



Flexible Reduction in Electric Energy and Power (FREE Power)

A Proposal for a Flexible Demand Program Framework and Model Tariff

October 1, 2026

Virtual Power Plants (VPPs) continue to offer the fastest and most cost-effective technology to support load growth from data centers, improve the utilization of the existing electric grid, and lower rates for consumers and ratepayers – yet current policy support and regulatory mechanisms for demand flexibility programs are insufficient. Despite countless reports, webinars, podcasts, comments in regulatory dockets, and other debates regarding the merits of VPPs, most flexible demand potential within the United States remains untapped, and in many cases unavailable to provide grid services, due to a lack of appropriate regulatory structures. The U.S. Department of Energy estimated that VPPs could provide up to 160 GW of flexible demand by 2030, yet today, the collective total of Demand Response (DR) and VPP programs across the country is estimated to be only 33 GW, less than 25% of the full potential.¹

Most existing utility-led and market-based VPP and DR programs today address on one or two aspects of the value stack (typically system-wide capacity or avoided peak energy prices) and do not incorporate other values (e.g. deferred transmission and distribution system investments, value of market price suppression). Existing programs often focus on large customers (or large aggregations of customers) with significant data and participation requirements, making participation difficult for some customers by requiring advanced commitments of certain technologies under specific participation rules. Existing programs are frequently constrained by administrative and structural barriers such as:

- Managed EV charging, net-metering, energy storage tariffs, DR programs, time-of-use rates, and energy efficiency are typically deployed as separate programs, leaving a homeowner to navigate a complex mix of programs with different program structures.
- Program rules for evaluation, measurement, and verification (EM&V) often impose challenging data requirements, which limit participation to technologies with sufficient data outputs to qualify.
- Where stakeholders have proposed flexible demand tariffs, they often have focused solely on solar and storage systems, missing entire market segments of flexible resources.

While these large-scale VPP and DR programs provide critical value for resource adequacy and accredited capacity reductions, they also limit realization of the full benefits of behind-the-meter (BTM) resources to the power system.

¹ [“U.S. Department of Energy Releases New Reports Highlighting Benefits of Consumer-Centric Solutions for Households, Businesses, and Utilities,” January 10, 2025](#)

The country therefore requires a complementary, rate tariff-based alternative² which expands upon existing programs, opening access to additional participants while avoiding double-paying for the same load reductions. Regulators are struggling with how to manage cost allocation of new grid infrastructure and potential implications on affordability due to load growth from data centers, new manufacturing loads, and electrification of transportation and heating. New regulatory constructs to overcome these barriers and unify different distributed energy resources (DERs) into coherent outcomes can therefore yield significant benefits for the grid and ratepayers.

Proposal: A Flexible Demand Framework Based on Hourly Savings, Measured and Verified at the Meter

To advance technology-neutral, flexible demand programs that fully compensate all elements of grid flexibility provided by DERs, the Flex Coalition is introducing a flexible demand program framework, termed the “**Flexible Reduction in Electric Energy and Power**” (**FREE Power**), consisting of:

- This concept whitepaper, describing the rationale and overall program structure;
- A design guide (Appendix A), including suggested best practices for quantifying the benefits across capacity, resiliency, transmission, distribution, and energy savings, and methods for allocating these benefits across the hours of the year; and
- Model program documentation (Appendix B), including terms and conditions and sample program manual language.

We hope these resources will be useful for utilities and stakeholders in proposing pilots, non-wires alternatives, and scalable programs to offset load growth, and to regulators and policymakers as they consider various proposals for deploying flexible demand at scale. The program framework and structure will undoubtedly need to be tailored to each specific utility and regulatory context – we have endeavored to preserve flexibility and highlight options to tailor the program wherever possible. Where data or procedures are not currently in place to meet all elements of the framework, we encourage an incremental approach to deploy some elements of the program and then add in additional value streams as data allows.

² “Rate tariffs” are pricing structures published by utilities after approval by regulators that determine how much customers pay for their electricity (or gas, water, etc.) consumption, outline the rules and rates for utilities service, and describe other charges and credits for utility programs. They include charges based on type of customer (e.g. residential vs. industrial,) participation in programs (e.g. opt-in renewable energy supply, electric vehicles, or net metering for rooftop solar,) and customer size (based on monthly energy and/or peak capacity used.)

A Cohesive System of Analysis, Planning, Programs, and Settlement Functions

VPP compensation mechanisms, implemented through rate tariffs or otherwise, on their own cannot fully optimize deployment of DER, either for system or individual customer value. In particular, the proposal we advance here is for a non-dispatchable VPP which operates by setting forward looking compensation structures and letting participants shift load based on those signals. This is not intended to replace DR and VPP programs for committed, dispatchable load reduction; rather, the FREE Power framework serves as a foundational element, deployed in concert with other programs, which can expand eligible participation in support of complementary grid utilization and cost-reduction goals. We anticipate this concept will be a prompt for, and a complement to, the other necessary investments, such as:

- Dispatchable DR and VPP programs for resource adequacy purposes;
- Distribution system analytics and planning systems to identify the optimal locations on the distribution and transmission grid for DERs;
- DER Management Systems (DERMS) and other dispatch capabilities;
- Improvements to customer energy data access and sharing mechanisms, enabling households and businesses to own, manage, and share their energy data freely and securely;
- Programs to target the deployment of specific DERs, such as energy efficiency or solar+storage up-front incentives;
- Holistic measurement and valuation approaches in support of settlement functions; and
- Streamlining of cost effectiveness testing and benefits-cost analysis (BCA), such as the emerging Open BCA project.³

Introducing the FREE Power Framework

The FREE Power framework establishes a forward-looking hourly compensation mechanism, paid to DER owners or aggregators based upon the verified energy savings of their portfolio against a measured baseline. The hourly compensation should reflect the local and temporal costs of serving the customer load at any given day, hour, and location on the local distribution grid, including upstream transmission, generation, and societal costs.

