant (VPPs), meaning that valuation methodologies with metrics in place to account for these grid services will only increase in importance over time.[12] The approaches that are taken to DER Valuation may vary depending on local circumstances, but the end goal of setting appropriate price signals and incentives for DER is consistent across the programs studied here.

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[11] National Energy Screening Project, *National Standard Practice Manual, 2020,* https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[12] See: Bhuiyan et. al. (2021), Brehm et. al. (2023), Hadayeghparast et. al. (2019), Hledik and Peters (2023), and Speetles, Lockhart, & Warren (2023) for more information on VPP.

V. Value of Resource

The first states examined here use Value of Resource methodologies as defined in the 2016 *NARUC Manual on Rate Design for DER*. This means that the contributions of any DER to the grid are valued based on localized BCA measuring how the DER affects the grid and society.

A. Minnesota

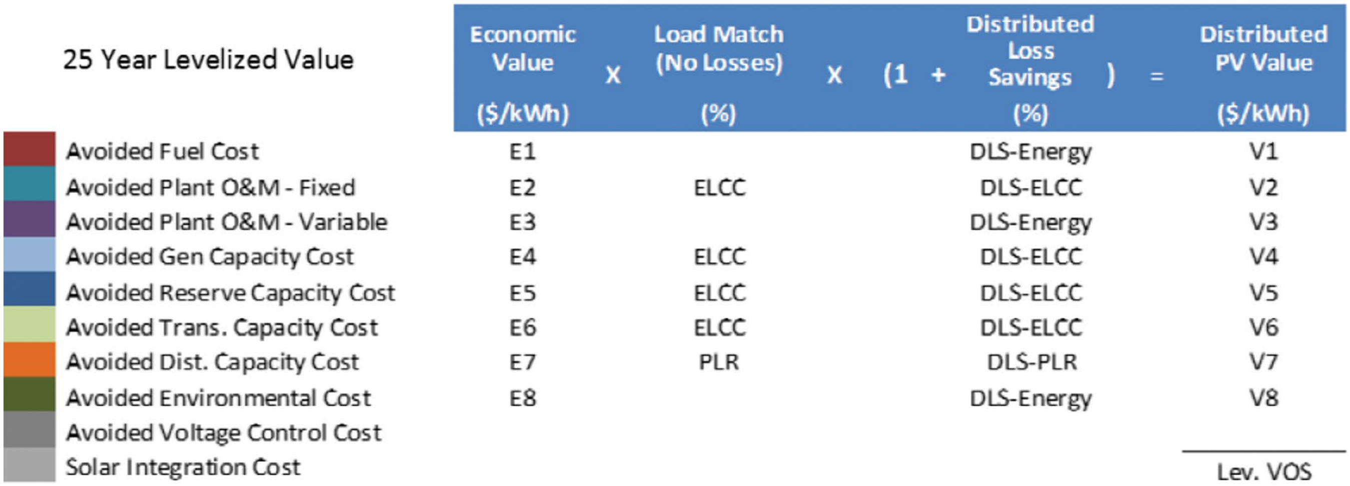
Minnesota's Public Utilities Commission was ordered by legislators to conduct a Value-of-Solar (VoS) study that could result in a successor tariff to NEM in 2013, becoming the first statewide implementation of a DER valuation framework leading to a DER rate design.[13] The resulting study was carried out in partnership with Minnesota Department of Commerce and Clean Power Research.[14]

The proceeding resulted in a VoS tariff that incorporated the following variables in a value stack based on a 25-year levelized value:

- Avoided fuel cost
- Avoided plant Operations & Maintenance (O&M) - fixed
- Avoided plant O&M – variable
- Avoided generation capacity cost
- Avoided reserve capacity cost
- Avoided Transmission & Distribution (T&D) capacity cost
- Avoided environmental cost
- Avoided voltage control cost

These variables combine to create a value stack as shown in **Figure 3**. Each value is adjustable to inflation changes over time to remain consistent throughout the life of the tariff. Additionally, it was explicitly noted that variables were only selected for inclusion in the valuation calculation "if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility."[15]

Figure 3: Minnesota VoS Methodology (Minnesota Value of Solar: Methodology 2014).



	25 Year Levelized Value	Economic Value ($/kWh)	X	Load Match (No Losses) (%)	X	(1 +	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
🟥	Avoided Fuel Cost	E1					DLS-Energy			V1
🟦	Avoided Plant O&M - Fixed	E2		ELCC			DLS-ELCC			V2
🟪	Avoided Plant O&M - Variable	E3					DLS-Energy			V3
🟦	Avoided Gen Capacity Cost	E4		ELCC			DLS-ELCC			V4
🟦	Avoided Reserve Capacity Cost	E5		ELCC			DLS-ELCC			V5
🟩	Avoided Trans. Capacity Cost	E6		ELCC			DLS-ELCC			V6
🟧	Avoided Dist. Capacity Cost	E7		PLR			DLS-PLR			V7
🟩	Avoided Environmental Cost	E8					DLS-Energy			V8
⬛	Avoided Voltage Control Cost									
⬜	Solar Integration Cost									Lev. VOS

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13 Taylor et al 2015.

14 Minnesota Value of Solar: Methodology 2014.

15 Ibid.

Specific inclusion of fuel cost and plant O&M create slightly different methodological considerations for Minnesota than the other tariffs examined despite having comparable components included in their valuation methodologies. Use of these short-run marginal costs for generation may be reflected in locational marginal prices (LMPs) in states with wholesale electricity markets for the purpose of cross-state comparison. Multiple features of the BCA implemented through this VoS tariff have come into question or have been modified since its adoption. This includes potential location-specific modifications to the valuation, using a baseline assumption of a natural gas generator as the marginal generator for cost estimation reasons, changes to forecasting natural gas fuel prices, and implementing a price adder for residential customers in an effort to increase adoption.[16] Externally to the Minnesota VoS tariff, the use of Effective Load Carrying Capacity (ELCC) has also been a subject of debate due to the discrepancies between ELCC calculation methodologies and increasing complexity of resource adequacy metrics as a whole.[17]

To date, NEM remains the dominant DER tariff in Minnesota, with limited adoption of the VoS methodology failing to displace. The Xcel Energy Community Solar Garden program employed this valuation methodology to set rates for participants from 2016 until 2023, the only program in the state to do so.18 Limited adoption of the VoS methodology in practice has yet to displace NEM in the state, and there is no indication that the VoS tariff will overtake NEM as the primary DER tariff.

