Pacific Northwest
NATIONAL LABORATORY

The Distribution System Operator with Transactive (DSO+T) Study

Executive Summary

PNNL-32170-Sum

JANUARY 2022

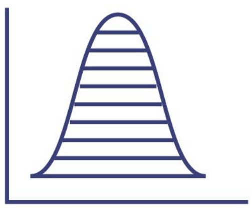
The DSO+T Study at a Glance

Transactive Energy coordinates flexible assets to improve grid operations...

Prices

Flexible Demand

...leading to a reduction in peak loads, energy prices, and required infrastructure...

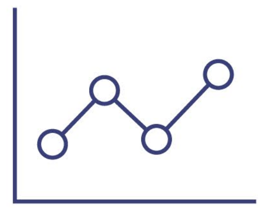


PEAK LOADS

9%-15%

Lower peak load means less infrastructure cost..

...and customers buy more electricity when it is cheaper



Wholesale Electricity Cost

7%-14%

...that lowers customers' utility bills and saves the nation billions of dollars every year

10-17% LOWER UTILITY BILLS

$33-50B ANNUAL NATIONAL NET SAVINGS

Prologue: The Need for Demand Flexibility

There has been no shortage of recent reminders that the nation's power grid is vulnerable to extreme weather events driven by climate change – severe winter storms in Texas, heat waves and wildfires in California, hurricanes in Louisiana – bringing the limitations of our current energy market and power grid operations into stark relief. These events can force grid operators and utilities to initiate large-scale rolling blackouts, causing customers to go without power

For example, the California rolling blackouts in August 2020 were a supply and demand problem driven by extreme heat, according to the final Root Cause Analysis report that was prepared by the California ISO and regulatory authorities and released earlier this year. The blackouts also refocused attention on the challenges presented by the state's notorious "duck curve," where distributed energy resources and the bulk power system cannot make up for the loss of large amounts of solar generation as those resources taper off in the late afternoon and early evening. The report also highlighted outdated market operations and energy trading practices that, by the time they knew what they were facing, resulted in grid operators not being able to secure adequate supply to prevent the wide-scale disruption.

While traditional utility and grid planning processes have focused on supply-side solutions, the value and practicality of pursuing demand side solutions to address persistent energy supply and demand challenges is becoming increasingly clear. Demand side flexibility did occur in the days after the California blackouts, preventing additional outages and showing the effectiveness of demand flexibility to support grid operations. However, such examples of demand reduction are typically emergency requests for load curtailment that are not well coordinated or automated and often rely on the uncompensated and manual actions of customers, who are starting to show fatigue at the increasing number of these requests from a strained grid.

There is a need for a solution that integrates the coordination of demand flexibility into everyday grid operation, ensures it is automated, puts the customer in control of how much or little they participate, and fairly compensates them for the level of flexibility they provide to the grid. What would such a system look like when deployed at scale? Would it achieve effective and stable coordination of a large number and range of end-loads? How much could peak load be reduced to ensure reliable electric service? And what is the impact on the customer's pocketbook?

With support from the U.S. Department of Energy's Office of Electricity, these are the key questions PNNL researchers set out to answer in the Distribution System Operator with Transactive (DSO+T) study, an unprecedented analysis of the impact and value transactive energy capabilities can deliver if deployed at scale and managed in an intelligent and coordinated manner. Our findings show the value proposition for coordinating flexibility in customer systems is compelling, and that through transactive energy the benefits accrue to a broad group of stakeholders. Our analysis shows that transactive energy reduces electricity costs for consumers. It does this by reducing peak load to avoid or defer expensive generation capacity costs and infrastructure upgrades.

Transactive energy can also act as an effective “shock absorber” by reducing the volatility from accelerating renewable integration efforts and electric vehicle deployment while also lowering required decarbonization investments by providing additional carbon-free resources in the form of reduced peak electricity demand. Finally, demand flexibility has the potential to improve the reliability of grid operation reducing the number and severity of grid outages.

We conducted the DSO+T study, a large-scale simulation of the grid, to assess the engineering and economic feasibility of using a transactive energy system to coordinate distributed energy resources. Customer-owned assets participate in efficient and reliable grid operations and are compensated for doing so. We analyzed the flexibility of a range of resources for both moderate and high renewable generation scenarios. Simulation results showed a 9–15% reduction in peak system load and a 20–44% reduction in daily load variation. A detailed economic valuation was used to show an annual benefit to customers of $3.3-5.0B for a region the size of Texas. This equals a national net annual benefit of $33-50B due to reduced electricity prices and the need for electrical infrastructure investment.

Distributed coordinated control of these resources can greatly reduce the investment needed in renewable generation and associated transmission and distribution system upgrades required to enable the electrification of the building and transportation sectors.

Overview of the DSO+T Study

Operating the large interconnected power systems is becoming more complex and challenging due to load growth associated with the use of intermittent renewable generation sources (such as wind and solar), the electrification of space heating and transportation, and the occurrence of extreme weather events that increase demand and reduce the reliability of supply beyond prior experience. Armed with intelligent controls, distributed energy resources (DERs) such as heating, ventilation, and air conditioning (HVAC) units, water heaters, batteries, and electric vehicles (EVs) offer considerable flexibility to grid operation, particularly during periods of peak load or abundant renewable generation. These distributed, flexible assets can improve overall system efficiency, cost effectiveness, reliability, and resilience and will be important as the power grid evolves from centralized, dispatchable forms of generation to more variable and distributed forms that are significantly more uncertain. Harnessing the potential of flexible assets also presents a key challenge: how to effectively and economically coordinate these assets to provide grid services when they are neither owned nor directly controlled by grid operators.

These growing challenges and opportunities show the need for the role of a distribution system operator (DSO) that coordinates planning and operation of the distribution system in a similar fashion to how an independent system operator (ISO) coordinates the planning and operation of the transmission system. That is, the DSO ensures reliable operation of the distribution system for all providers and users of electricity. To accomplish this, a DSO needs a coordination framework that allows access to the distribution system for suppliers and users of electricity and makes sure owners of flexible assets invest in and operate their assets in ways that support safe and reliable operation of the electric grid.

Transactive energy is a leading way to coordinate flexible assets through transparent, value-based means. While dynamic rates such as time-of-use and critical-peak-pricing have limited objectives that begin to engage customer participation, transactive energy puts the operating flexibility of these assets to work 24/7. It brings together the economics of customer priorities with grid operational needs to realize a more efficient

1. https://www.pnnl.gov/projects/transactive-systems-program/history energy system. It does this by facilitating transactions involving prices or incentives and energy quantities to give feedback necessary to “close the loop” and achieve effective, stable, and scalable coordination of flexible assets. Several field demonstrations of demand flexibility using transactive energy schemes1 have shown its feasibility and benefits at the building, campus, and community scale. However, questions remain about the behavior of flexible assets and transactive energy’s engineering and economic performance when deployed at scale across an entire grid interconnect.