³ "OpenBCA Tool," National Association of State Energy Officials, <https://naseo.org/nesp/openbca-tool>

Framework Design Principles

- The program should compensate DER owners (or their aggregators) for providing verified grid services that reduce energy costs, defer or avoid utility capital expenditures, manage transmission and distribution constraints, and/or enhance local and system-wide reliability.
- The program operates by encouraging shifts in electric demand without requiring dispatch by the utility or grid operator, opening new opportunities for participation by additional households, businesses, technologies, and market actors.
- The program is technology agnostic – any modification to behind-the-meter energy use qualifies for reductions under the program, including energy exported to the grid (which may be compensated at a different rate).
- The DER owner (or aggregator) is responsible for any and all electric demand behind the meter. It is the responsibility of the aggregator to offer and manage any compensation to the DER owner.
- The program compensation values shall, to the maximum extent practical, be based on actual system costs.
- The program should align utility, aggregator, customer, and ratepayer interests by promoting energy savings during the time periods of the greatest need and in areas of the distribution and transmission grid experiencing the greatest stress or required investments.
- The program shall adjust compensation as necessary to account for any incentives paid by ratepayers to the aggregator or customer for the same reduction or modification in energy use; this does not include compensation or incentives funded by mechanisms other than recovery on utility rates (e.g. such as tax credits or programs funded by state general funds).

The key steps in deploying the FREE Power program include:

1. **Establish avoided cost values.** This includes quantifying the avoided costs of generation capacity (\$/kW-year), transmission (\$/kW-year), distribution (\$/kW-year), energy (\$/MWh), and other societal impacts (e.g. emissions, \$/ton). To the maximum extent possible, these values should be localized to specific portions of the distribution and transmission grid. Utilities and regulators currently use a range of methods and sources for quantifying these costs, including energy and capacity markets, Integrated Resource Planning, distribution modeling, non-wires alternatives analysis, and general rate case proceedings. In some cases, utilities may not have an established value for each of these elements, particularly for location-specific or system-wide distribution avoided costs. In cases where insufficient data is available to precisely quantify the avoided cost

values, utilities should leverage reasonable assumptions of grid value, rather than assigning a zero value to the component. We present various example methodologies and best practices as part of the design guide in Appendix A.

2. **Allocate avoided costs to hours of the year.** Wholesale energy costs vary depending on utilities and market structures, ranging from day-ahead and real-time pricing in ISO/RTO markets to utility-owned generation to power purchase agreements and bilateral contracts with both fixed and variable components. Generation capacity, transmission, and distribution are typically calculated on an annual basis of \$/kW-year. The FREE Power framework allocates each of these cost components to specific hours of the year which drive those costs. We present various example methodologies and best practices as part of the design guide in Appendix A.
3. **Publish the localized hourly avoided cost values.** This includes an annual calendar of compensation values for each of the 8,760 hours of the year. The utility may also set some hourly values on a day-ahead basis to better reflect true avoided costs for wholesale energy, resiliency, and societal costs. Where possible, the utility should publish location-specific values for different segments of the transmission and distribution grid.
4. **Customer enrolls in the program (through an aggregator or as a self-aggregator).** The customer's energy use baseline is established at time of enrollment, based upon a weather-normalized baseline of the prior 24 months (ideally) of energy usage data,⁴ consistent with OpenDSM energy prediction methodologies.⁵ The customer's compensation rate is established based on the published hourly values at time of enrollment (excluding any day-ahead pricing), and is valid for a period of five years; after five years the compensation resets to the prevailing rate for another five years, and so on.
5. **Calculate the value of each aggregator portfolio's energy savings to the grid.** On a monthly [or quarterly] basis, the utility calculates the value to the grid generated by each aggregator portfolio. This is calculated as the sum, for each customer in the portfolio, of the weather-normalized energy savings in each hour against the customer baseline, multiplied by the difference between the FREE Power avoided cost value and the customer's electric rate for that hour.
6. **Aggregators (or self-aggregating customers) receive payment based on actual measured, ongoing reductions in energy use against the baseline.** Compensation payments represent a share of the overall grid savings; additional shares of the savings are allocated to the utility as a shared-savings incentive and towards rate reduction (not allocated, to be captured as savings by ratepayers).

⁴ 9-12 months could be acceptable in some circumstances

⁵ Open DSM (<https://opensm.energy/stable/>), formerly "OpenEEmeter," is the leading open-source library for measuring "the impacts of demand-side programs by using historical data to fit models and then create predictions (counterfactuals) to compare to post-intervention, observed energy usage." The regression analysis of historical usage serves as the baseline for future energy savings against which changes in technology or behavior can be measured in a weather-adjusted manner.

Aligning Incentives

The FREE Power program serves as a power tool to achieve improved grid outcomes by aligning compensation and incentives across customers, aggregators, contractors, utilities, and ratepayers. Legacy energy efficiency programs have suffered from overprediction of savings by contractors, and Demand Response programs based on enrollment or with opt-out provisions encourage customers to participate as little as possible to meet the minimum requirements. By offering compensation only for actual, delivered performance, FREE Power instead aligns the motivations of customers, contractors, and aggregators towards desired energy savings outcomes.

Similarly, by offering utilities a share of the savings as a performance incentive, the FREE Power program provides a framework to counter existing utility profit motives towards capital expenses. And by anchoring compensation below the full realized grid benefits, the FREE Power program ensures that ratepayers benefit as well through overall reductions in cost and rates.

Customer Energy Data Access

The FREE Power program relies upon the ability of customers to agree to share their energy usage data with aggregators prior to enrollment for estimation purposes and on an ongoing basis for performance measurement and evaluation. Utilities should implement a data exchange platform that enables third parties to embed electronic authorization into their customer enrollment workflows. To meet the needs of the FREE Power program, the data exchange platform should include, at a minimum, the following key characteristics:

- Secure customer authentication and frictionless authorization/revocation to promote data privacy and security;
- Efficient processes for third parties to register and be vetted to use the platform;
- Ability for third parties to promptly retrieve necessary interval, account, billing, and program participation data, both historic for enrollment and ongoing for performance evaluation, using APIs; and
- Current and active certification to the Green Button Connect standard for secure, permissioned data-sharing.