B. Kentucky

Kentucky's Public Service Commission issued an Order in September 2021 authorizing revisions to the state's NEM tariff design.[19] This was initiated by a request to adjust the NEM tariff in the state by two regulated utilities in Kentucky. Kentucky has relatively low penetration of DERs, with distributed solar accounting for 0.16% of the total electricity generated in the state in 2023 through the month of August according to EIA data, as compared with 1.58% in New York, 9.07% in California, and 9.84% in Hawaii.[20] Ultimately, the Order authorized a comprehensive adjustment to the NEM rate that included stacked values for contributions to the grid from avoided energy, ancillary services, and emissions, as well as deferred investment in transmission, distribution, and generation capacity. In the Order, the PSC consistently referenced best practices from intervenors as established by other PUC proceedings, and explicitly noted considerations that related to "standardization of valuation methods and transparent data."[21] The Commission also explicitly references the maturity of DER in the state when considering rate reforms, calling the penetration of such resources "miniscule."[22] The PSC specifically contradicted reductions in compensation for DER based on claims that NEM leads to cross-subsidization and requires expensive investments in distribution system upgrades including DER Management Systems (DERMS). The PSC rejected these arguments due to evidence that these issues have yet to affect Kentucky's power system and ratepayers with the limited penetration of distributed solar in the state. The PSC also mandated certain calculation methodologies be used for variables of interest, and left flexibility for the utilities in future proceedings to alter calculations or assumptions. These decisions show careful consideration of jurisdiction-specific conditions within Kentucky and adherence to standardized best practices outside of the state as well. This proceeding demonstrates the potential use to Commissioners and PUC staff of providing benchmarking

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[16] Minnesota Public Utilities Commission 2019.

[17] See: Reporting from Energy & Environmental Economics (Schlag et. al. 2020), material on ELCC methodologies from Energy & Environmental Economics (Olson et al. 2021), and Monitoring Analytics (Monitoring Analytics, LLC 2024) on use of ELCC.

[18] Xcel Energy 2024.

[19] Kentucky Public Service Commission 2021.

[20] Electric Power Monthly, Table 1.3B 2023 & Electric Power Monthly, Table 1.17B 2023. This difference in adoption rate may be in part due to lower retail rates for electricity than the comparison states, reducing the value proposition of distributed solar for individual customers.

[21] Kentucky Public Service Commission 2021, p. 26.

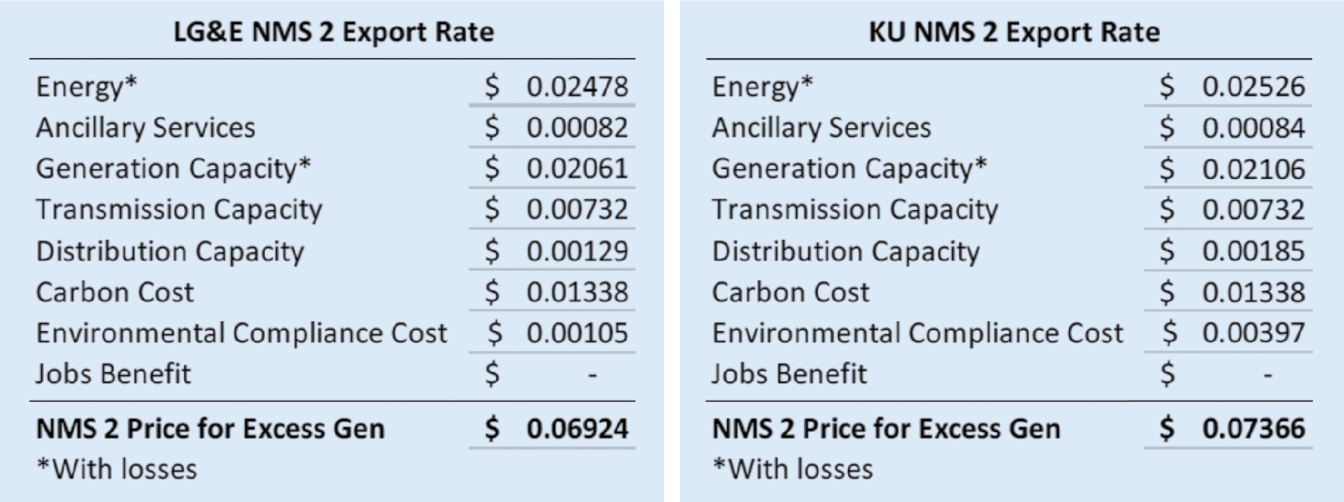
[22] Ibid. p.2.

examples of valuation methodologies, as well as evidence of how concerns around DER adoption such as cross-subsidization may be addressed based on local circumstances.

The final Order set a valuation methodology using the following variables:

- Avoided energy cost
- Avoided generation capacity cost
- Avoided T&D capacity costs
- Avoided ancillary services costs
- Avoided carbon cost
- Avoided environmental compliance costs
- Resultant jobs benefits

These components result in a value stack pictured in **Table 2** for each of the utilities affected by the Order. The methodologies used for calculating the values for each component were ordered by the Commission to follow best practices as established by expert witnesses in the proceedings and tracked closely with the methodologies used in Minnesota.



LG&E NMS 2 Export Rate	
Energy*	$ 0.02478
Ancillary Services	$ 0.00082
Generation Capacity*	$ 0.02061
Transmission Capacity	$ 0.00732
Distribution Capacity	$ 0.00129
Carbon Cost	$ 0.01338
Environmental Compliance Cost	$ 0.00105
Jobs Benefit	$ -
NMS 2 Price for Excess Gen	**$ 0.06924**
*With losses	

KU NMS 2 Export Rate	
Energy*	$ 0.02526
Ancillary Services	$ 0.00084
Generation Capacity*	$ 0.02106
Transmission Capacity	$ 0.00732
Distribution Capacity	$ 0.00185
Carbon Cost	$ 0.01338
Environmental Compliance Cost	$ 0.00397
Jobs Benefit	$ -
NMS 2 Price for Excess Gen	**$ 0.07366**
*With losses	

Table 2: Kentucky DER Valuation Components, $/kWh

Pictured with rates for Louisville Gas & Electric and Kentucky Utilities (Kentucky Public Service Commission 2021)

This framework is another example of a “Value of Resource” valuation methodology where the disparate effects that DER may have on grid operations are consolidated to a resource-specific calculation. The Net Metering Successor valuation methodology is currently used to set compensation rates for Kentucky’s regulated utilities.