To answer these questions, PNNL conducted the Distribution System Operator with Transactive (DSO+T) study to simulate and analyze how DSOs can use transactive energy principles and mechanisms to effectively integrate large numbers of flexible assets into everyday operation of the electric power system. We studied the performance of transactive coordination for two separate flexible asset deployments: flexible loads (HVAC units and residential water heaters) and behind-the-meter batteries. The results of each transactive case were compared to a corresponding business-as-usual (BAU) case without these flexible assets. The cases were subject to two scenarios: a moderate renewables generation scenario to represent current levels of deployment and a future high renewables scenario with 40% renewables generation, including the increased use of rooftop solar photovoltaic and ~30% of residences having an EV.

This evaluation was conducted using an integrated co-simulation and valuation framework that included the entire electrical delivery system from bulk system generation and transmission, through the distribution system, to the modeling of individual customer buildings and flexible assets. The financial impacts on each type of entity involved (grid operators and customers) are evaluated in detail in both percentage and absolute terms. The assessment framework has three key elements (as shown in Figure 1): an integrated simulation model; a transactive coordination and market integration scheme; and an economic valuation method. The remainder of this executive summary details these elements and presents key results. Full details of the study can be found in the five-volume final report. [1]

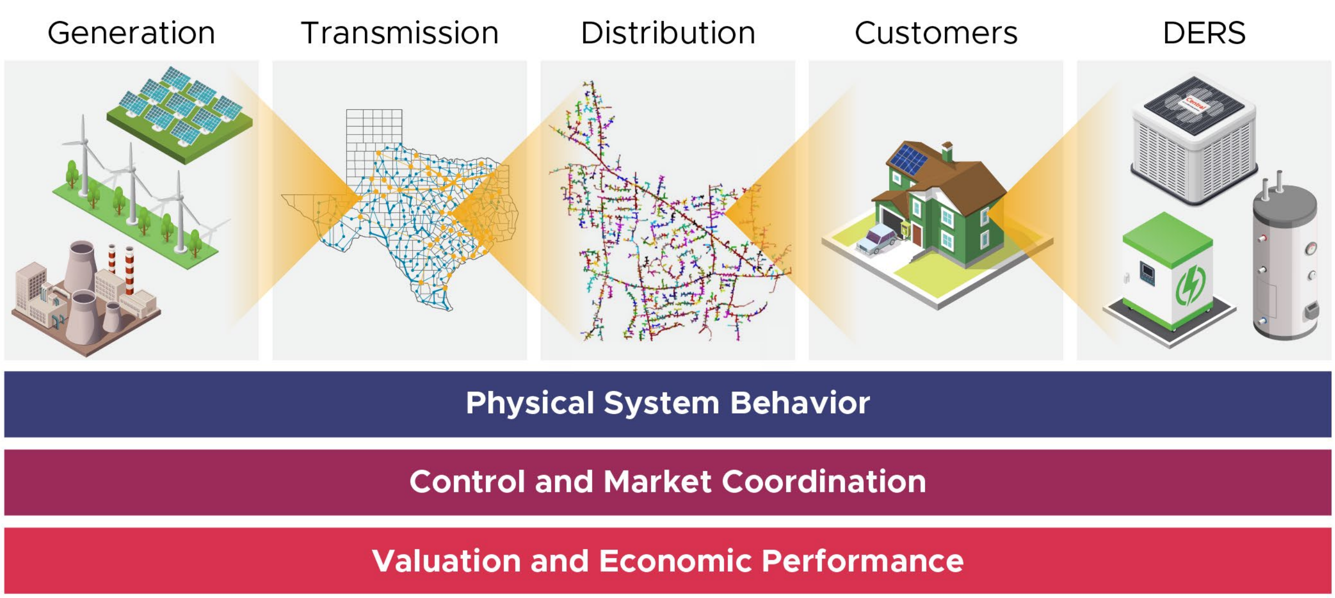


Figure 1. Overview of the DSO+T study breadth and depth.

1. https://www.pnnl.gov/projects/transactive-systems-program/dsot-study

The Integrated System Model

To successfully understand the impact of flexible assets on distribution and bulk power system operation, this study simulated a fully integrated electrical system, including over 100 generators on a 200-bus transmission system that was connected via substations to distribution feeders and approximately sixty thousand individual customer buildings, as well as their associated flexible assets. We selected the Electric Reliability Council of Texas (ERCOT) region to serve as the basis of this analysis. It has a generation mix that much of the U.S. system may soon resemble (wind generation mixed with fossil and nuclear generation), is summer peaking yet also has sub-regions that peak in winter due to a lack of natural gas supply, is served by an independent system operator (ISO) wholesale market, and is of tractable size with no synchronous interconnections to other regions and therefore little need to model imports and exports.

Forty DSOs of various types were modeled to capture a range of utility sizes, climate zones, regions (urban, suburban, and rural) and ownership types (investor-owned, municipal, and rural cooperative), and a mix of residential, commercial, and industrial load. To ensure a typical load profile, a variety of building types, ages, sizes, envelope insulation levels, heating fuel types, and occupancy levels were defined for residential and commercial customer segments based on national survey data and other literature sources. In addition, HVAC unit and water heater models had variations in size, performance, heating fuel (electric vs. gas), and usage schedules. We used weighting factors to expand the simulated substations, feeders, and customer loads to represent the entire ERCOT load. As shown in Figure 2, the resulting buildings and their equipment end-use loads helped ensure daily and seasonal load profiles that were representative of the ERCOT region in 2016 (the base year of the analysis).