Utilities may procure commercial off-the-shelf data exchange platforms from software companies that meet these requirements. Data exchange platforms designed to meet FREE Power program needs can also be extended to synergistically support energy efficiency programs, VPPs, and business energy management, often with limited modifications to the scope of data being included.

Appendix A

Design Guide and Methodology Best Practices

Allocating Generation/Transmission/Distribution Capacity to Peak Hours

Generation, transmission, and distribution capacity costs⁶ (and avoided costs) are typically expressed in dollars per kW-year, the value of avoiding one kW of load across that entire year. Yet for costs driven by system peak capacity, this oversimplifies the fact that in reality, these costs are driven by the peak system loads experienced only 1-2% of the year. For the FREE Power program, these avoided costs must be allocated to specific hours of the year to encourage energy savings and peak reduction when it is most beneficial to the electric grid.

There are various methods for allocating capacity costs to individual hours across the year, often referred to as Peak Capacity Allocation Factor (PCAF), and utilities and regulators may use different methods for different purposes. These methods can range from the most simplistic volumetric spread (e.g. using hourly kWh usage to allocate capacity costs, as is done under the supply component in most volumetric rates) up to highly complex models to predict probability of failure under varying load scenarios. California uses a detailed system simulation to allocate generation capacity values to hours with the highest risk of load events:

“The annual generation capacity avoided costs (\$/kW-yr.) produced by the Integrated Calculation are allocated to the hours of the year that exhibit the greatest risk of reliability events based on SERVVM modeled reliability event timing. Allocating generation capacity avoided costs in this manner is intended to value resources based on their marginal contributions to system reliability (or, in other words, based on their ability to improve system reliability). Based on the electric demand and generation profiles used in the PSP RESOLVE case, staff studied the PSP case in SERVVM to determine the timing and magnitude of Expected Unserved Energy (EUE) events. These results are based on simulations of a system tuned to total Loss of Load Expectation (LOLE) of 0.1 (1 expected event in ten years), which is the industry standard.”⁷

A more simplified approach approximates the full risk profile by allocating capacity costs to a small number of hours each year (often the top 100- 250 hours,⁸ or the loads above 80% of system peak load,⁹ though utilities may utilize different thresholds based on their load profile). These hours are then weighted based on the load over the threshold/cutoff load, such that hours with the greatest load over the threshold are assigned the greatest share of the capacity costs. Once applied to prior, historical data, the results must

⁶ Note that “capacity” is often used in general parlance to refer specifically to “generation capacity,” yet transmission and distribution costs also have a component that is driven by the peak capacity of the system (as well as system voltage, geographic spread, etc.). These methods for allocating capacity costs to hours of the year can apply to all forms of generation, transmission, and distribution capacity, though they may or may not overlap in the peak hours load profiles.

⁷ [“2024 Distributed Energy Resources Avoided Cost Calculator Documentation, For the California Public Utilities Commission” EThree, October 2, 2024, p. 45](#)

⁸ See [“The Value of, and Compensation for, Distributed Energy Resources in Illinois,” EThree, January 2025, p. 98](#) and [“Marginal Generation Cost – PG&E’s Methodology,” Pacific Gas and Electric, May 5, 2016, p. 14](#)

⁹ [PG&E 2017 Rate Case Exhibit PG&E-9, p. 9-2](#)

then be projected forward based on seasonal (month), daily (weekday/weekend), and hourly characteristics to make them usable for setting future compensation levels (such as in the FREE Power program).

Streamlined Process for Allocating Capacity/Transmission/Distribution Costs

The simplified example process described below calculates the PCAF by identifying the top [200] hours with the highest system level load in each of the prior [3] years. This threshold should be based on any critical system resiliency, performance, or cost thresholds, and tailored to the utility circumstances to the extent possible (e.g. some utilities may focus only on the top 80 hours, etc.). Stakeholders may also adjust the formula by including projected future year load profiles – allowing utilities to reflect future changes in grid utilization due to data centers, electrification, or other changes in load.

To calculate the PCAF for a given hour, the difference between the hourly load and the threshold load are summed according to month, weekdays/weekends, and by hour of the day, then divided by the summation:

$$PCAF_{month, hour, day-of-week} = \frac{Load_{h,y} - Threshold_y}{\sum_{y=1}^3 \sum_{h=1}^{200} Load_{h,y} - Threshold_y} \text{ for all hours, } h, \text{ above the Threshold value in each of the years, } y.$$

Table A1 shows an example calculation, using PJM data, for a systemwide peak hourly load across all customers of 160,154 MW on June 23, 2025, at 4:00pm. Table A1 calculates the relative weights of each of the top 200 hours of the years based on the overall load:

Table A1: Example PCAF Calculation for 2025				
Hour Rank (A)	Date and Time (B)	Load (MW) (C)	Load Minus Threshold (MW) (D) = (C) - C _{Threshold}	PCAF Weight Factor (E) = (D) / SUM(D)*
1	6/23/25 4:00 PM	160,154	23,699	.0174
2	6/23/25 5:00 PM	159,862	23,407	.0172
3	6/23/25 3:00 PM	158,370	21,915	.0161
...	...	...	...	
198	1/21/25 5:00 PM	136,535	80	.00005896
199	1/21/25 8:00 PM	136,481	26	.00001922
(Threshold) 200	7/23/25 6:00 PM	136,455	0	0
SUM:		828.2 TWh	1,361,831	1.000

* [Use the sum of relative weights for all years in the analysis; 2025 shown here]

These PCAF weight factors reflect a risk profile for specific days of the historical year; to apply these values to future years, the weights are then allocated and summed by month, hours, and weekdays/weekends, as shown in Figure A1:

Best Practices for Locational Distribution System Valuation

The valuation of locational distribution system benefits of distributed energy resources (DERs), or lack thereof, remains one of the biggest barriers to expanding flexible demand programs across the country. While multiple markets and frameworks exist for valuing electric generation capacity and system-wide avoided costs, very few programs have captured the distribution system benefits in their value stack, particularly at a location-specific level. These distribution system benefits may far exceed other benefits to the electric system in some cases, and programs that focus only on bulk generation capacity systemically undervalue demand flexibility.