C. New York

NEM was initiated in New York by order of the Public Service Commission (PSC) in 1997 and remained the dominant tariff design for DER until 2017.[23] The Value Stack was implemented as the successor to NEM for DER valuation in New York following the PSC’s Value of DER (VDER) proceedings. The VDER proceedings were initialized in an order released by the PSC on March 3, 2017, and officially implemented in a subsequent order on September 17, 2017.[24]

The proceedings resulted in a valuation framework for DER that considers value from traditional factors such as energy generation using Location-Based Marginal Price (LBMP) from the New York Independent System

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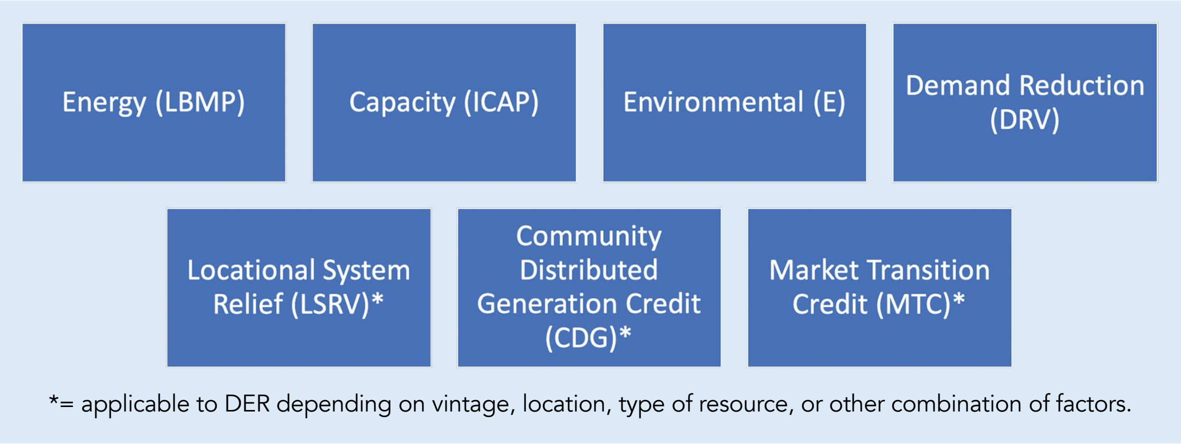
[23] NYSERDA The Value Stack.

[24] Ibid.

Operator (NYISO) Day-Ahead market, capacity contributions (ICAP), and additional components including environmental value (E), demand reduction value (DRV), and locational system relief value (LSRV) as shown in **Figure 4**.[25]

Figure 4: New York Value Stack Components



*= applicable to DER depending on vintage, location, type of resource, or other combination of factors.

These components build upon one another to create the Value Stack tariff for DERs, and customers served by the Value Stack tariff are subject to a fixed monthly fee to the host utility known as a Community Benefit Contribution (CBC) intended to offset the costs of hosting DERs. Rates for each component are based on location, grid conditions at the time in which energy is injected, and long-term changes in value. At initiation, the Value Stack also included a Market Transition Credit (MTC) meant to add additional revenue for customers to decrease payback periods for investments and ultimately to spur greater adoption of DER that was available in capped phases. There is also an additional Community Distributed Generation credit (CDG) for generation coming from Community Solar projects in the state, increasing investment viability for this category of projects.

The Value Stack is another example of a "Value of Resource" valuation methodology with features designed to respond to time, location, and grid conditions. The Value Stack does this by 1) increasing the granularity of location-based value down to the substation level with LSRV and utility service area with DRV; 2) integrating time-based value daily and seasonally using the NYISO LBMP and ICAP components; 3) capturing environmental value using the Social Cost of Carbon set by the New York Department of Public Service (NY DPS); and 4) providing additional credits for certain resource types to facilitate equitable access to the benefits of DER.[26]

The Value Stack has been the only existing DER tariff in New York since 2017, with all DER interconnected to the grid since then enrolled in this rate. It has been updated in the years since its initiation by resetting value components and retiring temporary components such as the MTC. Procedures and timelines for some of these updates were set during the initial rate proceedings. These tariff updates are reflected in a VDER calculator hosted by the New York State Energy Research and Development Authority, maintaining a publicly-accessible tool to demonstrate the application of the Value Stack for customers.[27] The tariff will continue to advance with the anticipated rollout of the Wholesale Value Stack allowing DER aggregations to participate in NYISO markets for energy, capacity, and ancillary services, enabling more transparent pricing and participation for VPPs and exposure to NYISO markets for DERs in the state.

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[25] NYSERDA The Value Stack – Frequently Asked Questions.

[26] NYSERDA The Value Stack – Frequently Asked Questions & NYSERDA Value Stack.

[27] NYSERDA Value Stack Calculator, www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Calculator.

D. California

California's Public Utilities Commission (CPUC) first adopted NEM in 1996, and is now on the third iteration of NEM in the state following a recent proceeding. The Net Billing Tariff, or NEM 3.0 as it has been termed, was finalized in a CPUC decision in December of 2022.[28]

California's "duck curve" of net load increases during peak load hours has been exacerbated in part by the high penetration of distributed solar in the state and has necessitated modifications to DER tariff design.[29] As such, NEM 3.0 focuses primarily on incentivizing injections to the grid during peak load hours in an effort to smooth the net load curve between the peak of solar production midday and the peak load hours in the evening. Other factors considered by the CPUC included cost-effectiveness of the rate design to prevent cost burdens shifting to non-participating ratepayers and reasonable payback periods for participating customers. The CPUC sought to balance these factors by providing adequate investment incentives to continue development of DER capacity in the state while preventing excessive cost burdens for non-participating ratepayers.[30] NEM 3.0 is designed to align the compensation for distributed generation in California with price signals from:

- Modeled day-ahead energy market prices,
- Cap and Trade emissions prices,
- Generation, Transmission, and Distribution capacity and losses,
- Ancillary service prices, and
- Methane leakage costs.

Customers using NEM 3.0 must also subscribe to a specially designed Time-of-Use (TOU) rate differentiating energy use in peak and off-peak hours for onsite energy consumption to better align DER behavior with system-level needs.[31] This tariff also includes the implementation of a "glide path" providing additional credits for exported generation that will prevent excessively long payback periods for investment in DER, comparable to the MTC in New York's Value Stack.[32]

The updates that the CPUC has implemented in their more recent proceedings have incorporated more robust valuation methodologies than traditional NEM tariff structures. These tariff changes intentionally reduce the average value for which DERs are compensated on California's electrical grid as the costs of hosting DERs in the state have increased over time. The intention of the CPUC appears to be to offset this decrease in compensation by providing higher compensation opportunities in hours of need, incentivizing the operation of DER to address grid needs. Per the CPUC, "The value of the export compensation is usually lower than the retail rate but can rise above the retail rate on late summer evenings," reflecting this shift in the CPUC's tariff design.[33]

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[28] California Public Utilities Commission 2022.

[29] Jones-Albertus 2017.

[30] California Public Utilities Commission 2022.

[31] Ibid.

[32] Ibid.

[33] California Public Utilities Commission 2024.