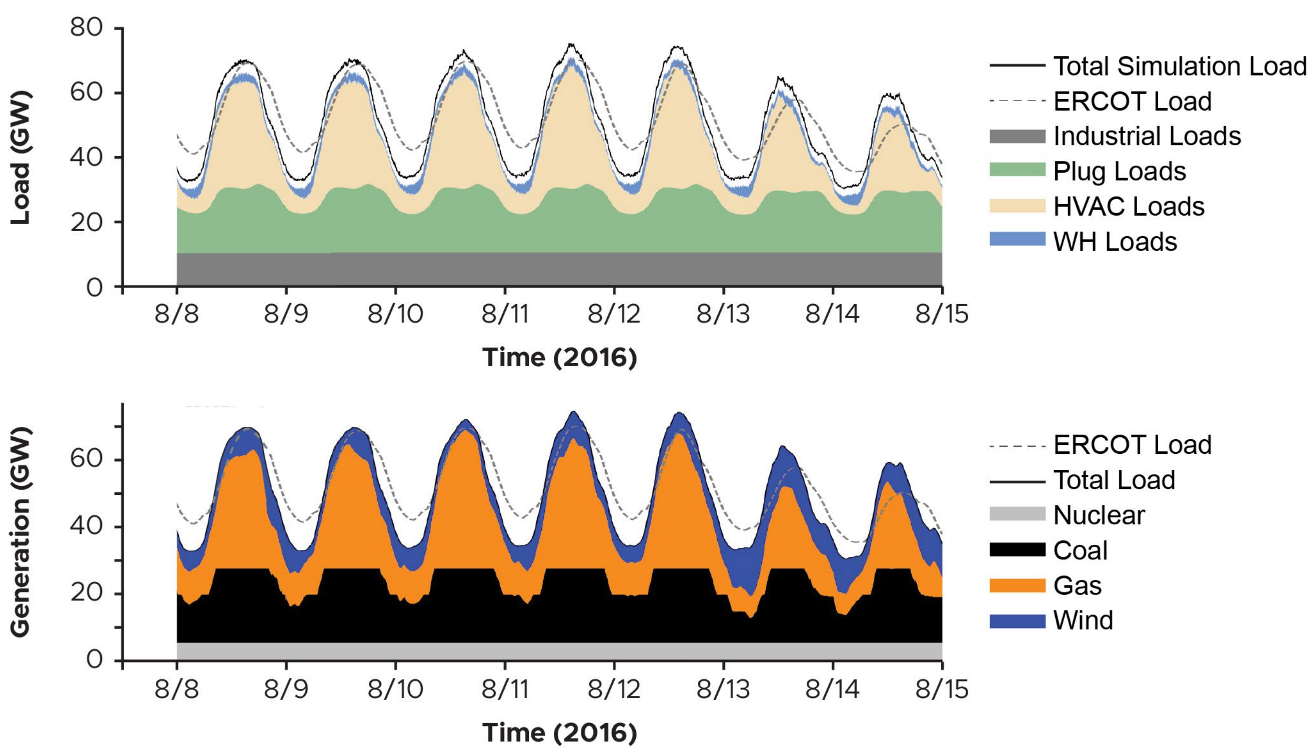


Figure 2. Daily variations in end-use loads (top) are matched by the generation fleet (bottom).

The load is served by a mix of coal, natural gas, nuclear, and wind generators defined so the moderate renewables scenario is representative of ERCOT for the 2016 study year. For the high renewables scenario, both utility-scale and rooftop solar generation were added along with an increase in wind capacity to achieve 40% annual renewable energy generation. Thermal generator startup and variable production costs, as well as performance constraints (like ramp rates and minimum and maximum load requirements), were defined from existing literature. Wind and solar generation outputs were determined using stochastic simulation models calibrated to historical ERCOT renewable generation and weather data. Forecast uncertainty was applied to day-ahead wind and solar generation estimates and is present in the DSO load forecasts.

The transmission network was modeled to capture the geographic variation in wholesale electricity prices (Figure 3). Constraints on transmission line capacity, combined with generator operating cost and performance, informed the solution of security-constrained unit commitment and economic dispatch optimizations to calculate both day-ahead and real-time wholesale market locational marginal prices for the entire region. This ensured prices reflected demand changes as a function of daily, seasonal, and geographic variations. We found the annual price data from the simulation to represent overall price trends seen in electricity markets across the country (for example, ERCOT, CAISO, and PJM) but underpredicted large but infrequent price excursions.

The resulting simulation model enables the impact of demand flexibility to be understood in terms of both loads and wholesale prices throughout the electricity delivery system. Figure 4 shows the contribution of annual average electrical loads by end use and customer types and the generation sources that meet these loads.

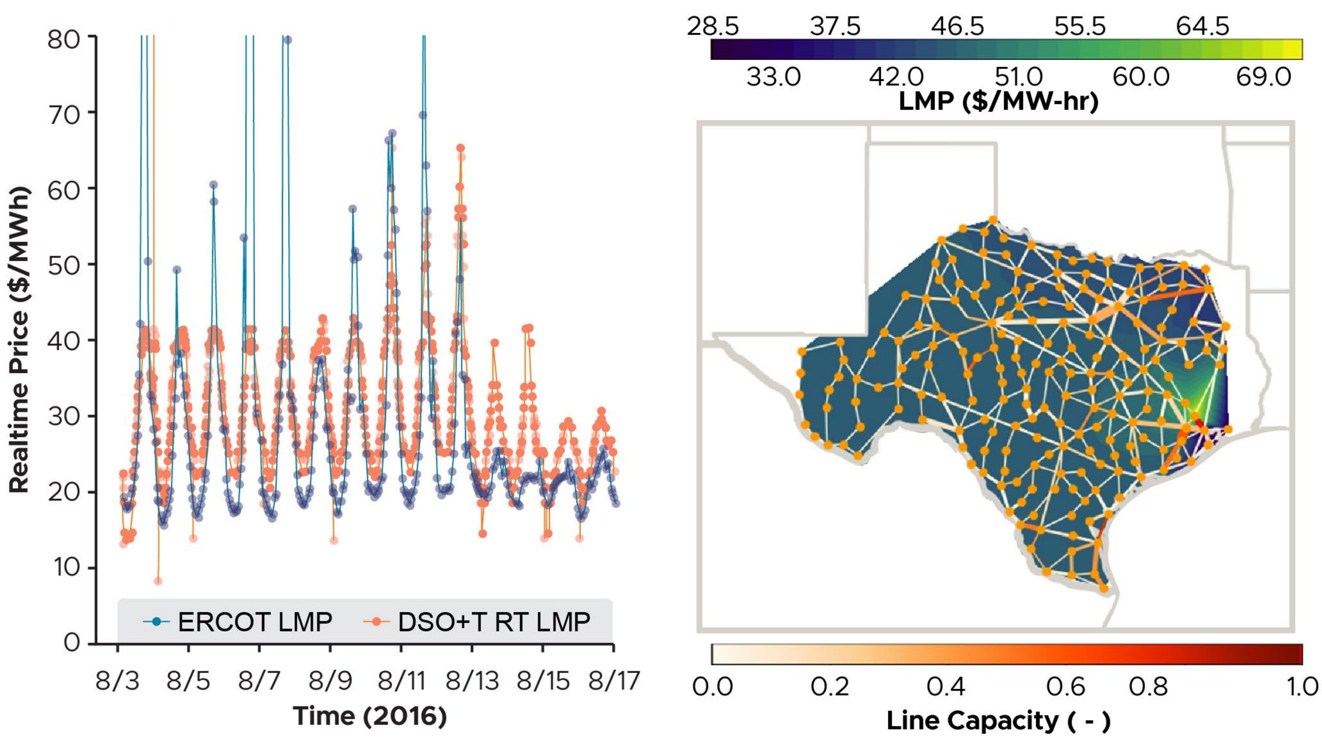


Figure 3. The magnitude, location, and ramping of loads, along with transmission line capacity, can affect the real-time price of electricity over time (left) and across the region (right).