Where states do value distribution system benefits, they often use system-wide averages to reflect avoided costs, which inherently understates the value of DERs to some substations and circuits, and overstates it for others. To fully unlock flexible demand and DER capabilities to achieve consumer affordability and rate reductions, utilities must better reflect, publish, and compensate DER deployment on currently- and soon-to-be-constrained distribution infrastructure. While such analysis inherently requires assumptions about future load growth, these are precisely the assumptions that are already considered in ongoing distribution system planning and integrated resource planning—and which increasingly need to be re-examined due to explosive load growth from data centers and electrification.

These challenges led the Flex Coalition to publish a paper, *Measuring the Locational Value of Avoided Costs on the Distribution Grid*, in September 2026 to document best practices regarding distribution system valuation. The details of the paper are summarized below, and [available in full here](#).

When possible, a location-specific or circuit-level analysis of every node on the distribution system – looking over medium and long-term horizons under varying load growth scenarios – provides the greatest fidelity and can identify opportunities for DER value beyond the traditional NWA. Where such detailed engineering and modeling analysis is not feasible, more simplified approaches can approximate the value of DERs using more limited data inputs, while still providing a level of locational granularity not captured in current distribution planning practices.

To support policymakers in exploring potential distribution system benefits of DERs, the Flex Coalition is releasing the accompany decision support tool to demonstrate a simplified methodology for calculating long-term distribution system value. Using just six inputs, the tool estimates the value of the avoided distribution costs for a given segment on the distribution system.¹⁰

The required inputs include:

- The current design capacity/peak load of the segment;
- The current/recent peak load on the segment, as a percent of design capacity;¹¹

¹⁰ A segment could include an individual distribution feeder circuit, a substation and all of the downstream circuits combines, or some other collection of utility infrastructure subject to shared physical load constraints.

¹¹ Distribution operators often have flexibility in shifting load across substations and circuits to avoid overload conditions; the estimated ability to shift loads should be included as a reduction in the current peak load of the distribution infrastructure to reflect these capabilities, where appropriate.

- The projected rate of load growth for the segment;¹²
- The average cost of distribution system capacity upgrades, ideally derived from actual recent distribution capacity upgrade projects;
- The average service life of representative distribution system upgrades; and
- The utility weighted-average cost of capital (WACC).

The tool is intended to help policymakers in understanding the potential for location-specific distribution value for constrained, partially constrained, and unconstrained segments of the utility distribution grid. While this methodology does not replace detailed power system engineering analysis, it provides a greatly simplified approach that can support decision makers in evaluating flexible demand, energy efficiency, and other DER program location-specific benefits at a greater level of accuracy than systemwide averages typically used in current practice. The tool also quantifies the portion of the system value from the reduced capacity of the upgrade and from the time-value of delaying/deferring the upgrade, providing insights into the components of the valuation to inform decision-making. A more detailed explanation of the decision support tool is included in the whitepaper.

Where high-fidelity, circuit-level data is not available – or where a more simplified approach is warranted – utilities should consider binning circuits based on similar, known characteristics. For example, if the precise system loading is not well measured, but the systems has experienced overload conditions in the past, the circuit may be binned as a “high load” circuit. Where specific costs are not known, anticipated costs may be used to bin circuits as “high cost” or “low cost”, for example. These simplifications reduce the specificity of the model, but allow for easier modeling and can make the programs easier to understand and engage with for stakeholders.

Securing Capacity Value without Capacity Accreditation

Generation capacity is only one portion of the overall value stack for load flexibility, but it currently accounts for the vast majority of all value attributed to load flexibility in existing programs. Yet even capturing the value of load flexibility for reducing generation capacity requirements poses challenges, particularly in ISO/RTO capacity markets, where registration, data, and participation requirements have posed barriers to entry for smaller flexible resources and aggregators. As DOE states in the VPP Liftoff report 2025 update:

“Although industry actors have been excited about the potential impact of Order 2222, slow implementation timelines, varied approaches across ISO/RTOs, and obstructive state, ISO/RTO, and utility rules have blocked the full integration of VPPs into wholesale markets.”¹³

Key challenges in capturing capacity value include:

- **Metering and telemetry requirements:** Markets require different levels of telemetry and data; the Texas ADER program initially required 5-minute telemetry,¹⁴ and other markets require even

¹² Where there is significant uncertainty regarding the potential load growth, utilities and policymakers should evaluate multiple different load growth scenarios as a sensitivity analysis.

¹³ “Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update,” U.S. Department of Energy, p. 40

¹⁴ [Walton, Robert, “Texas task force aims to ‘tear down barriers’ to virtual power plant pilot as participation lags,” UtilityDive, December 11, 2024.](#)