VI. Value of Service

The Value of Service approach values services that DERs can offer regardless of resource type, typically dependent on dispatch by a distribution utility. Hawaii's Value of Service approach assigns values to one or more specific functions that DERs may perform for the grid and provides compensation based on the customer's decision to provide each of these services.

A. Hawaii

Hawaii was an early adopter in shifting away from NEM due to the extremely high adoption of rooftop solar relative to most of the mainland US. The Hawaii PUC's Order No. 33258 ending traditional NEM came in October 2015 when about 10% of households in the state had rooftop solar installed as compared to a national average of 0.5% at the time.[34] Most recently, in December 2023 the Hawaii PUC fully finalized a new set of DER tariffs for basic and advanced DER services. The Smart DER and Bring Your Own Device (BYOD) tariffs were launched in March 2024 following a delay resulting from the catastrophic wildfires in Maui in 2023.[35] The Hawaii PUC has determined that the Smart DER program will consist of two sub-riders for customers; one allowing for on-site load reduction and one allowing for export to the grid.[36] The non-export tariff will facilitate rapid interconnection for DERs that will be serving on-site load and will not allow compensation from net injections to the grid. The export tariff will follow a time-based compensation paradigm that will follow the time-of-use (TOU) rates available to ratepayers, illustrated in **Table 3**.

Table 3: Hawaii Smart DER Compensation Rates, $/kWh (Hawaii Public Utilities Commission 2024)

Island	Overnight (9pm-9am)	Daytime (9am-5pm)	Evening Peak (5pm-9pm)
Oahu	$0.189	$0.135	$0.329
Hawaii Island	$0.148	$0.106	$0.231
Maui	$0.131	$0.066	$0.182
Lanai	$0.259	$0.267	$0.408
Molokai	$0.174	$0.179	$0.272

The BYOD tariff will open up the possibility for DER to provide more advanced services to utilities, at three distinct levels: Scheduled Dispatch (Level 1), Utility Dispatch (Level 2), and System Grid Services (Level 3). Scheduled Dispatch constitutes a commitment of a customer to dispatch their DER to the grid for a selected 2-hour period during the evening peak load window. Utility Dispatch is a customer's commitment to dispatch when requested by the utility for a period of one to two hours, up to 156 occasions per year. And finally, System Grid Services are composed of Capacity Load Reduction and Capacity Load Build, wherein a DER will respond to the utility's request to either dispatch energy to the grid or to charge from the grid, respectively, for a period of two to four hours. Effectively, this operates as a ramping service to smooth changes in net load. These tariff structures are clearly designed to deploy BES resources more effectively at the distribution level. The primary principles named by the PUC in designing these tariffs were 1) providing beneficial incentives to customers for DER adoption; 2) reducing peak loads; 3) deferring utility investments; and 4) offsetting or replacing fossil fuel use in the energy system.[37] This is an example of the "Value of Service" valuation framework for DER, which allows for DER to be compensated based on the needs that they elect to fulfill for the grid.

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[34] Gies 2015.

[35] Hawaii Public Utilities Commission 2024.

[36] Hawaii Public Utilities Commission 2023.

[37] Hawaii Public Utilities Commission 2023.

VII. Valuation Methodologies Price Signal Analysis

Each of the state valuation methodologies presented in the previous sections were examined using a standard model of a residential solar PV + BES system to examine how price signals are created for DERs in each of these jurisdictions. Importantly, these valuation methodologies are not designed to accomplish the same goals. Some are designed to increase DER adoption (or motivate adoption in specific areas), some are designed to motivate specific behaviors for existing DERs, and some are designed to balance these goals or to lay the groundwork for higher rates of DER adoption in the future. This is not a value judgment on any of the methodologies examined, simply a comparison of how they create incentives for DER owners. Also implicit to this analysis is the assumption that rates for exporting excess energy generation to the grid are a factor that drives investment and operation decisions for DER owners rather than solely offsetting their own consumption and maximizing the reduction to their onsite load using DER.

A. Modeling Methodology

An 11.85 kW fixed-tilt solar PV array and 10.1 kWh lithium-ion battery were used as a baseline resource based on average resource sizes purchased from the EnergySage marketplace in 2023.[38] Operation of this resource was modeled using the NREL System Advisory Model tool to create a model of hourly operation for the resource over one year with the location set to a suburb of Washington, DC. The identical resource operation data is then used to examine the resulting compensation from each methodology. This is a key feature of the model, as behavior changes from the DER operator would be required to maximize realized compensation and/or avoided cost from some of the methodologies studied. Nevertheless, understanding the potential for these methodologies to change DER behavior starts by examining how resources are compensated for grid services when behavior remains uniform. As a result, no changes are made to the operation of the modeled resource across the tariffs to establish a baseline for comparison. Values for compensation from each methodology were taken from 2023 or the most recent year for which data was available. A traditional NEM tariff was also modeled using a simple average of all EIA-reported retail electricity rates for the United States in December of 2023.[39] Additional details pertaining to the methodology used for the model can be found in Appendix A to this document. The specific tariffs used for this analysis are listed in **Table 4**. Hawaii's recent BYOD tariff is not modeled due to uncertainty of dispatch for participating resources.

Table 4: Rates Used for Analysis of DER Valuation Methodologies[40]

State, Tariff	Application
Minnesota, Value of Solar	Xcel Community Solar Garden participants, Vintage Year 2023 - Year 1 (2023)
Minnesota, Value of Solar	Xcel Community Solar Garden participants, Vintage Year 2023 - Year 25 (2048)
Kentucky, Net Metering Successor	Kentucky Utilities service territory
Kentucky, Net Metering Successor	Louisville Gas & Electric service territory
Kentucky, Net Metering Successor	Kentucky Power service territory

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[38] As reported in the FY 2023 EnergySage MarketPlace Report, www.energysage.com/data/?#intel-18).

[39] EIA. Electric Power Monthly February 2024. U.S. Energy Information Agency, 2024.

[40] Note: Minnesota's VoS tariff has not been implemented at the residential level, solely being employed for >1MW distributed solar projects.