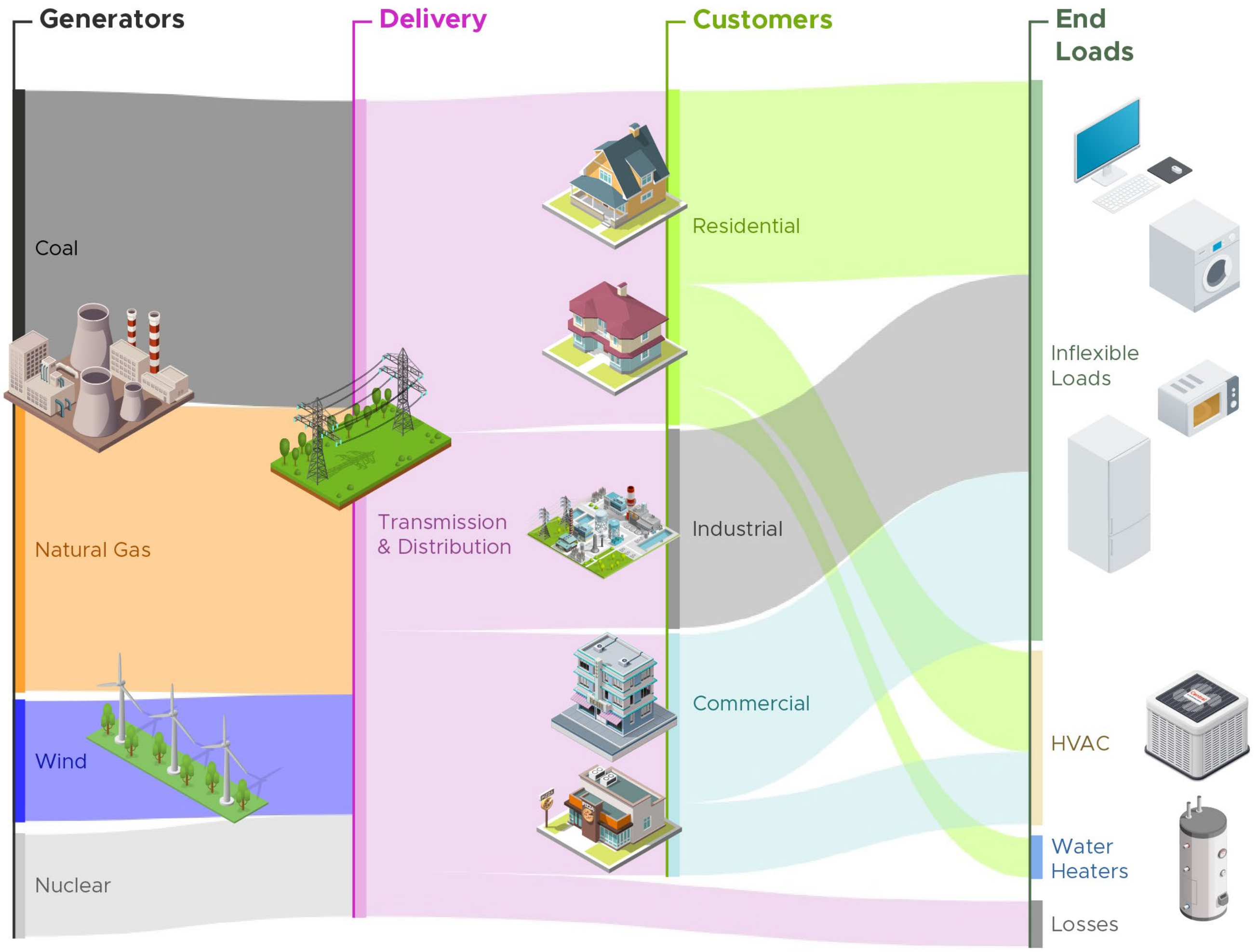


Figure 4. The study simulates flow of electrical power by generator, customer, and end-use types (average annual power shown for the moderate renewables BAU case).

The integrated system model simulates tens of thousands of buildings and their flexible assets in conjunction with distribution feeders and the bulk transmission system. This ensures that we understand the impact that changes in demand have on distribution and transmission constraints, generation dispatch and cost, and resulting wholesale market prices.

Demand Coordination via Transactive Energy

The DSO+T study required the design and implementation of a transactive energy coordination scheme and retail marketplace. This was used by each of the 40 DSOs to combine transactive bids from many customers, with a wide range of flexible assets, and bid the resulting value into existing competitive day-ahead and real-time wholesale energy markets. At the core of this design is a dynamic, transactive retail rate and price signal that is based on marginal system operating costs. This approach also manages distribution-level constraints, in this case substation congestion. In addition, we developed intelligent transactive agents to coordinate a range of flexible assets with operational flexibility including HVAC units, water heaters, batteries, and EV charging. An overview of the integrated market operation is shown in Figure 5.