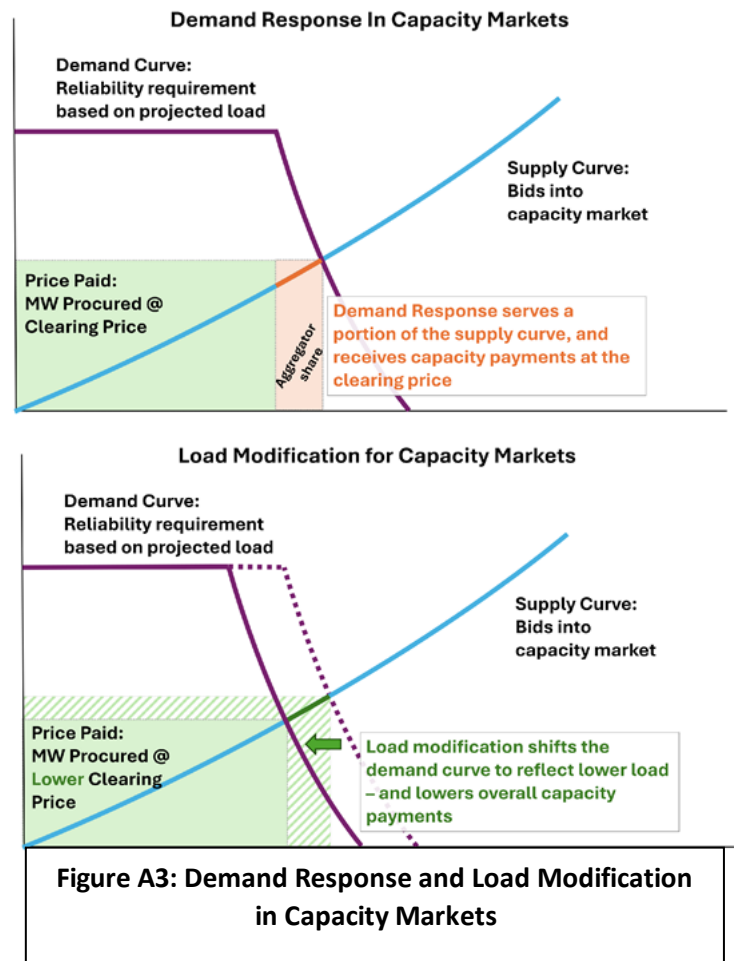
higher fidelity depending on the service provided, capabilities which far exceed the standard hourly or 15-minute increments of most residential AMI meters.

- **Short-term baselines:** Capacity markets often compare to a relatively recent baseline – 5-10 of the previous 45 days, for example.¹⁵ These baselines exclude other events days, but do not account for load-modifications for energy price optimization or distribution load reduction that may occur more frequently than ISO/RTO events, and do not address permanent load reduction.
- **Minimum Participation Sizes:** Some markets require minimum participation sizes, or transaction and soft costs make large aggregations a de facto outcome, excluding participation from smaller DERs and aggregators.

While active demand response remains a critical tool for managing peak load events and reducing capacity market costs, flexible loads can nevertheless deliver capacity value even without participating in an ISO/RTO capacity market. By reducing peak load, flexible resources can change the shape of the load curve, which is then reflected in utility (load serving entity) capacity obligations in the future. The FREE Power framework adopts this concept to allow all flexible customer load to reduce peak load and receive credit for generation capacity value, even without registering specific responsive load reductions in a capacity market.

As demonstrated in Figure A3, by consistently and regularly activating to lower the overall load profile, flexible demand resources can yield savings to all ratepayers through avoided capacity payments. A portion of that savings can be allocated to aggregators as compensation to achieve this outcome while a portion can also be allocated to utilities to enable participation (the utility incentive share) and towards overall cost reduction (the ratepayer share).

Load modifying flexible demand does not appear in reliability and load requirements for ISOs and RTO immediately, and there is a lag between when a DER is deployed and when it will show up in modified load profiles in a capacity market to result in cost savings. Nevertheless, the DER is providing real capacity



¹⁵ [“PJM Manual 11: Energy & Ancillary Services Market Operations” PJM, p. 193](#) and [MISO Tariff Attachment TT: Measurement and Verification \(M and V\) Criteria, p. 3](#)

requirement reduction and improved reliability as soon as it is deployed, even if capacity market structures take time to catch up. This reliability improvement provides real, immediate value as well; the PJM capacity auction for 2028/2029 fell short of the desired reserve resource level by 6.8GW, indicating that immediate load relief will provide real value towards the desired levels of reliability.¹⁶

Adjusting for Customer Rates

Electric rates are designed to recover the costs of operating and maintaining the electric grid – generally differentiated by customer class (e.g. residential, commercial, industrial, etc.). The standard flat volumetric rate is the most rudimentary method – the cost for every kWh of electricity is the same, regardless of when it is used or the cost to generate that electricity. Time of use (TOU) rates are a more tailored approach, where rates for peak periods are designed to better reflect the true cost to generate electricity at that point in time. Yet there are significant variations in the full grid costs across days and hours of the year which far exceed the TOU rate structure, as the value of peak reduction on the hottest or coldest day of the year is often significantly higher than a mild summer afternoon or winter morning. Energy suppliers facing wholesale markets and dynamic prices can further refine the temporal and locational specificity of customer rates and costs to the grid.

Sharing the grid savings with customers and aggregators to target demand reductions during the periods of higher cost can therefore offer a win-win scenario, where customers receive extra compensation and the grid still costs less to operate, reducing costs for all ratepayers.

In calculating how much of the savings should be shared with customers, it is important to take into account the amount they are already contributing to support the grid – namely their electric rate. If a customer saves 1kWh of energy during a peak period, it may save the utility and the grid \$1.00 in combined energy, generation, transmission, and distribution costs. Yet if their volumetric rate was \$0.20/kWh, the net savings to ratepayers is only \$0.80 – the utility no longer receives the \$0.20 for the saved kWh to contribute to grid costs. A customer on a TOU rate may have an even higher peak period rate (\$0.40/kWh, for example) and the net value to ratepayers of their peak savings is therefore only \$0.60/kWh. Failing to account for these differentials in any program could risk negative impacts to ratepayers.