State, Tariff	Application
New York, Value Stack	Westchester/NYC suburbs region, Con Edison service territory
New York, Value Stack	Albany/Capital region, National Grid service territory
Hawaii, Smart DER	Oahu Island
Hawaii, Smart DER	Hawaii Island
Hawaii, Smart DER	Maui Island
Hawaii, Smart DER	Lanai Island
Hawaii, Smart DER	Molokai Island
California, NEM 3.0	Southern California Edison service territory
California, NEM 3.0	Pacific Gas & Electric service territory
California, NEM 3.0	San Diego Gas & Electric service territory

B. Model Results & Discussion

An important note on interpreting the results presented here; this analysis uses the compensation achieved by rate designs employing DER valuation methodologies to support conclusions about price signals that DER valuation can create for exports to the grid. In the cases of Minnesota, Kentucky, New York, and California, the rate design is a direct translation of the valuation methodology into a rate design intended to reflect the value calculation. Hawaii has a clear rate design in the Smart DER program, but the underlying calculation of value that their rates are derived from is less visible than the Value of Resource methodologies. As a result, this analysis should be useful for interpreting incentive structures created by the valuation methodologies studied, including using the same methodology and metrics to study Hawaii's compensation for DER to demonstrate how their rate design creates incentives akin to the valuation methodologies that the other states employ. The value of behind-the-meter consumption being equal to the retail rate in each rate design, measuring the compensation for exports from a resource allows for an examination of if and how customers are encouraged to interact with the grid using DER.

However, analysis of disparities in valuation of DER itself (i.e. California, KY, and NY using different metrics to value emissions reductions, or Kentucky being the only state to include economic benefits of DER in valuation) would need to be examined independently of compensation and evaluated based on the reasoning behind application of metrics to components of valuation. The scope of this analysis does not reach the intricacies of selecting components to use in DER valuation and identifying metrics that most accurately measure these components. Rather, this analysis may be useful to project how the selected components and metrics of DER valuation are reflected in price signals received by end-users.

Moving to results and discussion, summary results of export compensation achieved by the resource modeled and average hourly compensation are shown in **Table 5** with the tariffed electricity rate for each utility as of December 2023 provided for reference.

Table 5: Summary Results – Total Annual Compensation ($), Total Annual Compensation Net of Onsite Consumption ($), Average Export Compensation Rate (¢/kWh)

	Total Annual Compensation ($)	Average Export Rate (¢/kWh)	Tariffed Residential Electricity Rate (¢/kWh)
Minnesota Value of Solar			
2023 Rate	1,723	10.58	8.22-13.07 (Xcel)
Kentucky NEM Successor			
Louisville Gas & Electric	741	6.93	10.84
Kentucky Utilities	788	7.37	10.53
Kentucky Power	1,042	9.75	12.05
New York Value Stack			
Westchester/NYC suburbs	1,637	18.69	31.95 (Con Edison)
Albany/Capital region	866	9.89	15.05 (National Grid)
Hawaii Smart DER (Hawaiian Electric Co.)			
Oahu	1,485	19.43	42.87
Hawaii Island	1,165	14.78	48.31
Maui	754	11.78	43.59
Lanai	2,850	28.65	50.39
Molokai	1,911	19.20	50.60
California NEM 3.0			
Pacific Gas & Electric	479	5.47	41.0-51.0
Southern California Edison	462	5.27	32.0-42.0
San Diego Gas & Electric	547	6.24	40.7-51.2

Note: Please see Appendix B for residential tariff rate sources.

VIII. Key Takeaways

There are five key takeaways resulting from the analysis of how differences in valuation methodologies create varying incentives via price signals.

1. **For rates in effect in December 2023, none of the average export rates calculated in this model equal or exceed the tariffed volumetric residential rates of the local utility.**[41] In practice, this means that it would be impossible to meet or exceed the compensation possible in traditional NEM without targeting hours of highest potential compensation, which is also not possible in methodologies that do not contain hourly components. The result is that DERs are compensated at lower values than the retail rate. Further study would be required to determine if DERs are able to operate in coordination with rates that include hourly variation to close this gap through changes in DER deployment and utilization.
2. **Each valuation methodology allows for some flexibility, but methodologies that allow for greater pricing variation (e.g. hourly pricing) allow for more precise alignment of price signals with hours of need.** Minnesota and Kentucky compensate production and export, respectively, at a flat rate, but the other rate designs studied include components that cause compensation for exports to the grid to fluctuate across hours. The variability in these methodologies is demonstrated through the difference between the minimum and maximum export values achieved in the model year as shown in **Table 6**.

Table 6: Difference between Maximum and Minimum Hourly Export Rate

Methodology	Difference between Maximum and Minimum Hourly Export Rate (¢/kWh)
NY Value Stack – Westchester	116.6 ($1.166)
NY Value Stack – Albany	65.8
Hawaii – Oahu	19.4
Hawaii – Hawaii Island	12.5
Hawaii – Maui	11.6
Hawaii – Lanai	14.9
Hawaii – Molokai	9.8
California – SCE	1,034 ($10.34)
California – PG&E	989.3
California – SDG&E	1,223 ($12.23)

Minnesota's VoS methodology is static throughout the year but has a yearly escalator built in for the rate paid to participants. This results in an increase in annual compensation of $1,351 (a 78.5% increase) over the 25-year life of a project with a 2023 vintage from an increase of 8.3 ¢/kWh paid for gross solar production over that time.

Kentucky's NEM successor tariff resulted in a difference of 2.82 ¢/kWh for exports to the grid between the lowest and highest active rates across utility service areas, but rates are static within each utility service area.

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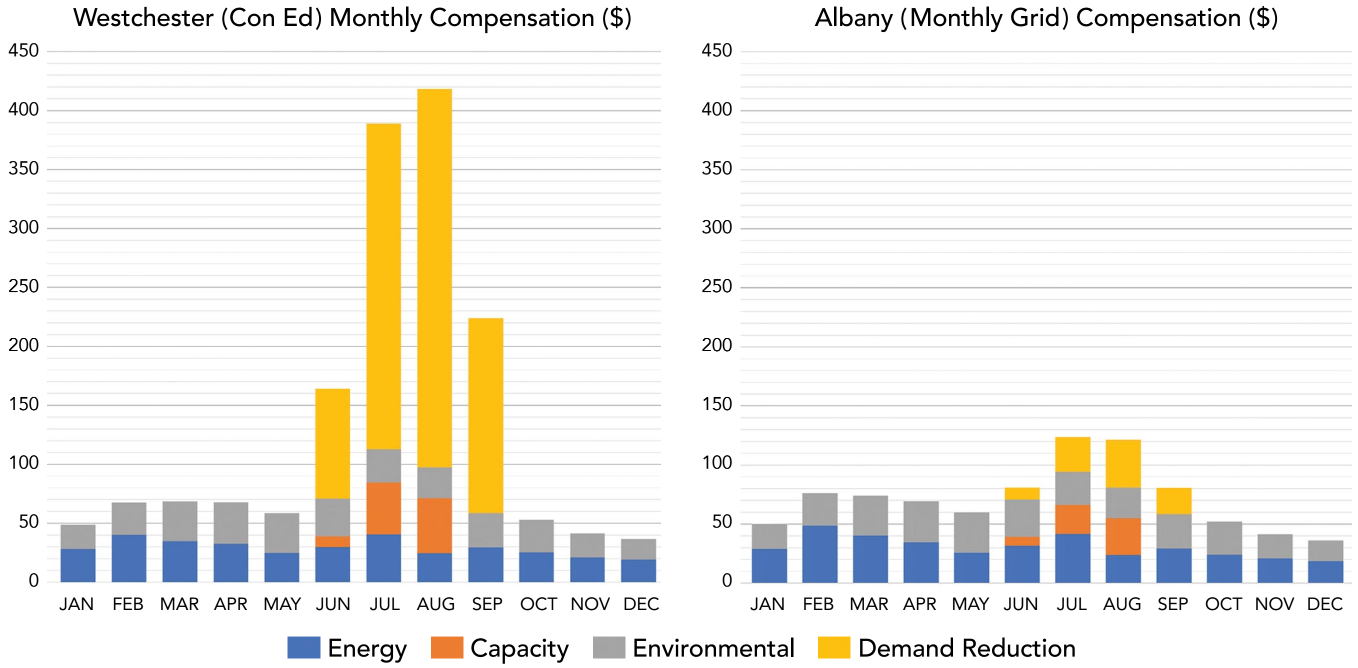
[41] EIA. Electric Power Monthly February 2024. U.S. Energy Information Agency, 2024.