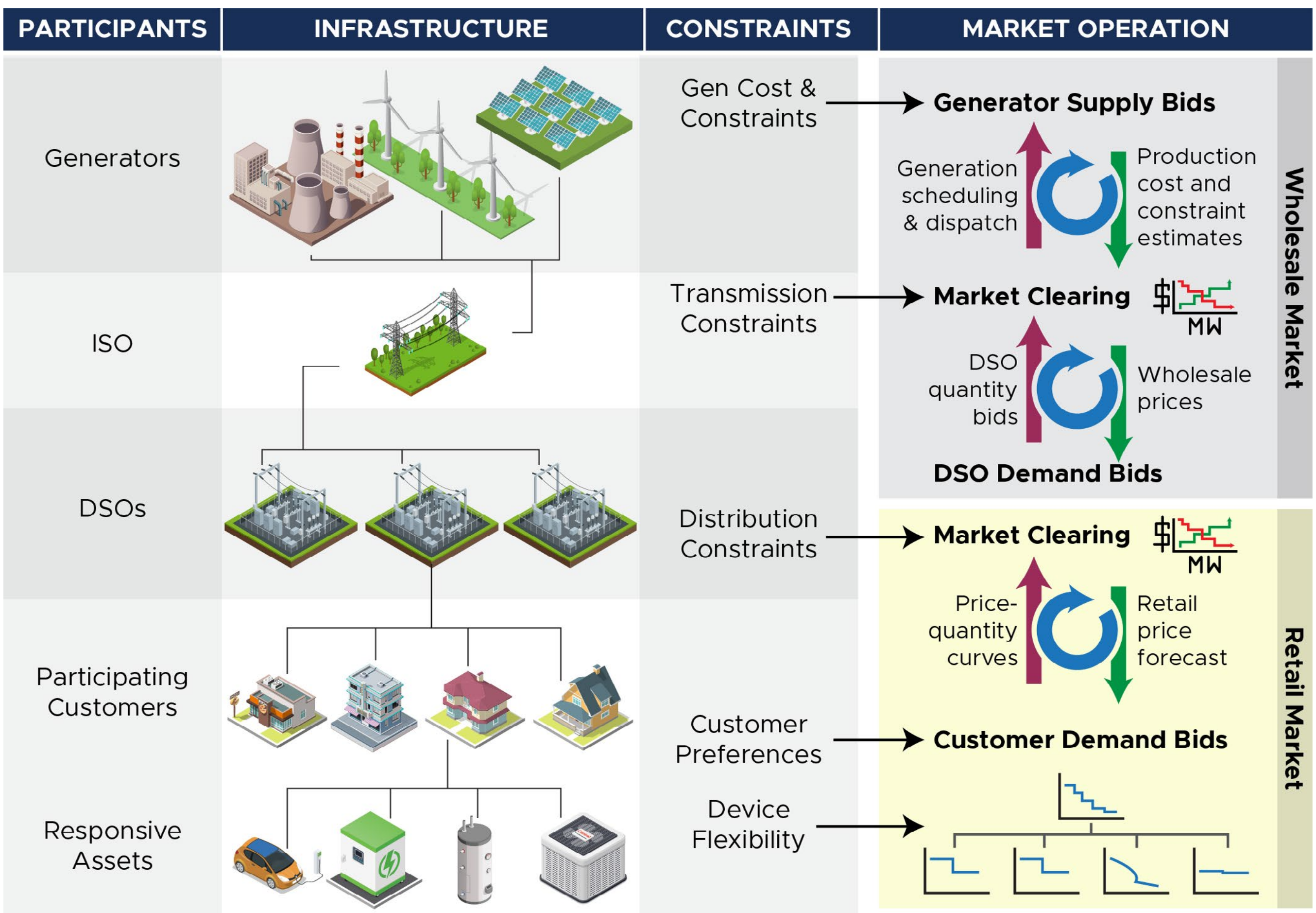


Figure 5. Summary of market participants, physical constraints, and market coordination.

The DSO runs an hourly transactive retail market for participating customers who have price-responsive flexible assets. This market broadcasts a 48-hour forecast of the dynamic retail prices to participating customers and combines the resulting customer price-quantity demand bids for the forecast horizon. These bids are cleared using a double auction, and updated price and cleared quantity forecasts are provided to participating customers at the next retail market interval. This repeats every hour, ensuring the convergence of retail prices and resulting quantities.

Once per day the DSO bids the cleared retail quantity into the wholesale day-ahead market. The DSO's hourly retail marketplace operation then continues until the creation of the real-time bid every 5 minutes of the current hour, which allows all participants a final adjustment to their evolving hourly response strategy. The DSO's retail price-quantity supply curve includes distribution constraints (such as substation capacity limits) to ensure the formulated retail price signal supports the management of these local constraints.

The DSO-managed transactive retail marketplace is designed to integrate with existing competitive wholesale markets. This study assumes an ISO operates a competitive hourly day-ahead and 5-minute real-time market. DSOs provide their day-ahead and, in a transactive case, their real-time load forecasts into this wholesale market. Simultaneously, merchant generators also provide their performance (marginal production price) and operating constraint information to the wholesale market operator. This information is used by the ISO to schedule and dispatch the generation fleet day-ahead and in real-time, respectively, thereby determining the locational marginal price for electricity at each transmission node. These prices inherently include the impacts of transmission-level congestion.

The fidelity of this simulation in representing actual system operations enabled thorough verification of the transactive marketplace performance and its interactions with tens of thousands of price-responsive flexible assets, ensuring stable and effective control and coordination. In doing so, we identified a number of key requirements for the accurate and stable operation of this marketplace. For example, the transactive agents need to adjust their hourly price-quantity results derived from the day-ahead retail market when used as a basis for bidding in the 5-minute retail real-time market to smooth the difference between adjacent day-ahead hour periods. Failure to do so results in jumps in desired response targets as the hour changes, causing an unintended synchronization of agent behavior, which results in large demand surges.

The DSO+T transactive coordination scheme and retail market design manages distribution-level constraints and integrates into existing day-ahead and real-time wholesale markets. Large-scale simulations showed successful market integration and coordination of tens of thousands flexible customer assets. This enabled significant, sustained, and stable demand flexibility throughout annual simulations that covered multiple scenarios.

Valuation Analysis

To understand the impact of demand flexibility on the financial performance of stakeholders, we developed a valuation analysis based on a rigorous mapping of value flows between market participants. This analysis determined the annualized cash flow of grid stakeholders (customers, DSOs, transmission system operators, generators, and the ISO) at a level of detail sufficient to understand the financial benefits and costs incurred by each party in absolute and percentage terms.

The study modeled the annualized cash flow of a DSO for both BAU and transactive energy cases. Revenues were determined by applying retail rate structures to recover the required revenue from customer bills as modeled in the large-scale simulation described above. This required the design of retail BAU fixed-price and transactive rates (the latter incorporating dynamic day-ahead and real-time pricing).

To determine DSO energy purchase costs, we used the simulation results to calculate their wholesale energy purchases (including a mix of bilateral, day-ahead, and real-time purchases). We also calculated capacity costs, ancillary services costs, transmission access fees, and ISO payments. Models were developed to estimate the annualized costs of capital investments including substations, feeders, meters, and information technology systems. The impact of both greenfield and brownfield growth rates on substation infrastructure capital costs was included by developing a distinct growth rate model.

We estimated fixed operating costs for labor, workspace, operations, and maintenance materials. The labor expenses were based on an employee count and organizational structure model that estimated the total number of DSO employees by job category (e.g., accounting, retail operations, engineering operations). This was combined with U.S. Bureau of Labor Statistics data for hourly wages to determine total labor costs. Finally, the effect of DSO attributes (rural, suburban, and urban) as well as ownership model (investor-owned, municipal, or rural cooperative) factored into the analysis of the annualized cost of capital.

The system-wide effective cost of energy sold for the BAU case was within 10% of the national average. This level of agreement indicates the model is representative of typical electrical system operating expenses.