TOU Rate (\$/kWh)	Cost of Energy and Infrastructure (\$/kWh)	Net Value of 1 kWh Savings to the Grid
\$0.10	\$0.03	-\$0.07
\$0.10	\$0.03	-\$0.07
\$0.15	\$0.03	-\$0.12
\$0.15	\$0.03	-\$0.12
\$0.15	\$0.06	-\$0.09
\$0.15	\$0.10	-\$0.05
\$0.15	\$0.25	\$0.10
\$0.15	\$0.40	\$0.25
\$0.30	\$0.50	\$0.20
\$0.30	\$0.60	\$0.30
\$0.30	\$0.55	\$0.25
\$0.30	\$0.50	\$0.20
\$0.15	\$0.40	\$0.25
\$0.15	\$0.25	\$0.10
\$0.15	\$0.10	-\$0.05
\$0.15	\$0.03	-\$0.12
\$0.10	\$0.03	-\$0.07

¹⁶ [“PJM Capacity Auction Procures 138,318 MW of Generation Resources as Work Continues To Address Growing Electricity Demand,” PJM Inside Lines, July 14, 2026](#)

The same is also true of shifting load to off-peak times – adding load (negative savings) to a customer on a standard volumetric rate (e.g. \$0.20/kWh) offers more benefit to ratepayers than doing so for a customer on a TOU rate with super off-peak hours (e.g. \$0.05/kWh).

The FREE Power Framework therefore subtracts the customers' current electric rate from the hourly compensation value to reflect the net impact on the grid and ensure that the grid savings outweigh the lost revenue from the customer rate to ensure affordability protections for other ratepayers. This also encourages increased usage when the customer's electric rate is higher than the grid costs – offering a payment to the aggregator to encourage usage that improves load factor and supports affordability.

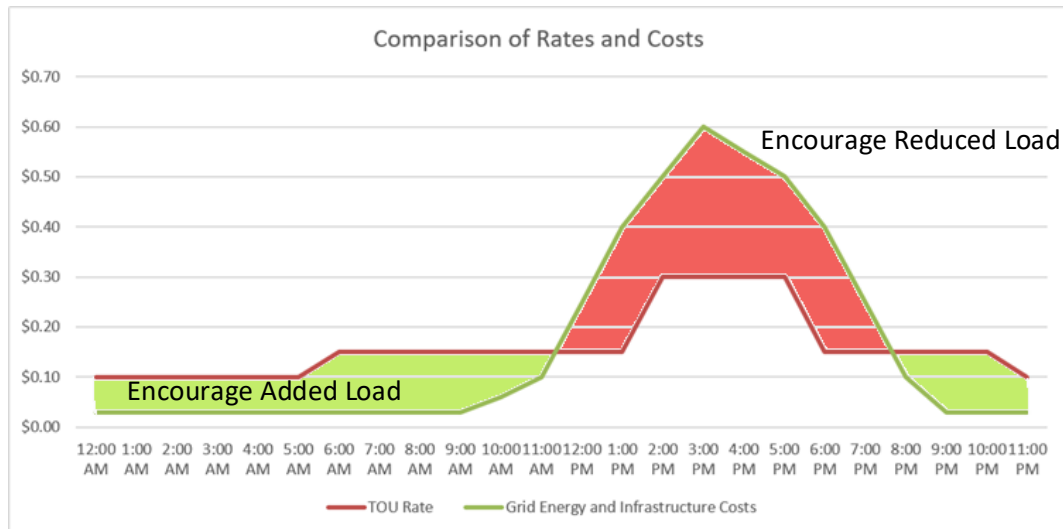


Figure A4: Example Differential Between Grid Costs and Customer Rates

Appendix B – Sample Program Documentation

Definitions

- **Aggregator:** An Aggregator is a service provider that enrolls, manages, and controls a portfolio of Customer behind-the-meter load, including DERs, to provide grid services and reduce overall costs as set forward in this program. Aggregators are responsible for compensating customers for participating. A customer may choose to self-enroll as an aggregator.
- **Company:** [The Public Service Company of XXXXX]
- **Customer:** A customer of the Company receiving qualifying service at a specific electric meter; see *Eligibility* for specific customer requirements. If a person has multiple accounts with the Company for different premises, or different meters at the same premise, each meter is considered a Customer and is able to participate independently.
- **Portfolio:** A group of customers enrolled through a single aggregator.

Applicability and Eligibility:

- **Aggregator:** FREE Power is available to Aggregators managing portfolios of customers interconnected at the distribution level. Prospective Aggregators must apply and be qualified by the Company. A prospective Aggregator must submit a completed FREE Power Aggregator Agreement. After approving the prospective Aggregator to participate in the FREE Power Program, the Company will countersign the FREE Power Aggregator Agreement. Approved Aggregators will be added to a publicly available list of participating Aggregators.
- **Customer:** Participation under this program requires that the entire service for each Customer account be measured by interval metering with a minimum of hourly data collection.¹⁷ Customers must have had an active account with the Company at the specified location for the prior [24] consecutive months, or have a sufficient history of usage necessary to establish a reliable baseline for energy usage. Customers receiving service under the following rate schedules are eligible for participation under this tariff:
 - [List appropriate Standard Offer Service, Time of Use, and other rate schedules for residential and commercial customer classes]

¹⁷ FREE Power relies upon hourly data collection, but other programs may benefit from higher fidelity in the data (e.g. 5 minutes, 10 seconds, etc.). Green Button Connect data standards support these higher data rates, and utilities should consider other data needs in implementing their data access processes to maximize synergy between programs.

Participation

Aggregator Enrollment: Aggregators will be approved for participation in the program on a quarterly basis; the company shall provide at least 30 calendar days' notice to aggregators regarding their approval (e.g. approvals for the quarter beginning July 1st shall be provided no later than June 1st). Aggregators may enroll at any time during the calendar year.

Aggregator Re-Enrollment: Aggregators shall re-enroll in the program annually by submitting the Aggregator Agreement Re-Enrollment form by no later than October 15th for the following calendar year.

Aggregator Termination: An aggregator may withdraw from the program by notifying the Company in writing; the effective date of the withdrawal must be no less than 60 days from the date of the notice. If an aggregator withdraws or fails to re-enroll in the program, the aggregator shall notify all customers enrolled through their aggregation at least 60 calendar days before their withdrawal shall take effect.