Kentucky's NEM successor sets a value that is determined by a regulatory proceeding at the Public Service Commission for each utility, so there is no inter-period variation within a utility service area.

Hawaii's Smart DER program resulted in a difference of 16.87 ¢/kWh weighted average export value between the lowest and the highest active hourly rates between islands. The difference between the maximum and minimum export values for individual islands ranged from 9.8 to 19.4 ¢/kWh for Molokai and Oahu, respectively.

The projected difference in average compensation for export between the suburbs of New York City (within the Consolidated Edison service territory) and the New York Capital region (National Grid) is 8.8 ¢/kWh. However, these regions varied significantly in export rates across months and hours of the day, with the Westchester region outside of NYC earning as much as 3.35x the Albany region for exports during the summer months as illustrated in **Figures 5 & 6**. Value in the Westchester region is primarily driven by the Demand Reduction Value (DRV) in the Value Stack, meaning that the compensation increase is a result of exporting power to the grid during the hours in which it is experiencing the highest loads during the summer months. The Westchester region also resulted in a maximum hourly export rate about 1.8x higher than the maximum in the Capital region.

Figures 5 & 6: New York Value Stack Monthly Compensation, Westchester vs Albany.*


Westchester (Con Ed) Monthly Compensation ($)

Albany (Monthly Grid) Compensation ($)

***Note:** for New York's Value Stack, the LSRV, CDG, and MTC components were omitted because they do not apply equally across utility service areas, date of interconnection, and resource type. As a result, they could skew estimation of baseline compensation rates dependent on granular resource-specific assumptions. However, only the LSRV component would affect the analysis of price signals carried out here as the CDG and MTC components apply evenly to export at all hours.

The California NEM 3.0 methodology resulted in a small (< 1 ¢/kWh) difference in the average hourly export rate of the three utility service areas studied. However, they displayed by far the highest ceilings and ranges for possible export rates, with maximum values over $10/kWh for Pacific Gas & Electric and San Diego Gas & Electric during the model year, as compared with other maximums in **Table 7**. These methodologies also had hours in which the export rate was below 0 ¢/kWh, implying a cost for injecting energy during some hours typically falling in the 1-4pm range of peak solar PV production. This results in the highest ranges in export price of any methodology studied here, as compared in **Table 6**. However, high-export rate hours are very rare and are largely canceled out in the calculation of average ¢/kWh available as a result, leading to the NEM 3.0 methodologies with lowest average ¢/kWh export rates available to participants due to the relatively low export rates in median hours.

Table 7: Maximum Hourly Export Rate Available in Model Year

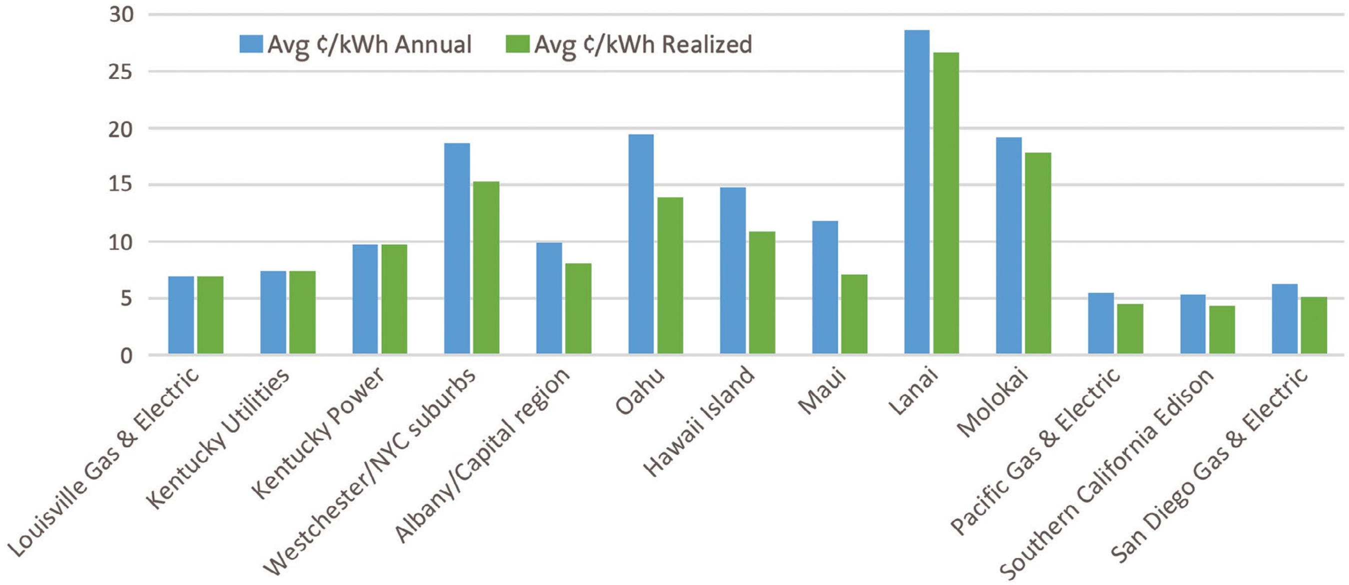
Methodology	Max. Hourly Export Rate (¢/kWh)
NY Value Stack – Westchester	120.9 ($1.209)
NY Value Stack – Albany	68.7
Hawaii – Oahu	32.9
Hawaii – Hawaii Island	23.1
Hawaii – Maui	18.2
Hawaii – Lanai	40.8
Hawaii – Molokai	27.2
California – SCE	989.1 ($9.891)
California – PG&E	1,034.0 ($10.34)
California – SDG&E	1,222.5 ($12.225)

3. **Stronger price signals and incentives can be observed in methodologies that offer high compensation rates that are not achieved without behavior change from participants.** The average ¢/kWh values paid to participants in Hawaii's Smart DER program represent five of the six highest values currently active but showed mixed results in the annual compensation received (see **Table 5**). This demonstrates that to best utilize the high rates available on certain islands, DERs must export in alignment with peak load hours. As described elsewhere, our analysis did not account for behavior changes in response to price signals.