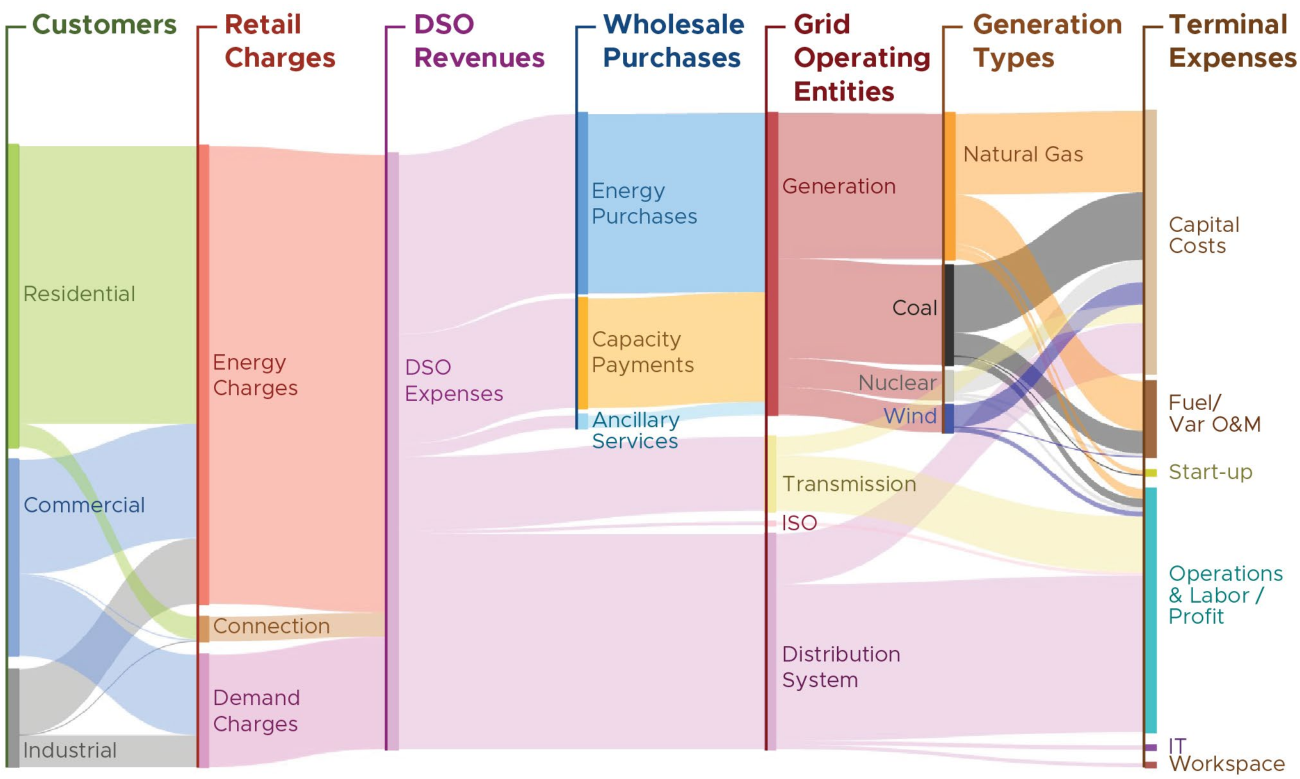


Figure 6. Integrated valuation analysis of DSO revenues and expenses (moderate renewables BAU case).

We also developed cash flow models and analysis methods for customers, generators, the ISO, and transmission operator. Customer cash flows include both retail utility charges and annualized costs for applicable flexible assets (e.g., smart thermostats and water heaters, batteries, and smart EV chargers). The transmission operator's revenues are based on a fixed 'postage stamp' rate representative of typical values. A detailed transmission capital cost model captures substation, transmission line construction, right-of-way, and planning and operations costs.

The result is a precise parametric modeling framework that can track value flows throughout the entire electrical delivery system. It has a level of detail that allows analysts to understand the sources of value from implementing demand flexibility solutions as well as sources for increased expenditure. These results can be viewed at the entire system level or broken down by stakeholder type to understand the impacts to various parties within the electricity delivery system. Comparisons to available public data show the model is representative of typical North American grid operation cost structures.

The detail provided by the valuation analysis helps determine where benefits and costs occur within the electricity delivery system and to which stakeholders they accrue. This helps to understand the value proposition for various stakeholders and identifies where cost and value accrual do not align.

Results and Impact

The transactive coordination framework reduces energy use during periods of high prices (typically associated with high demand during the afternoon and evening) and encourages higher energy consumption (for example, battery and EV charging, air conditioning precooling, water heating) during periods of low prices (typically during nighttime or periods of abundant renewable energy). Figure 7 shows a 5-day example of this behavior and the stable control and coordination of flexible assets that was seen throughout the entire annual simulation. Across the various cases this results in 9–15% lower peak load and ~20–44% lower daily load swings, with similar reductions in wholesale price variation. Larger load reductions are seen in the high-renewables scenario where the presence of smart EV charging provides additional flexibility.