Customer Enrollment: All customer participation shall be conducted through an aggregator (including customers choosing to self-aggregate, who shall first enroll as an aggregator). Customers may enroll in the FREE Power program and select an aggregator through the online portal within the Company's standard customer-facing website; customer enrollments will be effective at the start of the customer's next billing cycle. A customer shall remain enrolled until they elect to terminate their enrollment or until they are no longer eligible (e.g. through participation in an ineligible rate schedule).

Customer Reassignment: A customer may choose to switch from one aggregator to another through the online portal; such change will take effect at the start of the customer's next billing cycle. A change in aggregator shall not modify the customer energy use baseline or established compensation rate.

Customer Termination: A customer may terminate their participation in the program at any time via the customer portal or by notifying their aggregator or the Company in writing; terminations shall take effect at the end of the customer's current billing cycle.

Customer Re-enrollment: A customer may re-enroll in the FREE Power program following prior termination only after a period of at least one billing cycle has elapsed. Re-enrolling customers will establish a new energy usage baseline based on the prior [24] months of energy usage and will establish new compensation rates based on the current rates for the program.

Grid Savings Compensation

The Grid Savings Compensation shall be calculated for each aggregator's portfolio of customers enrolled in the program. The value shall be calculated as the summation of the kWh savings achieved for each hour of the period multiplied by the hourly compensation value for each hour of the period. The calculation of the hourly savings and compensation values are described below.

$$\text{Grid Savings Compensation} = \sum_{h=1}^{8760} (\text{Hourly Savings}_h) \times (\text{Hourly Compensation}_h)$$

where

$$\text{Hourly Savings}_h = \text{Baseline Energy Usage}_h - \text{Actual Energy Usage}_h$$

The Grid Savings Compensation shall be allocated according to the following shares [may include the following components]:

Component	Share
Aggregator Share The Company may update this value annually when establishing the Fixed Hourly Compensation values for the upcoming year.	[X]%
Ratepayer Relief This portion shall not be allocated and shall be returned to ratepayers through reductions in overall system costs.	[X]%
Performance Incentive Share The Company may retain up to this percent of the Grid Savings Compensation, as approved by the Commission, to further motivate overall grid cost reductions.	[X]%

Hourly Savings

Calculation of hourly customer savings shall be conducted in a manner consistent with OpenDSM (formerly OpenEEmeter) and Normalized Metered Energy Consumption (NMEC).

Customer Baseline: At time of enrollment, the Company will establish the customer baseline from the prior [24] months of hourly customer electric usage. This baseline will remain valid for the duration of the customer’s participation in the FREE Power program.

Hourly Usage: Hourly usage shall be based on measured energy usage (in kWh) at the customer meter for each hour of the period.

Hourly Savings: The hourly savings shall be calculated for each hour of the period as the baseline usage minus the actual hourly usage.

Weather Normalization: The hourly savings shall be adjusted based on OpenDSM weather normalization protocols to adjust for differences in weather between the baseline year and the performance year.

Adjustments: The Company may adjust a customer baseline or energy savings to account for changes such as customer participation in an energy efficiency program within the baseline or current period, net-metered customers, or other non-standard circumstances. Adjustments to the baseline may be made by the Company with notice to the aggregator and customer, or at the customer or aggregator request, consistent with approved OpenDSM methodologies for adjustments.

Hourly Compensation

The components of the hourly compensation include:

$$\begin{array}{rcl}
 \text{Hourly Compensation}_h = & & \\
 & \text{Capacity-Resiliency}_h & \left. \begin{array}{l} + \\ \text{Transmission}_h \\ + \\ \text{Distribution}_h \\ + \\ \text{Energy}_h \\ + \\ \text{Resiliency Bonus}_h \\ + \\ \text{[Emissions}_h \text{]} \\ - \\ \text{Customer Electric Rate}_h \end{array} \right\} \begin{array}{l} \text{Fixed Compensation – Set} \\ \text{annually in December for each} \\ \text{hour of the upcoming year} \\ \\ \text{Variable Compensation – Set} \\ \text{daily for the following day} \\ \text{based upon projected load} \\ \text{conditions} \\ \\ \text{Customer's Current Rate – Can be} \\ \text{either static of time-of-use rates} \end{array}
 \end{array}$$

Fixed Compensation

The values for the Fixed Compensation (Capacity-Resiliency, Transmission, and Distribution components) shall be established on an annual basis and published through the web portal by December 1 for the coming year. The Fixed Compensation rates will apply to newly enrolled customers and be valid for a period through the end of the [5th] calendar year from enrollment (e.g. a customer enrolling on October 1, 2026, shall receive the same fixed compensation rates through December 31, 2031). At the expiration of the customer's set fixed compensation rates, the customer will be re-enrolled at then-current published rates for an additional [5] years.

- Capacity-Resiliency Component:** The Capacity-Resiliency component is calculated based upon the Company's marginal cost of capacity (\$/kW-year), allocated across the hours of the year.¹⁸ The marginal cost of capacity value shall be based upon [ISO/RTO auction results for the period of performance / results in latest IRP or rate case / other approved source, as appropriate]. The Company may adjust the Capacity-Resiliency component to ensure that aggregators and customers participating in the [ISO/RTO] capacity market are not paid twice for the same load reduction. Suggested methodologies for allocating Capacity-Resiliency values across the hours of the year and calculating an hourly value are included in Appendix A.

¹⁸ The FREE Power program may not qualify as accredited load reduction for capacity markets or resource adequacy purposes – rather, it incentivizes reductions to the baseline which are then reflected in lower load curves for the Company's requirements within capacity [markets/procurements]. As these reduced load baselines take some time to be reflected in updated load projections, they may not result in immediate savings within capacity markets for a period of [1-3] years until the lower load is reflected in future load projections. Nevertheless, reduced load provides additional resiliency value and improved reserve margins immediately, and therefore warrants compensation during the first [1-3] years of program participation.