High hourly compensation rates, most visible in New York and California, show that strong price signals are created in specific hours using components with inherent hourly variation, incentivizing DER export at those hours. Having a high differential between the maximum and the average rates of compensation for exports means that DER owners will be very strongly incentivized to export energy in the hours that provide the highest compensation, particularly when rates in these hours exceed retail rates as they do in each state (i.e. creating an incentive to export to the grid rather than simply reduce onsite load at a later time). One way of measuring this difference over the course of the model year is to calculate the difference between the average rate of compensation realized by a resource against the average rate of compensation over the model year within the rate design, as shown in **Figure 7**.

Rate designs that provide a higher level of compensation on average provide the strongest overall incentives to DER owners, and those with the greatest differential between the annual average and realized compensation rates provide the strongest price signals to users. For example, the rates on Lanai Island demonstrate an incentive for DER adoption with the greatest average compensation available to customers, while the rates for areas like Oahu, Maui, and the Westchester area of New York send strong price signals for DERs to operate in alignment with grid needs. Although the NEM 3.0 export rates in California can reach high hourly export values, the low average export rates for the model year (particularly in contrast to the state retail rates) indicate relatively weak incentives for DERs to export across the year despite those exceptionally strong price signals in specific hours. Based on the CPUC proceedings, this is likely an intentional feature of California's rate design meant to solidify the economic value of distributed BES resources on the grid to smooth energy consumption throughout the

Figure 7: Average Export Compensation Rate Possible vs. Realized (¢/kWh)



Minnesota's VoS is not included because a resource is compensated for production rather than export under that rate.

day and mitigate the evening peak load in the state. The other states here provide greater average value to DERs, but further study would be required to understand the potential for DERs to realize higher compensation than the average export rate based on behavior change.

Generally, valuation methodologies and rate designs that concentrate value in specific hours at times of need for the grid are likely to bring DER behavior in line with grid needs at the distribution level. Several methodologies here attempt to do that using price signals of varying strength, the efficacy of which in changing DER behavior remains to be seen. This is in part due to the next key takeaway.

4. **Improved transparency in rate design could facilitate DER deployment in response to grid needs.** Data availability and ease of interpretation to customers will be a factor in enabling effective deployment of DERs and providing appropriate price signals to DERs engaging with the distribution system. These methodologies take very different approaches to this challenge. Some provide extremely clear rates but limited insight into the calculation of these rates, while others use extremely in-depth calculations to demonstrate how value is derived, which may come at the cost of predictability and ease of use for customers. Finding a balance is key as investors at the residential and commercial levels seek to solidify their revenues from DERs and grid operators seek to align price signals with system needs.

5. **Further study should be completed to understand the technical potential of implementation and compensation for each of these methodologies given changes in DER deployment responding to price signals, as well as retrospective study on resource deployment following the implementation of each methodology.** It is possible that DER could realize higher average hourly compensation for export than the annual average export rate based on behavior change in rates with hourly components, pending the ability to predict and schedule operation to comply with hourly rate changes. Although that analysis is beyond the scope of this report, it will be important to understand 1) how DERs are responding to the rates here that are currently active and influencing the operation of DERs; 2) how total possible compensation can be compared across valuation methodologies to fully interpret the power of the incentives that they offer to users; and 3) how existing valuation methodologies can be improved to offer the closest alignment of price signals and incentives for users to provide value to the grid. Retrospective study of DER operation on

the grid following the implementation of new tariffs using regression discontinuity or time-series methods would provide insight into the potential for these rate designs to influence resource behavior. Additional study of compensation possible within a specific tariff, assessed by modeling optimized resource behavior to maximize realized export rates, would provide valuable insights as well. Each of these studies should be conducted with a critical eye toward existing valuation methodologies and rate designs to determine areas where improvement may be achieved using metrics such as possible and realized average export rates to make standardized comparisons that are universally applicable. This analysis has provided some insight into how price signals and incentives are structured and how they may be measured, but extensions from this report will be required to elucidate each of these topics going forward.

IX. Conclusion

The first key to unlocking the potential of DERs is to understand the current state of DER adoption in a jurisdiction and actively evaluate whether changes are necessary. If it is determined that changes should be made to the status quo, the next step should be to consider the maturity of DERs on the local distribution grid in quantity (capacity and generation), type (solar PV, solar PV + BES), and current effects on grid operations. For example, the Kentucky PSC actively evaluated the maturity of DER in the state throughout the course of their proceedings on designing a successor to NEM, guiding the decisions made to value DER on their system. This includes discussion on the quantity of DERs present in the state and the effects that this can have on cost shifting for ratepayers (or the lack thereof). This type of evaluation provides necessary context for DERs to be valued appropriately. Similarly, states with significantly higher shares of DER on the grid like Hawaii and California have begun to deal with different costs from DER than many other states are experiencing, and it will become important to understand how their systems adapt to the reforms they are currently undertaking.

Determining metrics based on grid conditions is another key aspect of advanced rate design for DERs, and an especially crucial consideration for states that have begun to experience drawbacks from traditional NEM. The methodologies studied here seek to accomplish this using different approaches, in part because they are experiencing different issues. New York has a relatively unique system due to the load pocket and infrastructure constraints around NYC, and as a result has designed a system that is highly responsive to the location of a resource and provides price signals based on grid conditions that are granular to the substation level using components of the Value Stack. In contrast, Kentucky and Minnesota have created generalizable methodologies to guide BCA for DERs across the utility service areas in the state in an effort to streamline the application of value-of-resource tariffs for utility rate design to enable deployment and customer transparency. Each of the states examined here have designed their approach to DER Valuation to meet the needs of their ratepayers and their grid.