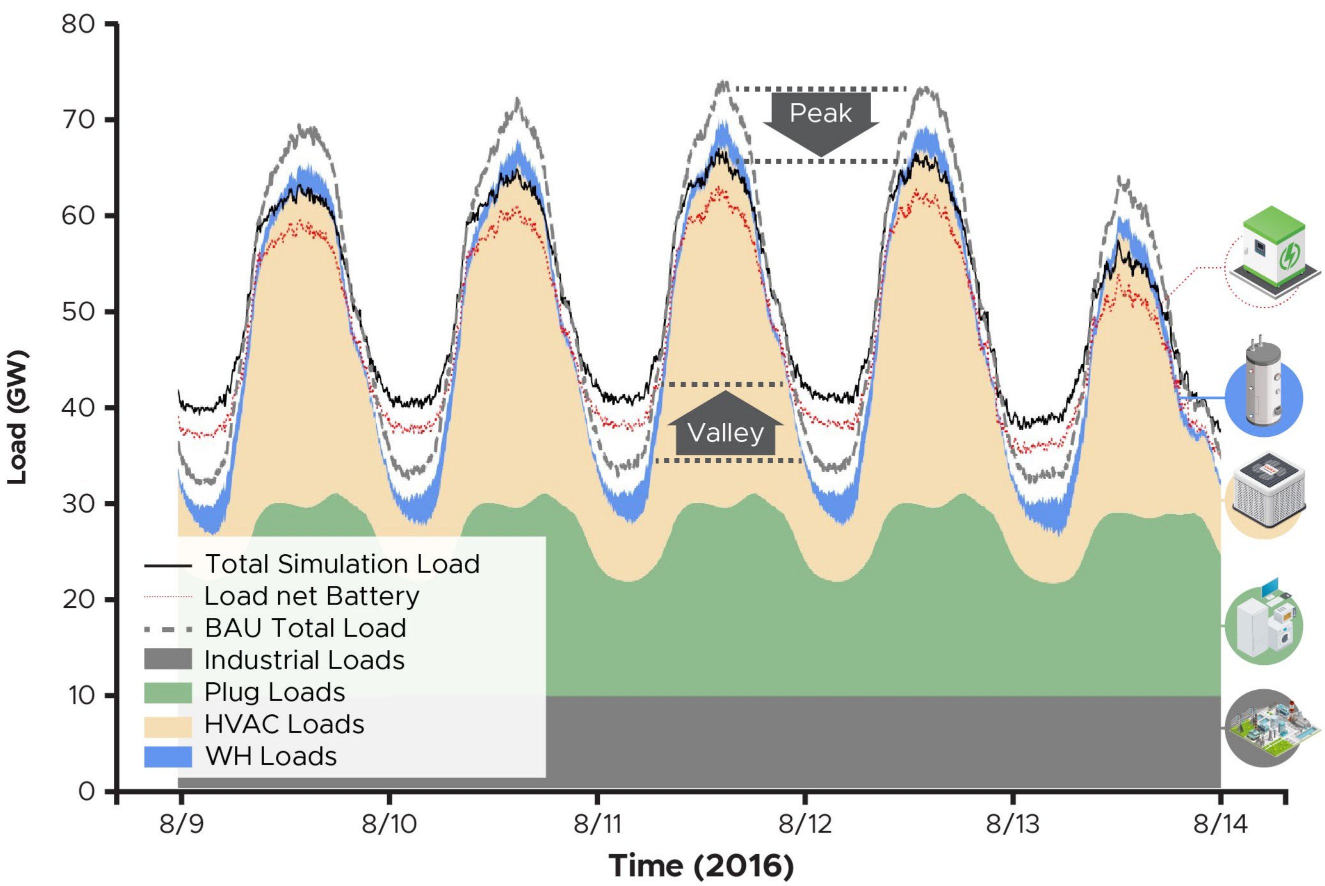


Figure 7. Example peak load reduction achieved in the battery case (black line) versus the BAU case (grey dashed line) for the moderate renewable case.

The impact these changes in load profile and market price have on the overall system operating cost is shown in Figure 8. All wholesale costs are lower with less generation capacity needed, which reduces the capacity market unit price, wholesale energy prices are lowered as customers purchase more electricity at periods of lower prices, and transmission system costs are lower due to infrastructure investment deferral.

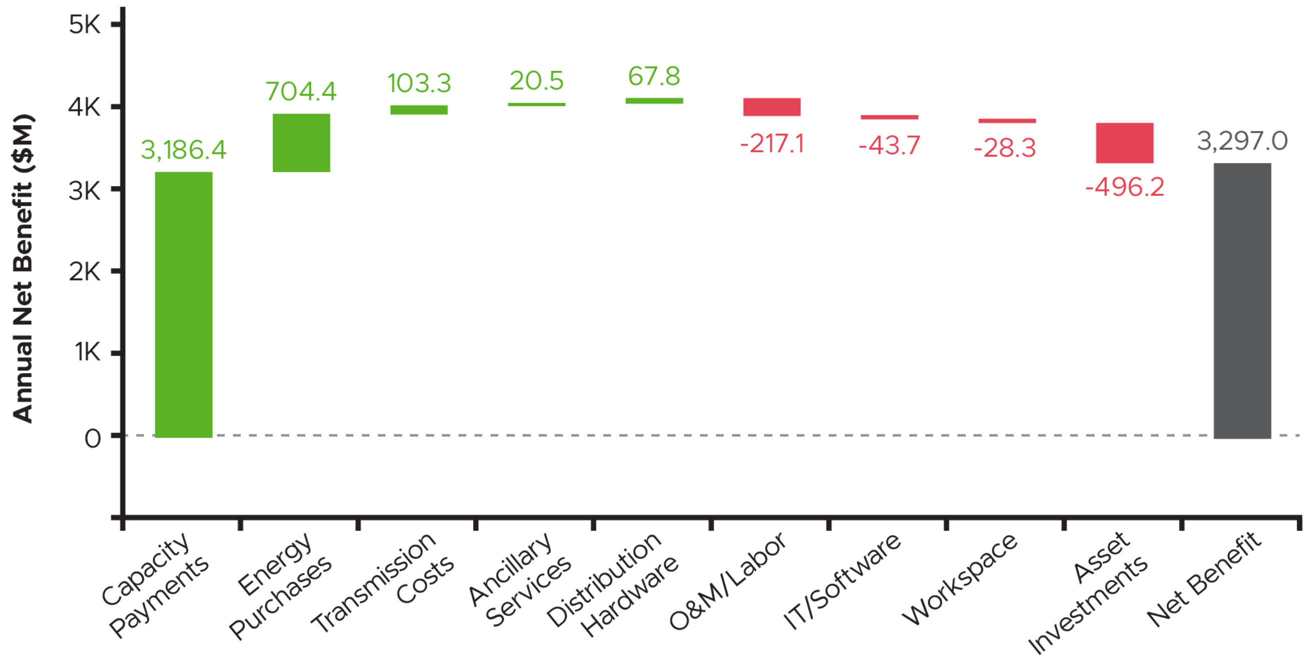


Figure 8. Summary of changes in annualized cash flow between the BAU and battery cases (for the moderate renewables scenario) showing economic benefits and costs of implementation.

While DSOs' save money by delaying substation infrastructure upgrades, their retail operation labor and software expenses increase to support coordinated DER operations. Finally, there are incurred costs for buying and installing customer-sited flexible assets. The benefits from reduced wholesale and infrastructure expenses more than cover DSO and customer implementation costs resulting in a net annual benefits of $3.3-5.0B (Figure 9).