- **Transmission Component:** The Company shall calculate the Transmission component based upon the marginal cost of transmission (\$/kW-year), allocated across the hours of the year. The Company may calculate different Transmission components for different delivery zones within the service territory. The marginal cost of transmission shall be based upon [latest IRP or rate case / other approved source, as appropriate]. Suggested methodologies for allocating Transmission costs across the hours of the year and calculating an hourly value are included in Appendix A.
- **Distribution Component:** The Company shall calculate the Distribution component for up to [20] Distribution Profiles across the system. The Company shall assign each customer meter to a Distribution Profile. To facilitate customer and aggregator engagement and maximize participation, Aggregators may query customer account numbers to determine which Distribution Profile they are assigned to before having a signed customer agreement in place.¹⁹

The Company shall calculate a Distribution Relief Zone (DRZ) profile for each circuit/feeders downstream of any substation with a planned capacity upgrade within the near-to-medium term planning horizon, as well as for any circuit/feeder on the distribution grid experiencing regular overload conditions. The Company shall calculate a system-wide distribution profile for any customers not covered by a DRZ profile.

For DRZ Profiles, the Company shall use the annualized projected costs of all projects to service customers within that Profile, divided by the incremental capacity of the projects to calculate the marginal cost of capacity (\$/kW-year). Some projects may serve multiple Profiles and be included in the calculation for multiple DRZs.

Profiles not designated as a DRZ shall use marginal cost of distribution as determined in the [utility cost of service study / value in latest rate case / other approved source, as appropriate]. Suggested methodologies for allocating Distribution requirements across the hours of the year and calculating an hourly value are included in Appendix A.

- **Energy Exports:** Hours where Customers achieve negative net energy usage (energy exports) may receive different compensation for the portion of the savings which are above their baseline. This may include a negative fixed distribution compensation value to reflect the costs to the distribution system of energy exports during certain hours.

Variable Compensation

The values for the Variable Compensation (Generation, Resiliency Bonus, [and Emissions components]) shall be published for the following day by no later than 12pm the day prior.

- **Energy:** The Energy component is calculated based upon the day-ahead marginal cost of wholesale energy (\$/kWh) from the [ISO/RTO value for the prior year / results in latest IRP or rate case / other approved source, as appropriate].

¹⁹ At a minimum, utilities should calculate DRZ profiles for any planned improvements and a high / medium / systemwide profile to reflect circuits with high / medium / low loading but no specific planned improvement. Utilities may further differentiate and calculate additional profiles to add fidelity beyond these minimum categories.

- **Emissions [depending on state policy]:** The Emissions component is calculated based upon the marginal hourly emissions intensity for the Company's generation mix, as determined in [ISO/RTO operations reporting / the latest approved IRP or rate case / EPA eGRID / other appropriate source] multiplied by the social cost of carbon emissions [approved by the Commission in docket # XXXXXX].
- **Resiliency Kicker:** The Company may offer an additional Resiliency Bonus to further prioritize system load reductions during predicted periods of peak grid stress, such as when:
 - The grid operator has called a grid emergency;
 - For which the Company predicts [specific contingencies such as condition yellow, mandated voltage reduction, etc.]

Customer Baseline Rate

Customers on different rates can have different impacts on overall grid costs. Customers on time-of-use (TOU) rates already pay higher prices during peak periods, and the benefit to other ratepayers of shifting their usage is lower than for customers on rates that do not reflect TOU.

The Company shall subtract the customer's current rate from the overall hourly compensation value paid to the aggregator; the remaining hourly compensation therefore reflects the impact that the customer's usage has on the grid which is not already covered in their rates.²⁰

Data Access

The Company shall provide a data exchange platform that enables enrolled aggregators to request and retrieve customer data through a streamlined, electronic process. The Company shall ensure that the data exchange platform maintains certification for the Green Button Connect My Data standard administered by the Green Button Alliance.

Customer Authorization. A request for authorization to receive customer data shall specify the type and frequency of data and the purpose for which it is requested by the aggregator. Prior to authorization, the customer must securely authenticate with the Company using their standard login credentials, including multifactor authentication for account login (if applicable) [or a process no more onerous than that used to log into the Company's website].

Customer Data. The Company shall enable an aggregator to request and retrieve billing-quality customer data that is necessary for program participation, including account data, billing data, and energy usage data in at least hourly intervals. Upon authorization, at least [24] months of historic customer data shall promptly (withing [5] minutes) be made available to the aggregator during the enrollment process. Once

²⁰ This may result in times where the hourly compensation is negative (i.e. hours where the total of the Fixed Compensation and Variable Compensation components are less than the customer's current \$/kWh rate). These hours would disincentivize energy savings (negative compensation) and would encourage increasing customer load (e.g. negative savings times negative compensation equals positive compensation for increased load). This increase in load during hours of lower cost to the grid provides overall benefits to ratepayers by increasing load factor and allows aggregators to be compensated not just for savings, but for load shifting to optimal hours.

permitted by the customer, ongoing billing-quality customer data shall be made available to the aggregator within 48-72 hours, until the expiration date established by the customer.

Aggregator Registration and Retrieval. Once enrolled, an aggregator is eligible to request customer data through the data exchange platform. The Company shall maintain APIs and dashboards that enable aggregators to securely retrieve customer data.

Consumer Protection. Upon securely sharing data with an aggregator by means of a certified data exchange platform, the Company is not liable for any use or misuse of data by the aggregator. Customers should review the terms of use provided by aggregators prior to sharing data. Customers may revoke an aggregator's access to data at any time through their online utility account, or through a means provided by the aggregator.

Compensation and Settlement

The Company shall calculate the total performance of each aggregation over each calendar quarter and shall issue a single payment for the net quarterly compensation to each aggregator. The payment shall be issued within 30 calendar days following the end of the performance period.

Customer Bill Transparency

The aggregator shall annually provide each customer, by no later than January 31st of each year, an estimate of their savings (not including any direct compensation provided by aggregators) based on their actual bills compared to an estimated bill using the weather-normalized baseline energy usage.