As the proliferation of DERs continues, innovation will continue to be necessary in valuation and rate design. Regulators will need to adapt to the landscape of forthcoming energy technology and policy, facing issues including integrating wholesale markets with DER rate design to operationalize FERC Order 2222, adapting valuation methodologies in response to deployment of aggregations in VPPs, and incorporating components of value that are currently difficult to quantify (i.e. resilience or energy access) into future rate designs. Another layer of this challenge will be determining how to fully address stakeholder feedback in DER proceedings and ensure that adequate incentives remain for households and businesses to continue investing in DER for as long as it is economical to do so. Addressing these issues will necessitate consideration of approaches examined here along with tariffs that are designed completely differently, such as Connecticut's DER tariff that prioritizes reaching deployment targets to meet policy goals.[42] Existing and novel rate designs and programs will be needed to measure the value of DER accurately and comprehensively in the face of rapidly shifting grid conditions and guiding policy.

Ultimately, every state is balancing different obstacles and opportunities in DER adoption. The approaches to DER Valuation examined here each attempt to align incentives for DER owners with the needs of their local grids and state energy policy goals. Continuing to do so in future proceedings will guide the efficient and just development of each phase of the electric grid for years to come.

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[42] More information available at www.portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/residential-renewable-energy-solutions-program.

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Appendix 1: Modeling Methodology & Additional Inputs and Outputs

Resource Assumptions / SAM Inputs

- PV array: 11.85 kW
- Type: fixed-tilt, 20 degrees, 180 degrees azimuth
- Battery size: 10.1 kWh
- Type: lithium-ion
- Battery dispatch: Peak shaving (look-ahead)
- Inverter size: 10.3 kWac, efficiency 96%
- System losses: 14.08%
- Weather file: Washington, DC. Latitude 38.89, Longitude -77.02, Elevation 26m

Resource Operation Data (SAM Output, Input to Compensation Model)

System Annual Results (universal)	kWh
Total electricity generated onsite	16,282
Generation used to reduce onsite load	5,586
Electricity exported to grid	10,696
Electricity purchased from grid	5,243
Net export to grid	5,453

Full Data Sources

Data	Source	Link
Average PV and Storage size + performance specifications	EnergySage Solar+Storage Marketplace Report 2023	www.energysage.com/data/
Solar PV hourly production	NREL System Advisory Model (PV Watts)	www.sam.nrel.gov/
Onsite hourly load	NREL System Advisory Model	Ibid.
Minnesota Xcel Community Solar Garden 2023 Residential Rate Vintage	Minnesota Public Utilities Commission	www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={10AFDA8C-0000-CE12-A38E-E93E23E93478}&documentTitle=20241-201889-01
Kentucky Power Residential NEM Successor Tariff	Kentucky Public Service Commission	www.psc.ky.gov/agencies/psc/press/052021/0514_r01.pdf
Kentucky Utilities and Louisville Gas & Electric NEM Successor Tariff	Kentucky Public Service Commission	www.psc.ky.gov/order_vault/Orders_2021/202000350_09242021.pdf

Data	Source	Link
New York LBMPs	New York Independent System Operator	www.nyiso.com/custom-reports?report=dam_lbmp_zonal
New York Value Stack Historical Credits	New York State Energy Research and Development Authority	www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Frequently-Asked-Questions
New York Value Stack Hourly Attribution	VDER Value Stack Calculator	Ibid.
Hawaii Smart DER Tariff	Hawaii Public Utilities Commission	Hawaii PUC Decision and Order No. 40418 (www.puc.hawaii.gov/energy/der/programs/)
California NEM 3.0	California PUC 2022 Avoided Cost Calculator Electric Model Version 1b	www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/der-cost-effectiveness
Electricity Rate Data	EIA Average Price of Electricity to Residential Customers by State (Table 5.6a of Electric Power Monthly, February 2024 release)	www.eia.gov/electricity/monthly/archive/february2024.pdf

Calculations

Total Annual Compensation – Gross compensation for all methodologies other than Kentucky, which uses a traditional net metering system for true-up. Minnesota uses compensation for all production rather than exports to the grid.

Average Annual Export Rate – Simple average of rates available to resources for exports to the grid over 8,760 hours. For Minnesota, this is equal to the rate paid for production.

Average Realized Export Rate – Total Annual Compensation / Total Annual Exports to the Grid /100

Appendix 2: Residential Tariffed Electricity Rate Sources

Flat electricity rates, rather than time-of-use options, were used for utilities where customers can select between tariff options.

Con Edison – Con Edison volumetric rate is derived using a delivery rate ranging from $0.16107–0.18518 (see Leaf 388 from www.lite.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf) with an additional cost component from market-based supply charges. Average supply + demand rate approximated using 2024 data from www.lite.coned.com/_external/cerates/documents/average_monthly_electric_bills.pdf for Westchester region, subtracting bill riders and dividing by 600 kWh of consumption. Residential rate also includes a monthly customer charge that is not used in this study. Rates effective January 2025.

Hawaiian Electric Co. – all rates retrieved from www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity.

Kentucky Power – retrieved from www.psc.ky.gov/tariffs/Electric/Kentucky%20Power%20Company/Tariff.pdf, tariffed rate for energy is used but an additional monthly customer charge that is not used in this study is included in the residential tariff. Rates effective December 2024.

Kentucky Utilities – retrieved from www.lge-ku.com/regulatory/rates-and-tariffs, tariffed rate for energy is used but an additional daily customer charge that is not used in this study is included in the residential tariff. Rates effective September 2024.

Louisville Gas & Electric – retrieved from www.lge-ku.com/regulatory/rates-and-tariffs, tariffed rate for energy is used but an additional daily customer charge that is not used in this study is included in the residential tariff. Rates effective September 2024.

National Grid – Includes a delivery charge of 7.576¢ (retrieved from www.nationalgridus.com/Upstate-NY-Home/Rates/Service-Rates) and additional supply rate of 7.478¢ approximated using average value across load zones for 2024 (retrieved from www.nationalgridus.com/media/pdfs/billing-payments/electric-rates/upstate-ny/2025/nimo-e_average_prices_ending_december_31_2024.pdf). Residential rate also includes a monthly customer charge that is not used in this study. Rates effective date not shown, but effective when retrieved (April 2025).

Pacific Gas & Electric – rates retrieved using the tiered rate structure from www.pge.com/assets/pge/docs/account/rate-plans/residential-electric-rate-plan-pricing.pdf. Rates effective March 2025.

San Diego Gas & Electric – rates retrieved using the tiered rate structure from www.sdge.com/residential/pricing-plans/about-our-pricing-plans/whenmatters#STANDARD. Rates effective February 2025.

Southern California Edison – rates retrieved using the tiered rate structure from www.sce.com/residential/rates/Standard-Residential-Rate-Plan. Rate also includes a daily customer charge for electricity service that is not used in this study. Rates effective March 2025.

Xcel Energy Minnesota – retrieved from www.mn.my.xcelenergy.com/s/billing-payment/residential-rates/residential-plan, rate range displays includes consideration for customers qualifying for discount-rate tariffs based on electric heating installation.

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