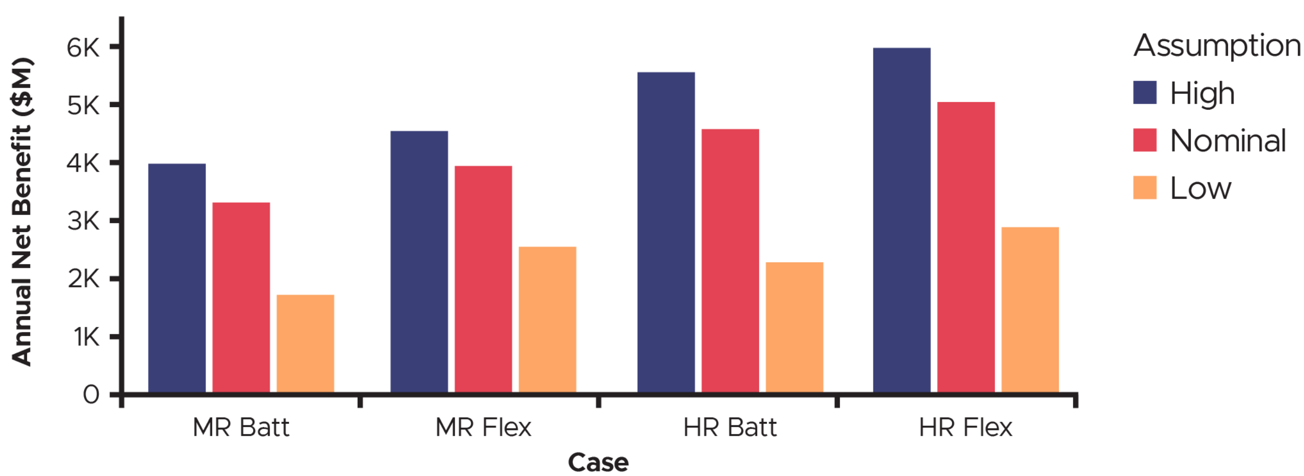


Figure 9. Summary of annualized net benefit to customers for each case under a range of capacity market assumptions.

Consistent with other studies, the majority of the system benefit stems from the need for less generation capacity. However, even in the absence of a capacity market there would still be a net benefit due to reduced wholesale energy and delivery infrastructure expenses. Further, to understand the sensitivity of savings to capacity market prices, we performed an analysis to determine the net benefits using high and low values of capacity price. The low estimates halved the capacity market price and the high estimates almost doubled capacity costs (to reflect construction costs). Figure 9 shows that, even under conservative capacity market price assumptions, there are net benefits for all cases studied.

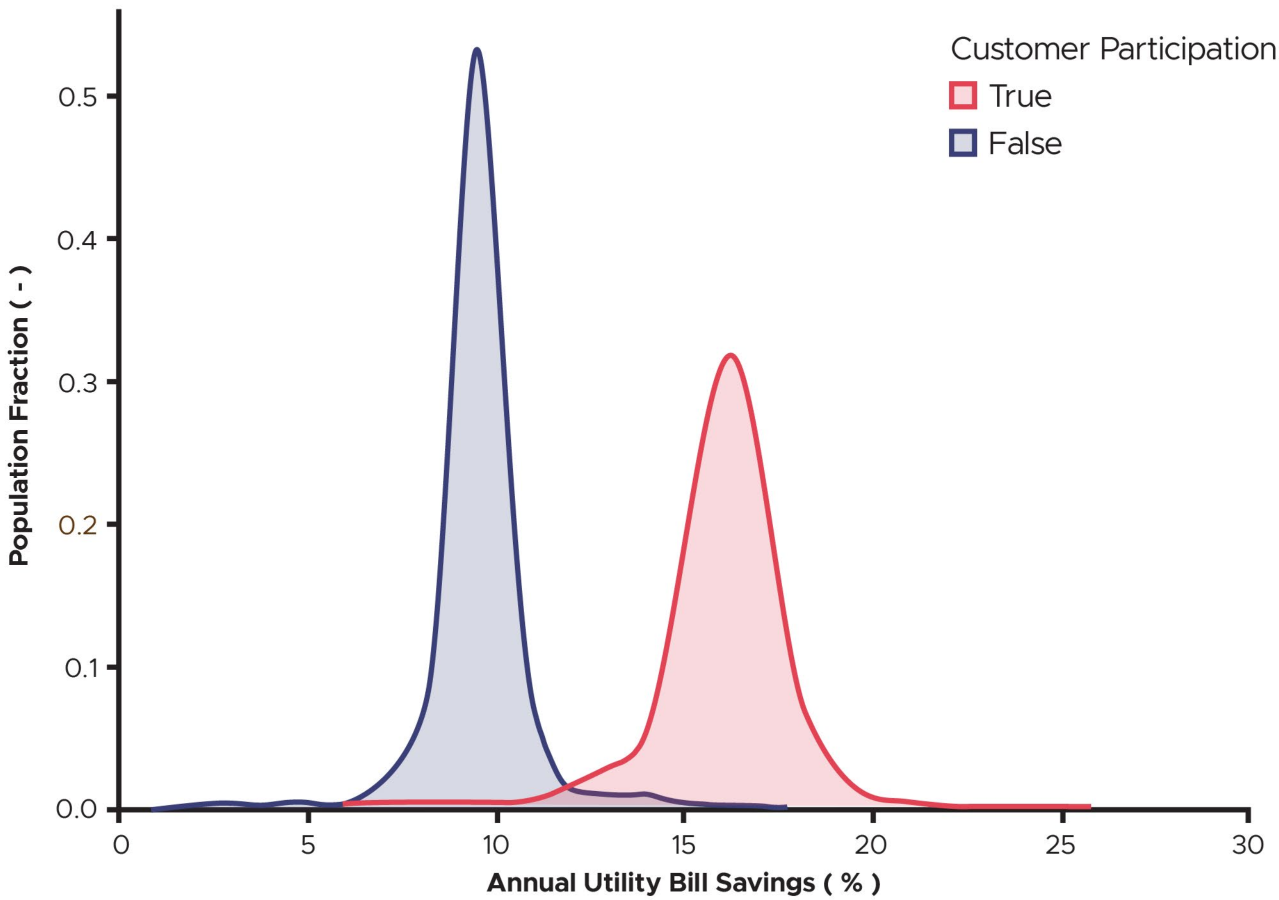


Figure 10. Reduction in residential customers' annual electric bills between the BAU and battery cases (for the moderate renewable scenario) showing savings for both transactive market participants and non-participants. (DSO #1)

The detail of this study also allowed the benefits to be studied by customer class and DSO type, all of which saw net benefits. For example, Figure 10 shows the range of savings on residential customers' annual electric bill for the moderate renewable battery case for an example DSO. The study found that not only do customers participating in the transactive market save on utility bills (by 14-16% on average) but so do non-participants who remain on a fixed-price tariff (and see a 10-14% average reduction). This is due to the reduced overall cost basis that is applicable to all customers.

In conclusion, the DSO+T study's integrated simulation and valuation of a transactive retail market have a nominal net economic benefit to a region the size of Texas of $3.3–5.0B (12-19% of total cost of electricity) per year depending on future renewable, DER, infrastructure growth, and market price scenarios. Given that ERCOT is approximately 10% of the national electrical load, we project a national benefit of $33-50B per year associated with the large-scale coordination of flexible distributed assets.

The dynamic coordination of flexible customer assets can save a region the size of Texas $3.3–5.0B (12-19% of electrical costs) per year, even under a range of future renewable generation, DER deployment, infrastructure growth, and market price assumptions.

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